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September 8, 2008

Ms. Kirstin Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Re: EB-2008-0221 Bluewater Power 2009 Rate Application

Dear Ms. Walli:

Please find attached the submission of Bluewater Power Distribution Corporation for recovery of the revenue requirement and associated rates for 2009. This application is being filed electronically through the Ontario Energy Board's e-Filing services. Two hard copies will follow in the mail.

Should there be any questions, please contact me at the number below.

Yours truly,

L. Dugas

Leslie Dugas
Manager of Regulatory Affairs
Email: ldugas@bluewaterpower.com
519-337-8201, ext. 255

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ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an application by Bluewater Power Distribution Corporation for an Order or Orders pursuant to section 78 of the *Ontario Energy Board Act, 1998* for 2009 distribution rates and related matters.

APPLICATION

1. The Applicant is Bluewater Power Distribution Corporation ("Bluewater Power"). Bluewater Power is a licensed electricity distributor operating pursuant to license ED-2002-0517. Bluewater Power distributes electricity to approximately 35,000 customers in the municipalities of the City of Sarnia, the Town of Petrolia, the Village of Point Edward, the Village of Oil Springs, the Township of Warwick and the Township of Brooke-Alvinston in south-western Ontario.

2. Bluewater Power hereby applies to the Ontario Energy Board (the "Board") for an order or orders made pursuant to Section 78 of the *Ontario Energy Board Act, 1998,* as amended, (the "OEB Act") approving just and reasonable rates for the distribution of electricity based on a 2009 test year.

3. Specifically, Bluewater Power hereby applies for an order or orders granting approval of:

   a. its forecasted 2009 service revenue requirement of $21,436,076, which leads to a base distribution revenue requirement of $20,707,479, net of other revenue;

   b. distribution rates that allow Bluewater Power to recover its forecasted 2009 distribution revenue requirement, effective May 1, 2009;

   c. specific distribution service charges;

   d. the disposition of certain deferral and variance account principal balances as at December 31, 2007 along with the carrying charges projected to April 30, 2009;

e. Bluewater Power's current distribution rates becoming interim commencing May 1, 2009 until Bluewater Power's proposed distribution rates are approved and implemented; and

f. Recovery of amounts related to a Lost Revenue Adjustment Mechanism ("LRAM"), and Shared Savings Mechanism ("SSM").

4. As indicated by Bluewater Power's pre-filed evidence, Bluewater Power's 2009 total service revenue requirement is forecasted to be $21,436,076, and base revenue requirement is forecasted to be $20,707,479. Based on current distribution rates and forecasted load, Bluewater Power forecasts a 2009 revenue deficiency of $4,843,712.

5. The 2009 distribution rates proposed by Bluewater Power will result in overall monthly bill impacts as follows:

Rate Class	kWh	kW	Total $ Change	Total % Change
Residential	1,000		$6.35	6.03%
GS<50	2,000		$9.99	4.70%
GS 50 to 999 kW	52,000	135	$79.94	1.63%
GS 1000 to 4999 kW	1,700,000	3,532	($1,935.72)	-1.38%
Large	4,446,000	6,900	$4,974.14	1.4%
USL	1,000		$18.34	17.9%
Sentinel (per connection)	176	0.46	$2.63	15.6%
Streetlighting (per connection)	99	0.21	$1.44	15.6%

6. This Application is made in accordance with the Board's *Filing Requirements for Transmission and Distribution Applications* dated November 14, 2006.

7. This Application is supported by written evidence. The written evidence will be pre-filed and may be amended from time to time, prior to the Board's final decision on this Application.

8. The Applicant requests that, pursuant to Section 34.01 of the Board's *Rules of Practice and Procedure*, this proceeding be conducted by way of written hearing.

9. The Applicant requests that a copy of all documents filed with the Board in this proceeding be served on the Applicant and the Applicant's counsel, as follows:

The Applicant:

Bluewater Power Distribution Corporation
855 Confederation Street
Sarnia, ON N7T 7L6

Attention:

Mr. Alex Palimaka, VP Corporate Services and General Counsel
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Attention:

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Telephone: (416) 216-4771
Fax: (416) 216-3930

DATED at Sarnia, Ontario, this 8th day of September, 2008.

BLUEWATER POWER DISTRIBUTION CORPORATION

Alex Palimaka

Summary of Application

1.0 Introduction

Bluewater Power Distribution Corporation ("Bluewater Power") is applying to the Ontario Energy Board (the "Board") for distribution rates to be effective from May 1, 2009 to April 30, 2010. As illustrated by Table 1.1.3.1 below, the proposed rates will recover Bluewater Power's forecasted revenue requirement of approximately $20.708 million. Bluewater Power's proposed distribution rates are necessary to avoid a forecasted revenue deficiency in the amount of approximately $4.844 million during the 2009 rate year (Exhibit 1, Tab 1, Schedule 9).

Table 1.1.3.1 summarizes the general components of Bluewater Power's 2009 revenue requirement.

Table 1.1.3.1 – Summary of Revenue Requirement:

	2009 Test Year	Reference
Cost of Capital		
Rate Base	53,158.5	Ex 2, Tab 1, Sch 1
Cost of Capital	7.71%	Ex 6, Tab 1, Sch 1
Return on Rate Base	4,098.9	
Cost of Service		
Operations, Maintenance & Admin.	11,358.4	Ex 4, Tab 2, Sch 1
Depreciation	4,358.1	Ex 2, Tab 2, Sch 4
Municipal & Capital Taxes	297.8	Ex 4, Tab 3, Sch 1
Income Taxes	1,322.9	Ex 4, Tab 3, Sch 1
Service Revenue Requirement	21,436.1	Ex 3, Tab 1, Sch 2
Other Revenue	-728.6	Ex 3, Tab 3, Sch 1
Base Revenue Requirement	**20,707.5**	

The comparison of the 2009 Test Year revenue requirement to the last Board Approved revenue requirement from 2006 EDR, can be found in Exhibit 9, Tab 1, Schedule 1.

The major components of Table 1.1.3.1 are described in detail below.

2.0 Rate Base

As set out at Exhibit 2, Tab 1, Schedule 1, Bluewater Power's rate base from 2007 to 2009 is shown in Table 1.1.3.2 below:

Table 1.1.3.2 – Rate Base Summary

($000's)	2007 Actual	2008 Bridge	2009 Test
Net Fixed Assets	$37,495.6	$37,785.9	$39,545.1
Working Capital Allowance	12,180.5	13,308.5	13,613.4
Rate Base	**49,676.1**	**51,094.4**	**53,158.5**

Bluewater Power's last full rebasing took place as part of the 2006 EDR process where rate base was primarily based on 2004 data. Capital expenditures since that time are not reflected in Bluewater Power's current rates although capital expenditures have increased since 2004 and the need for more capital improvements will continue over the next three years.

Bluewater Power's rate base in the 2009 test year is forecasted to be approximately $53.16 million, an increase of approximately $2.06 million from Bluewater Power's forecasted 2008 rate base.

This increase is almost entirely attributable (85%) to capital expenditures in the test year. The increase in Bluewater Power's 2008 to 2009 capital expenditures is primarily caused by the following three "non-routine" capital projects, all of which are described at Exhibit 2, Tab 3, Schedule 6:

- the building renovations/expansion project
- the SAP upgrade project
- the Modeland transmission station meter upgrade project.

The remaining 15% of the 2008 to 2009 rate base variance is attributable to an increase in working capital allowance, as illustrated in Table 2.1.3.1.

Bluewater Power's 2008 rate base is forecasted to be approximately $51.1 million, approximately $1.4 million more than its actual 2007 rate base.

Approximately $1.13 million (80%) of the $1.4 million rate base variance from 2007 to 2008 is attributable to an increase in working capital allowance. This increase in Bluewater Power's working capital allowance is almost entirely attributable (92%) to an increase in cost of power, as illustrated by Table 2.1.3.1, and in more detail at Exhibit 2, Tab 4, Schedule 2, Attachment 1.

Rate base is a direct result of capital expenditures. Bluewater Power's capital expenditures are primarily attributable to routine sustaining capital investment – a baseline amount that Bluewater Power must invest every year to maintain its system. Fluctuations in annual capital expenditures are caused by non-routine capital projects. For a list of Bluewater Power's capital projects in 2007, 2008 and 2009, please refer to Exhibit 2, Tab 3, Schedule 1**.** For descriptions of capital projects that exceed $100,000 in any year, please refer to Exhibit 2, Tab 3, Schedule 6. For a variance analysis of gross assets on an account basis, please refer to Exhibit 2, Tab 2, Schedule 3.

3.0 Load Forecasts

The Revenue Requirement calculated in Table 1.1.3.1 is based on load forecasts proposed for 2009. Bluewater Power prepared a weather normalized forecast for 2008 and 2009 volumes for each class (Exhibit 3, Tab 2, Schedule 3). In addition, a forecast of customer numbers was developed based on historic trends and economic signals within Bluewater Power's service territory.

Table 1.1.3.3 below provides a numerical summary of Bluewater Power's operating revenues from 2007 to 2009 based on load forecasts, with distribution rates constant in 2008 and 2009.

Table 1.1.3.3 – Operating Revenue Summary

($000's)	2007 Actual	2008 Bridge at Current Rates	2009 Test at Current Rates
Total Operating Revenue	**15,610.8**	**15,705.6**	**15,863.7**

4.0 Operating Costs

Bluewater Power's operating costs include: operations, maintenance and administration ("OM&A"); depreciation and amortization; capital and property taxes; and income taxes. A summary of Bluewater Power's operating costs for 2007 through 2009 are set out in Table 1.1.3.4 that follows:

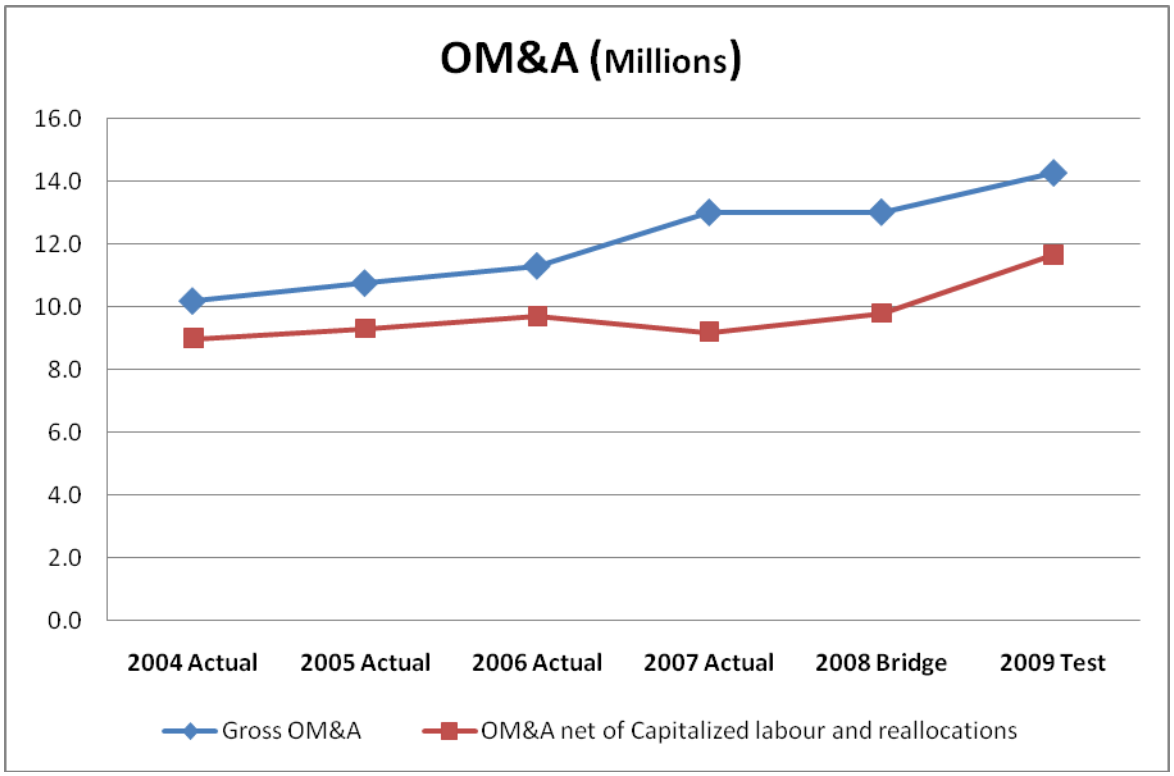
Table 1.1.3.4 – Operating Costs Summary

($000's)	2007 Actual	2008 Bridge Year	2009 Test Year
Operations, Maintenance & Administration	$8,915.2	$9,495.8	$11,358.4
Depreciation & Amortization	3,847.9	4,045.3	4,358.1
Capital & Property Taxes	278.9	290.0	297.8
Income Taxes	1,309.9	762.1	1,322.9
Total Operating Costs	**14,351.9**	**14,593.2**	**17,337.2**

Table 1.1.3.4 demonstrates that depreciation has increased steadily over the past several years at Bluewater Power indicating an increased level of spending on capital projects. Another contributing factor to the increase in the level of amortization is the increased level of capital spending in the areas of Information Technology. These issues are discussed at Exhibit 2, Tab 2, Schedule 5.

Bluewater Power has experienced a steady upward trend in its total Gross OM&A over the period from 2004 to 2009. This trend is explored further in Exhibit 4, Tab 1, Schedule 2 – Summary of Operating costs. What Table 1.1.3.5 demonstrates is that the proposed distribution OM&A for the 2009 Test Year is in line with historical trends. However, the increase from 2007 to 2009 is distorted by an atypical year in 2007 caused by a significant increase in Non-Core Distribution Activities which serve to offset distribution OM&A by reallocating base costs and overhead to Account 4380.

Table 1.1.3.5



The OEB Filing Guidelines requires variance analyses year-over-year on an account group basis. That analysis is provided at Exhibit 4, Tab 2, Schedule 3. However, Bluewater Power has included an additional variance analysis of 2007 to 2009 to provide an essential context to explain and justify the increase in OM&A. That analysis reveals the primary drivers of the variance in OM&A over that period as follows:

Table 1.1.3.6
2007 to 2009 Primary Variances

	2007 Actual	2009 Test Year	Variance	% variance
Payroll Related costs (net of capitalized labour)	$5,850,612	$7,598,516	$1,747,904	71%
Future Benefits	$523,092	$694,415	$171,323	7%
Rebasing Costs	$ -	$113,007	$113,007	5%
External Costs	$595,308	$716,206	$120,898	5%
Advertising	$16,352	$59,400	$43,048	2%
Employee Costs	$495,333	$536,627	$41,294	2%
All other	$1,713,384	$1,937,998	$224,614	9%
Net O&M	**$9,194,081**	**$11,656,169**	**$2,462,088**	**100%**

As would be expected, the primary driver of the variance is Payroll Related Costs. A full discussion of the increases in Payroll Related Costs can be found in Exhibit 4, Tab 2, Schedule 2. The increase in Payroll Related Costs can be summarized as falling within one of four categories: (1) Routine Increases representing 32% of the increase, (2) New Staff hired prior to the Test Year representing 21% of the increase, (3) New Staff hired for the Test Year representing 37% of the increase (4) Miscellaneous Changes representing 10% of the increase.

5.0 Cost of Capital

Bluewater Power has followed the Board's *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* in determining its cost of capital. The ROE has been set at the most recently approved OEB rate and the long-term debt costs reflects the embedded costs of debt for the utility. A full discussion of this issue is found at Exhibit 6, Tab 1, Schedule 1.

Table 1.1.3.7 – Cost of Capital Summary ($000's)

	2007 Actual	2008 Bridge Year	2009 Test Year
Rate Base	49,676.1	51,094.4	53,158.5
Equity Component	50%	46.7%	43.3%
Debt Component	50%	53.3%	52.7%
Short Term Debt Component			4.0%
ROE	9.00%	9.00%	8.57%
Debt Rate	7.25%	7.25%	7.25%
Short Term Debt Component			4.47%
Cost of Capital	8.125%	8.07%	7.71%
Deemed Return on Equity	2,235.4	2,147.5	1,974.1
Deemed Interest Expense	1,800.8	1,974.4	2,124.8
Regulated Return on Capital	**4,036.2**	**4,121.9**	**4,098.9**

6.0 Rates and Rate Impacts

Bluewater has proposed distribution rates based on its current Board-approved cost allocation methodology. A simplified update to the cost allocation model as filed with the OEB in January 2007 was performed with the assistance of Elenchus Research Associates Inc and is attached as Exhibit 8, Tab 1, Schedule 1, Attachment 1.

The Report of the Board on Application of Cost Allocation for Electricity Distributors (EB-2007-0667), presented Target Floor and Ceiling ranges for the revenue to cost ratios. Bluewater Power believes it is appropriate to consider rate impacts that customers would face by moving 50% towards the Floor level in the first year. Therefore, Bluewater Power has proposed to move one-third towards the Floor level in this application for the Unmetered Scattered Load ("USL"), Sentinel and Street Lighting customers.

The distribution rates proposed by Bluewater Power are set out at Exhibit 9, Tab 1, Schedule 8. The rate impacts associated with the proposed rates are set out at Exhibit 9, Tab 1, Schedule 9.

7.0 Other Rate Matters

Bluewater Power proposes an increase in the smart meter rate adder to $1 per month per metered customer in anticipation of the increase in smart meter activity as set out in Exhibit 5, Tab 1, Schedule 4.

Bluewater Power proposes to recover amounts for lost revenue associated with conservation and demand management activities, as well as an amount calculated in accordance with the shared savings mechanism. These proposals are discussed in detail in Exhibit 5, Tab 1, Schedule 3 and form part of the calculation that lead to the rate riders shown in Table 1.1.3.8.

Also included in the rate rider shown below, Bluewater Power has proposed the disposition of an amount necessary to dispose of a credit of approximately $3.9 Million in deferral and variance accounts. This issue is discussed in detail in Exhibit 5, Tab 1, Schedule 1.

Table 1.1.3.8 – Proposed Rate Riders

Rate Classification	Proposed Rate Rider	Per kWh or kW
Residential	(0.0009)	kWh
General Service <50 kW	(0.0011)	kWh
General Service 50 to 999 kW	(0.4555)	kW
General Service 1,000 to 4,999 kW	(0.6174)	kW
Large	(0.8908)	kW
Unmetered Scattered Load	(0.0008)	kWh
Sentinel Lighting	(0.3737)	kW
Street Lighting	(0.3256)	kW

Finally, we note that Bluewater Power is currently pursuing a corporate restructuring that would see certain Non-Core Distribution Activities moved from the regulated utility to an affiliate. That restructuring has been driven by concerns regarding compliance with the Affiliate Relationships Code ("ARC") and certain compliance bulletins issued by the Ontario Energy Board Compliance Office. The proposed structure will result in the removal of all Non-Core Distribution Activities from the utility, with the only exception being water billing as well as conservation and demand management ("C&DM") activities which are specifically authorized by legislation as permitted activities for a licensed electricity distributor in Ontario. This issue is discussed in detail in

Exhibit 1, Tab 2, Schedule 6, and it is also addressed through this application as it has impacts on OM&A, revenue from affiliates and shared services.

Current Rates Schedule

Below is the current rate schedule based on the Ontario Energy Board Decision issued for EB-2007-0862.

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	13.90
Distribution Volumetric Rate	$/kWh	0.0117
Retail Transmission Rate – Network Service Rate	$/kWh	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0048
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	25.42
Distribution Volumetric Rate	$/kWh	0.0128
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 999 KW

Service Charge	$	330.82
Distribution Volumetric Rate	$/kW	1.6241
Retail Transmission Rate – Network Service Rate	$/kW	1.7399
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6988
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 1,000 to 4,999 kW

Service Charge	$	3084.55
Distribution Volumetric Rate	$/kW	1.5252
Retail Transmission Rate – Network Service Rate	$/kW	1.8479
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.8623
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Large Use

Service Charge	$	18,021.4
Distribution Volumetric Rate	$/kW	1.1431
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.0461
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.1296
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	12.58
Distribution Volumetric Rate	$/kWh	0.0128
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	1.81
Distribution Volumetric Rate	$/kW	4.8230
Retail Transmission Rate – Network Service Rate	$/kW	1.3188
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3407
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	1.37
Distribution Volumetric Rate	$/kW	3.7378
Retail Transmission Rate – Network Service Rate	$/kW	1.3122
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3133
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Duplicate invoices for previous billing	$	15.00
Income tax letter	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	10.00
Returned Cheque charge (plus bank charges)	$	15.00
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
Disconnect/Reconnect Charge - At Meter During Regular Hours	$	65.00
Disconnect/Reconnect Charge - At Meter After Hours	$	185.00
Specific Charge for Access to the Power Poles – $/per pole/year	$	22.35

1
2

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)

Retail Service Charges (if applicable)

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

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

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0446
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0342
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

Proposed Rates Schedule

The proposed rates schedule is attached as Exhibit 1, Tab 1, Schedule 5, Attachment 1.

Proposed Monthly Rates and Charges

		Effective May 1/09
Residential		
Service Charge	$	18.50
Distribution Volumetric Rate	$/kWh	0.0150
Regulatory Asset Recovery	$/kWh	(0.0009)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0048
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
General Service <50 kW		
Service Charge	$	32.52
Distribution Volumetric Rate	$/kWh	0.0160
Regulatory Asset Recovery	$/kWh	(0.0011)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
General Service 50 to 999 kW		
Service Charge	$	434.49
Distribution Volumetric Rate	$/kW	2.1298
Regulatory Asset Recovery	$/kW	(0.4555)
Retail Transmission Rate – Network Service Rate	$/kW	1.7399
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6988
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
General Service 1,000 to 4,999 kW		
Service Charge	$	3,508.63
Distribution Volumetric Rate	$/kW	1.7345
Regulatory Asset Recovery	$/kW	(0.6174)
Retail Transmission Rate – Network Service Rate	$/kW	1.8479
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.8623
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Proposed Monthly Rates and Charges

		Effective May 1/09
Large		
Service Charge	$	25,756.94
Distribution Volumetric Rate	$/kW	1.6337
Regulatory Asset Recovery	$/kW	(0.8908)
Retail Transmission Rate – Network Service Rate	$/kW	2.0461
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.1296
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
Unmetered Scattered Load		
Service Charge (per connection)	$	22.37
Distribution Volumetric Rate	$/kWh	0.0228
Regulatory Asset Recovery	$/kWh	(0.0008)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Proposed Monthly Rates and Charges

		Effective May 1/09
Sentinel Lighting		
Service Charge (per connection)	$	3.11
Distribution Volumetric Rate	$/kW	8.2803
Regulatory Asset Recovery	$/kW	(0.3737)
Retail Transmission Rate – Network Service Rate	$/kW	1.3188
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3407
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
Street Lighting		
Service Charge (per connection)	$	2.36
Distribution Volumetric Rate	$/kW	6.4356
Regulatory Asset Recovery	$/kW	(0.3256)
Retail Transmission Rate – Network Service Rate	$/kW	1.3122
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3133
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Proposed Monthly Rates and Charges

		Effective May 1/09
Specific Service Charges		
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	$	10.00
Late Payment - per month	%	1.50
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Retailer Service Agreement -- monthly fixed charge (per retailer)	$	20.00
Retailer Service Agreement -- monthly variable charge (per customer)	$	0.50
Distributor-Consolidated Billing -- monthly charge (per customer)	$	0.30
Retailer-Consolidated Billing -- monthly credit (per customer)	$	(0.30)
Service Transaction Request -- request fee (per request)	$	0.25
Service Transaction Request -- processing fee (per processed request)	$	0.50
Interval Meter Load Management Tool	$	50.00
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)
LOSS FACTORS		
Secondary Metered Customer < 5000 kW		1.0356
Secondary Metered Customer > 5000 kW		1.0145
Primary Metered Customer < 5000 kW		1.0253
Primary Metered Customer > 5000 kW		1.0045

Summary of Bill Impact

Table 1.1.6.1 below is a summary of the proposed average monthly bill impacts for each rate class. Full rate impacts by line item can be found at Exhibit 9, Tab 1, Schedule 9.

Table 1.1.6.1

Rate Class	kWh	kW	Total Bill $ Change	Total Bill % Change
Residential	1,000		$6.35	6.0%
GS<50	2,000		$9.99	4.7%
GS 50 to 999 kW	52,000	135	$79.94	1.6%
GS 1000 to 4999 kW	1,700,000	3,532	($1,935.72)	-1.4%
Large	4,446,000	6,900	$4,974.14	1.4%
USL	1,000		$18.34	17.9%
Sentinel (per connection)	176	0.46	$2.63	15.6%
Streetlighting (per connection)	99	0.21	$1.44	15.6%

List of Issues

Are the rates that Bluewater Power seeks just and reasonable?

List of Specific Approvals Requested

Bluewater Power requests approval of the following, effective May 1, 2009:

- Authorization of revised distribution rates for the period May 1, 2009 to April 30, 2010; (Exhibit 1, Tab 1, Schedule 5)
- To dispose of the balances in several variance and deferral accounts; (Exhibit 5, Tab 1, Schedule 2)
- Authorization of rate riders; (Exhibit 5, Tab 1, Schedule 5)
- To recover an amount for the LRAM and SSM for conservation and demand management programs implemented for the period 2005 to 2007; (Exhibit 5, Tab 1, Schedule 3)
- To continue with the current authorized special service charges; (Exhibit 3, Tab 3, Schedule 1)
- To update the loss factor from the current factor of 1.0446 to a proposed factor of 1.0356 for secondary metered customers < 5000 kW. (Exhibit 4, Tab 2, Schedule 10)
- Authorization to increase the smart meter rate adder from $.26 to $1 per metered customer per month; (Exhibit 5, Tab 1, Schedule 4)
- Authorization to recover $559,364 related to transformer allowance paid to customers who own their own transformer; (Exhibit 9, Tab 1, Schedule 1)
- Authorization to recover $189,602 related to Low Voltage (“LV”) charges levied by Hydro One Networks Inc. (Exhibit 1, Tab 3, Schedule 4)
- Bluewater Power’s current distribution rates being declared interim commencing May 1, 2009 until Bluewater Power’s proposed distribution rates are implemented

Schedule of Overall Revenue Deficiency/Sufficiency

	2009 Projection
Utility Income	492,229
Utility Rate Base	53,158,483
Indicated Rate of Return	0.93%
Requested / Approved Rate of Return	7.71%
Sufficiency / (Deficiency) in Return	(6.78%)
Net Revenue Sufficiency / (Deficiency)	**(3,606,715)**
Provision for PILs/Taxes	(1,236,997)
Gross Revenue Sufficiency / (Deficiency)	**(4,843,712)**
Deemed Overall Debt Rate	*7.05%*
Deemed Cost of Debt	*2,124,815*
Utility Income less Deemed Cost of Debt	*(1,632,586)*
Return On Deemed Equity	*(7.09%)*

UTILITY INCOME

Total Net Revenues	16,592,364
OM&A Expenses	11,358,419
Depreciation & Amortization	4,358,109
Taxes other than PILs / Income Taxes	297,750
Total Costs & Expenses	16,014,278
Utility Income before Income Taxes / PILs	578,086
PILs / Income Taxes	85,857
Utility Income	**492,229**

Causes of the Deficiency/Sufficiency

Exhibit 1, Tab 1, Schedule 9 indicates a revenue deficiency of $4,843,712 for the 2009 test year at current rates.

The forecasted revenue deficiency is mainly attributable to:

(i) the fact that current rates do not reflect the forecasted increase in OM&A, which, as described at Exhibit 4, Tab 2, Schedule 2, is significantly caused by the increase in Payroll Related Costs;

(ii) an increase in depreciation as discussed in Exhibit 2, Tab 2, Schedule 5;

(iii) an increase of rate base as described at Exhibit 2, Tab 1, Schedule 3;

(iv) the resulting return on capital as described at Exhibit 6, Tab 1, Schedule 1.

Board Findings and Directions from 2008 IRM

Exhibit 1, Tab 1, Schedule 11, Attachment 1 is the Rate Order from EB-2007-0862.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2007-0862

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

AND IN THE MATTER OF an Application by Bluewater Power Distribution Corporation pursuant to section 78 of the Ontario Energy Board Act seeking approval to amend electricity distribution rates.

BEFORE: Paul Vlahos
Presiding Member

Paul Sommerville
Member

RATE ORDER

Bluewater Power Distribution Corporation ("Bluewater") is a licensed distributor of electricity providing service to consumers within its licensed service area. Bluewater filed an application with the Ontario Energy Board (the "Board") for an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other charges, to be effective May 1, 2008.

On March 18, 2008, the Board issued its Decision (the "Decision") regarding Bluewater's application.

The Board directed that Bluewater file with the Board a proposed Tariff of Rates and Charges reflecting the Board's Decision, within 7 days of the date of the Decision.

Bluewater has provided the Board with a proposed Tariff of Rates and Charges.

The Board is satisfied that the document accurately reflects the Decision.

For completeness of the regulated charges, the Board has included in the Tariff of Rates and Charges the charges pertaining to services provided to retailers or consumers regarding the supply of competitive electricity, which are referenced in Chapter 12 of the 2006 Electricity Distribution Rate Handbook.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Appendix "A" of this Rate Order is approved, effective May 1, 2008, for electricity consumed or estimated to have been consumed on and after May 1, 2008.

2. The Tariff of Rates and Charges set out in Appendix "A" of this Order supersedes all previous distribution rate schedules approved by the Board for Bluewater and is final in all respects.

3. Bluewater shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

DATED at Toronto, April 18, 2008

ONTARIO ENERGY BOARD

Original Signed by

Kirsten Walli
Board Secretary

Appendix “A”

To The Rate Order Arising from Decision

EB-2007-0862

Bluewater Power Distribution Corporation

April 18, 2008

Bluewater Power Distribution Corp.
TARIFF OF RATES AND CHARGES
Effective May 1, 2008

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

EB-2007-0862

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders 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, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES - May 1, 2008 for all charges incurred by customers on or after that date.
RETAIL SERVICE CHARGES – May 1, 2008 for all charges incurred by retailers or customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2008 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential Customers
All service supplied to single-family dwelling units for domestic or household purposes shall be classed as residential service. Where electricity service is provided for combined residential and business purposes (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be in the discretion of Bluewater Power Distribution Corporation ("Bluewater Power") and shall be based on such considerations as the estimated predominant consumption or the municipal tax roll classification. A residential customer may be found in a detached, semi-detached, linear row housing, apartment building or mixed-use building. Where more than one dwelling is served by a single meter, that service shall be considered a General Service Customer.

General Service Less Than 50 kW
This classification applies to a customer not designated as Residential, and that over a twelve month period has, or is forecast to have, an average monthly peak demand less than 50 kW, and has a monthly peak demand that never exceeds 100 kW. Bluewater Power shall review this rate class designation on an annual basis and the customer's designated rate class may change as a result.

General Service 50 to 999 kW
This classification applies to a customer not designated as Residential, and that over a twelve month period has, or is forecast to have, an average monthly peak demand equal to or greater than 50 kW and less than 1,000 kW. This rate class designation is reviewed on an annual basis and the customer's designated rate class may change as a result.

General Service 1,000 to 4,999 kW
This classification applies to a customer not designated Residential, and that: over a twelve month period has, or is forecast to have, an average monthly peak demand equal to or greater than 1,000 kW and less than 5,000 kW. This rate class designation is reviewed on an annual basis and the customer's designated rate class may change as a result.

Large Use
This classification applies to a customer not designated as Residential, and that over 12 consecutive billing periods has, or is forecast to have, an average monthly peak demand equal to or greater than 5,000 kW. This rate class designation is reviewed on an annual basis and the customer's designated rate class may change as a result.

Bluewater Power Distribution Corp.
TARIFF OF RATES AND CHARGES
Effective May 1, 2008

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

EB-2007-0862

Unmetered Scattered Load
This classification applies to an account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by Bluewater Power and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption.

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

Street Lighting
This classification 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.

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	13.90
Distribution Volumetric Rate	$/kWh	0.0117
Retail Transmission Rate – Network Service Rate	$/kWh	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0048
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	25.42
Distribution Volumetric Rate	$/kWh	0.0128
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 999 KW

Service Charge	$	330.82
Distribution Volumetric Rate	$/kW	1.6241
Retail Transmission Rate – Network Service Rate	$/kW	1.7399
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6988
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 1,000 to 4,999 kW

Service Charge	$	3084.55
Distribution Volumetric Rate	$/kW	1.5252
Retail Transmission Rate – Network Service Rate	$/kW	1.8479
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.8623
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Bluewater Power Distribution Corp.

TARIFF OF RATES AND CHARGES

Effective May 1, 2008

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

EB-2007-0862

Large Use

Service Charge	$	18,021.42
Distribution Volumetric Rate	$/kW	1.1431
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.0461
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.1296
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	12.58
Distribution Volumetric Rate	$/kWh	0.0128
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	1.81
Distribution Volumetric Rate	$/kW	4.8230
Retail Transmission Rate – Network Service Rate	$/kW	1.3188
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3407
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	1.37
Distribution Volumetric Rate	$/kW	3.7378
Retail Transmission Rate – Network Service Rate	$/kW	1.3122
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3133
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Duplicate invoices for previous billing	$	15.00
Income tax letter	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	10.00
Returned Cheque charge (plus bank charges)	$	15.00
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
Disconnect/Reconnect Charge - At Meter During Regular Hours	$	65.00
Disconnect/Reconnect Charge - At Meter After Hours	$	185.00
Specific Charge for Access to the Power Poles – $/per pole/year	$	22.35

Bluewater Power Distribution Corp.
TARIFF OF RATES AND CHARGES
Effective May 1, 2008

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

EB-2007-0862

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)

Retail Service Charges (if applicable)

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

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

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0446
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0342
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

Board Findings and Directions from 2007 IRM

Exhibit 1, Tab 1, Schedule 12, Attachment 1 is the Rate Order from EB-2007-0508.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2007-0508

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B);

AND IN THE MATTER OF an application by Bluewater Power Distribution Corporation for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2007.

BEFORE: Paul Sommerville
Presiding Member

Paul Vlahos
Member

Ken Quesnelle
Member

DECISION AND ORDER

Bluewater Power Distribution Corporation ("Bluewater") is a licensed distributor providing electrical service to consumers within its licensed service area. Bluewater filed an application with the Ontario Energy Board (the "Board") for an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other charges, to be effective May 1, 2007.

Bluewater is one of 85 electricity distributors in Ontario that are regulated by the Board. To streamline the process for the approval of distribution rates and charges for these distributors, the Board issued its *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Report") on December 20, 2006. The Report contained the relevant guidelines for 2007 rate adjustments ("the guidelines") for distributors applying for rates only on the basis of the

cost of capital and 2nd generation incentive regulation mechanism policies set out in the Report.

Public notice of Bluewater's rate application was given through newspaper publication in Bluewater's service area. The evidence filed as part of the rate application was made available to the public. Both Bluewater and interested parties had the opportunity to file written submissions in relation to the rate application. The Board received no submissions. While the Board has considered the entire record in this rate application, it has made reference only to such evidence as is necessary to provide context to its findings.

Bluewater's rate application was filed on the basis of the guidelines. In fixing new rates and charges for Bluewater, the Board has applied the policies described in the Report.

After confirming the accuracy of the 2006 rate tariff and accompanying materials submitted in the rate application, the Board applied its approved price cap index adjustment to distribution rates (fixed and variable) uniformly across all customer classes. The price cap index is calculated as a price escalator less an X-factor of 1.0%, intended to represent input price and productivity trends. Based on the final 2006 data published by Statistics Canada, the Board has established the price escalator to be 1.9%. The resulting price cap index adjustment is therefore 0.9%.

The 2006-approved Conservation and Demand Management funding that was included as a component of the 2006 rates was removed prior to the application of the price cap index adjustment.

The price cap index adjustment was not applied to the following components of the rates:

- the specific service charges;
- the regulatory asset recovery rate rider; and
- the smart meter rate adder (an amount in the fixed components of the rates associated with smart meter cost recovery).

Bluewater requested an amount for smart meter costs. The Board has approved an amount of $0.26 per month per metered customer. Bluewater's variance accounts for smart meter program implementation costs, previously authorized by the Board, are

continued. It is the Board's understanding that Bluewater will not be undertaking any smart metering activity (i.e. discretionary metering activity) in 2007. The amount collected through the smart meter rate adder will be booked into the existing variance accounts, and retained in those accounts, to help fund future smart meter activity. As the notice of this application indicated, the Board will be holding a combined proceeding to consider, among other things, appropriate recovery of smart meter costs.

The Board has made the necessary adjustments to Bluewater's filed 2006 Tariff of Rates and Charges to produce a new Tariff of Rates and Charges to be effective May 1, 2007. The Board finds the rates and charges in the Tariff of Rates and Charges attached as Appendix A to this decision to be just and reasonable.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Appendix A of this order is approved, effective May 1, 2007, for electricity consumed or estimated to have been consumed on and after May 1, 2007.

2. The Tariff of Rates and Charges set out in Appendix A of this order supersedes all previous distribution rate schedules approved by the Ontario Energy Board for Bluewater, and is final in all respects.

3. Bluewater shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

DATED at Toronto, April 12, 2007.

ONTARIO ENERGY BOARD

Original signed by

Peter H. O'Dell
Assistant Board Secretary

Appendix A

EB-2007-0508

April 12, 2007

ONTARIO ENERGY BOARD

Bluewater Power Distribution Corp.
TARIFF OF RATES AND CHARGES
Effective May 1, 2007

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

EB-2007-0508

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders 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, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES - May 1, 2007 for all charges incurred by customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential Customers
This classification applies to single-family dwelling units for domestic or household purposes shall be classed as residential service. A residential customer may be found in a detached, semi-detached, linear row housing, apartment building, or mixed-use building. Where electricity service is provided for combined residential and business purposes (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be in the discretion of Bluewater Power Distribution Corporation ("BPDC") and shall be based on such considerations as the estimated predominant consumption or the municipal tax roll classification. Where more than one dwelling is served by a single meter, that service shall be considered a General Service Customer

General Service Less Than 50 kW
This classification applies to a customer not designated as Residential, and that over a twelve month period has, or is forecast to have, an average monthly peak demand less than 50 kW, and has a monthly peak demand that never exceeds 100 kW. BPDC shall review this rate class designation on an annual basis and the customer's designated rate class may change as a result.

General Service 50 to 999 kW
This classification applies to a customer not designated as Residential, and that over a twelve month period has, or is forecast to have, an average monthly peak demand equal to or greater than 50 kW and less than 1,000 kW. This rate class designation is reviewed on an annual basis and the customer's designated rate class may change as a result.

General Service 1,000 to 4,999 kW
This classification applies to a customer not designated Residential, and that: over a twelve month period has, or is forecast to have, an average monthly peak demand equal to or greater than 1,000 kW and less than 5,000 kW. This rate class designation is reviewed on an annual basis and the customer's designated rate class may change as a result.

Large Use
This classification applies to a customer not designated as Residential, and that over 12 consecutive billing periods has, or is forecast to have, an average monthly peak demand equal to or greater than 5,000 kW. This rate class designation is reviewed on an annual basis and the customer's designated rate class may change as a result.

Unmetered Scattered Load
This classification applies to an account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by BPDC and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption.

Bluewater Power Distribution Corp.
TARIFF OF RATES AND CHARGES
Effective May 1, 2007

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

EB-2007-0508

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

Street Lighting
This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and 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.

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	13.90
Distribution Volumetric Rate	$/kWh	0.0117
Regulatory Asset Recovery	$/kWh	0.0068
Retail Transmission Rate – Network Service Rate	$/kWh	0.0057
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0050
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	25.42
Distribution Volumetric Rate	$/kWh	0.0128
Regulatory Asset Recovery	$/kWh	0.0022
Retail Transmission Rate – Network Service Rate	$/kWh	0.0052
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 999 KW

Service Charge	$	330.82
Distribution Volumetric Rate	$/kW	1.6241
Regulatory Asset Recovery	$/kW	0.2300
Retail Transmission Rate – Network Service Rate	$/kW	2.1218
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7882
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 1,000 to 4,999 kW

Service Charge	$	3,084.55
Distribution Volumetric Rate	$/kW	1.5252
Regulatory Asset Recovery	$/kW	(0.6980)
Retail Transmission Rate – Network Service Rate	$/kW	2.2535
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.9603
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Bluewater Power Distribution Corp.
TARIFF OF RATES AND CHARGES
Effective May 1, 2007

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EB-2007-0508

Large Use

Service Charge	$	18,021.42
Distribution Volumetric Rate	$/kW	1.1431
Regulatory Asset Recovery	$/kW	(0.1287)
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.4952
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.2417
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	12.58
Distribution Volumetric Rate	$/kWh	0.0128
Regulatory Asset Recovery	$/kWh	0.0052
Retail Transmission Rate – Network Service Rate	$/kWh	0.0052
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	1.81
Distribution Volumetric Rate	$/kW	4.8230
Regulatory Asset Recovery	$/kW	3.2763
Retail Transmission Rate – Network Service Rate	$/kW	1.6083
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4113
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	1.37
Distribution Volumetric Rate	$/kW	3.7378
Regulatory Asset Recovery	$/kW	(1.0840)
Retail Transmission Rate – Network Service Rate	$/kW	1.6002
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3824
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Duplicate invoices for previous billing	$	15.00
Income tax letter	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	10.00
Returned Cheque charge (plus bank charges)	$	15.00
Special meter reads	$	30.00

Bluewater Power Distribution Corp.
TARIFF OF RATES AND CHARGES
Effective May 1, 2007

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

EB-2007-0508

Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect Charge - At Meter During Regular Hours	$	65.00
Disconnect/Reconnect Charge - At Meter After Hours	$	185.00
Specific Charge for Access to the Power Poles – $/per pole/year	$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0446
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0342
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

Board Findings and Directions from 2006 EDR

Exhibit 1, Tab 1, Schedule 13, Attachment 1 is the Rate Order from EB-2005-0340.

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

RP-2005-0020
EB-2005-0340

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B);

AND IN THE MATTER OF an Application by Bluewater Power Distribution Corporation for an order or orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2006.

BEFORE: Paul Vlahos
Presiding Member

Bob Betts
Member

DECISION AND ORDER

Bluewater Power Distribution Corporation ("Bluewater Power" or the "Applicant") is a licensed distributor providing electrical service to consumers within its defined service area. Bluewater Power filed an application (the "Application") with the Ontario Energy Board (the "Board") for an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other matters, to be effective May 1, 2006.

Bluewater Power is one of over 90 electricity distributors in Ontario that are regulated by the Board. To streamline the process for the approval of distribution rates and charges for these distributors, the Board developed and issued the 2006 Electricity Distribution Rate Handbook (the "Handbook") and complementary spreadsheet-based models. These materials were developed after extensive public consultation with distributors, customer groups, public and environmental interest groups, and other interested parties. The Handbook contains requirements and guidelines for filing an application.

The models determine the amounts to be included for the payments in lieu of taxes ("PILs") and calculate rates based on historical financial and other information entered by the distributor.

Also included in this process was a methodology and model for the final recovery of regulatory assets flowing from the Board's decision dated December 9, 2004 on the Review and Recovery of Regulatory Assets – Phase 2 for Toronto Hydro, London Hydro, Enersource Hydro Mississauga and Hydro One Networks Inc. In Chapter 10 of the decision, the Board outlined a Phase 2 process for the remaining distributors. By letter of July 12, 2005, the Board provided guidance and a spreadsheet-based model to the distributors for the inclusion of this recovery as part of their 2006 distribution rate applications.

As a distributor that is embedded in Hydro One Network's low voltage system, the Applicant has included the recovery of certain Regulatory Assets that have been allocated by Hydro One Networks. The amount claimed by the Applicant was provided by Hydro One Networks as a reasonable approximation of the actual amount that Hydro One Networks will assess the Applicant. To the degree that the amount differs from the actual amount approved for Hydro One Networks in another proceeding (RP-2005-0020/EB-2005-0378), this difference will be reconciled at the end of the Regulatory Asset recovery period, as set out in the Phase II regulatory assets decision issued on December 9, 2004 (RP-2004-0064/RP-2004-0069/RP-2004-0100/RP-2004-0117/RP-2004-0118).

In its preliminary review of the 2006 rate applications received from the distributors, the Board identified several issues that appeared to be common to many or all of the distributors. As a result, the Board held a hearing (EB-2005-0529) to consider these issues (the "Generic Issues Proceeding") and released its decision (the "Generic Decision") on March 21, 2006. The rulings flowing from that Generic Decision apply to this Application, except to the extent noted in this Decision. The Board notes that pursuant to ss. 21 (6.1) of the *Ontario Energy Board Act, 1998*, and to the extent that it is pertinent to this Application, the evidentiary record of the Generic Issues Proceeding is part of the evidentiary record upon which the Board is basing this Decision.

In December 2001, the Board authorized the establishment of deferral accounts by the distributors related to the payments that the distributors make to the Ministry of Finance

in lieu of taxes. The Board is required, under its enabling legislation, to make an order with respect to non-commodity deferral accounts once every twelve months. The Board has considered the information available with respect to these accounts and orders that the amounts recorded in the accounts will not be reflected in rates as part of the Rate Order that will result from this Decision. The Board will continue to monitor the accounts with a view to clearing them in due course.

Public notice of the rate application made by Bluewater Power was given through newspaper publication in its service area. The evidence filed was made available to the public. Interested parties intervened in the proceeding. The evidence in the Application was tested through written interrogatories from Board staff and intervenors, and intervenors and the Applicant had the opportunity to file written argument. While the Board has considered the entire record in this proceeding, it has made reference in this Decision only to such evidence and argument as is necessary to provide context to its findings.

Bluewater Power has requested an amount of $20,612,464 as revenue to be recovered through distribution rates and charges. Included in this amount is a debit of $1,861,936 for the recovery of regulatory assets. Except where noted in this Decision, the Board finds that Bluewater Power has filed its Application in accordance with the Handbook and the guidelines for the recovery of regulatory assets.

Notwithstanding the Bluewater Power's general compliance with the Handbook and associated models, in considering this Application the Board reviewed the following matters in detail:

- Low Voltage Rates;
- Harmonization of Time of Use Rates;
- Conservation and Demand Management ("CDM") Funding;
- Payment in Lieu of Taxes ("PILs"); and
- Impact of the Generic Decision (EB-2005-0529).

Low Voltage Rates

Bluewater Power included in its Application recovery of ongoing Low Voltage ("LV") charges that Hydro One Networks will be levying on Bluewater Power for Low Voltage wheeling distribution services provided to Bluewater Power.

The Board notes that this estimate reflects Hydro One Networks' current approved LV rate of $0.56/kW. The Board further notes that Hydro One Networks applied for an LV rate of $0.63/kW in its 2006 rate application RP-2005-0020/EB-2005-0378, and the Board has approved this rate.

The Board is of the view that the LV adjustment that Bluewater Power has included in its Application is insufficient to recover its expected LV charges in 2006, as this amount does not reflect the updated Hydro One Networks rate. Although the Generic Decision provides that embedded distributors are to track differences between LV costs charged by the host distributor(s) and corresponding revenues recovered from ratepayers, the Board seeks to minimize systemic sources of variance. The Board is of the view that Bluewater Power's rates should reflect the LV rates authorized by the Board for the host distributor. Accordingly, the Board has revised the amount for LV charge recovery in Bluewater Power's revenue requirement.

Harmonization of Time of Use Rates

Bluewater's sub-classification for Time of Use ("TOU") customers creates a distinction between customers with similar demand based solely on the type of meter installed. This distinction applies only for those customers with demand between 500 KW and 1000 KW. The effect of this distinction has been that different rates have applied to customers with similar demand patterns. A rate distinction based on meter type is inconsistent from the normal practice of rate design which is based, in large part, on cost causality.

Bluewater Power proposes to raise the consumption threshold for this sub-class from 500 KW to 1000 KW to eliminate any distinction in rates based on type of meter, given that all customers with demand greater than 1000 KW have an Interval/TOU meter. The name of the new rate class would be changed to remove any reference to interval meters and would be "GS (Intermediate)". The remaining "GS (>50KW)" rate class would be renamed to "GS (50KW-999KW)", and similarly would contain no reference to meter type.

The Board notes that the proposed harmonization will remove a distinction between customers based on meter types and that it will not create undue customer rate impacts. The Board finds the proposed rate harmonization reasonable and accepts the Applicant's implementation plan.

CDM Funding

Bluewater Power has applied for approval to recover $250,000 in distribution rates to be invested in CDM activities. Bluewater Power has proposed commercial/industrial and residential programs, which focus on lighting.

The Vulnerable Energy Consumers Coalition ("VECC") expressed concern that the focus of Bluewater's CDM efforts appears to be exclusively on lighting related initiatives. VECC is of the opinion that incremental CDM funds should not be approved "unless the program offering is balanced such that it reaches all customers and, in particular includes targeted low income programs".

The Board has noted VECC's concerns, but observes that low-income program targets are not specifically required under the Board's guidelines for incremental CDM spending. In addition, Bluewater Power has stated that its program is open to and particularly advantageous for low-income customers.

The Board has reviewed Bluewater Power's CDM plan and accepts it for inclusion in 2006 rates. The Board notes that Bluewater Power has performed the Total Resource Cost effectiveness screening required for approval, and consequently satisfies the Board's prudence test for CDM investments.

PILs

Bluewater Power has included an amount of $1,064,913 in the PILs "Test Year Taxable Income". This amount relates to the PILs payable on revenue received for the recovery of regulatory assets.

Bluewater Power has stated, "the related regulatory asset deductions were also included in the taxable income calculation in the 2004 corporate tax returns and, thus, were included in the 2006 OEB Tax Model". Bluewater Power asserts that the recovery of regulatory assets and the treatment in determining the PILs Allowance for 2006 is appropriate.

The Board has previously determined in the Phase II regulatory assets decision issued on December 9, 2004 (RP-2004-0064/RP-2004-0069/RP-2004-0100/RP-2004-0117/RP-2004-0118), that no PILs allowance should be made for revenues that recover regulatory assets since these have already been expensed for tax purposes, which fact

has been acknowledged by Bluewater Power. The Board finds that the amount of $1,064,913 should be removed as this amount relates to the PILs payable on revenue received for the recovery of regulatory assets.

Consequences of the Generic Decision on this Application

The Generic Decision contains findings relevant to funding for smart meters for electricity distributors. The Applicant did file a specific smart meter plan in the revenue requirement. In this situation, the Generic Decision provides that an amount determined as $3.50 per meter per month installed during the rate year be reflected in the Applicant's revenue requirement, instead of the smart meter-related costs proposed by the Applicant. Consequently, the amounts that the Applicant has proposed in the 2006 rate Application have been removed and replaced with the amount determined in accordance with the Generic Decision. Furthermore, the Board finds in this Decision that this smart meter revenue will be allocated to all metered customers and recovered through the monthly service charge. The revised amount is reflected in the approved monthly service charges contained in the Tariff of Rates and Charges appended to this Decision. Pursuant to the Generic Decision, a variance account will be established, the details of which will be communicated in due course.

Resulting Revenue Requirement

As a result of the Board's determinations on these issues, the Board has adjusted the revenue requirement to be recovered through distribution rates and charges to $19,960,800 and a debit amount of $1,861,936 for the recovery of Regulatory Assets.

In its letter of December 20, 2004 to electricity distributors, the Board indicated that it would consider the disposition of the 2005 OEB dues recorded in Account 1508 in this proceeding. However, given that the final 2005 OEB dues are not available because of the difference in fiscal years for the Board and the distributors, and given that the model used to develop the Application does not incorporate this provision, the Board will review and dispose of the 2005 OEB dues at a later time.

Cost Awards

This application is one of a number of applications before the Board dealing with 2006 rates chargeable by distributors. Intervenors may be parties to multiple applications and, if eligible, their costs associated with a specific distributor may not be separable. Therefore, for these applications, the matter of intervenor cost awards will be addressed

by the Board at a later date, upon the conclusion of the current rate applications. If an intervenor that is eligible to recover its costs is able to uniquely identify its costs associated with this application, it must file its cost claim within 10 days from the receipt of this Decision.

THE BOARD ORDERS THAT:

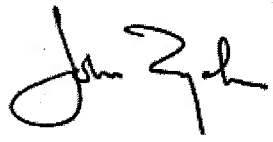
1) The Tariff of Rates and Charges set out in Appendix "A" of this Order is approved, effective May 1, 2006, for electricity consumed or estimated to have been consumed on and after May 1, 2006. The application of the revised distribution rates shall be prorated to May 1, 2006. If Bluewater Power Distribution Corporation's billing system is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors shall be implemented upon the first subsequent billing for each billing cycle.

2) The Tariff of Rates and Charges set out in Appendix "A" of this Order supersedes all previous distribution rate schedules approved by the Ontario Energy Board for Bluewater Power Distribution Corporation.

3) Bluewater Power Distribution Corporation shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

DATED at Toronto, April 12, 2006.

ONTARIO ENERGY BOARD



John Zych
Board Secretary

Appendix "A"

RP-2005-0020
EB-2005-0340

April 12, 2006

ONTARIO ENERGY BOARD

Bluewater Power Distribution Corp.

TARIFF OF RATES AND CHARGES

Effective May 1, 2006

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

RP-2005-0020
EB-2005-0340

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders 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, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2006 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES - May 1, 2006 for all charges incurred by customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2006 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential Customers

This classification applies to single-family dwelling units for domestic or household purposes shall be classed as residential service. A residential customer may be found in a detached, semi-detached, linear row housing, apartment building, or mixed-use building. Where electricity service is provided for combined residential and business purposes (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be in the discretion of Bluewater Power Distribution Corporation ("BPDC") and shall be based on such considerations as the estimated predominant consumption or the municipal tax roll classification. Where more than one dwelling is served by a single meter, that service shall be considered a General Service Customer

General Service Less Than 50 kW

This classification applies to a customer not designated as Residential, and that over a twelve month period has, or is forecast to have, an average monthly peak demand less than 50 kW, and has a monthly peak demand that never exceeds 100 kW. BPDC shall review this rate class designation on an annual basis and the customer's designated rate class may change as a result.

General Service 50 to 999 kW

This classification applies to a customer not designated as Residential, and that over a twelve month period has, or is forecast to have, an average monthly peak demand equal to or greater than 50 kW and less than 1,000 kW. This rate class designation is reviewed on an annual basis and the customer's designated rate class may change as a result.

General Service 1,000 to 4,999 kW

This classification applies to a customer not designated Residential, and that: over a twelve month period has, or is forecast to have, an average monthly peak demand equal to or greater than 1,000 kW and less than 5,000 kW. This rate class designation is reviewed on an annual basis and the customer's designated rate class may change as a result.

Large Use

This classification applies to a customer not designated as Residential, and that over 12 consecutive billing periods has, or is forecast to have, an average monthly peak demand equal to or greater than 5,000 kW. This rate class designation is reviewed on an annual basis and the customer's designated rate class may change as a result.

Unmetered Scattered Load

This classification applies to an account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by BPDC and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption.

Sentinel Lighting

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

Bluewater Power Distribution Corp.
TARIFF OF RATES AND CHARGES
Effective May 1, 2006

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

RP-2005-0020
EB-2005-0340

Street Lighting
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.

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	13.92
Distribution Volumetric Rate	$/kWh	0.0117
Regulatory Asset Recovery	$/kWh	0.0068
Retail Transmission Rate – Network Service Rate	$/kWh	0.0057
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0050
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

General Service Less Than 50 kW

Service Charge	$	25.45
Distribution Volumetric Rate	$/kWh	0.0128
Regulatory Asset Recovery	$/kWh	0.0022
Retail Transmission Rate – Network Service Rate	$/kWh	0.0052
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

General Service 50 to 999 KW

Service Charge	$	331.21
Distribution Volumetric Rate	$/kW	1.6252
Regulatory Asset Recovery	$/kW	0.2300
Retail Transmission Rate – Network Service Rate	$/kW	2.1218
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7882
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

General Service 1,000 to 4,999 kW

Service Charge	$	3,088.16
Distribution Volumetric Rate	$/kW	1.5261
Regulatory Asset Recovery	$/kW	(0.6980)
Retail Transmission Rate – Network Service Rate	$/kW	2.2535
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.9603
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Large Use

Service Charge	$	18,042.49
Distribution Volumetric Rate	$/kW	1.1436
Regulatory Asset Recovery	$/kW	(0.1287)
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.4952
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.2417
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Bluewater Power Distribution Corp.

TARIFF OF RATES AND CHARGES

Effective May 1, 2006

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

RP-2005-0020
EB-2005-0340

Unmetered Scattered Load		
Service Charge (per connection)	$	12.60
Distribution Volumetric Rate	$/kWh	0.0128
Regulatory Asset Recovery	$/kWh	0.0052
Retail Transmission Rate – Network Service Rate	$/kWh	0.0052
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25
Sentinel Lighting		
Service Charge (per connection)	$	1.81
Distribution Volumetric Rate	$/kW	4.8281
Regulatory Asset Recovery	$/kW	3.2763
Retail Transmission Rate – Network Service Rate	$/kW	1.6083
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4113
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25
Street Lighting		
Service Charge (per connection)	$	1.37
Distribution Volumetric Rate	$/kW	3.7416
Regulatory Asset Recovery	$/kW	(1.0840)
Retail Transmission Rate – Network Service Rate	$/kW	1.6002
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3824
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25
Specific Service Charges		
Customer Administration		
Duplicate invoices for previous billing	$	15.00
Income tax letter	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	10.00
Returned Cheque charge (plus bank charges)	$	15.00
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
Disconnect/Reconnect Charge - At Meter During Regular Hours	$	65.00
Disconnect/Reconnect Charge - At Meter After Hours	$	185.00
Specific Charge for Access to the Power Poles – $/per pole/year	$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0446
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0342
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

Originally Issued April 12, 2006
Revised April 27, 2006

Status of Board Directives

There are no specific Board directives active for Bluewater Power at this time.

Company Overview

Utility Description

Bluewater Power Distribution Corporation was incorporated under the *Ontario Business Corporations Act* on October 30, 2000 upon the completion of a merger of the Sarnia Hydro-Electric Commission, Petrolia Public Utilities Commission, Point Edward Public Utilities Commission, Watford Public Utilities Commission, Alvinston Public Utilities Commission, and Oil Springs Hydro-Electric Commission.

Overview

Bluewater Power currently provides electricity distribution to over 35,000 customers via 589 kilometers of overhead lines, 160 kilometers of underground lines, 2,748 pole-mount transformers, 1,407 pad-mount transformers, 20 substations, and 15,866 poles located throughout the 204 square kilometers of service territory.

Contact Information

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Alex Palimaka
Vice President Corporate Services and General Counsel
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Neighbouring Utilities

Bluewater Power is comprised of six geographically separate service territories and each service territory is bounded by Hydro One Networks Inc.

Host or Embedded Utilities

Bluewater Power is an embedded distributor of Hydro One Networks Inc.

LDC's Distribution License

Attached as Exhibit 1, Tab 2, Schedule 2, Attachment 1 is a copy of the Distribution License of Bluewater Power Distribution Corporation dated October 15, 2003.

Electricity Distribution Licence

ED-2002-0517

Bluewater Power Distribution Corporation

Valid Until
March 31, 2023

Mark C. Garner
Secretary
Ontario Energy Board

Date of Issuance: October 15, 2003

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
26th. Floor
Toronto, ON M4P 1E4

Commission de l'Énergie de l'Ontario
C.P. 2319
2300, rue Yonge
26e étage
Toronto ON M4P 1E4

1 Definitions

In this Licence:

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

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

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

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

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

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

"**Licensee**" means: Bluewater Power Distribution Corporation;

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

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

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

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

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

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

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

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

18 **2 Interpretation**

19 2.1 In this Licence words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this licence where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day.

20 **3 Authorization**

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

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

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

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

25

4 Obligation to Comply with Legislation, Regulations and Market Rules

26

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

27

4.2 The Licensee shall comply with all applicable Market Rules.

28

5 Obligation to Comply with Codes

29

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

30

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

31

b) the Distribution System Code;

32

c) the Retail Settlement Code; and

33

d) the Standard Supply Service Code.

34

5.2 The Licensee shall:

35

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

36

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

37

6 Obligation to Provide Non-discriminatory Access

38

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

39

7 Obligation to Connect

40

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

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

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

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

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

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

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

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

8 Obligation to Sell Electricity

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

9 Obligation to Maintain System Integrity

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

10 Market Power Mitigation Rebates

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

54

11 Distribution Rates

55

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

56

12 Separation of Business Activities

57

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

58

13 Expansion of Distribution System

59

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

60

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

61

14 Provision of Information to the Board

62

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

63

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

64

15 Restrictions on Provision of Information

65

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

66

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

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

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

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

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

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

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

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

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

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

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

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

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

81

17 Term of Licence

82

17.1 This Licence shall take effect on October 15, 2003 and expire on March 31, 2023. The term of this Licence may be extended by the Board.

83

18 Fees and Assessments

84

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

85

19 Communication

86

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

87

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

88

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

89

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

90

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

91

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

92

20 Copies of the Licence

93

20.1 The Licensee shall:

94

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

95

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

96

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

97

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

98

1 The City of Sarnia as defined in Bill 35 of 1989, an Act respecting the amalgamation of the City of Sarnia and the Town of Clearwater.

99

2 The Town of Petrolia as of December 31, 1999.

100

3 The Village of Point Edward as defined in Schedule 'A' of zoning by-law # 9 of 1982.

101

4 The former Village of Alvinston as of December 31, 2000, now part of the Township of Brooke-Alvinston.

102

5 The former Village of Oil Springs as defined on Schedule 'A' of zoning by-law #192 of 1986, plus all customers located south of Gum Bed Line and North of Aberfeldy Line between Kelly Road and Gypsie Flats Road.

103

6 The former Village of Watford as of December 31, 1997, now part of the Township of Warwick.

104

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

105

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

106

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

107

SCHEDULE 3 LIST OF CODE EXEMPTIONS

108

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

109

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

110

APPENDIX A MARKET POWER MITIGATION REBATES

111

1 Definitions and Interpretation

112

In this Licence,

113

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

114

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

115

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

116

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

117

2 Information Given to IMO

118

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

119

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

120

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

121

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

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

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

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

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

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

127 ## 3 Pass Through of Rebate

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

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

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

131 c embedded distributors to whom the distributor distributes electricity.

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

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

134 "ONTARIO POWER GENERATION INC. rebate"

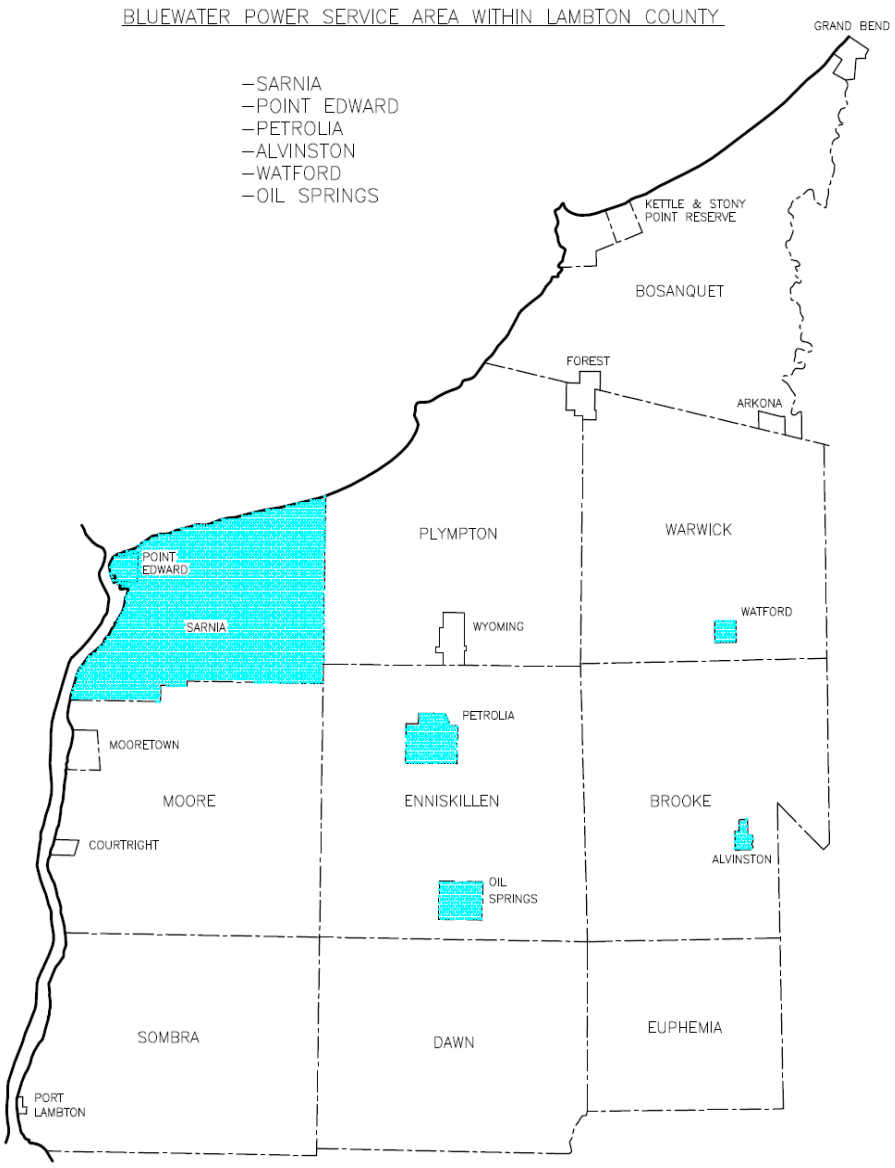
135 Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IMO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on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

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

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

Map of LDC's Distribution System

A map of Lambton County is below, showing the service territories of Bluewater Power.



The following maps of Bluewater Power's distribution system are attached:

Exhibit 1, Tab 2, Schedule 3, Attachment 1, Map of Alvinston 8.32 kV

Exhibit 1, Tab 2, Schedule 3, Attachment 2, Map of Oil Springs 8.32 kV

Exhibit 1, Tab 2, Schedule 3, Attachment 3, Map of Petrolia 4.16 kV

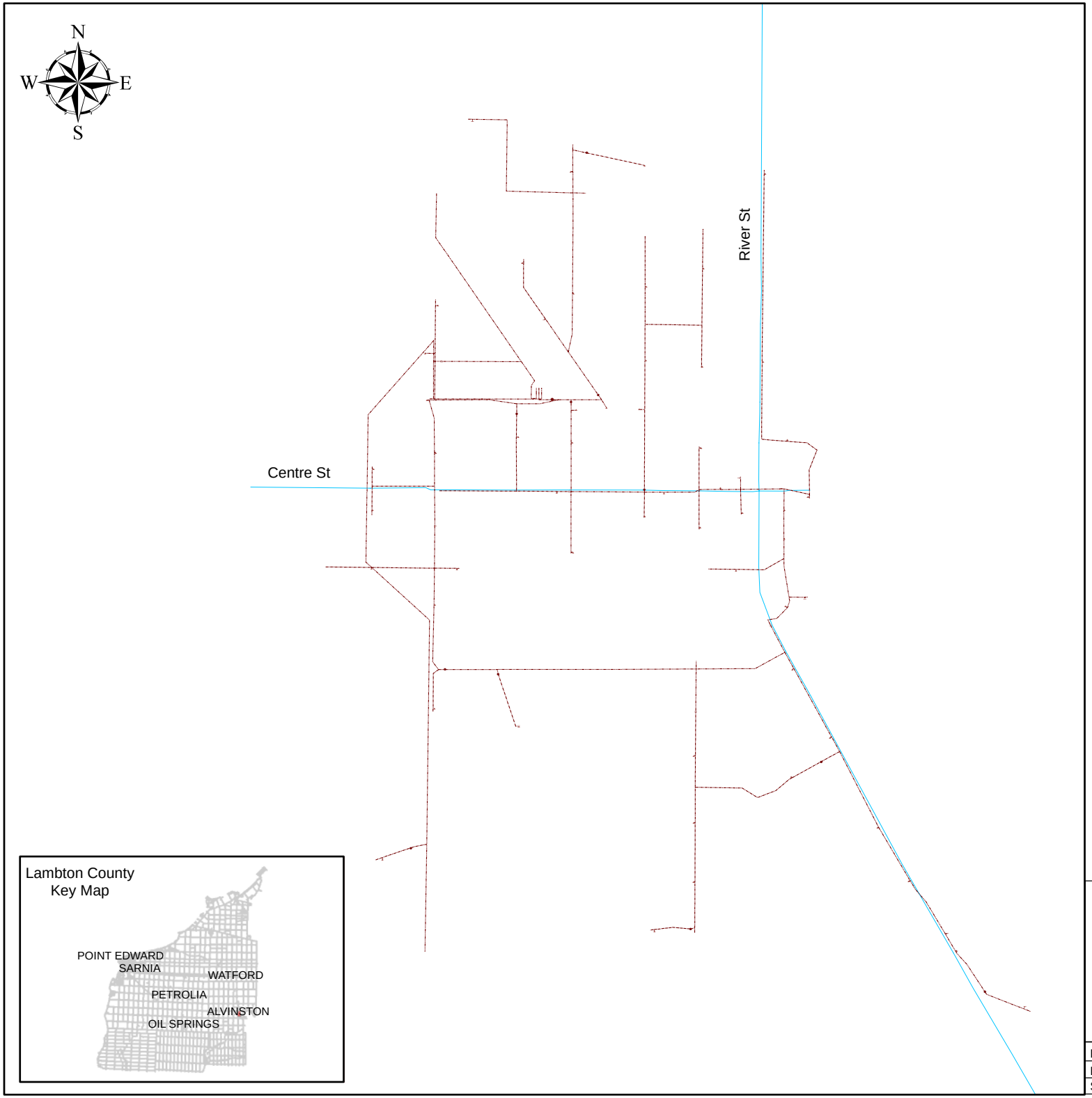
Exhibit 1, Tab 2, Schedule 3, Attachment 4, Map of Petrolia 27.6 kV

Exhibit 1, Tab 2, Schedule 3, Attachment 5, Map of Sarnia and Point Edward 4.16 kV

Exhibit 1, Tab 2, Schedule 3, Attachment 6, Map of Watford 4.16 kV

Exhibit 1, Tab 2, Schedule 3, Attachment 7, Map of Sarnia and Point Edward 8.32 kV

Exhibit 1, Tab 2, Schedule 3, Attachment 8, Map of Sarnia and Point Edward 27.6 kV



Legend

- OH - 3 PHASE 8.32 KV
- OH - 2 PHASE 8.32 KV
- OH - 1 PHASE 8.32 KV
- UG - 3 PHASE 8.32 KV
- UG - 1 PHASE 8.32 KV
- AIRBREAK - 8.32 KV - CLOSED
- SOLID - 8.32 KV - CLOSED
- SOLID - 8.32 KV - OPEN
- Gang - Not Remotely Operated - 8.32 KV - CLOSED
- Gang - Not Remotely Operated - 8.32 KV - OPEN
- FUSED SWITCH - 8.32 KV - CLOSED
- FUSED SWITCH - 8.32 KV - OPEN
- PADMOUNT TX - 8.32 KV
- POLEMOUNT TX - 1 UNIT - 8.32 KV
- POLEMOUNT TX - 2 UNITS - 8.32 KV
- POLEMOUNT TX - 3 UNITS 8.32 KV
- Substations

Lambton County
Key Map

BLUEWATER POWER DISTRIBUTION CORPORATION

Alvinston
8.32 KV Distribution

Prepared by:	Ena Forbes
Date:	July 16, 2008
Scale:	1:10,000

Legend

- OH - 3 PHASE 8.32 KV
- OH - 2 PHASE 8.32 KV
- OH - 1 PHASE 8.32 KV
- UG - 3 PHASE 8.32 KV
- UG - 1 PHASE 8.32 KV
- AIRBREAK - 8.32 KV - CLOSED
- SOLID - 8.32 KV - CLOSED
- SOLID - 8.32 KV - OPEN
- Gang - Not Remotely Operated - 8.32 KV - CLOSED
- Gang - Not Remotely Operated - 8.32 KV - OPEN
- FUSED SWITCH - 8.32 KV - CLOSED
- FUSED SWITCH - 8.32 KV - OPEN
- PADMOUNT TX - 8.32 KV
- POLEMOUNT TX - 1 UNIT - 8.32 KV
- POLEMOUNT TX - 2 UNITS - 8.32 KV
- POLEMOUNT TX - 3 UNITS 8.32 KV
- Substations

Lambton County
Key Map

BLUEWATER POWER DISTRIBUTION CORPORATION

Oil Springs
8.32 KV Distribution

Prepared by:	Ena Forbes
Date:	July 16, 2008
Scale:	1:20,000

Legend

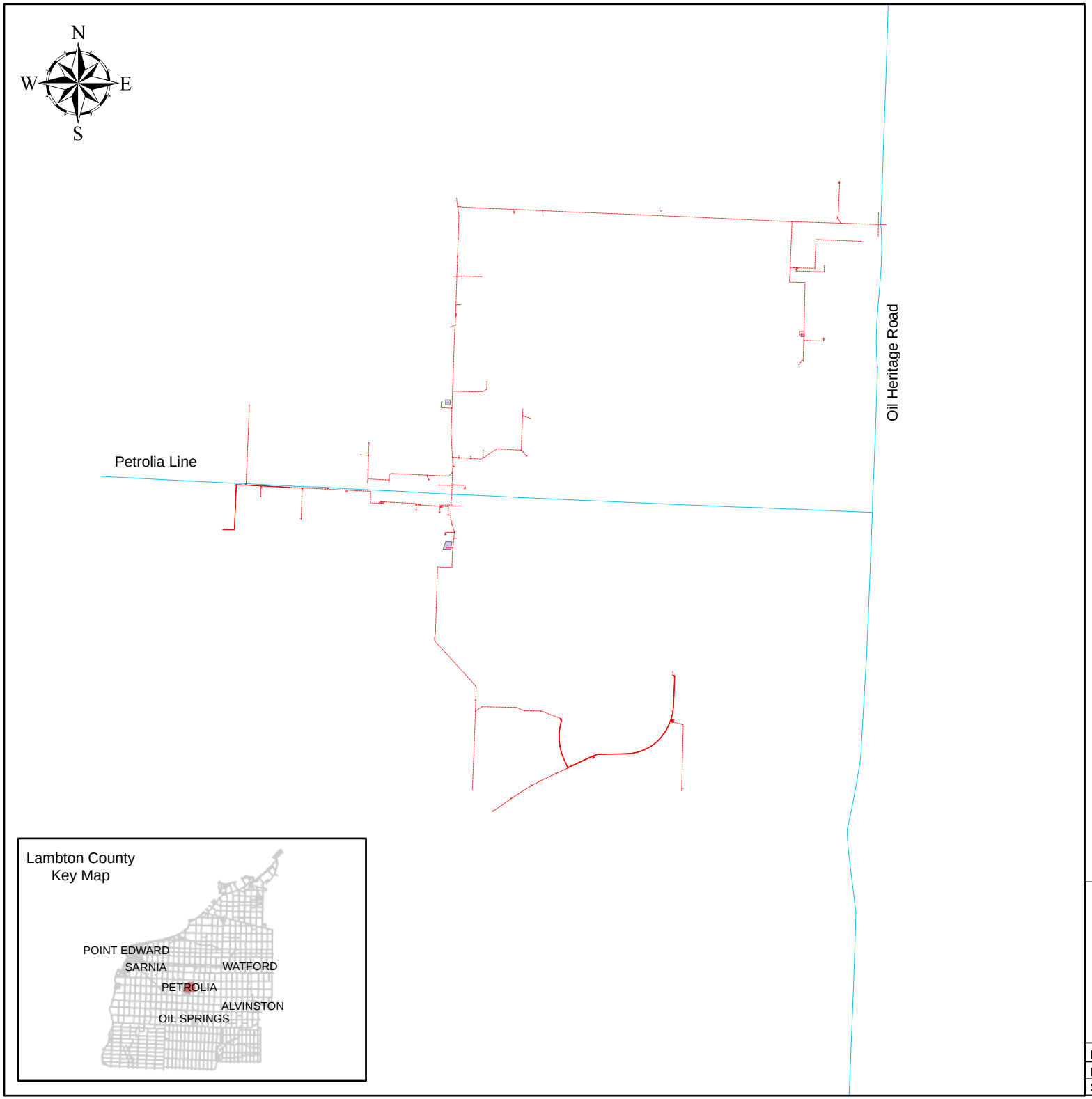
- OH - 3 PHASE 4.16 KV
- OH - 2 PHASE - 4.16 KV
- OH - 1 PHASE 4.16 KV
- UG 3 PHASE 4.16 KV
- UG 2 PHASE 4.16 KV
- UG 1 PHASE 4.16 KV
- AIRBREAK - 4.16 KV - CLOSED
- AIRBREAK - 4.16 - OPEN
- SOLID - 4.16 - CLOSED
- SOLID - 4.16 - OPEN
- Gang - Not Remotely Operated - 4.16 KV CLOSED
- Gang - Not Remotely Operated - 4.16 KV - OPEN
- FUSED SWITCH - 4.16 KV - CLOSED
- FUSED SWITCH - 4.16 KV - OPEN
- PADMOUNT TX - 4.16 KV
- POLEMOUNT TX - 1 UNIT- 4.16 KV
- POLEMOUNT TX - 2 UNITS- 4.16 KV
- POLEMOUNT TX - 3 UNITS- 4.16 KV
- RABBIT - 1 UNIT- 4.16 KV
- POLETRANS - 1 UNIT- 4.16 KV
- Substations

Lambton County
Key Map

BLUEWATER POWER DISTRIBUTION CORPORATION

Petrolia
4.16 KV Distribution

Prepared by:	Ena Forbes
Date:	July 16, 2008
Scale:	1:25,000



Legend

- OH - 3-PHASE 27.6 KV
- OH - 2-PHASE 27.6 KV
- OH - 1-PHASE 27.6 KV
- UG - 3-PHASE 27.6 KV
- UG - 2-PHASE 27.6 KV
- UG - 1-PHASE 27.6 KV
- SOLID - 27.6 KV - CLOSED
- SOLID - 27.6 KV - OPEN
- Gang -Not Remotely Operated - 27.6 KV - CLOSED
- Gang -Not Remotely Operated - 27.6 KV - OPEN
- Gang - Remotely Operated - 27.6 KV - CLOSED
- Gang - Remotely Operated - 27.6 KV - OPEN
- FUSED SWITCH - 27.6 KV - CLOSED
- FUSED SWITCH - 27.6 KV - OPEN
- PADMOUNT - 27.6 KV
- POLEMOUNT - 1 UNIT - 27.6 KV
- POLEMOUNT - 2 UNIT - 27.6 KV
- POLEMOUNT - 3 UNIT - 27.6 KV
- RABBIT - 1 UNIT - 27.6 KV
- RABBIT - 3 UNIT - 27.6 KV
- Substations

Lambton County
Key Map

BLUEWATER POWER DISTRIBUTION CORPORATION

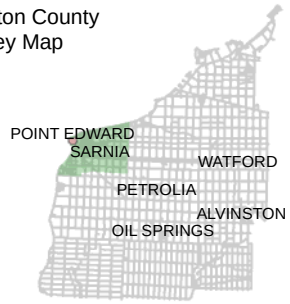
Petrolia
27.6 KV Distribution

Prepared by:	Ena Forbes
Date:	July 16, 2008
Scale:	1:25,000

Legend

- OH - 3 PHASE 4.16 KV
- OH - 1 PHASE 4.16 KV
- UG 3 PHASE 4.16 KV
- UG 2 PHASE 4.16 KV
- UG 1 PHASE 4.16 KV
- AIRBREAK - 4.16 KV - CLOSED
- AIRBREAK - 4.16 - OPEN
- SOLID - 4.16 - CLOSED
- SOLID - 4.16 - OPEN
- Gang - Not Remotely Operated - 4.16 KV CLOSED
- Gang - Not Remotely Operated - 4.16 KV - OPEN
- FUSED SWITCH - 4.16 KV - CLOSED
- FUSED SWITCH - 4.16 KV - OPEN
- PADMOUNT TX - 4.16 KV
- POLEMOUNT TX - 1 UNIT - 4.16 KV
- POLEMOUNT TX - 2 UNITS - 4.16 KV
- POLEMMOUNT TX - 3 UNITS - 4.16 KV
- RABBIT - 1 UNIT - 4.16 KV
- POLETRANS - 1 UNIT - 4.16 KV
- Substations

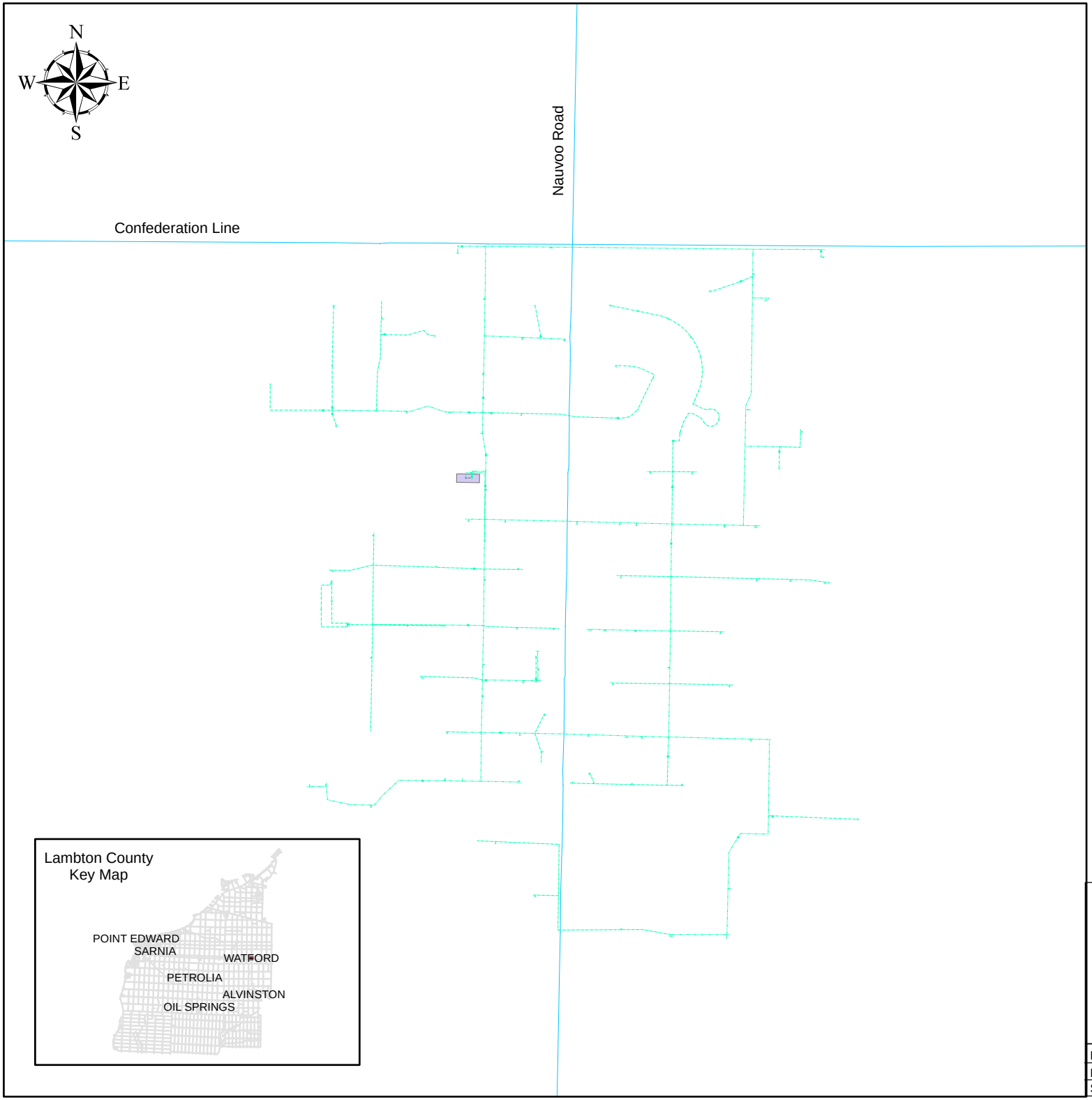
Lambton County
Key Map



BLUEWATER POWER DISTRIBUTION CORPORATION

Sarnia & Point Edward
4.16 Distribution

Prepared by:	Ena Forbes
Date:	July 16, 2008
Scale:	1:100,000



Legend

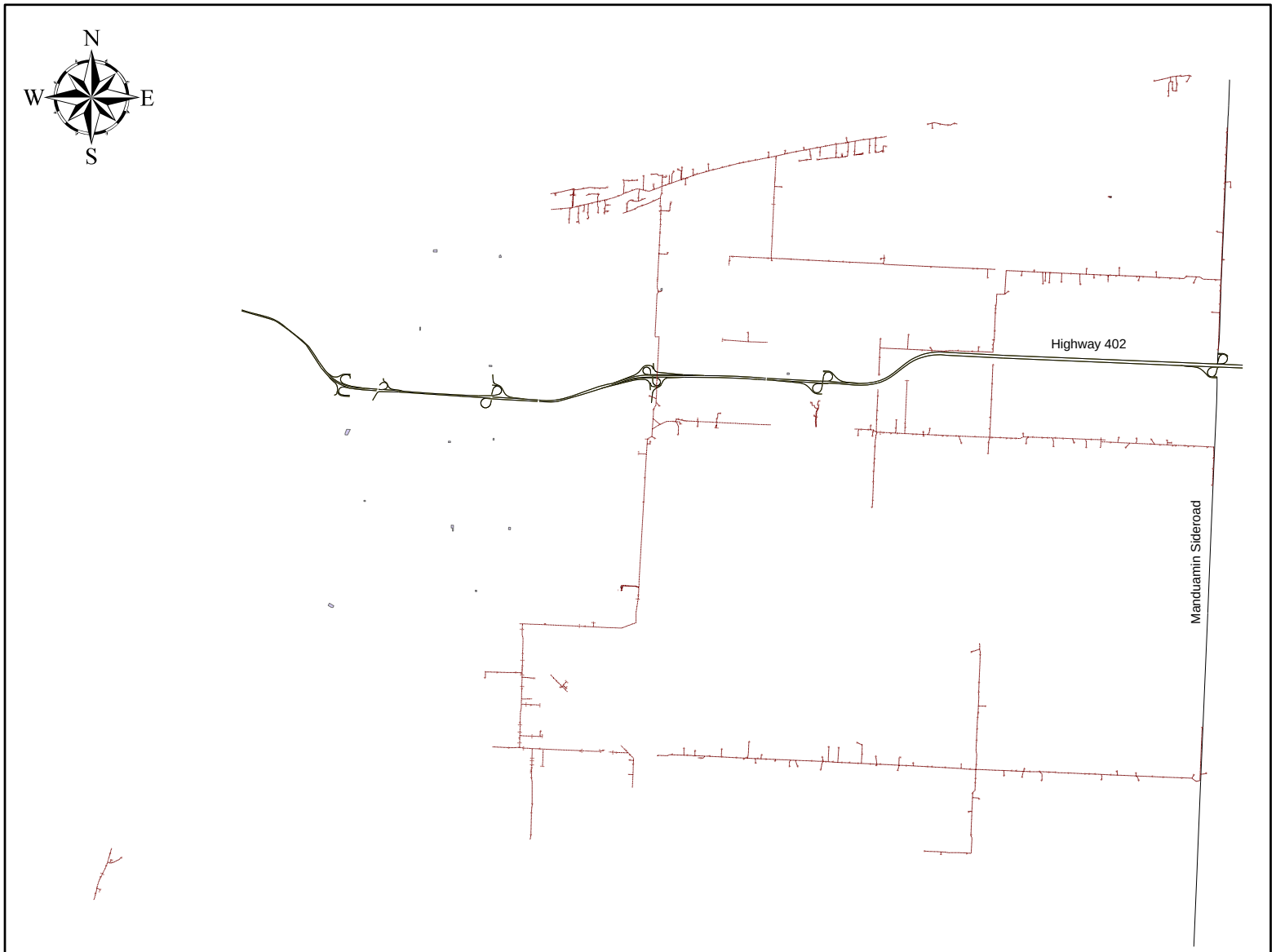
- OH - 3 PHASE 4.16 KV
- OH - 2 PHASE - 4.16 KV
- OH - 1 PHASE 4.16 KV
- UG 3 PHASE 4.16 KV
- UG 2 PHASE 4.16 KV
- UG 1 PHASE 4.16 KV
- AIRBREAK - 4.16 KV - CLOSED
- AIRBREAK - 4.16 - OPEN
- SOLID - 4.16 - CLOSED
- SOLID - 4.16 - OPEN
- Gang - Not Remotely Operated - 4.16 KV CLOSED
- Gang - Not Remotely Operated - 4.16 KV - OPEN
- FUSED SWITCH - 4.16 KV - CLOSED
- FUSED SWITCH - 4.16 KV - OPEN
- PADMOUNT TX - 4.16 KV
- POLEMOUNT TX - 1 UNIT - 4.16 KV
- POLEMOUNT TX - 2 UNITS- 4.16 KV
- POLEMOUNT - 3 UNITS- 4.16 KV
- RABBIT - 1 UNIT- 4.16 KV
- POLETRANS- 1 UNIT - 4.16 KV
- Substations

Lambton County
Key Map

BLUEWATER POWER DISTRIBUTION CORPORATION

Watford
4.16 KV Distribution

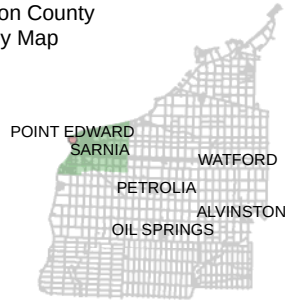
Prepared by:	Ena Forbes
Date:	July 16, 2008
Scale:	1:10,000



Legend

- OH - 3 PHASE 8.32 KV
- OH - 2 PHASE 8.32 KV
- OH - 1 PHASE 8.32 KV
- UG - 3 PHASE 8.32 KV
- UG - 1 PHASE 8.32 KV
- AIRBREAK - 8.32 KV - CLOSED
- SOLID - 8.32 KV - CLOSED
- SOLID - 8.32 KV - OPEN
- Gang - Not Remotely Operated - 8.32 KV - CLOSED
- Gang - Not Remotely Operated - 8.32 KV - OPEN
- FUSED SWITCH - 8.32 KV - CLOSED
- FUSED SWITCH - 8.32 KV - OPEN
- PADMOUNT TX - 8.32 KV
- POLEMOUNT TX - 1 UNIT - 8.32 KV
- POLEMOUNT TX - 2 UNITS - 8.32 KV
- POLEMOUNT TX - 3 UNITS 8.32 KV
- Substations

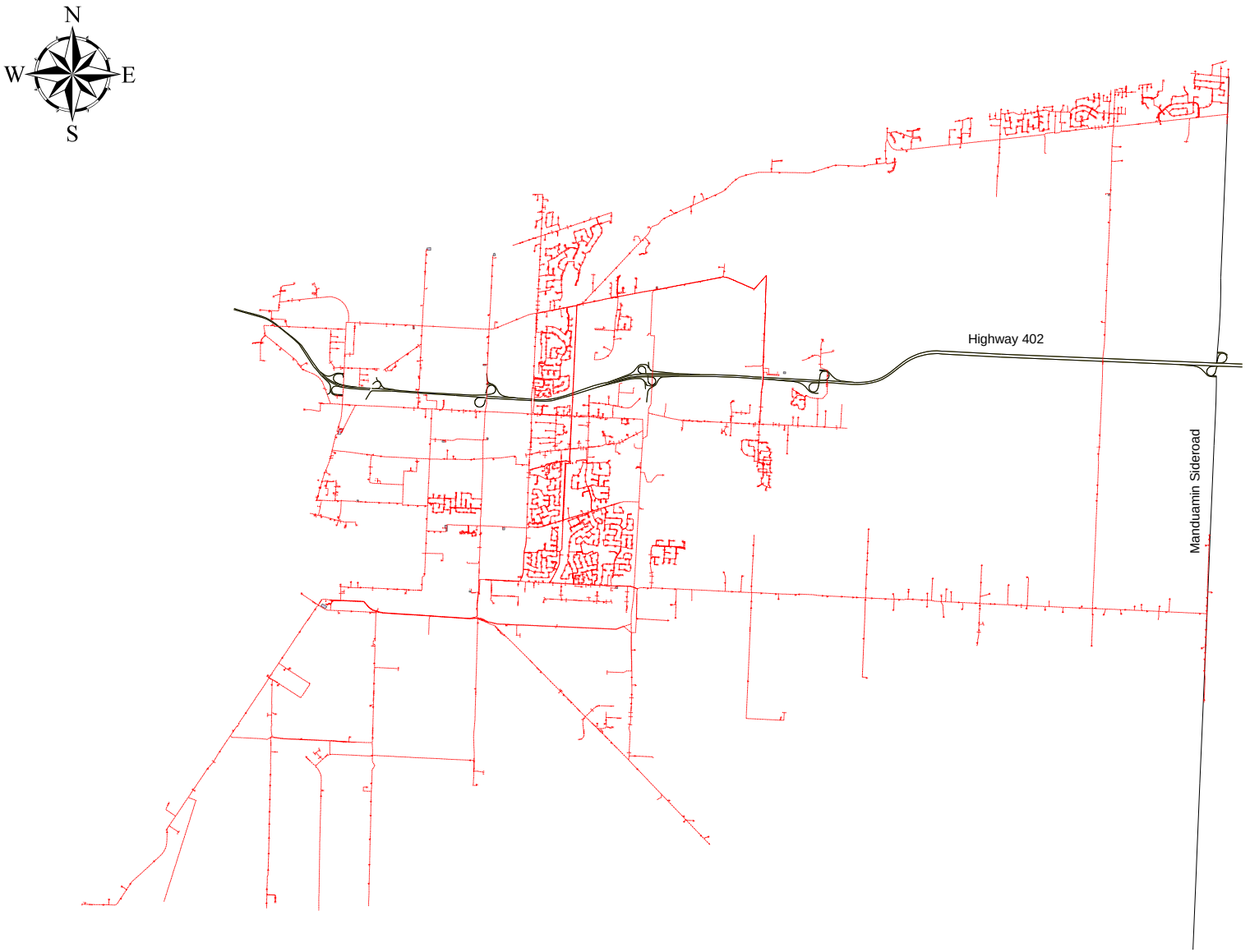
Lambton County
Key Map



BLUEWATER POWER DISTRIBUTION CORPORATION

Sarnia & Point Edward
8.32 Distribution

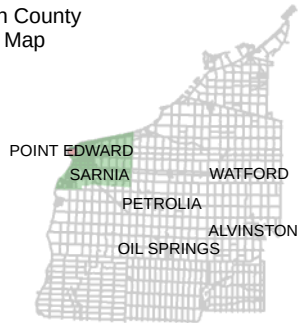
Prepared by:	Ena Forbes
Date:	July 16, 2008
Scale:	1:100,000



Legend

- OH - 3-PHASE 27.6 KV
- OH - 2-PHASE 27.6 KV
- OH - 1-PHASE 27.6 KV
- UG - 3-PHASE 27.6 KV
- UG - 2-PHASE 27.6 KV
- UG - 1-PHASE 27.6 KV
- SOLID - 27.6 KV - CLOSED
- SOLID - 27.6 KV - OPEN
- Gang -Not Remotely Operated - 27.6 KV - CLOSED
- Gang -Not Remotely Operated - 27.6 KV - OPEN
- Gang - Remotely Operated - 27.6 KV - CLOSED
- Gang - Remotely Operated - 27.6 KV - OPEN
- FUSED SWITCH - 27.6 KV - CLOSED
- FUSED SWITCH - 27.6 KV - OPEN
- PADMOUNT TX - 27.6 KV
- POLEMOUNT TX - 1 UNIT - 27.6 KV
- POLEMOUNT TX - 2 UNIT - 27.6 KV
- POLEMOUNT TX - 3 UNIT - 27.6 KV
- RABBIT - 1 UNIT - 27.6 KV
- RABBIT - 3 UNIT - 27.6 KV
- Substations

Lambton County
Key Map



BLUEWATER POWER DISTRIBUTION CORPORATION

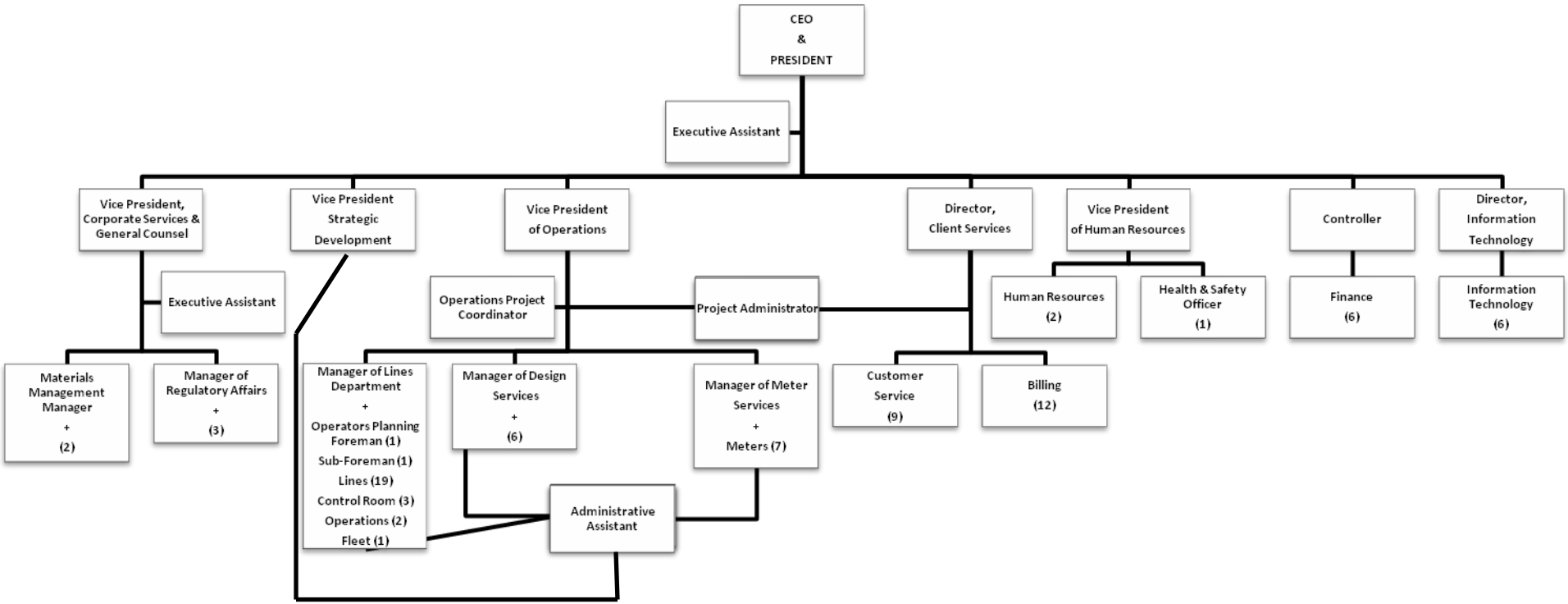
Sarnia & Point Edward 27.6 Distribution

Prepared by:	Ena Forbes
Date:	July 16, 2008
Scale:	1:100,000

Utility Organizational Chart

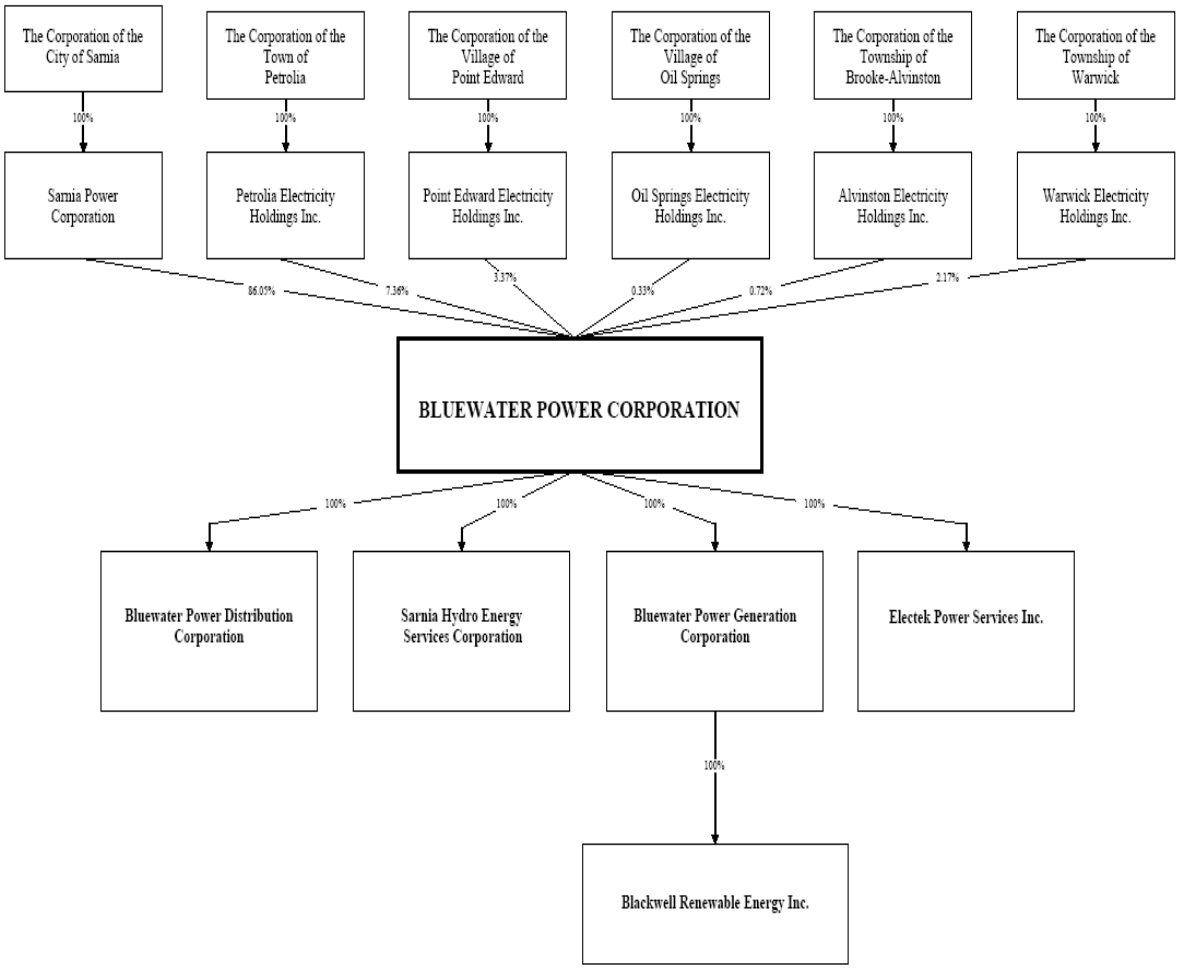
The organizational chart of Bluewater Power is attached as Exhibit 1, Tab 2, Schedule 4, Attachment 1.

BLUEWATER POWER
ORGANIZATIONAL CHART



Corporate Entities Relationships Chart

The corporate entities relationships chart for Bluewater Power is below.



Planned Changes in Corporate or Operational Structure

Bluewater Power is currently pursuing a corporate restructuring that would see certain Non-Core Distribution Activities moved from the regulated utility to an affiliate. That restructuring has been driven by concerns regarding compliance with the Affiliate Relationships Code ("ARC") and certain compliance bulletins issued by the Ontario Energy Board Compliance Office. The proposed structure will result in the removal of all Non-Core Distribution Activities from the utility, with the only exception being water billing as well as conservation and demand management ("C&DM") activities which are specifically authorized by legislation as permitted activities for a licensed electricity distributor in Ontario.

The impact on this rate application is demonstrated below to be non-material because, although these Non-Core Distribution Activities are currently undertaken within the utility, all costs are reallocated to "Account 4380 – Expenses of Non-Utility Operations" in accordance with the Accounting Procedures Handbook ("APH"). Therefore, whether the activities were carried out within the utility or an affiliate, the costs would not form the basis of rates.

Bluewater Power is a fully-integrated utility that directly employs personnel providing distribution services to customers. Bluewater Power does not, for example, employ the so-called "asset management model" wherein the regulated utility has very few employees and assets and as such, receives its services from an affiliate. The Bluewater Power employees providing distribution services also engage in Non-Core Distribution Activities that fall within one of the classifications that follow:

1. Water billing for the City of Sarnia and Town of Petrolia (both are shareholders);
2. C&DM through Ontario Power Authority ("OPA") funded conservation programs;
3. Street light capital work and maintenance for all shareholder municipalities;
4. Traffic light capital work and maintenance for all shareholder municipalities;
5. Civil construction (subdivision installations, as well as installations for other utilities and non-utility third parties);
6. Miscellaneous on-demand line work.

When Non-Core Distribution Activities are undertaken by Bluewater Power, all related costs are booked in accordance with the APH to "Account 4380 - Expenses of Non-Utility Operations". This accounting treatment ensures that ratepayers do not pay for costs related to the provision of non-utility services. To the extent that Bluewater Power employees are able to perform these Non-Core Distribution Activities during "off-peak" periods for the distribution business, they allow for a more efficient use of Bluewater Power's assets, including employees.

Nevertheless, these Non-Core Distribution Activities cannot continue because Bluewater Power is forced to address Compliance Bulletin #200605 which reads as follows:

> ***"This Bulletin is intended to provide guidance to licensed electricity distributors in relation to compliance with section 71(1) of the Ontario Energy Board Act, 1998.***
> *Under section 71(1) of the Ontario Energy Board Act, 1998 (the "Act"), a distributor may not, except through one or more affiliates, carry on any business activity other than transmitting or distributing electricity. The only exceptions to this general limitation on a distributor's permitted activities are those set out in legislation. These exceptions include those identified in section 71(2) of the Act and in the Definitions and Exemptions Regulation, O. Reg. 161/99.*
> *It has come to the attention of the Compliance Office that distributors may have different views as to the nature of the activities that are permitted under section 71(1) of the Act.*
> *It is my view that the business activities authorized by section 71(1) are limited to distribution activities. I consider distribution activities to be those that enable the conveyance of electricity for distribution purposes. Such activities must be conducted within the distributor's licensed service area and include, but are not limited to, the operation and maintenance of the distribution system, meter reading services, and services for billing and collecting electricity charges.*
> *I do not consider the following to be distribution activities and, as such, these would not be permitted business activities for a distributor under section 71(1) of the Act (this list is not intended to be exhaustive):*
>
> - *Contracting out of distributor employees to a third party, including an affiliate.*
> - *Services for billing and collecting charges other than electricity charges (such*

as billing for water heater rentals or sales).

- *Street lighting services.*
- *Sentinel lighting services.*
- *Provision of engineering and construction services, where such services are provided outside the scope of a distributor's obligations (for example, in relation to privately-owned electrical infrastructure)."*

These provisions specifically state that street lighting services are not a permitted activity for a utility. If that is accepted, then it would certainly follow that traffic light services are not a permitted activity for a utility. Moreover, the general prohibition on contracting out distributor employees would prevent a regulated utility from contracting its services for civil construction, as well as miscellaneous on-demand line work where the work is not carried out on Bluewater Power's distribution system.

Accordingly, the restriction found in Compliance Bulletin #200605 purports to prohibit the Non-Core Distribution Activities identified above as #3 through #6, inclusive (henceforth this subset of Non-Core Distribution Activities will be referred to as "Affiliate Activities"). Bluewater Power may not agree with the opinion expressed in the compliance bulletin, but it is prepared to accept that direction from the Compliance Office and, therefore, Bluewater Power has proposed this reorganization to ensure complete technical compliance.

Therefore, Bluewater Power is working to move the Affiliate Activities to an affiliate effective January 1, 2009. Sarnia Hydro Energy Services Corporation ("SHESC") is currently an inactive affiliate. SHESC holds an electricity retailer license from the OEB, but no activity has ever taken place within the company and that license will eventually be given up.

As of January 1, 2009, it is proposed that the only Non-Core Distribution Activities to continue within Bluewater Power are water billing for municipal shareholders (as permitted by Section 5(2) of *O.Reg.161/99*) and C&DM (as permitted by Section 71(2) of the *Ontario Energy Board Act*). The costs associated with those activities will continue to be reallocated to Account 4380.

The restructuring of all other Non-Core Distribution Activities, defined above as Affiliate Activities, will be accomplished by moving two linepersons, the four person civil crew, civil equipment and all other related costs from Bluewater Power to SHESC. The cost assumed by SHESC in 2009 is $592,967.

The impact on ratepayers from this restructuring is minimal because during the historic and bridge years, costs were also removed from distribution OM&A as these costs were reallocated to Account 4380. In other words, the costs avoided by moving employees and equipment to the affiliate are substantially similar to the costs avoided by reallocating those costs to Account 4380.

The following table looks at the benefit received by ratepayers from Non-Core Distribution Activities whether they take place within the utility (2007 and 2008) or through an affiliate (2009). That benefit is found in the form of reduced distribution OM&A that would otherwise be recovered through rates and is found in two forms:

(1) cost avoided from being included in distribution OM&A by either (i) reallocating distribution OM&A to Account 4380, or (ii) avoiding costs from being included in OM&A by transferring the cost to the affiliate; or

(2) revenue earned from the affiliate as rent or management fees.

Table 1.2.6.1

	2007 Treatment (Actual)	2008 Treatment (Budgeted)	2009 Treatment (Budgeted)
Reallocation of payroll and benefits to Account 4380 in respect of Affiliate Activities	$435,265 [1]	$275,216	
Capitalized Labour by Civil Crew	$126,369 [2]	$136,000 [2]	
Salary and benefits removed from Bluewater Power to SHESC (represents 4 person civil crew and 2 linepersons)			$507,620 [3]
Management and supervision fees earned by Bluewater Power from SHESC (revenue offset)			$46,560
Reallocation of overhead & use of capital	$2,614	$1,668	
Rental earned by Bluewater Power from SHESC (revenue offset)			$12,000
Reallocation of vehicle costs to Account 4380	$55,518	$41,714	
Capitalization of civil vehicle costs	$21,551	$32,805	
Vehicle costs avoided for civil equipment			$32,975
Vehicle rental earned by Bluewater Power from SHESC			$20,800
NET BENEFIT RECEIVED BY RATEPAYERS	$641,317	$487,403	$607,967

[1] The year 2007 also included $129,534 in costs reallocated to Account 4380 in respect of one-time projects, but those costs have not been included in this analysis because they are extraordinary costs that ought not reasonably be anticipated to be repeated.

[2] The purpose of this analysis is to examine costs avoided in distribution OM&A. In 2007 and 2008, the civil crew performed certain capital work and payroll costs were capitalized resulting in distribution OM&A being lowered. Including those OM&A offsets in this table allows a more equivalent comparison to 2009 where all costs related to the civil crew have been removed from distribution OM&A.

[3] This cost represents the cost to the affiliate in 2009 dollars. It is worth noting here that the cost shown in Exhibit 4, Tab 2, Schedule 2, in Section 2.8 reflects the 2007 equivalent figure, which is $471,929.

What table 1.2.6.1 demonstrates is that ratepayers are not materially impacted by the corporate restructuring proposed. Year to year comparisons are difficult because 2007 was an exceptionally busy year for Non-Core Distribution Activities, whereas 2008 has been budgeted as a more normal year. From a practical perspective, SHESC will need to be staffed sufficiently to handle both types of years and, therefore, the costs of running the affiliate shown above ($607,967) are slightly higher than the average cost reallocated to Account 4380 in the years 2007 and 2008 ($564,360).

This corporate restructuring has broad reaching impacts on this application, and Bluewater Power has attempted to provide a fulsome explanation wherever possible to assist the Board. Many times during this application, readers will be referred back to this section to recall the implications of this restructuring.

Those sections of this application where this corporate restructuring are most relevant are as follows:

- EXHIBIT 3- REVENUE
  - Tab 3, Schedule 4 – Revenue From Affiliates
- EXHIBIT 4 – OPERATING COSTS
  - Tab 2, Schedule 2 – Variance Analysis on OM&A Costs Table
  - Tab 2, Schedule 4 – Shared Services
  - Tab 2, Schedule 5 – Service Agreement(s)
  - Tab 2, Schedule 7 – Non-Core Distribution Activities

Conditions of Service/Service Charges

The Conditions of Service document is attached as Exhibit 1, Tab 2, Schedule 7, Attachment 1.

CONDITIONS

of

ELECTRICAL SERVICE

May 1, 2007

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PART 1 – INTRODUCTION

1.1 Identification of Distributor and Service Territory

1.1.1 The Distributor

These Conditions of Electrical Supply are relevant to Bluewater Power Distribution Corporation (BPDC), which is an Ontario Business Corporation Act Corporation whose shares are owned by the Municipal Corporation representing the areas that BPDC services. The address for BPDC:

Bluewater Power Distribution Corporation
P.O. Box 2140
855 Confederation Street
Sarnia, Ontario
N7T 7L6
Phone: 519-337-8201
Fax: 519-332-3878

1.1.2 Service Territory

As outlined in the Distributors License and the map contained in Appendix 5.1, BPDC's service territory is within the municipal boundaries of the following municipalities:

City of Sarnia
Village of Point Edward
Town of Petrolia
Township of Warwick
Township of Brook-Alvinston
Village of Oil Springs

1.2 Related Codes, and Governing Laws

1.2.1 The operations of BPDC are regulated by the Ontario Energy Board [OEB]. The OEB has regulatory responsibility under the Energy Competition Act, 1998. The OEB administers these regulatory tasks through a series of Codes and laws as follows:

The hierarchy of Codes and laws is as follows:

Electricity Act
Ontario Energy Board Act
Distribution License
Affiliate Relationships Code
Distribution System Code
Retail Settlement Code

Adherence to these codes is a condition of obtaining and maintaining a Distribution License to operate as an Electrical Distributor within the Province of Ontario. In the event of a conflict between these Conditions of Service and any of the above, the documents listed above shall prevail in the order of priority indicated above. If there is a conflict between these Conditions of Service and a Connection Agreement with a customer, the Connection Agreement shall govern.

BPDC also complies with the Personal Information Protection and Electronic Documents Act in managing its relationship with its customers and to protect the information they provide.

1.3 Interpretations

1.3.1 Words and phrases shall have the meaning ascribed to them in the Glossary of Terms included herein, or in the absence of a definition, the meaning may be found in any of the Codes and Laws listed in Section 1.2.1 above.

1.3.2 This document has been prepared by BPDC as mandated by the Ontario Energy Board. It has been prepared in accordance with the format of the "Conditions of Service Template" issued with the Distribution System Code.

1.3.3 Any disagreement of interpretations will be decided by BPDC through a dispute resolution process referred to in paragraph 1.8 below.

1.4 Amendments and Changes

1.4.1 BPDC shall provide advance public notice of any pending changes to its Conditions of Service by placing a notice in the Sarnia Observer, or equivalent newspaper or, at least, with a note on each customer account. The notice shall provide a proposed time-line of implementation of the changes. The public may make written comment on the proposed changes to BPDC, which shall be included with the document that is submitted to the OEB.

1.5 Contact Information

1.5.1 Bluewater Power Distribution Corporation
P.O. Box 2140
855 Confederation Street
Sarnia, Ontario
N7T 7L6

Phone: 519-337-8201
Fax: 519-332-3878
email: emailus@bluewaterpower.com

Regular office hours are:	Monday to Friday, except statutory holidays 8:30 am to 4:30 pm Customer Service phone – 519-337-8201
Operations Staff Hours:	Monday to Friday, except statutory holidays 7:30 am to 4:00 pm
Operations Control Room:	Monday to Friday, except statutory holidays 7:30 am to 4:30 pm

1.6 Customer Rights

1.6.1 Customers have the right to be treated in the same manner as other like customers and in compliance with these Conditions of Service.

1.6.2 Customers have the right to make enquiries on these Conditions of Service.

1.6.3 Customers have the right to review these conditions and provide comments as they deem appropriate.

1.7 Distributor Rights

1.7.1 BPDC has the right to enforce these Conditions of Service.

1.8 Customer Complaint and Dispute Resolution Process

1.8.1 Customer complaints and/or disputes that are received by the Distributor shall be dealt with according to company policy US-GE-014 – Responding to Customer Power Quality Complaints (Schedule 1).

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PART 2 – DISTRIBUTION ACTIVITIES (General)

2.1 Connections

2.1.1 Obligation to Connect a Building that "Lies Along"

The Distribution System Code obligates the Distributor (BPDC) to provide an electrical connection to any Building that "Lies Along" its electrical distribution system.
A building "lies along" a distribution line if the building is directly adjacent to or abuts onto the public road allowance where BPDC has distribution facilities of the appropriate voltage and with sufficient capacity.

2.1.2 BPDC's obligation to connect a building that "lies along" does not imply there will be no cost to the customer. Connection charges will apply as outlined in section 2.9 Tariffs and Charges.

2.1.3 For both primary and secondary services, BPDC will designate a supply point. This could be a manhole, handhole, pole, or pad-mounted device. This supply location could also be located on an adjacent property for which BPDC has an authorized easement. In all cases, the final supply point will be the decision of BPDC.

2.1.4 A request for electrical connection shall be made in writing to the BPDC Customer Service department. In determining BPDC's compliance with time lines for the processing of the request, time will commence on the date the written request is received by BPDC.

2.1.5 BPDC may require, at its sole discretion that a customer enter into a Distribution Connection Agreement (Schedule 14) in the form and substance similar to that set out in Schedule 13 attached hereto. A customer may request a Distribution Connection Agreement but the decision as to whether an agreement is required, or would be beneficial shall be made by BPDC.

2.2 Exceptions to the Obligation to Connect in Section 2.1.1

2.2.1 A building that "lies along" a distribution line may be refused connection to that line should the distribution line not have sufficient capacity for the requested connection.

2.2.2 A building that "lies along" a distribution line may be refused connection to that line should the service voltage level requested by the customer not be available.

2.2.3 A building that "lies along" a distribution line may be refused connection to that line should the connection be deemed to be unsafe or detrimental to the electrical distribution system as outlined in section 2.5 Connection Denial.

2.2.4 Where the customer requests a service upgrade to an existing building that has more than one service connection onto the property, BPDC may require that all services be consolidated into a single service connection. This position is supported by the Electrical Safety Authority and is consistent with the Electrical Safety Code.

2.3 Expansions/Obligation to Offer to Connect

2.3.1 Where the Distribution System Code and/or these Conditions of Service obligate BPDC to provide service to a customer through an expansion of the distribution system, that process shall commence with the filing by the customer of the Request for Connection, followed by the issuance by the distributor of an Offer to Connect substantially in the form and substance attached hereto as Schedule 12.

2.3.2 BPDC may respond to a request for service with an Offer to Connect even where a building or property is not included in its service territory, although any Offer to Connect so issued is conditional upon a service area amendment being approved by the OEB.

2.3.3 The Offer to Connect will be sent to the customer within thirty (30) days of the date the Request for Connection is received by BPDC.

2.3.4 The Offer to Connect will be based on BPDC's incremental cost of providing the service, including the expansion directly attributable to the customer's project, as well as any general system enhancement, to facilitate the supply. Costs shall include engineering, supervision, labour, equipment, materials, and associated administrative overhead costs. The revenue considered in the economic evaluation shall be based on the incremental load proposed by the customer determined by taking the total forecasted load provided by the customer and subtracting any existing load at the customer's property, or any customer load in the BPDC service territory that is being transferred to the site of the expansion. It is the responsibility of the customer, or their agent, to provide a forecast that reasonably approximates the anticipated monthly average demand/consumption.

2.3.5 The written Offer to Connect will outline the following items in detail:

- A description of the work, equipment, labour, and materials to be used to construct the expansion project.
- The process for determining the level of capital contributions required from the customer.
- The connection fees, if any, applicable to making the connection.
- Expansion Deposit required of the customer.

2.3.6 Where a customer submits a revised plan, a new Offer to Connect shall be provided to the customer. However, prior to the preparation of the new Offer to Connect, the customer shall pay the cost of the review, design and

preparation of the revised estimate. The costs of responding to the revised plan will not form part of the capital cost of the project.

2.4 Alternative Bids for Offers to Connect that Require Capital Contributions from the Customer

2.4.1 In its Offer to Connect, a customer interested in an alternative bid is required to do all work eligible for alternative bid.

2.4.2 Where an Offer to Connect has been issued, the customer has the right to obtain an alternative quote, at their own expense, for work indicated in the Offer to Connect as eligible for alternative bid, generally described as work on existing circuits. That work must be undertaken in accordance with the Offer to Connect.

2.4.3 If the customer elects to accept a bid from an alternative contractor, the customer shall accept the responsibilities associated with the work set out below. The customer shall pay any costs incurred by BPDC that are associated with the customer electing to accept a bid from an alternative contractor, including, but not be limited to, the following:

- Costs for additional design, engineering, or installation of facilities required to complete the project that was made in addition to the original Offer to Connect.
- Costs for inspection or approval of the work performed by the contractor hired by the customer.
- Costs for administering the contract.

2.5 Connection Denial

2.5.1 The Distribution System Code provides for the ability of a Distributor to deny connections. A Distributor is not obligated to connect a building within its service territory if the connection would result in any of the following:

- Contravention of existing laws of Canada and the Province of Ontario.
- Violations of conditions of BPDC's License.
- Use of a distribution system line for a purpose that it does not serve and that the Distributor does not intend it to serve.
- Adverse effect on the reliability and safety of the distribution system.
- Imposition of an unsafe work situation beyond normal risks inherent in the operation of the distribution system.
- A decrease in the efficiency of the distributor's distribution system.
- An adverse effect on the quality of distribution services received by an existing connection.
- Discriminatory access to distribution services.
- Potential increases in monetary amounts that already are in arrears with the distributor.
- A breach of any other condition generally documented in BPDC's Conditions of Service document that are generally consistent with the

conditions identified above and with the goals delineated in the Electricity Act.

2.5.2 If BPDC refuses to connect a building in its service territory that lies along one of its distribution lines, BPDC must inform the customer requesting the connection of the reasons for not connecting. Where the distributor is able to provide a remedy that would permit the connection, it shall do so in accordance with an Offer to Connect.

2.5.3 If the Distributor is unable to provide a remedy, it is the responsibility of the customer to do so before a connection can be made.

2.6 Inspection before Connections

2.6.1 Civil Construction

2.6.1.1 A BPDC representative shall inspect all underground civil installations by the customer prior to backfilling. The customer can backfill an excavation only after receiving approval from a BPDC representative. Any defects in workmanship or deviations from the BPDC Construction and Design Standards shall be corrected at the customer's expense prior to receiving BPDC approval to backfill.

2.6.1.2 The customer shall call for BPDC site inspection a minimum of two (2) working days in advance to co-ordinate any excavation and again two (2) days in advance of backfilling any excavations. The BPDC representative will indicate a time and date for the site visit.

2.6.1.3 Any work outside of the scope of the BPDC Construction and Design Standards shall be subject to inspection by the Electrical Safety Authority prior to electrical connection. Confirmation of electrical inspection approval must be received by BPDC prior to electrical connection.

2.6.2 Electrical Installations

2.6.2.1 All customer electrical installations shall be inspected and approved by the Electrical Safety Authority (ESA) and shall meet BPDC Construction and Design Standards. BPDC requires notification from ESA of its approval prior to energizing a customer's supply of electricity. Services that have been disconnected for the purposes of upgrade or change, or services that have been altered subsequent to ESA approval must be re-inspected and approved by the ESA prior to energization.

2.6.2.2 BPDC has the right to inspect all materials and workmanship related to any electrical installation that will be connected to the distribution system in order to determine compliance with items listed in section 2.5 Connection Denial.

2.6.2.3 Other customer specific requirements are outlined in Part 3 Distribution Activities (Customer Specific) and are applicable to customers who fall into each class of customer.

2.6.2.4 Metering must comply with BPDC requirements set out in Section 2.8 of these Conditions of Service and shall be inspected and approved by BPDC prior to energization.

2.6.3 Relocation of Plant

2.6.3.1 The relocation of BPDC electrical distribution plant will be governed by Public Service Works on Highways Act, letters of agreement, easement agreements, and the laws of Ontario as applicable. In the absence of an existing agreement, BPDC is not obligated to relocate its facilities.

2.6.3.2 If a customer requests the relocation of BPDC plant, BPDC will accommodate the request, if possible, where it is satisfied that the relocation will not result in a degradation to system reliability. All costs associated with the relocation, including the cost associated with negotiating for and acquiring land to accommodate the relocation, shall be borne by the customer requesting the relocation.

2.6.4 Easements

2.6.4.1 Where BPDC indicates that an easement is required as a condition of connection, the customer shall pay all costs of obtaining survey services and the creation of a reference plan, legal fees associated with registration at the Land Registry Office, and all BPDC costs related to obtaining the easement. The width and extent of the easement shall be determined by BPDC. The connection shall not be energized until the easement has been registered on title.

2.6.4.2 Any unregistered easements used and enjoyed openly by BPDC shall continue to be used and enjoyed by BPDC subject to the land owner's right to make application to court to prove that BPDC's use of that easement substantially interferes with the owner's use of their lands. The right of BPDC and the landowners are in accordance with Section 43.1 of the Electricity Act and described in Section 91 of the Municipal Act, 2001.

2.6.5 Contracts

2.6.5.1 BPDC may require any customer to enter into a Connection Agreement (Schedule 14), whether that is prior to connection or subsequent to connection.

2.6.5.2 Other types of contracts that customers may be required to enter into are identified in Part 3 Distribution Activities (Customer Specific).

2.6.5.3 Where there is no signed contract, BPDC has an implied contract with all customers connected to its distribution system, the terms of which are found in the rules and guidelines approved or filed with the Ontario Energy Board, including these Conditions of Service, the Rate Handbook, the Distribution Systems Code, and the applicable BPDC rate order. The use or reliance upon BPDCs distribution system by any person or persons constitutes acceptance of such a binding contract. That contract can be enforced in accordance with the laws of the Province of Ontario against the person, their heirs, administrators, successors and assigns.

2.6.6 Disconnection

2.6.6.1 BPDC may disconnect a customer for non-payment of an overdue amount on their electrical account, including an amount for a security deposit unpaid.

2.6.6.2 BPDC may also disconnect a customer if continuance of the connection results in any of the following:

- Adverse effect on the reliability and safety of the BPDC distribution system.
- Imposition of an unsafe worker situation beyond normal risks inherent in the operation of the BPDC distribution system.
- A material decrease in the efficiency of the BPDC distribution system.
- A materially adverse effect on the quality of distribution services received by an existing BPDC customer.
- Inability of BPDC to perform planned inspections and maintenance of its distribution system, due to a customer denying access to the electrical system, or otherwise.
- Failure of a consumer or customer to comply with a BPDC directive that is relevant for BPDC to meet the obligations of its Distribution License or any other obligation.
- Any other customer specific conditions stipulated by BPDC in Part 3 Distribution Activities (Customer Specific).

2.6.6.3 The process for disconnection of electrical service is identified in the BPDC procedure CL-CS-007, Dunning Procedure (Schedule 2).

2.6.6.4 BPDC may disconnect an electrical service without notice in accordance with a court order or for an emergency, safety, or system reliability reason.

2.6.6.5 Re-connection of electrical services that have been disconnected for more than six months shall be inspected by the Electrical Safety Authority prior to re-connection.

2.6.6.6 An electrical service that has been disconnected in response to tampering

with, or by-passing of, a meter shall not be re-connected until the customers' electrical system has been inspected by the Electrical Safety Authority at the customer's expense.

2.7 Conveyance of Electricity

2.7.1 Guarantee of Supply

2.7.1.1 BPDC will endeavour to maintain a constant, uninterrupted supply of electrical energy to all consumers, but cannot and does not guarantee a constant supply of power or assure that voltages and frequency will be unvaried.

2.7.1.2 Neither BPDC, nor any of its consumers, shall be liable for any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential, incidental or special damages, including but not limited to punitive or exemplary damages, whether any of the liability, loss or damages arise in contract, tort or otherwise.

2.7.1.3 Consumers shall be responsible for providing their own equipment to maintain power quality, back-up, or standby facilities, if normal supply limitations are not acceptable to the consumer.

2.7.1.4 BPDC will occasionally be required to interrupt the power supply to consumers during emergencies or during the performance of construction and maintenance duties. Power interruptions initiated by BPDC shall be based on practical considerations, including the inconvenience to customers to the extent reasonable. BPDC will aim to provide the consumer with reasonable advance notice of planned power interruptions, generally 2 – 4 days in advance on radio, or through hand delivered notes where practical.

2.7.1.5 In performing the duties and obligations of its distribution license, BPDC has the right to exercise its powers of entry under Section 40 of the Electricity Act, 1998.

2.7.2 Power Quality

2.7.2.1 BPDC is obligated to maintain a voltage variance standard that is in accordance with the Canadian Standards Association standard CAN3-235, due to Copyright restrictions CSA Standards are available for purchase at "http://www.csa.ca/". BPDC will practice reasonable diligence in maintaining voltage levels, but is not responsible for variations in voltage from external forces.

2.7.2.2 Customers or consumers can file power quality complaints and BPDC

shall respond in accordance with its procedure US-GE-014, Responding To Customer Power Quality Complaints (Schedule 1).

2.7.2.3 Consumers are responsible to ensure that their electrical usage does not have an adverse affect on the distribution system.

2.7.2.4 If the source of a power quality problem is caused by the consumer making the complaint, BPDC will seek reimbursement for the costs of investigating the complaint.

2.7.2.5 No electrical equipment shall be connected to, or remain connected to, the BPDC electrical distribution system that will produce an undesirable system disturbance that may be reflected back to the BPDC distribution system. BPDC may direct a consumer connected to its electrical distribution system to take corrective or preventative action on the consumer's system, at the consumer's cost when there is a direct hazard to public safety, or the consumer is causing, or could cause adverse effects to the reliability or quality of supply of the BPDC distribution system. If the situation is not corrected, BPDC may disconnect the consumer in accordance with the procedure in section 2.6.6.3 of this document.

2.7.3 Electrical Disturbances

2.7.3.1 BPDC will endeavour to maintain the electrical distribution system characteristics as per the CAN3-235 specification. Typical voltage excursions that can be expected on distribution systems are capacitor switching transients, voltage sags caused by faults on adjacent feeders, and auto-reclosure operations. It is the customer's responsibility to protect itself from any external disturbances.

2.7.3.2 Customers requiring an electrical supply that meets a higher degree of quality in terms of fluctuations and electrical noise shall provide their own power conditioning equipment to their satisfaction and at their cost.

2.7.3.3 Customers must ensure that their equipment does not cause any disturbances such as harmonics, spikes, or sags that might interfere with the operation of adjacent customer equipment. In planning the installation of large motors, welders and variable speed drives, the customer shall consult with BPDC.

2.7.4 Standard Voltage Offerings

2.7.4.1 BPDC offers a number of available secondary service voltages. Some voltages are not available in some areas. The service voltages available are listed in Appendix 5.3.1.

2.7.4.2 For reasons of design capacity, BPDC has set maximum capacities for connections on some service voltages. These restrictions are identified in the Customer specific requirements in Part 3.

2.7.5 Voltage Guidelines

2.7.5.1 BPDC maintains service voltage at the customer's service entrance in accordance with the CAN3-235 specification.

2.7.5.2 When voltages lie outside the acceptable limits for Normal Operating Conditions but within the acceptable limits for Extreme Operating Conditions, improvement or corrective action will be taken on a planned and programmed basis, but not necessarily on an emergency basis. When voltages lie outside the acceptable limits for Extreme Operating Conditions, improvement or corrective action will be taken on an emergency basis. The urgency for such action will depend on factors such as the location and nature of the circuit involved, and the extent to which limits are exceeded.

2.7.6 Backup Generators

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

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

2.7.6.3 Where BPDC believes there to be emergency generation equipment present at a customers' connection, it can take all measures necessary to guarantee the safety of its workers and equipment, including the disconnection of the customer until the customer has satisfied BPDC, acting reasonably, that the appropriate safety measure have been put in place.

2.8 Metering

2.8.1 General

2.8.1.2 BPDC shall provide, install, and maintain a meter installation for retail settlements and billing for all customers connected to the BPDC distribution system in accordance with this section.

2.8.1.3 Meters and all other BPDC owned equipment located on the customers' premises shall be in the care of the customer. If destroyed or damaged by other than ordinary wear and tear, the customer shall pay the material and labour costs of repair and/or replacement.

2.8.1.4 The customer shall provide BPDC, free of charge, a safe and convenient space for the installation of meters and metering equipment necessary for the connection of the customer.

2.8.1.5 The customer shall also allow BPDC staff, or authorized agents, access to the customer's premises at all reasonable times to read, repair or maintain, or to inspect meters and meter equipment.

2.8.1.6 The customer shall also obtain direction from BPDC as to the location of service connection prior to proceeding with the installation or relocation of any electrical service. Failure to do so may result in the relocation of the point of service at the customer's cost.

2.8.1.7 No devices other than those required by BPDC for its purposes are permitted to be connected to the BPDC metering equipment or circuits.

2.8.1.8 Any metering or load control equipment required by the customer shall be installed on the load side of the utility metering equipment.

2.8.1.9 Notwithstanding the above, the customer may request the use of duplicate meter pulses from the BPDC metering equipment. The customer shall be responsible for all associated costs.

2.8.1.10 The general rule is that only one service is permitted per property, however, multiple meters may be permitted by BPDC on that service. All new construction of:

- Apartment buildings
- Condominiums
- Multi-unit Commercial

shall be required to have individual meters for each occupant in accordance with the DSC and regulations issued by the OEB or the Province of Ontario from time-to-time. Where multiple meters are required, or otherwise approved by BPDC, BPDC may require that the meters be grouped together in a single location.

2.8.1.11 Meters are to be mounted at a height of 1.7 meters (+/- 100 mm) measured from the center of the meter to finished grade in the immediate area of the meter.

2.8.1.12 Other utilities such as natural gas, sewer, water, communications, etc. shall not be allowed to encroach upon the safe working space requirements of the meter and metering equipment.

2.8.1.13 No meters or metering equipment shall be permitted to be installed inside a hazardous location. A hazardous location shall be any location classified as such under the Ontario Electric Safety Code or where BPDC employees could be at risk from moving machinery, equipment, dust,

fumes, or moisture.

2.8.1.14 Where excessive vibration may affect or damage the metering equipment, the customer shall provide and install an adequate vibration absorbing mounting suitable to BPDC.

2.8.1.15 Meter Rooms shall be accessible via an outside door or from a public area. Where this is not possible and as approved by BPDC, the customer shall be responsible for providing access by keying all locks to BPDC specifications.

2.8.1.16 In general, all meters and metering equipment shall be located on the load side of the step down transformer (i.e. secondary metering). However, some rate classes of customers will be required to install primary metering as determined by BPDC.

2.8.1.17 For services greater than 200 amps metering equipment cabinet and conduit shall be required from the customer at the customer's expense. These are specifications for such cabinet and conduit found in Appendix 5.6.2.

2.8.1.18 In areas of possible vandalism, the customer shall be responsible for providing suitable protection for the metering equipment.

2.8.2 Metering Equipment Boxes

2.8.2.1 Where such equipment is required for an electrical connection the customer shall provide BPDC with the items listed in Appendix 5.6 and the space to mount them within an electrical room.

2.8.2.2 Safe working space of not less than 1 m in front of the meter/equipment location. This shall apply from the floor to ceiling.

2.8.2.3 A minimum ceiling height of 2.5 m from the floor, and adequate lighting to a minimum of 25 foot candles shall also be provided.

2.8.2.4 The mounting height of the cabinet shall be no lower than 1.2 m above the floor measured to the bottom of the cabinet. The top of the cabinet shall be no higher than 2.5 m above the floor.

2.8.3 Interval Metering

2.8.3.1 BPDC may install a demand meter on the customer premises for the purpose of measuring demand to assign the customer to a rate category or for any other purpose, including determining if a customer is required to install an interval meter.

2.8.3.2 Any existing customers with an average monthly peak demand of over 1MW during a calendar year, BPDC is required to install a MIST (Meter inside the Settlements Time Frame) meter. [NOTE: the thresholds expressed herein are subject to change by the province, and customers should contact BPDC for current information.]

2.8.3.3 All new customers with a projected average monthly peak demand of greater than 500kW during a calendar year; BPDC is required to install a MIST meter. Where demand figures provided by the customer appear inaccurate, BPDC shall investigate and if demand is more likely than not to exceed 500KW, as determined is the sole discretion of BPDC, an interval meter shall be installed at the customer's cost. [NOTE: the thresholds expressed herein are subject to change by the province, and customers should contact BPDC for current information.]

2.8.3.4 BPDC shall install an interval meter to any customer upon receipt of a written request only at such time as the regulations of the Province of Ontario or the OEB require, or permit. The request may come directly from the consumer or through it's retailer in accordance with the Retail Settlements Code.

2.8.3.5 BPDC shall provide the interval meter so requested subject to the following conditions:

- The consumer, or it's retailer compensate BPDC for all incremental costs associated with that interval meter including the capital cost, installation costs, on-going maintenance (including allowance for meter failure) verification and re-verification, installation and on-going maintenance of a communication line or link to the customers meter, and costs of all metering made redundant by a customer request for interval metering.
- BPDC shall determine whether the meter will be a MIST or a MOST (Meter outside the Settlements Time Frame) meter.
- A communication system utilized for MIST meters shall be in accordance with BPDC requirements.
- A communication line shall be required in the case of inside or restricted access to meters.

2.8.3.6 The type of metering available to each customer rate class, and the charges for each, are listed later in the Customer Specific sections of these Conditions of Supply.

2.8.4 Meter Reading

2.8.4.1 All metering data collected by BPDC shall be subjected to a Validating, Estimating, and Editing (VEE) process as required by the Distribution

System Code. The VEE process followed by BPDC is included as Appendix 5.5 of the document.

2.8.4.2 All metering activities performed by BPDC shall be governed by and shall comply with the requirements of Measurement Canada.

2.8.4.3 BPDC endeavours to bill based on actual reads 99.5% of the time. Where it is deemed necessary to bill based on estimates, those estimates shall be based on historical, or neighbourhood information, plus an adjustment to account for weather and other similar factors.

2.8.4.4 Where access to meters is restricted, customers are encouraged to cooperate with BPDC to ensure that meter reads can be obtained. To encourage cooperation and recognize the risk to BPDC of not obtaining an actual read, customers accept that BPDC may add a reasonable amount to estimates.

2.8.5 Final Meter Reading

2.8.5.1 Final meter reads for the purpose of performing a service transfer from one retailer to another shall be done in accordance with the Retail Settlements Code.

2.8.5.2 Final meter reads for purposes of transferring property ownership or tenancy shall be in accordance with BPDC Policy CL-CS-019, Final Bill Credits Transferred to Accounts Payable System (Schedule 5).

2.8.5.3 Where a tenant requests a final read because they are moving out of a premises and a new tenant fails to request service, then the account shall automatically be put in the Landlord's name.

2.8.6 Faulty Registration of Meters

2.8.6.1 Meter errors identified shall be dealt with in accordance with BPDC policy CL-CS-015, Metering (Schedule 6).

2.8.7 Meter Dispute Testing

2.8.7.1 Meter errors resulting in a dispute request by the customer or BPDC will be dealt with according to BPDC Policy CL-CS-003, Billable Charges (Schedule 7).

2.9 Tariffs and Charges

2.9.1 Service Connections

2.9.1.1 Service and Connection Fees shall apply to all new electrical service connections, as well as where the customer is undertaking equipment upgrades that necessitate an upgraded service.

2.9.1.2 No Service and Connection fee shall be payable in respect of a basic connection, as that connection is considered to be included in distribution rates. Basic connections shall be as follows:

(a) for Residential, the basic connection shall considered to be included in the distribution rate is a 200 Amp, overhead service measuring 30 meters in length.
(b) for all other customer types, there is no basic connection included in the distribution rates.

2.9.1.3 Service and Connection fees as required by customer rate class in accordance with the paragraph in section 2.9.1.2 shall be as set out in Appendix 5.4 and as further described in the appropriate customer class found in Part 3 of the Conditions of Service.

2.9.1.4 Where a customer requests an upgrade for an existing service that does not fall within Section 2.9.1.1, the upgrade may be undertaken but 100% at the customer's cost.

2.9.2 Energy Supply

2.9.2.1 BPDC is obligated to provide Standard Supply Service (SSS) to customers connected to its distribution system according to the requirements of the (Standard Supply Service Code) and the Retail Settlements Code (RSC).

2.9.2.2 Electrical Energy rates for Standard Supply Service customers of BPDC shall be in accordance with the requirements of the relevant codes.

2.9.2.3 BPDC shall provide Standard Supply Service to any customer connected to its distribution system who has:

- Done nothing to advise BPDC in writing that the customer does not want to purchase electrical energy from BPDC;
- Requested in writing to purchase electrical energy from BPDC; or
- Agreed to purchase electrical energy from a retailer other than BPDC, but the retailer is unable to sell electricity to the customer.

2.9.3 Deposits

2.9.3.1 BPDC requires a security deposit to be paid by the customer as a condition of connecting to, or maintaining service connection to, the BPDC

distribution system. A schedule of these deposit requirements are contained in CL-CS- 009, Security Deposits, Interest, Refunds and Transfers (Schedule 8).

2.9.4 Billing

2.9.4.1 BPDC must accommodate a number of options for customer billing. These are:

a) Distributor Consolidated Billing,
b) Retailer Consolidated Billing, and
c) Split Billing where the retailer and BPDC each send the customer a bill.

2.9.4.2 The default billing option shall be Distributor Consolidated Billing until advised otherwise by the Retailer selected by a customer.

2.9.4.3 All billing activities performed by BPDC shall be in accordance with the Retail Settlements Code and all other relevant Codes.

2.9.5 Payments and Late Payment Charges

2.9.5.1 Payment terms, timing, and late payment charges shall be according to BPDC Policy CL-CS–003, Billable Charges (Schedule 7).

2.9.5.2 As directed by the OEB, late payment charges shall be 1.5% per month, compounded monthly (19.56% per annum), and imposed following the 15th day past the due date and on the monthly anniversary of that date thereafter.

2.9.6 Customer Information

2.9.6.1 BPDC shall ensure that all customer information remains confidential. When exchange of information from BPDC to retailers and/or the customer is required, the exchange shall be in accordance with the requirements and processes set out in the Standard Supply Service Code, Retail Settlements Code, Affiliate Relationships Code, all other relevant codes.

2.9.6.2 The release of any customer information shall require written authorization from the customer except as follows:

- The customer requests that the historical, consumer specific information be delivered directly to the customer's service or billing address. This request can be satisfied on a verbal authorization.
- If a Retailer requests that a customer be transferred back to the Standard Supply Service of BPDC. This shall be performed in accordance with processes established in the Retail Settlements Code.

- When BPDC must transfer a customer back to the Standard Supply Service in the event of a payment default of the Retailer according to the requirements of the Retail Settlements Code.

2.9.6.3 BPDC is also subject to the Personal Information Protection and Electronic Documents Act and BPDC shall collect, use and disclose all customer information in accordance with its Privacy Policy.

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PART 3 – DISTRIBUTION ACTIVITIES (Customer Class Specific)

3.1 Residential Customers

3.1.1 All service supplied to single-family dwelling units for domestic or household purposes shall be classed as residential service. Where electricity service is provided for combined residential and business purposes (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be in the discretion of BPDC and shall be based on such considerations as the estimated predominant consumption or the municipal tax roll classification.

3.1.2 A Residential Customer may be found in a detached, semi-detached, linear row housing, apartment building, or mixed-use building. Where more than one dwelling is served by a single meter, that service shall be considered a General Service Customer.

3.1.3 A customer requesting a new or upgraded electrical service shall be expected to pay BPDC the Connection Charge required by Section 2.9.1 and outlined in Appendix 5.4, prior to the time of the final connection.

3.1.4 In some areas, municipal by-laws or BPDC Policy may dictate that new services are to be underground. These areas shall be identified by BPDC to the customer when a Request for Service Connection is made.

3.1.5 Points of Ownership and Demarcation

	Ownership Demarcation	**Operational Demarcation**
Underground	BPDC owns wires up to, but not including, line side connections within the meter base. Customer owns duct work, and associated structures on the property.	Same
Overhead Secondary	BPDC owns wires up to, but not including, the point of attachment on the building above the service entrance stack.	Same
Overhead Primary	BPDC owns wires to the customers' property line	Same

3.1.6 Service and Metering Requirements

3.1.6.1 The minimum service ampacity for new connections shall be 100 amps. The maximum service ampacity shall be 200 amps. Where a customer requests a new residential service greater than 200 amps, BPDC will grant the request provided there is sufficient capacity and the customer shall be responsible for costs as set at in Schedule 5.4, plus any extraordinary engineering costs. Upgrade of existing services shall be entirely at the customer's cost.

3.1.6.2 BPDC will provide one service per individual property. Existing properties with more than one service will be required to combine the services when an upgrade is required or performed.

3.1.6.3 Meters locations shall be approved by BPDC. For residential customers, the meter shall be located on the outside of the building at the front or on the side of the building within 3 m of the front of the building. Where building additions, fencing, or other obstructions render the meter location inaccessible, the meter shall be relocated or a remote interrogation device installed in an accessible location at the customers expense.

3.1.7 Overhead Secondary Voltage Services

3.1.7.1 BPDC will supply to its specifications the first 30 meters of overhead wire, on the property, at no charge to the customer at the time of connection. For services in excess of 30 meters in length, the customer will be charged for all additional materials and labour on top of the Connection Charge.

3.1.7.2 For residential overhead installations only, BPDC shall supply secondary wiring to reach the property line. Further, where street cross over poles are required, these will be placed on the road allowance and will be provided by BPDC as part of the Connection Charge.

3.1.7.3 Where transformation is required beyond the basic connection that connection shall be treated as an expansion and be subject to Section 2.3.

3.1.7.4 The customer shall be responsible for the supply installation and maintenance of a service entrance mast and clevis bolted to the building as per the Electrical Safety Authority requirements.

3.1.7.5 Where the service is in excess of 60 m in length, BPDC may require that the service be designed and installed at primary voltage. BPDC will supply the first 30 meters of overhead wire, on the property, at no charge to the customer at the time of connection. The customer shall be responsible for the materials and labour required to construct the primary voltage line to point.

3.1.7.6 The customer shall be responsible for the supply, installation, and maintenance of a meter base and all service entrance equipment according to the requirements of the Electrical Safety Authority (ESA).

3.1.7.7 Overhead service conductors under the ownership of BPDC shall be maintained by BPDC.

3.1.7.8 Initial clearing and tree trimming on the customer's property shall be done by the customer according to the requirements of the Electrical Safety Authority.

3.1.7.9 Subsequent tree trimming and brush removal required on the customer's property to protect the service from damage shall be the responsibility of the customer and must be completed by either qualified personnel or with the line isolated and de-energized by BPDC. BPDC will disconnect the power, free of charge during normal business hours, for tree trimming to occur once per year at the request of the customer.

3.1.8 Underground Services

3.1.8.1 BPDC shall supply the first 30 meters of underground service wire, at no charge to the customer at the time of connection.

3.1.8.2 For services in excess of 30 meters in length, the customer will be charged for all additional materials and labour as part of the Connection Charge.

3.1.8.3 The customer is responsible for all materials and labour associated with installing the underground duct from the meter base to the point of connection at the pole. This duct work shall be installed to BPDC specifications and will be inspected prior to backfilling.

3.1.8.4 Where transformation is required in order to service a customer beyond the basic connection, that shall be treated as a system expansion and be subject to Section 2.3.

3.1.8.5 BPDC shall not be responsible for any restoration costs of the grounds, driveways, sidewalks, shrubs and plants in the area of the work occurring at the time of construction or during subsequent repairs.

3.1.8.6 For repairs to underground services, BPDC will locate the point of the fault at no cost to the customer. The customer is responsible for the excavation and exposure of the wire or duct sufficient to allow BPDC staff access to make the necessary repairs. If the fault cannot be located, or there are multiple faults, BPDC may request the customer to install a new trench and duct to the property line and BPDC will replace the wire and the customer shall only be responsible for the cost of the wire in excess of

30 meters.

3.1.8.7 The customer shall be responsible for the supply and installation and maintenance of a meter base and all service entrance equipment beyond according to the requirements of the ESA.

3.1.9 Special Contracts

3.1.9.1 No specific contract for service, relating to the supply of electrical distribution services, is required with a residential customer.

3.1.10 Other Conditions

3.1.10.1 Any other specific conditions related to residential customer connections will be communicated in writing to the customer at the time of the customer connection application.

3.1.10.2 BPDC shall own all transformers once installed.

3.2 General Service (Below 50kW Demand)

3.2.1 A General Service (Below 50kW Demand) Customer shall be any customer not designated as Residential under Sections 3.1.1 and 3.1.2, and that over a twelve month period has an average monthly peak demand of less than 50kW, and has a monthly peak demand that never exceeds 100kW. BPDC shall review this rate class designation on an annual basis and the customer's designated rate class may change as a result.

3.2.2 Points of Ownership and Operational Demarcation

	Ownership Demarcation	**Operational Demarcation**
Overhead	BPDC owns wires up to, but not including, the point of attachment to the building above the service stack	The first gang operated load break device within the building.
Underground	BPDC owns wires to the point of connection on the pole. Customer owns wires, duct work and associated equipment from the point	The first gang operated load break device within the building.

	of connection on the pole to its building.	

3.2.3 Service and Metering Requirements

3.2.3.1 The minimum service ampacity for new connections shall be 100 amps. The maximum service ampacity shall be 200 amps. Where a customer requests a new service greater than 200 amps, BPDC will grant the request provided there is sufficient capacity and the customer shall be responsible for costs as set at in Schedule 5.4, plus any extraordinary engineering costs. Upgrade of existing services shall be entirely at the customer's cost.

3.2.3.2 A customer requesting a new or upgraded electrical service shall be expected to pay BPDC the Connection Charge required by Sections 2.9 and outlined in Appendix 5.4, prior to the time of the final connection.

3.2.3.3 In some areas, municipal by-laws or BPDC Policy may dictate that new or upgraded services shall be underground. These areas shall be identified by BPDC to the customer when a Request for Service Connection is made.

3.2.3.4 BPDC will provide one service to each individual property. Existing properties with more than one service may be required to combine the service when an upgrade is required or performed. However, BPDC may, in its sole discretion, provide individual services on a single property under one ownership to separate and free standing buildings. The customer will be required to pay the Connection charges for each service on the property.

3.2.3.5 Service voltages available to General Service (Below 50kW Demand) customers are detailed in Appendix 5.3. The customer will be supplied at one voltage only. Where more than one service per property is granted by BPDC, all services shall be of the same voltage. Single phase step-down transformers from 600/347V to another voltage level may be supplied and installed by the customer on his premises provided the total capacity of these units does not exceed 25% of the customers total demand and does not to exceed 24kVA.

3.2.3.6 Meter locations shall be approved by BPDC. For customers installing single phase 120/240V services, the meter shall be located on the outside of the building at the front or on the side of the building within 3 meters of the front of the building. For customers installing three phase services, the meters shall be located on the inside of the building within the

electrical service room. Where building additions, renovations, or other obstructions render the meter location inaccessible, the meter shall be relocated or a remote interrogation device installed in an accessible location at the customer's expense.

3.2.3.7 The customer shall be responsible for the supply, installation and maintenance of a meter base and all service entrance equipment beyond according to the requirements of the ESA. All installations shall be inspected and approved by the ESA prior to connection.

3.2.4 Overhead Secondary Voltage Services

3.2.4.1 If overhead transformation with sufficient capacity and service voltage exists, BPDC shall supply and install the service wires to the customer service entrance mast and shall charge the customer the applicable Connection Charge.

3.2.4.2 Where there is no existing overhead transformation or existing transformation capacity is insufficient, or of an incorrect service voltage, BPDC shall consider the service to be an expansion to the system and will provide the customer with an Offer to Connect for the service as per section 2.3 of this document.

3.2.4.3 The customer shall be responsible for the supply installation and maintenance of a service entrance mast and clevis bolted to the building as per the Electrical Safety Authority requirements.

3.2.4.4 Where the service wires are in excess of 30 meters in length, additional support poles may be required. These will be installed by BPDC at the customers' expense.

3.2.4.5 Where the service is in excess of 60m in length, BPDC may require that the service be designed and installed at primary voltage. An Offer to Connect shall be provided that will outline all costs associated with the connection of the customer service.

3.2.4.6 Initial clearing and tree trimming on the customer's property shall be done by the customer according to the requirements of the Electrical Safety Authority.

3.2.4.7 Subsequent tree trimming and brush removal required on the customer's property to protect the service from damage shall be the responsibility of the customer and must be completed by either qualified personnel or with the line isolated and de-energized by BPDC. BPDC will disconnect the power, free of charge during normal business hours, for tree trimming to occur once per year at the request of the customer.

3.2.5 Underground Secondary Voltage Services

3.2.5.1 If transformation with sufficient capacity and service voltage exists, the customer shall supply and install the service wires to the point of connection on the pole.

3.2.5.2 Where there is no existing transformation or existing transformation capacity is insufficient, or of an incorrect service voltage, BPDC shall consider the service to be an expansion to the system and will provide the customer with an Offer to Connect for the service as per section 2.3 of this document.

3.2.5.3 The customer is responsible for all materials and labour associated with installing the underground duct and service wire from the meter base or service entrance panel to the point of connection on the pole.

3.2.5.4 BPDC shall not be responsible for any restoration costs of the grounds, driveways, sidewalks, shrubs and plants in the area of the work occurring at the time of construction or during subsequent repairs.

3.2.6 Special Contracts

3.2.6.1 Generally, no specific contract for service is required, relating to any supply of electrical distribution services. Depending on the nature of the customer's facility, BPDC may require the customer to enter into a Connection Agreement (Schedule 14), which is an agreement outlining the mutual obligations of the parties and the technical aspects of the connection.

3.2.7 Other Conditions

3.2.7.1 A customer requesting a new service connection should be aware that BPDC will require at least 6-8 weeks notice of the intention to proceed in advance of the requested in-service date. This is required to ensure delivery of the required materials and labour scheduling.

3.2.7.2 Coreflex cables attached to the pole will not be allowed. All service wires attached to BPDC poles must be in conduit.

3.2.7.3 BPDC shall own all transformers once installed.

3.3 General Service (Above 50kW Demand)

3.3.1 A General Service (Above 50kW Demand) Customer shall be any customer not designated as Residential, and that over a twelve month period has an average monthly peak demand of more than 50kW, and less than 5000kW, but not including those customers that fit the definition of General Service

Intermediate Use in Section 3.4. This rate class designation is reviewed on an annual basis and the customer's designated rate class may change as a result.

3.3.2 Points of Ownership and Operational Demarcation

	Ownership Demarcation	**Operational Demarcation**
Underground	BPDC owns wires up to the point of connection on the pole. Customer owns wires, duct work, and associated equipment from the point of connection on the pole to its building.	The first gang operated load break device within the building.
Overhead	BPDC owns wires up to, but not including, the point of attachment to the building above the service stack.	The first gang operated load break device within the building.

3.3.3 Service and Metering Requirements

3.3.3.1 The minimum service ampacity for an overhead connection shall be 100amp. The maximum service ampacity for an underground connection from pole mounted transformation shall be 300kVA. For services requiring greater than 300kVA, the service must be supplied from a pad mounted transformer installation.

3.3.3.2 BPDC will provide one service to each individual property. Existing properties with more than one service may be required to combine them when an upgrade is required.

3.3.3.3 The Customer shall be responsible for paying a Connection Charge for all new and upgraded electrical services (as applicable) to BPDC based on the schedule contained in Appendix 5.4.

3.3.3.4 In some areas, municipal by-laws or BPDC Policy may dictate that new or upgraded services shall be underground. These areas shall be identified by BPDC to the customer when a Request of Service Connection is made.

3.3.3.5 Service voltages available to General Service (Above 50kW Demand) customers are detailed in Appendix 5.3.

3.3.3.6 Meters locations shall be approved by BPDC. For General Service (Above 50kW Demand) customers, the meter shall be located on the inside of the building within the electrical service room. Where building additions, renovations, or other obstructions render the meter location inaccessible, the meter shall be relocated or a remote interrogation device installed in an accessible location at the customers expense.

3.3.3.7 For commercial malls with multiple separate business units, each business or business unit may be metered separately. The location of meters shall be approved by BPDC.

3.3.4 Overhead Secondary Voltage Services

3.3.4.1 If overhead transformation with sufficient capacity and service voltage exists, BPDC will supply and install the service wires to the customer service entrance mast and will charge the customer the applicable Connection Charge.

3.3.4.2 Where there is no existing overhead transformation or existing transformation capacity is insufficient, or of an incorrect service voltage, BPDC will consider the service to be an expansion to the system and will provide the customer with an Offer to Connect for the service as per section 2.3 of this document.

3.3.4.3 The customer shall be responsible for the supply and installation of a service entrance mast and clevis bolted to the building as per the Electrical Safety Authority requirements.

3.3.4.4 Where the service wires are in excess of 30 meters in length, additional support poles may be required. These will be installed by BPDC at the customer's expense.

3.3.4.5 Where the service is in excess of 60m in length, BPDC may require that the service be designed and installed at primary voltage. The Offer to Connect will outline all costs associated with the connection of the customer service.

3.3.4.6 Initial clearing and tree trimming on the customer's property shall be done by the customer according to the requirements of the Electrical Safety Authority.

3.3.4.7 Subsequent tree trimming and brush removal required on the customer's property to protect the service from damage will be the responsibility of the customer and shall be completed by qualified personnel or with the line isolated and de-energized by BPDC. BPDC will disconnect the power, free of charge during normal business hours, for this work to occur once per year at the request of the customer.

3.3.5 Underground Secondary Voltage Services From Pole Mounted Transformation

3.3.5.1 If overhead transformation with sufficient capacity and service voltage is existing, the customer shall supply and install the service wires, conduit, weather head, etc to the point of connection on the pole.

3.3.5.2 Where there is no existing overhead transformation or existing transformation capacity is insufficient, or of an incorrect service voltage, BPDC will consider the service to be an expansion to the system and will provide the customer with an Offer to Connect for the service as per section 2.3 of this document.

3.3.5.3 The customer is responsible for all materials and labour associated with installing the underground duct from the meter base to the point of connection on the pole.

3.3.5.4 BPDC is not responsible for any restoration costs of the grounds, driveways, sidewalks, shrubs and plants in the area of the work.

3.3.5.5 BPDC is responsible for all costs of installation and connection from the property line to the distribution system on the road allowance.

3.3.6 Services Supplied From Pad Mounted Transformer

3.3.6.1 For all new services to a single customer that are to be supplied from a new pad mounted transformer(s), BPDC will consider these as system expansions and will provide the customer with an Offer to Connect for the service as per section 2.3 of this document.

3.3.6.2 For new services from an existing pad mounted transformer with sufficient capacity and service voltage, the customer shall supply and install the service wires, connectors, conduit, etc to the point of connection on the secondary terminals of the transformer.

3.3.7 Special Contracts

3.3.7.1 Generally no specific contract for service is required, relating to the supply of electrical distribution services. Depending on the nature of the customer's facility, BPDC may require the customer to enter into a Connection Agreement (Schedule 14).

3.3.8 Other Conditions

3.3.8.1 A customer requesting a new service connection should be aware that BPDC will require at least 6-8 weeks notice of the intention to proceed in advance of the requested in-service date. This is required to ensure delivery of the required materials and labour scheduling.

3.3.8.2 Coreflex cables attached to the pole will not be allowed. All service wires attached to BPDC poles must be in conduit.

3.3.8.3 BPDC shall own all transformers once installed where those transformers are of a capacity of 1000 kVa or less. Transformers larger than 1000 kVa may be owned by BPDC, at its discretion or in consultation with the customer.

3.4 General Service - Intermediate Use

3.4.1 A General Service – Intermediate customer shall be any customer not designated residential, and that has over a twelve month period, had an average monthly peak demand of more than 1,000 kW and less than 5,000 kW.

3.4.2 Points of Ownership and Operational Demarcation

	Ownership Demarcation	**Operational Demarcation**
Underground	BPDC owns wires up to the point of connection on the pole. Customer owns wires, duct work, and associated equipment from the point of connection on the pole to its building.	The first gang operated load break device within the building.
Overhead	BPDC owns wires up to, but not including, the point of attachment to the building above the service stack.	The first gang operated load break device within the building.

3.4.3 Service and Metering Requirements

3.4.3.1 The minimum service ampacity for an overhead connection shall be 100amp. The maximum service ampacity for an underground connection from pole mounted transformation shall be 300kVA. For services requiring greater than 300kVA, the service must be supplied from a pad mounted transformer installation.

3.4.3.2 BPDC will provide one service to each individual property. Existing properties with more than one service may be required to combine them

when an upgrade is required.

3.4.3.3 The Customer shall be responsible for paying a Connection Charge for all new and upgraded electrical services (as applicable) to BPDC based on the schedule contained in Appendix 5.4.

3.4.3.4 In some areas, municipal by-laws or BPDC Policy may dictate that new or upgraded services shall be underground. These areas shall be identified by BPDC to the customer when a Request for Connection is made.

3.4.3.5 Service voltages available to General Service (Above 50kW Demand) customers are detailed in Appendix 5.3.

3.4.3.6 Meter locations shall be approved by BPDC. For General Service (Above 50kW Demand) customers, the meter shall be located on the inside of the building within the electrical service room. Where building additions, renovations, or other obstructions render the meter location inaccessible, the meter shall be relocated or a remote interrogation device installed in an accessible location at the customers expense.

3.4.3.7 For commercial malls with multiple separate business units, each business or business unit may be metered separately. The location of meters shall be approved by BPDC.

3.4.4 Overhead Secondary Voltage Services

3.4.4.1 If overhead transformation with sufficient capacity and service voltage exists, BPDC will supply and install the service wires to the customer service entrance mast and will charge the customer the applicable Connection Charge.

3.4.4.2 Where there is no existing overhead transformation or existing transformation capacity is insufficient, or of an incorrect service voltage, BPDC will consider the service to be an expansion to the system and will provide the customer with an Offer to Connect for the service as per section 2.3 of this document.

3.4.4.3 The customer shall be responsible for the supply and installation of a service entrance mast and clevis bolted to the building as per the Electrical Safety Authority requirements.

3.4.4.4 Where the service wires are in excess of 30 meters in length, additional support poles may be required. These will be installed by BPDC at the customer’s expense.

3.4.4.5 Where the service is in excess of 60m in length, BPDC may require that the service be designed and installed at primary voltage. The Offer to Connect will outline all costs associated with the connection of the

customer service.

3.4.4.6 Initial clearing and tree trimming on the customer's property shall be done by the customer according to the requirements of the Electrical Safety Authority.

3.4.4.7 Subsequent tree trimming and brush removal required on the customer's property to protect the service from damage will be the responsibility of the customer and shall be completed by qualified personnel or with the line isolated and de-energized by BPDC. BPDC will disconnect the power, free of charge during normal business hours, for this work to occur once per year at the request of the customer.

3.4.5 Underground Secondary Voltage Services From Pole Mounted Transformation

3.4.5.1 If overhead transformation with sufficient capacity and service voltage existing, the customer shall supply and install the service wires, conduit, weather head, etc to the point of connection on the pole.

3.4.5.2 Where there is no existing overhead transformation or existing transformation capacity is insufficient, or of an incorrect service voltage, BPDC will consider the service to be an expansion to the system and will provide the customer with an Offer to Connect for the service as per section 2.3 of this document.

3.4.5.3 The customer is responsible for all materials and labour associated with installing the underground duct from the meter base to the point of connection at the pole.

3.4.5.4 BPDC is not responsible for any restoration costs of the grounds, driveways, sidewalks, shrubs and plants in the area of the work.

3.4.5.5 BPDC is responsible for all costs of installation and connection from the property line to the distribution system on the road allowance.

3.4.6 Services Supplied From Pad Mounted Transformer

3.4.6.1 For all new services to a single customer that are to be supplied from a new pad mounted transformer(s), BPDC will consider these as system expansions and will provide the customer with an Offer to Connect for the service as per section 2.3 of this document.

3.4.6.2 For new services from an existing pad mounted transformer with sufficient capacity and service voltage, the customer shall supply and install the service wires, connectors, conduit, etc to the point of connection on the secondary terminals of the transformer.

3.4.7 Special Contracts

3.4.7.1 Generally no specific contract for service is required, relating to the supply of electrical distribution services. Depending on the nature of the customer's facility, BPDC may require the customer to enter into a Connection Agreement (Schedule 14).

3.4.8 Other Conditions

3.4.8.1 A customer requesting a new service connection should be aware that BPDC will require at least 6-8 weeks notice of the intention to proceed in advance of the requested in-service date. This is required to ensure delivery of the required materials and labour scheduling.

3.4.8.2 Coreflex cables attached to the pole will not be allowed. All service wires attached to BPDC poles must be in conduit.

3.4.8.3 BPDC shall own all transformers once installed, where those transformers are of a capacity of 1000 kVa, or less. Transformers larger than 1000 kVa may be owned by BPDC, in its discretion and in consultation with the customer.

3.5 General Service - Large Use (Above 5,000kW Demand)

3.5.1 A Large Use customer shall be any customer not designated as Residential, and that has an average monthly peak electrical demand of more than 5,000kW over 12 consecutive billing periods. This rate class designation is reviewed on an annual basis and the customer's designated rate class may change as a result.

3.5.2 Points of Ownership and Operational Demarcation

	Ownership Demarcation	**Operational Demarcation**
Overhead	The single phase in-line switches, or in-line fuses, located at or near the property line. Customer owns wires, poles, and associated equipment beyond the point to its building.	Unless agreed to in writing otherwise, the first gang operated load break device.

Underground	The line side terminals of the customer's primary cable connection. Customer owns duct work, wires, and associated equipment beyond this point to its building.	Unless agreed to in writing otherwise, the first gang operated load break device.

3.5.3 Service and Metering Requirements

3.5.3.1 BPDC will provide one service to each individual property. Existing properties with more than one service may be required to combine them when an upgrade is required.

3.5.3.2 The Customer shall be responsible for paying a Connection Charge for all new and upgraded electrical services (as applicable) to BPDC based on the schedule contained in Appendix 5.4.

3.5.3.3 Service voltages available to Large Use customers are detailed in Appendix 5.3.

3.5.3.4 Metering installations and locations shall be approved by BPDC. For Large Use customers, the metering facilities shall be interrogated remotely through MV-90 metering system operated by BPDC. The customer shall be responsible for providing access for BPDC to provide and maintain a phone line into the metering recorders.

3.5.3.5 Large Use customers may be required to be Primary Voltage Metered. This determination of primary versus secondary metering will be made by BPDC and communicated to the customer at the early stage of discussions or through the Offer to Connect.

3.5.4 Overhead Services

3.5.4.1 In addition to the connection charge, the customer will also be charged for any work performed by BPDC at the request of the customer on the customer's property. An estimate of the cost of such work shall be provided to the customer.

3.5.4.2 The customer shall be responsible for the supply and installation of all station components, transformers and service entrance equipment as per the Electrical Safety Authority (ESA) requirements.

3.5.4.3 Initial clearing and tree trimming on the customer's property shall be done by the customer according to the requirements of the Electrical Safety Authority (ESA).

3.5.4.4 Subsequent tree trimming and brush removal required on the customer's

property to protect the service from damage will be the responsibility of the customer. BPDC will disconnect the power, free of charge during normal business hours, for this work to occur once per year at the request of the customer.

3.5.5 Underground Services

3.5.5.1 The customer shall supply and install all labour, hardware, and underground wire to the point of connection on the pole.

3.5.5.2 The customer shall also be charged for any work performed by BPDC at the request of the customer on the customers' property. An estimate of the cost of such work shall be provided to the customer.

3.5.5.3 The customer shall be responsible for the supply and installation of all station components, transformers and service entrance equipment as per the Electrical Safety Authority requirements.

3.5.6 Special Contracts

3.5.6.1 The customer must enter into a Connection Agreement (Schedule 14) with BPDC before a service is connected. Part of the Connection Agreement will be an Operations and Maintenance Schedule outlining the mutual obligations of the parties and the technical aspects of the connection.

3.5.7 Other Conditions

3.5.7.1 No customer connections over 300kW demand will be allowed on the 4kV or 8kV distribution systems.

3.5.7.2 A customer requesting a new service connection should be aware that BPDC will require significant notice of the intention to proceed in advance of the requested in-service date. This is required to ensure delivery of the required materials and labour scheduling.

3.5.7.3 Coreflex cables attached to the pole will not be allowed. All service wires attached to BPDC poles must be in conduit.

3.5.7.4 BPDC shall own all transformers once installed, where those transformers are of a capacity of 1000 kVa or lower. Transformers larger than 1000 kVa may be owned by BPDC at its discretion and in consultation with the customer.

3.6 Embedded Generation

3.6.1 An Embedded Generator is any unit that is, or may be, connected in parallel with the BPDC distribution system for the purposes of:

- full displacement of the customer's existing electrical load,
- partial displacement of the customer's existing load,
- sale of over capacity through the BPDC distribution system

3.6.2 BPDC shall ensure that the distribution system is adequately protected from potential damage or increased operating costs resulting from the connection of an embedded generator to the system. BPDC shall also ensure that the safety, reliability, and efficiency of the distribution system is not compromised by the connection of an embedded generator.

3.6.3 Application to connect an embedded generator to the BPDC distribution system must be made in writing according to the process identified in the BPDC forms contained in Schedule 14 - Guideline for Applicant Connecting Distributed Generation (Schedule 13).

3.6.4 The initial consultation with the applicant will be at no charge to the applicant and will occur within 30 days of receipt of the written Request for Connection.

3.6.5 The final Offer to Connect for the embedded generator shall be returned to the applicant within 90 days of the receipt of a complete Request For Connection. The Applicant will be advised whether the information is complete.

3.6.6 The customer will be charged for all subsequent costs of consultations, preparation of estimates, system impact studies, designs, costs of system modifications, charges from Hydro One Networks Inc. or the Independent Electricity System Operator and of commissioning and testing necessary to connect the generation facilities to the BPDC distribution system. This will ensure that each applicant remains responsible for the costs of processing their connection to the system.

3.6.7 BPDC will provide the applicant with estimated cost of analysis and engineering for each phase of the process. BPDC will not proceed without written authorization and pre-payment of a deposit from the applicant.

3.6.8 Points of Ownership and Operational Demarcation

3.6.9 Ownership Demarcation

3.6.9.1 The Ownership Demarcation is the point on the electrical distribution system where ownership, repair, and maintenance responsibility for the customer facilities transfers from BPDC to the customer.

3.6.9.2 For Embedded Generators this point of demarcation will be designated during the design stages of the project and indicated in the Connection Agreement (Schedule 14). However, in general, the point of Ownership Demarcation will be at the point of connection to the customer's facilities.

This will typically be the first gang operated load break device on the property.

3.6.10 Operational Demarcation

3.6.10.1 Operational Demarcation is the point on the electrical distribution system where responsibility for operational control, for safety and work protection reasons, changes from BPDC to the customer.

3.6.10.2 For Embedded Generators this point of demarcation will be designated during the design stages of the project and indicated in the Connection Agreement (Schedule 14).

3.6.11 Service and Metering Requirements

3.6.11.1 All service and metering requirements will be identified and communicated to the customer during the application/connection process.

3.6.12 Special Contracts

3.6.12.1 The owner of the facilities where the generator is located and the operator of the embedded generator (if they are different) shall enter into a Connection Agreement (Schedule 14) with BPDC for the operation, maintenance, and legal obligations of the embedded generation facilities that are connected to the BPDC distribution system.

3.6.13 Other Conditions

3.6.13.1 Final authorization to connect the embedded generator to the BPDC distribution system shall be made by BPDC. This authorization shall be given only after all of the conditions of supply have been met, which include payment of all costs of connection, a signed Connection Agreement (Schedule 14) on file at the BPDC offices, and all test and commissioning reports have been submitted for final review by BPDC.

3.6.14 Embedded Market Participant

3.6.14.1 Any customer who meets the requirements of the Independent Electricity System Operator (IESO), and chooses to be a Wholesale Market Participant.

3.6.15 Embedded Distributor

3.6.15.1 BPDC does not have an Embedded Distributor within its distribution system.

3.6.15.2 BPDC is, itself, an embedded distribution within the Hydro One Networks Inc. system and that relationship is not governed by the Conditions of Service.

3.6.16 Other Conditions

3.6.16.1 Final authorization to connect the embedded distributor to the BPDC distribution system shall be made by BPDC. This authorization shall be given only after all of the conditions of supply have been met, which include payment of all costs of connection, a signed Connection Agreement (Schedule 14) on file at the BPDC offices, and all test and commissioning reports have been submitted for final review by BPDC.

3.7 Un-metered Connections

3.7.1 Application to connect an un-metered load to the BPDC distribution system can be made by calling the Customer Service department to initiate the process for connection.

3.7.2 Any un-metered connection to the system shall be installed according to the requirements of the Electrical Safety Authority.

3.7.3 As a general rule, no new load will be connected without a meter. BPDC may, in its sole discretion, approve a connection to the BPDC system without a meter where it is satisfied that it is appropriate having regard to the type of use, the comfort that the customers will not offer its use or estimated consumption without notice to BPDC.

3.7.4 The customer shall provide detailed manufacturer's information with regard to electrical demand/consumption and schedule for usage to BPDC as part of the application for connection process. No change can be made by a customer to their connected load without providing details of the change in writing prior to the change. Any failure to provide notice shall lead to the customer being required to install a meter at their cost.

3.7.5 Where it is advantageous to BPDC, BPDC may require the customer to provide metering facilities for a specific load or group of devices. This determination shall be made prior to connection and shall be indicated to the customer immediately after the submission of the Application to Connect. All metering facilities shall be according to the general metering requirements detailed in Part 2.

3.7.6 Each un-metered connection, whether it is the customer's only connection or one of many connections for the customer, shall be billed according to the reasonable estimate of electrical demand for a device multiplied by the time during which the device is assumed to be in operation all is determined by BPDC, acting reasonably.

3.7.6.1 The customer shall submit drawings and detailed manufacturers information prior to the connection to the distribution system being made. This information will be used to determine the billing in accordance with section 3.7.6.

3.7.7 Street Lights

3.7.7.1 Street lights shall be categorized and billed as unmetered scattered load.

3.7.7.2 All new streetlights connected to the system shall be installed according to the requirements of the Electrical Safety Authority.

3.7.7.3 BPDC shall not permit streetlights to be attached to its poles without the party agreeing to pay for all future maintenance and agreeing that BPDC shall perform all maintenance on a cost of service basis.

3.7.7.4 All new streetlights shall be equipped with a photocell switch integral to the light housing, or an equivalent technology.

3.7.7.5 Wherever possible, all streetlight retrofits or upgrades shall be as per current specifications.

3.7.7.6 Each un-metered connection, whether it is the customer's only connection or one of many connections for the customer, shall be billed according to the reasonable estimate of electrical demand for a device multiplied by the time during which the device is assumed to be in operation all is determined by BPDC, acting reasonably.

3.7.7.7 The customer shall submit drawings and detailed manufacturers information prior to the connections to the distribution system being made. This information will be used to determine the billing in accordance with 3.7.6.

3.7.7.8 Unless notified in writing by the customer, once a streetlight is installed, it will be considered connected to the system and operational at all times in accordance with the applicable profit and it will be billed accordingly.

3.8 Sentinel Lights

3.8.1 BPDC does not permit any new Sentinel Lights to be installed within its distribution territory.

3.8.2 Customers with Sentinel Lights in existence prior to April, 2000 were advised by letter that they owned the Sentinel Light from that point further and that no rent shall be payable.

3.8.3 Customers with Sentinel Lights are responsible for the distribution rate

and consumption charge as set in the Schedule of Rates (Schedule 9).

3.8.4 Maintenance of Sentinel Lights is to be performed by a qualified licensed electrician or by BPDC on a fee for service basis.

3.9 Net Metered Generation

3.9.1 Net metering is available to a customer who generates electricity primarily for their own use from a renewable source using equipment of maximum cumulative output of up to 500 kilowatts in size.

3.9.2 Application to connect a net meter to the BPDC distribution system must be made in writing with at least 90 days notice by using the Net Metering Application Form as set out in Schedule 15.

3.9.3 The customer will be required to complete a Net Metering Connection Agreement as set out in Schedule 16.

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PART 4 – GLOSSARY OF TERMS

Apartment Building	A residential structure containing four or more dwelling units to which access to each unit is through a common entrance or entrances from the outside and through a corridor or hallway from the inside.
Cluster Row Housing	A group of three or more attached one family dwelling units, all of which are held in single ownership or by the participants in a condominium corporation or housing cooperative and so located on a lot so that each dwelling unit may not have frontage on public street or highway.
Condominium	A building in which each individual dwelling unit is held in separate ownership.
Connection	The process of installing and activating connection assets in order to distribute electricity to a customer.
Connection Agreement	An agreement entered into between a distributor and a person connected to its distribution system that delineates the conditions of the connection and delivery of electricity to that connection.
Connection Assets	That portion of the distribution system used to connect a customer to the existing main distribution system, and consists of the assets between the point of connection on a distributor's main distribution system and the ownership demarcation point with that customer.
Consumer	A person who uses, for the person's own consumption, electricity that the person did not generate.
CSA	The Canadian Standard Association - website (www.csa.ca).
Customer	A person that has contracted for or intends to contract for the connection of a building. This includes developers of residential or commercial subdivision.
Demand	Is 100% of peak KW demand or 90% of the peak kVA demand of the customer's load metered by the utility. This interpretation is as per the Standard Application of Rates.
Demand Meter	A meter that measures a consumer's peak usage during a specified period of time.

Detached Dwelling	A dwelling that is designed for occupancy by one family or household only and is situated on a separate lot and is not attached by any means to any other dwelling.
Disconnection	A deactivation of connection assets that results in cessation of distribution services to a consumer
Distribute	With respect to electricity, means to convey electricity at voltages of 50kV or less.
Embedded Distributor	A distributor who is not a wholesale market participant and that is provided electricity by a host distributor.
Embedded Generator or Embedded Generation Facility	A generator whose generation facility is not directly connected to the IESO controlled grid but instead is connected to a distribution system.
Embedded Retail Generator	An embedded generator that settles through a distributor's retail settlements system and is not a wholesale market participant.
Embedded Wholesale Generator	An embedded generator that is a wholesale market participant.
Enhancement	A modification to an existing distribution system that is made for the purposes of improving system operating characteristics such as reliability or power quality or for relieving system capacity constraints resulting, for example, from general load growth.
ESA	Electrical Safety Authority (website www.esa.ca).
Expansion	An addition to a distribution system in response to a request for additional customer connections that otherwise could not be made; for example by increasing the length of the distribution system
IESO	The Independent Electricity System Operator – (website www.ieso.com)
Linear Row Housing	A group of three or more attached one family dwelling units each of which has legal frontage on a public street.

MIST	Metering Inside the Settlement Timeframe. This refers to an interval meter from which data is obtained and validated within a designated settlement timeframe.
MOST	Metering Outside the Settlement Timeframe. This refers to an interval meter from which data is only available outside the designated settlement timeframe.
Multi-Unit Commercial	A commercial building occupied or intended to be occupied by two or more unrelated commercial entities.
OEB	The Ontario Energy Board – (website www.oeb.gov.on.ca)
Primary	High voltage wires or service components operating at above 750Vac.
Property	Is a contiguous block of land, and buildings, in a single ownership.
Secondary	Low voltage wires or service component operating at 750Vac or less.
Semi-Detached	A dwelling divided vertically to provide two dwelling units separated by a common wall.
Service	The service wires or components used to provide the connection to the customer property for the purpose of supplying electrical energy to the customer premises.
SSS	Stands for “Standard Supply Service” and means a customer who is sold electricity under Section 29 of the Electricity Act.

PART 5 – APPENDICES

5.1 Bluewater Power Service Area Within Lambton County & Distribution Licence

Bluewater Power's Service Area (Schedule 10).

Distribution System Licence 2002 0517.pdf (Schedule 11).

See Tab # 11

5.2 Customer Complaints and Dispute Resolution

Procedure - US-GE-014 Responding to Customer Power Quality Complaints (Schedule 1).

5.3 Service Voltages Available

5.3.1 BPDC offers a number of **Primary Service Voltages** within its service area. These are:

27.6/16kV, 3 phase, 4 wire	Within the City of Sarnia, Point Edward, and Petrolia only
8.32/4.8 VkV, 3 phase, 4 wire*	City of Sarnia only, East of Modeland Road only, Oil Springs and Alvinston
4.16/2.4kV, 3 phase, 4 wire*	City of Sarnia (west of Murphy Road only), Petrolia, Watford, Point Edward

* Maximum of 300kVA capacity (1000kva where 27.6 kv is available)

Secondary Service Voltages

Three Phase, 4 wire	Single Phase
120/208Vac 347/600Vac	120/240Vac

The City of Sarnia (Downtown Core) is served by a 120/208 Vac network. No other secondary service voltages are available in this area.

5.4 Connection Charges

Residential Customers		
Overhead Services		
- less than 30 m	(not including wire on public property)	$ no charge
- more than 30 m	(not including wire on public property)	$ actual costs – cost of first 30 m of length (estimate provided)
Underground Services		
- Excavation, backfill, supply and install conduit to point of connection on pole		$ customer cost
- Wire less than 30 m (including wire on public property)		$ no charge
- Wire more than 30 m (including wire on public property)		Actual cost – cost of first 30 m of length (estimate provided)
- Transformation, beyond basic connection		$ Actual Costs (estimate provided)
General Service Under 50kW Demand Estimate and/or Offer to Connect will be provided to the customer for approval prior to any work		$ Actual Costs
General Service Over 50kW Demand Estimate and/or Offer to Connect will be provided to the customer for approval prior to any work		$ Actual Costs
General Service Intermediate Use Estimate and/or Offer to Connect will be provided to the customer for approval prior to any work		$ Actual Costs
General Service Over 5000kW Demand Estimate and/or offer to connect will be provided to the customer for approval prior to any work		$ Actual Costs
Temporary Service (any size) Estimate and/or offer to connect will be provided to the customer for approval prior to any work		$ Actual Costs

5.5 Sample Offer to Connect Agreement:

This contract is used for residential and commercial developments (Schedule 12).

5.6 Details of Metering Requirements

5.6.1 Where customers are supplied with a three phase, four wire service and single phase (network) metering is requested, the customer is required to pay a flat rate charge for each meter. This charge is the additional cost to supply a three-phase meter over the cost of a single-phase meter.

All instrument transformers that may be required for BPDC metering shall be supplied by BPDC.

5.6.2 Single Phase Metering Requirements

5.6.2.1 For a service greater than 200Amps, a 90cm x 90cm x 30cm metering cabinet complete with removable cover and backplate shall be provided by the customer. A 25mm conduit shall be provided from the metering cabinet to the outside meter base. The distance between the meter cabinet and the meter base shall be no more than 10 meters. The meter base supplied by the customer must be 4 jaw type and must be equipped with an automatic bypass for current transformer circuits on the left side.

For underground services, a 50mm approved conduit is to be supplied and installed from the meter base to a point 500mm to 600mm below finished grade by the customer.

5.6.3 Three Phase Metering Requirements

5.6.3.1 All three phase metering installations must be located indoors and installed with a customer owned and operated disconnect ahead of the meter. Exceptions to this may be granted only where it is advantageous to BPDC.

5.6.3.2 For 120/208V, 4 wire services a 7 jaw meter socket is required for up to 200 amps service.

5.6.3.3 For 120/208V, 3 wire services, a 5 jaw meter socket is required and shall be limited to 200 amp capacity.

5.6.3.4 For all three phase services greater than 200 amps, the customer shall provide an appropriate sized meter cabinet inside the building. The cabinet shall have a removable backplate and a lockable cover that will accept a BPDC padlock.

5.6.3.5 Where switchgear is used, the customer shall provide adequate space in the switchgear, subject to approval of BPDC, for the metering transformers. In addition, a minimum 60cm x 60cm x 25cm cabinet shall be supplied and installed in an approved location separate from the switchgear.

5.6.3.6 The customer shall provide the backplate to the BPDC metering department at least 5 working days prior to requested in-service date of the facility to allow BPDC staff to install the metering equipment.

5.6.3.7 BPDC will determine when a Primary Voltage Metering Unit is required. Where a Primary Voltage metering unit is required, the customer will be responsible for providing the required space and allowance in switchgear for all required metering components.

5.7 VEE Process - Validating, Estimating and Editing of Interval & Non-Interval Metering Data

Definitions

MIST Meter; refers to "*Metering Inside the Settlement Timeframe*" and means interval meters from which data are obtained and validated within a designated settlement timeframe.

MOST Meter; refers to "*Metering Outside the Settlement Timeframe*" and means interval meters from which data are only available outside the designated settlement timeframe.

Validation, Estimating and Editing (VEE); Validation refers to a process of comparing collected meter data and its characteristics against predefined constant limits and checking the meter's event log (if applicable) for indications of a problem with either the instrument transformers or meter. Estimating refers to a process for substituting provisional meter data in the place of data that failed the predefined validation criteria. Editing refers to manually changing the data for a particular revenue meter.

Bandwidth; refers to the LDC defined tolerance used to flag data for further scrutiny at the stage in the VEE process where a current reading is compared to a reading from an equivalent historical billing period. For example, a 60 % bandwidth means a current reading that is either 60% lower or 60% higher than an equivalent historical billing period will be identified by the VEE process as requiring further scrutiny & verification.

Non-Interval & MOST Data

See flowchart:

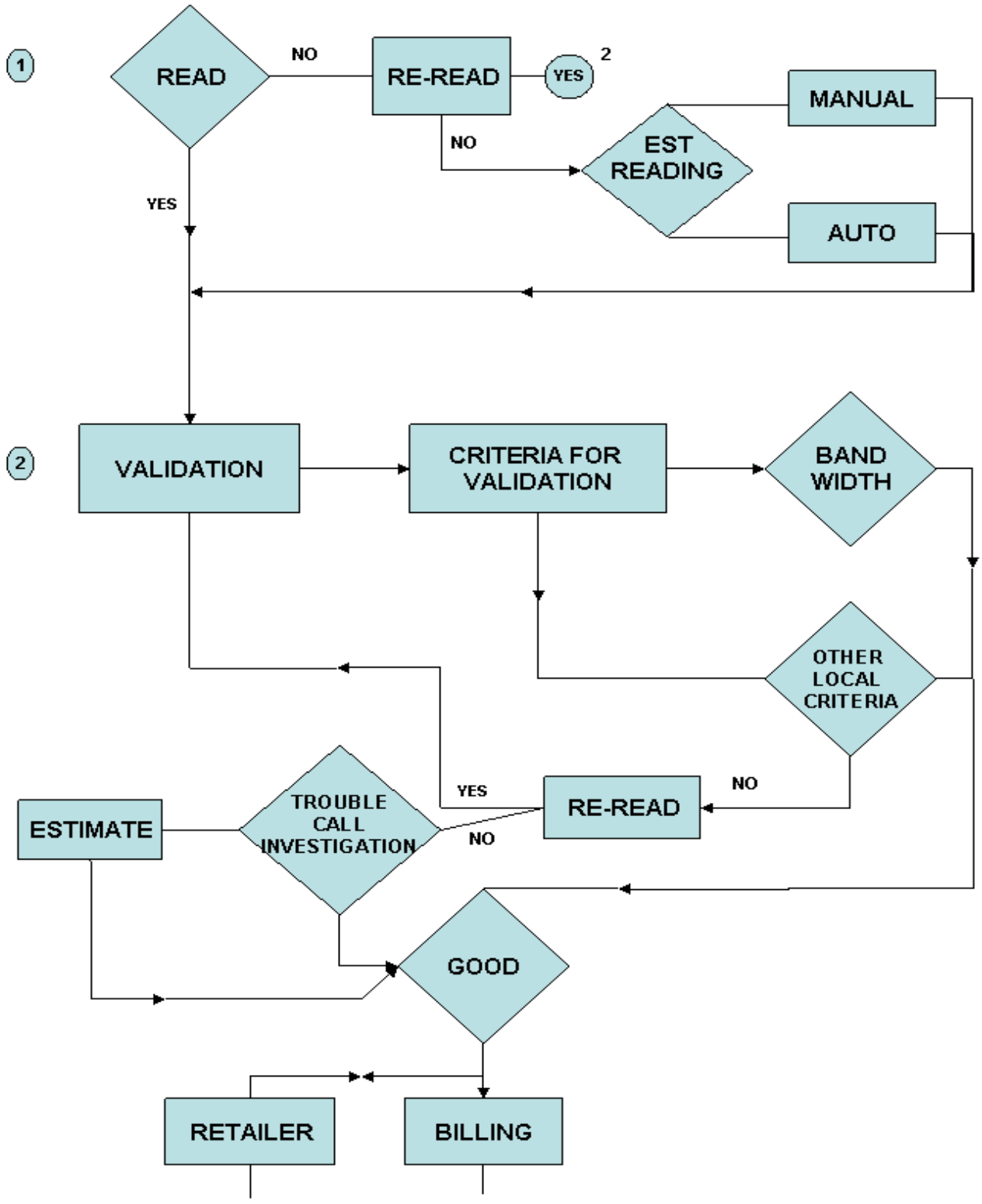
Criteria for validation: compare energy & demand (if applicable) readings from at least one equivalent historical billing period.
Bandwidth: Season and customer class specific: 40-100%
Local considerations: weather anomalies, site-specific factors.

For MIST Data

See flowchart:

Criteria for validation includes: Intervals found versus intervals expected, time tolerance, number of power outage intervals, missing intervals, high limit on interval demand, data overflow on interval comparison to previous read.
Bandwidth: Season and customer specific: 20-50%
Local considerations: weather anomalies, site-specific factors.

VEE Flowchart



5.8 Information Requirement at the Time of Application

General Service (Above 500kW Demand)

General Service customers will be required to provide the following information when applying for a new or upgraded electrical service.

Schedule C of the Offer to Connect (see Section 2.3)

Engineering drawings showing:
- Site plan details
- Electrical single line diagram
- Protective device schematics and design information

All drawings shall be submitted in AutoCAD format **and** in paper format.

5.9 Embedded Generation Guideline for Interconnection Requirements Relevant Application Forms

[YOUR LETTERHEAD]

[date]

Bluewater Power Distribution Corporation
P.O. Box 2140
855 Confederation Street
Sarnia, Ontario
N7T 7L6

Dear Madam/Sir:

Re: Application to Connect Embedded Generator

Please accept this letter as our application to connect an embedded generator in the Bluewater Power Distribution Corporation ("Bluewater") distribution territory.

The project is generally described as a ___MVa Generator installed on the property with municipal address of _____. A detailed project description is attached and includes the following information:

1. the name-plate rated capacity of the generation unit.
2. generator parameters.
3. transformer parameters.
4. exciter parameters.
5. the fuel type of the unit.
6. the type of generator technology.
7. a single-line drawing dated _____.
8. a preliminary design of the proposed interface protection dated _____.

We undertake to provide up-to-date information under all of the above categories as soon as new, or more complete, information becomes available.

We are providing this information in order to allow Bluewater, Hydro One Networks Inc. ("HONI"), and the Independent Electricity System Operator ("IESO") to assess potential impacts on the systems under their control and to provide feedback on any upgrades required. We understand that Bluewater has 90 days from today's date in which to prepare its own impact assessment and to receive the impact assessments from HONI and the IESO.

We understand and agree that we are required to reimburse Bluewater for its costs of carrying out an impact assessment, as well as any costs it may incur from HONI and the IMO for their impact assessments. We agree to provide by _____ a deposit in the amount of $25,000, which represents a rough

estimate of the cost of the impact assessments. We understand that Bluewater has agreed to use best efforts to provide advance notice should the estimated cost increase significantly above the $25,000 figure.

We understand and agree that, should we choose to proceed with the project, we may be required by Bluewater, in its sole discretion, to enter into a Connection Agreement dealing with this matter enumerated in Appendix E of the Distribution System Code.

We understand that we are required to abide by the *Electricity Act* and its regulations, the Rules and Directions of the Ontario Energy Board, as well as the IMO. We also understand that we are responsible for complying with the requirements found in Bluewater's Conditions of Service, as well as the rules of the Electrical Safety Authority for Ontario.

We trust the foregoing is satisfactory.

Sincerely,

_____
I have authority to bind the Corporation

5.10 Distribution Rates

Bluewater Power Distribution rates (Schedule 9).

PART 6 – INDEX OF SCHEDULES

	SECTION Number Conditions of Service:	POLICY #	Schedule
Responding to Customer Power Quality Complaints	1.8.1 5.2 2.7.2.2	US-GE-014	**1**
Dunning Procedure	2.6.6.3	CL-CS-007	**2**
CSA Preferred Voltage Levels for AC Systems, 0 to 50 000 V	2.7.3.1 2.7.5.1	CAN-3-C235-83	**3**
Protection and Control of Generators Ontario Electrical Safety Code	2.7.6.1	ESA Code	**4**
Final Bill Credits Transferred to Accounts Payable System	2.8.5.2	CL-CS-019	**5**
Metering	2.8.6.1	CL-CS-015	**6**
Billable Charges	2.8.7.1 2.9.5.1	CL-CS-003	**7**
Security Deposits, Interest, Refunds and Transfers	2.9.3.1	CL-CS-009	**8**
Bluewater Power May 2007 Rate Schedule	3.8.3 5.10		**9**
Bluewater Power Service Territory for Lambton County	5.1		**10**
OEB Distribution Licence	5.1		**11**
Bluewater Power Offer to Connect Contract	5.5		**12**
Guidelines for Applicants Connecting Distributed Generation			**13**
Distribution Connection Agreement			**14**
Net Metering Application Form			**15**
Net Metering Connection Agreement			**16**

Number: US-GE - 014	**Date Issued:** November 1, 2000	**Date Revised:** May 3, 2007
Initiated by: Operations	**Authorized by:** Brad Gray Vice President of Operations	
Approved by: Janice McMichael-Dennis President & Chief Executive Officer		
Subject: RESPONDING TO CUSTOMER POWER QUALITY COMPLAINTS		

Purpose

To establish a clear process for responding and dealing with power quality complaints that come from the customer.

Power Quality Obligations of Bluewater Power Distribution
(taken from the Bluewater Power Conditions of Electrical Service)

BPDC is obligated to maintain a voltage variance standard that is in accordance with the Canadian Standards Association standard CAN3-235. BPDC will practice reasonable diligence in maintaining voltage levels, but is not responsible for variations in voltage from external forces.

If the consumer making the complaint causes the source of a power quality problem, BPDC will seek reimbursement for the costs of investigating the complaint.

No electrical equipment shall be connected to, or remain connected to, the BPDC electrical distribution system that will produce an undesirable system disturbance that may be reflected back to the BPDC distribution system.

Any electrical disturbance caused by a customer will be corrected or eliminated immediately by the customer and at the customer's expense.

BPDC may direct a customer connected to it's electrical distribution system to take corrective or preventative action on the customers system when there is a direct hazard to the public safety, or the consumer is causing, or could cause adverse effects to the reliability of the BPDC distribution system.

Procedure

1. All power quality complaints received from the customer (or their agent) will be directed to the Manager of Meter Services. All complaints shall be in writing even if the initial contact from the customer is by phone or through personal contact. BPDC staff are to request that the customer provide the details of the power quality problem in writing. This will ensure the proper paper work is created for the Performance Based Regulation reporting required by the Ontario Energy Board.

2. Manager of Meter Services will open the necessary service order and send a Meter Technician (or other designated staff) to contact the customer to arrange for the installation of a voltage analyzer. This instrument will be left in place for a period of time (usually 1-day to 1 week, as required) in order to record the customer's load and voltage profile.

3. Once the recording instrument has been removed, the chart record will be forwarded to the Distribution Engineer for review. The Distribution Engineer will review the information collected and will determine:

a. If the voltage profile at the customer's terminals is within the parameters of the CSA CAN3-235 standard, then the customer will be notified in writing that we are meeting our obligations in this regard.

b. If the voltage profile at the customer's terminals is not within the specifications of the CSA Can3-235 standard, the Distribution Engineer will initiate a further investigation of the cause and potential corrective measures.

    i. If the cause of the disturbance is found to be within the customer premises, then all costs of remedial work required to correct the problem will be at the customer's expense. If the effects of the disturbance are felt by other Bluewater Power customers, then the customer will be given a limited time to correct the problem or Bluewater Power will take steps to disconnect the electrical service until the problem is rectified to the satisfaction of the Utility.
    ii. If the cause of the disturbance is the caused by some component of the Bluewater Power electrical distribution system, BPDC will take steps to rectify the problem at BPDC expense.

4. If the cause of the electrical disturbance is not determined in a reasonable period of time, BPDC will enlist the services of a Power Quality Specialist of its choosing and at BPDC expense to determine the cause of the disturbance.
   However, if the Specialist determines that the cause of the electrical disturbance is caused by the customer's equipment or systems, BPDC will invoice the customer for all costs associated with determining the cause of the problem.

   If the cause of the problem is determined to be from BPDC equipment or systems, then BPDC will be responsible for all costs of the investigation.

Number: CL-CS - 007	**Date Issued:** November 1, 2000	**Date Revised:** May 7, 2007
Initiated by: Kathy Gadsby Manager of Market & Customer Service	**Authorized by:** Kathy Gadsby Manager of Market & Customer Service	
Approved by: Janice McMichael-Dennis President & Chief Executive Officer		
Subject: DUNNING PROCEDURE		

Customer Service
Past due accounts (sixteen (16) days after the original due date) will receive a notice. Depending on their payment history, notices will either print as a 'friendly reminder' if customer's payment history warrants it. Or if payment history indicates numerous previous late payments the notice will print a 'final notice' requesting payment or account will be disconnected.

Junior Clerk
Process notices for 4:00pm delivery.

Customer Service/Field Representatives

Non application of service or deposit not paid:

Disconnection will automatically take place when customer has made no application for service or has not paid deposit requested.

If full payment has not been received or suitable arrangements made for current active accounts by notice date the following steps will be taken:

1. Rep will call or activate the auto dialer to contact the delinquent portion customers currently in the process for collection. With a pre-recorded message the customers will be informed the day (am or pm) before the final day for payment that payment is required and to contact our office with any concerns.

2. Once the Rep/auto dialer has made contact with the customer reference will be made on the customer's account. The following day the Customer Service Rep will attempt to manually contact those customers who were unreachable via the auto dialer and record such on customer's account.

3. Unless payment arrangements have been made and honored, on the following day of the 'last payment' day the Customer Service Rep will issue a collection service order for any outstanding amounts that fall within the dunning procedure guidelines.

   Residential R1 (delinquent) - $100.00
   Residential R2 (on time) - $150.00
   B/C – Small/Large General Service Businesses - $150.00

4. The Field Rep will attempt to make personal contact with the customer regarding the arrears outstanding. His first visit to the property will consist of collecting payment and/or leaving a collection notice (see notice BB) stating the full payment must be received within three (3) business days (by 10:00am) if customer is

presumed low risk. If customer is deemed high risk full payment must be received within 24 hours. The customer will be billed a collection charge and applicable taxes.

5. If payment has not been received by the 'final payment' date as noted on the collection notice or previous payment arrangements have not been fulfilled then the Customer Service Rep will attempt to contact the customer by phone one **last** time. If unsuccessful, a disconnect service order will be created immediately stating what amount is owing and any additional charges.

6. On his final visit to the property the Field Rep will attempt to collect the full outstanding amount or disconnect the service at that time. No collection charges is applicable. Field Rep will leave a cut notice at the main entrance door outlining customer's options regarding reconnection of service and applicable charges, including new/additional security deposit etc. See notice example CC.

    - If the collection card is found in the same place it was left during the 1st visit this will mean that personal contact has **not** been made and the service will be left on until further investigation can be done. Customer Service Rep and or Field Rep to attempt to contact owner, superintendent, employment phone number, real estate agent or neighbor.

MULTIPLE DWELLINGS

1. Tenants residing in bulk billed complexes must be given thirty-five (35) days written notice informing them that the hydro service will be disconnected on the 36th day for non-payment unless full payment has been received. This will allow them to make other living arrangements, if necessary. Notices are hand delivered to each unit and posted on all entrance doors. See notice example **AA.**

2. Tenants residing in an individually metered multi unit that the landlord pays must be given thirty-five (35) days written notice informing them that the hydro service will be disconnected on the 36th day for non-payment unless full payment has been received. The tenant is given the option to apply for service and pay the necessary deposit for reconnection. Notices are hand delivered to each unit and posted on all entrance doors. See notice example **AA.**

WINTER RULES FOR DISCONNECTING SERVICE

Winter residential rules only apply when the weather drops to sub zero temperatures and there is a chance of damage to the property, such as water pipes freezing.

During winter months, service may be disconnected after 8:00 am each morning, but will be turned back on by 4:30 pm each night until account is paid in full. There will be heat throughout the night. For indoor meters, the assistance of the Line Department staff will be at a minimum.

COURTESY METERS: We have two types of courtesy meters:

115 Volt 15 Amp, which is used with gas heated homes to allow the customer to run his furnace and a few lights.
230 Volt 30 Amp, will be used in cases where electric heat is the heat source. The customer will need to turn off most of the baseboard heaters or breakers so that they will have heating in living areas only.

If weather warrants, certain courtesy metes can be sealed inoperative during the day and seal removed for night operation.

Winter general service rules allow the hydro to be cut.

PROPERTY OWNERS RESPONSIBILITY AFTER THREE WEEKS

For hydro services that have been disconnected due to **tenant's** failure to submit payment after three (3) weeks the account will automatically be final billed. The hydro will remain off but the owner will then be responsible for any monthly fixed service charges etc. and any reconnection inspection fees after six (6) months or he/she can make application for the hydro service to be turned back on. In all situations disconnect/connect service orders are to be requested and processed. The owner will be notified via mail of any changes made to the account.

FINAL BILL LETTERS

Credit Leadhand
Will generate final bill letters based on the following guidelines:

- **Twenty** days after the final bill reading date the 1st Final Bill Letter will be generated. This letter will indicate that the customer has up to ten days to pay the outstanding final bill.

- **Ten** days after the 1st final letter has been mailed, the Credit Leadhand will generate the 2nd final bill letter for Customer Service Representatives. This letter will confirm that the account is outstanding and further action is necessary. The Customer Service Representative at this time is to use their discretion how to collect the amount owing transfer balance to an active account or transfer to credit department immediately to start legal action.

  Ten Days after the 2nd final bill letter has been generated a 3rd final bill letter of outstanding accounts will be printed advising Customer Service Representatives of outstanding balance and to transfer this account immediately to Credit Department.

Junior Clerk
To process letter for 4:00 p.m. delivery.

Customer Service Representatives

Will be responsible to check final bill letters to our billing records for duplicate account names, SIN, phone numbers, or account numbers. If you find a match this account should be transferred immediately and write transferred with new account and sub number on letter and mail. If the customer is a good paying customer or a landlord that may not want this account transfer immediately, you may want to bypass transferring amount and mail the reminder notice. Please check to see if account is paid by PAP.

After doing the above check and you cannot locate customer at another address 1st final bill reminder letter should be mailed. If mail is returned to us you could phone customer for their new address to mail out or pass all information to credit department and change final bill code to #4 in general maintenance, also enter message to customer account that account has been transferred to credit dept.

When you receive the 2nd final bill letter please mail after checking for promises and payments.

If you are working on the 3rd final bill letter you are required to make a file folder (record info in record management system) for that account with all pertinent information such as name, initials, etc. and transfer this file immediately to the ‘Credit and Collection’ process and record message to customer account that account has been transferred. File reports.

Guidelines for transferring to collection agency: < than $50.00 keep on file, > than $50.00 transfer to collection agency.

Sample: Advance Cut Notice for Tenants in Bulk-Individual Metering Building

Today's date **notice AA**

NOTICE TO ALL TENANTS: full service address here

For your information, Bluewater Power Distribution Company is advising you that hydro services to this apartment building/unit will be discontinued on **day of week, date and year and time.**

Bluewater Power Distribution Company is compelled to take this action as a result of non-payment of utility accounts by the owner of this property.

For the units that are individually metered, tenants have the right to apply for hydro under the name and pay the appropriate deposit of $300.00 to avoid disconnection of service.

Please contact Bluewater Power Distribution Company should there be any further inquiries.

BLUEWATER POWER DISTRIBUTION COMPANY
337-8201

Sample: Customer Collection Notice

COLLECTION NOTICE **notice BB**

Our Customer Service Field Representative visited your property today for the purpose of collecting your overdue electric account.

The electric service will be disconnected on the third (3rd) business day from today's date if payment is not received.

To avoid disconnection, payment in full (as detailed below) is required in our office before that time. If you wish to discuss this issue, please contact our Customer Service Department at (519) 337-8201.

Name: _____

Address: _____

Account No. _____

Date: _____

Deposit: _____

Overdue Amount: _____

Collection Charge: _____

Other: _____

Total Due: _____

Please note: We are collecting on the overdue portion of your electrical account. There may still be an outstanding current portion not included in this notice. A collection charge applies any time we visit your premises for the purpose of collecting on your electrical account.

Bluewater Power Distribution Corporation assumes no responsibility for any loss or damage to property resulting from the disconnection of the electrical service. If service is disconnected for non-payment, the total amount due (includes past and current amounts owing) plus a security deposit and a reconnection charge ($20.00 + gst during regular hours/$120.00 + gst after hours) must be paid at our office before service is restored. Payment after disconnection must be in the form of cash, money order or certified cheque.

Sample: Cut Notice for Tenant-Owner

Date: **notice CC**

NOTICE TO TENANT/OWNER: full service address here

For your information, Bluewater Power Distribution Company is advising you that hydro services to this location have been **disconnected** today.

Bluewater Power Distribution Company is compelled to take this action as a result of non-payment of utility accounts by the responsible party.

Bluewater Power Distribution Corporation assumes no responsibility for any loss or damage to property resulting from the disconnection of the electrical service. If service is disconnected for non-payment, the total amount due plus a security deposit and a reconnection charge ($20.00 + gst during regular hours/$120.00 + gst after hours) must be paid at our office before service is restored. Payment after disconnection must be in the form of cash, money order or certified cheque.

Arrears of $_____ plus reconnection charges and security deposit to be paid before reconnection.

Please note that services disconnected for longer than six (6) months will require an inspection by the Electricial Safety Authority at our expense before reconnection.

Please contact Bluewater Power Distribution Company should there be any further inquiries.

BLUEWATER POWER DISTRIBUTION COMPANY
337-8201

Sample: Courtesy Metering Instructions

COURTESY METER INSTRUCTIONS **notice DD**

$ Your service has been put on a courtesy meter at your meter base

$ You are allowed 15 - 30 amps, 230/115 volts only (gas heating) or 15 – 30 amps, 240 volts only (electric heating)

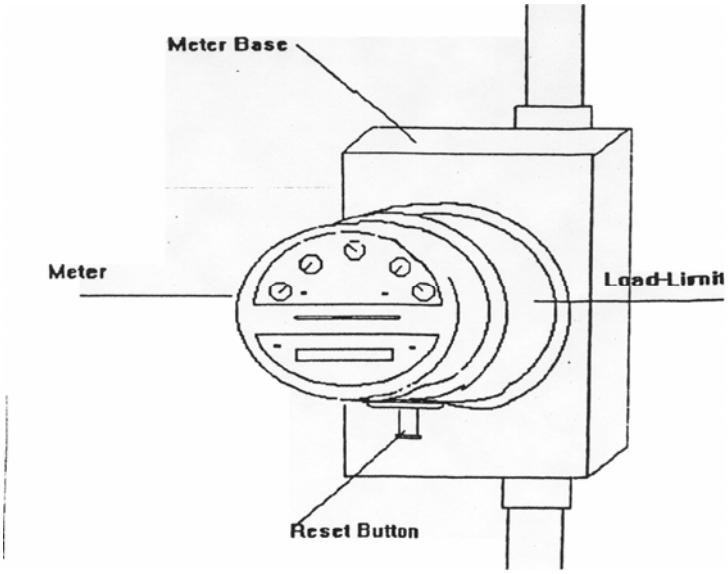
$ If you lose power - reduce your load by shutting off electrical appliances and lights, then reset the service switch button (push up) located at the bottom of the meter base.

$ If the button does not reset, you will have to reduce more power by switching off MORE electrical appliances.

$ If the courtesy meter, sealing rings or meter are damaged you will be held responsible for the full cost of replacement and subject to a tampering charge.

$ If the furnace is not operating after the courtesy meter has been installed and you have reduced your load, please contact our office immediately at **337-8201**

THE COURTESY METER WILL BE REMOVED ONLY WHEN ALL DEBTS AND CHARGES OWED TO BLUEWATER POWER ARE PAID IN FULL
OR
IF WEATHER PERMITS AFTER FIVE (5) BUSINESS DAYS THE COURTESY METER WILL BE REMOVED AND HYDRO DISCONNECTED UNTIL ALL DEBTS AND CHARGES OWED TO BLUEWATER POWER ARE PAID IN FULL.



Number: CL-CS - 019	**Date Issued:** November 1, 2000	**Date Revised:** May 8, 2007
Initiated by: Customer Service	**Authorized by:** Kathy Gadsby Manager of Market & Customer Service	
Approved by: Janice McMichael-Dennis President & Chief Executive Officer		
Subject: FINAL BILL CREDITS TRANSFERRED TO ACCOUNTS PAYABLE SYSTEM		

PURPOSE

To ensure the final bill credit balances are processed correctly and an accounts payable cheque sent to customer.

SENIOR CUSTOMER SERVICE REP

Final Bill Procedure

1. Billing Menu #2 option 17 "bill process complete" and wait for message indicating "bill close complete"

2. Payments & Adjustment Menu #3 option 15 "charge off small balances on disconnected accounts"

   "do you want files to be updated **Y**"

   Accounts with a balance greater than $ 2.00 - and less that $ 2.00 will be adjusted.

   A printout of write offs is automatically printed and passed to Credit Leadhand for review and filing.

   Wait for message then proceed with the next step

3. Payments & Adjustment Menu #3 option 17 "credit refund list"

   A printout is automatically printed and is circulated among the Customer Representatives to transfer any final bill credit balances to another sub account.

   Wait for message then proceed with next step

4. Payments and Adjustment Menu #3 option 18 "transfer credits to accounts payable system"

   A printout is given to the Credit Dept for approval and then given to the Finance Dept. and each Customer Rep will receive their own copy of this printout and use it for reference when mailing out the AP cheques.

   The system automatically sends a message to the Finance Clerk informing her of the AP transfer.

JUNIOR CLERK

1. Junior Clerk will sort the final bill credits and give to the CSR's.

CUSTOMER SERVICE REP

1. CSR's will each receive their own copy of the Credit Refund List and transfer any balances to another sub account. Type a comment on the final bill informing the customer that you have transferred their credit. The Credit Dept will also receive a copy and will keep it on file.

2. CSR's will get their own copy of the Transfer to A/P list and will keep it a separate in yellow folder along with the final bill credits.

3. When CSR receives the AP cheques from switchboard/receptionist make sure the credit on the bill final matches the cheque. Mail out cheque and final bill. Send out the cheque 10 days after the last payment especially if the account has a poor credit history.

4. When a customer pays an additional payment after the final bill has been paid in full the credit amount will appear on the credit refund list to be either transferred to another sub account or will be transfer to AP system. Either way you will **not** get a copy of the final bill and **you** will have to request one and make any necessary changes to the bill regarding the extra payment. File the copy of the bill and wait for the cheque to be printed.

5. If a final bill credit has been transferred to the AP system and you wish to cancel/void the cheque (customer cheque returned NSF) you will be required to complete a AP Cancel form (found on the intranet). Give the Finance Dept the completed form.

   It will be **your** responsibility to enter an adjustment (adjustment code 87 - Cancel AP System Credit Cheque) into the customers account. Give Finance Dept the cancelled cheque with information on the stub part indicating when you cancelled the cheque and why.

6. If you require to stop payment once a cheque has been mailed (lost in mail, stale dated etc) it will be necessary to notify the Finance Department so that they can verify that the cheque has not cleared the bank account.

   It will be **your** responsibility to enter the credit adjustment (adjustment code 87 Cancel AP System Credit Cheque) into the customer's account. Give Finance Dept the cancelled cheque with information on the stub part indicating when you cancelled the cheque and why.

   The credit will then be again transferred to the AP System in the next cycle run and a cheque will be printed on the following Tuesday.

7. CSR's will have the option to refund a credit from an active account or an account that has another sub account. By taking option 19 Manual Credit Transfer to Accounts Payable System on menu #3 Payments & Adjustment enter the account number and make sure that is the amount you want the cheque to be for. You have the choice of overwriting the comment on the "invoice description line" but something must be written on the line. A Transfer to A/P listing will automatically print off the CSLAZ1 printer. The printout is to be signed by the CSR and then given to the Finance Dept.

8. Customer requests for refunds for under $200.00 - process a red stub for the credit amount and have two staff signatures on the slip, yourself and another staff member being supervisory or a Leadhand employee. Make a comment on the customers account relating to

the cash refund. Use your discreation!!

CREDIT LEADHAND

1. Credit leadhand will scrutinize write off report and file.

2. Credit leadhand will scrutinize the cheques. To cancel cheque complete AP Cancel Form and give to the Finance Dept along with the cheque.

   It will be your **responsibility** to enter an adjustment (adjustment code 87 - Cancel AP System Credit Cheque) into the customers account. Remember you must transfer the credit immediately or else in the next billing the credit will be transferred to the AP System.

3. Forward the signed and approved cheques to the Customer Service Representative.

ACCOUNTS PAYABLE CLERK

1. A message will be sent when final bill credits are transferred to AP System. You will also receive a list of customers/amounts and totals transferred. This list will have an approved customer service signature.

2. AP Clerk will process Customer's AP cheques every Tuesday morning and give cheques to Senior Management for appropriate signatures. Give complete cheques to Credit Leadhand or Office Supervisor for further processing.

3. Upon receiving notification to cancel/void a cheque the clerk will process that information into the AP System.

ITEMS OF INTEREST

**** DO NOT PAY ***** will appear as a description beside the amount payable if the customer is on PAP or if this a final bill customer whose amount payable is > 0 and < the charge off amount (currently $2.00)

WE DO NOT CHARGE OR REFUND AMOUNTS PAYABLE UNDER $2.00 ON FINAL BILLS will appear if this is a final bill customer whose amount payable is not 0 and within the charge off amount window.

Number: CL-CS - 015	**Date Issued:** November 1, 2000	**Date Revised:** May 8, 2007
Initiated by: Customer Services **Revised by:** Kathy Gadsby Manager of Market & Customer Service Mark Vanderheide Manager of Meter Services	**Authorized by:** Kathy Gadsby Manager of Market & Customer Services	
Approved by: Janice McMichael-Dennis President & Chief Executive Officer		
Subject: METERING		

DAMAGED ELECTRICAL METERS

CUSTOMER SERVICE

When a meter is damaged or broken, through to vandalism, on the first occurrence Bluewater Power Distribution Corporation will generally replace that meter at no charge to the owner. It should be suggested to the owner that the meter should be enclosed in an approved locked metal cabinet.

When meters are damaged more than once it is Bluewater Power Distribution Corporation policy to bill the owner for the cost of the meter and labor to replace the meter and insist that the meter be enclosed in an approved locked metal cabinet as soon as possible. If the customer does not do this, we may refuse to supply an electrical service to this location.

In both the above situations the Customer Service staff will send a letter confirming what should be done along with a list of cabinet suppliers. The customer is responsible for the cost of the cabinet (supplier: Custom Steel at 519-737-6808). All information regarding the letter and conversations with the owner will be recorded on the customers account.

METER DEPARTMENT

The Meter Department should be aware of the above policy when speaking to the customer and inform and make suggestions to the Customer Service staff in the handling of the account. The Meter Department should be able to make minor repairs to the cabinet when required and be sure the cabinet is secured with an A-1 lock.

ONE (1) METER SERVICING MORE THAN ONE (1) UNIT

1. Two (2) apartments on 1 meter

When the situation occurs where only one (1) meter is servicing two or more apartments the meter will

remain in the owner's name. The Customer Service Reps will make a note of the same in the account description field.

2. Two (2) meters in a duplex but the furnace on one (1) of the meters

When the situation occurs where one of the tenants has the furnace on their meter and arrangements have been made between that tenant and the owner, the meter will remain in the tenant's name unless there is a collection problem with this tenant, in which case it will be put in the owner's name.

THEFT OF POWER

METER DEPARTMENT

To assemble data on the possible theft of power the Meter Department should consider to following:

1. Metering at pole or another location may be required to compare quantities of usage.

2. Photograph or drawing should be made of improper connection.

3. Documentation of all activity in the field regarding discussions and field action.

4. Review attached guidelines

CUSTOMER SERVICE

1. Review findings to ensure a proper follow up procedure.

2. Review attached guidelines.

METERING ERRORS

Metering errors pertain to: improper multipliers, mixed up meters vs. customer premises, potential meter errors and others

The Standard Application of rates, as approved by Ontario Energy Board and Bluewater Power's Condition of Service will be the official guide when determining the amount owed to the customer or due to Bluewater Power as a result of billing errors.

Where billing errors resulted in over billing the General Service and Residential customer will normally be credited for a period not exceeding six (6) years.

Where billing errors have resulted in under billing the customer will normally be charged for a period not exceeding:

1. Two (2) years in the case of an individual "**residential customer**" who was not responsible for the error.

2. Six (6) years in other cases.

CUSTOMER SERVICE

When billing errors are first detected, a thorough investigation will be completed which will verify the circumstances. The amount owing or due can now be calculated as per the General Policy by showing the actual amount that was paid vs. the corrected amount for the time period involved. The Manager and/or the Supervisor of Customer Service must now be advised of the problem.

SENIOR CUSTOMER SERVICE REPRESENTATIVE

The customer can now be contacted and informed of the situation by the Senior Customer Service Representative or in the case of larger amounts it is advisable to have the Manager or Supervisor address the problem as we may now be in negotiations with the customer as per the general policy.

The Senior Customer Service Representative can now make corrections to the customers account. Dummy meter changes will be made to reverse the error with all pertinent messages being displayed on the customers account and on the meter change slips.

If the last billing has not been paid, cancel the billing and rebill at the corrected amount. Please check the customers account to ensure that any NSF or late charges etc. are not included in the corrected amounts. The balance of the amount owing, the calculated credit or the negotiated amount can now be applied to the customers' account through a billing correction.

MANAGER/SUPERVISOR OF CUSTOMER SERVICE

All negotiations must be under the direction of the Manager/Supervisor of Customer Service.

POTENTIAL METERING ERRORS

If a Bluewater Power employee suspects that there may be a problem with a meter, they should take the initiative to resolve the potential problem. This may require investigation into the billing history and perhaps having the meter changed by the meter shop as well as inspected by our staff. If the meter is found to be inaccurate, refer to the General Policy on Metering Errors. The meter should then be held for a minimum of 3 months for possible further inspection by Measurement Canada.

BLUEWATER POWER POLICIES AND PROCEDURES

Number: CL-CS - 003	**Date Issued:** November 1, 2000	**Date Revised:** May 7, 2007
Initiated by: Customer Service	**Authorized by:** Kathy Gadsby Manager of Market & Customer Service	
Approved by: Janice McMichael-Dennis President & Chief Executive Officer		
Subject: BILLABLE CHARGES		

TAX STATEMENT/ACCOUNT HISTORY CHARGE – requests for written documentation on consumption history. The fee is applicable for each location request and for every twelve (12) month history.

COLLECTION CHARGES – fee applied when Bluewater Power personnel are sent to premises for collection of delinquent balance of account

METER DISPUTE TEST: should a customer request a meter dispute test conducted by Measurement Canada there is a fee of $40.00 for the cost of removing and reinstalling the meter. If the meter is defective then we will reimburse the customer of any charges. There is no fee if the test is requested by Bluewater Power personnel.

SPECIAL METER READING (other reason): this charge will be used primarily for owners who kept the hydro account in their name so that their tenant would not have to pay a deposit. This charge is for when the owner requests us to read the meter and manually calculate the amount owing by the tenant. In some cases a final bill is done then the account is put back into the owners name. We will be charging for this "special meter reading". Additionally, this charge is for when a customer requests a change of retailer and requires us to read the meter outside his normally reading schedule.

SERVICE CALLS-AFTER HOURS: for non-emergency issues after hours at customer's request.

ADMINSTRATION FEE: this charge is applied to the FIRST bill only for all residential and general service customers and covers the cost of our Field Rep to read the meter and for the Reps to change our billing records at the time of EVERY transaction. This charge does not cover the full cost of changing records but to have customers that move more frequent than others to pay their share. Otherwise, any undue amount must be assessed against the revenue obtained from established customers.

Exemptions: change of name (marriage) and spouse deceased

ARREARS CERTIFICATE/LAWYERS: when lawyers, mortgage companies (taking back the house) etc request a WRITTEN documentation stating what arrears are outstanding on a property sale.

EASEMENT SEARCH/LAWYERS: when lawyers request WRITTEN documentation on a property sale. The Engineering Dept will look in Bluewater Power files or conduct a site visit.

CUSTOMER REQUEST/CHG OF ASSIGNMENT: this will typically apply to general service customers. If a customer wishes to have his account rate be reclassified (eg. the load has changed considerably) we will assess the past history consumption billed. The charge is applied to the account even if the decision is not favorable.

TRANSFORMER ALLOWANCE CREDIT: applies to large general service customers who own their transformers, as BWP doesn't have to supply large transformers and stock backups.

LATE PAYMENT INTEREST: 2% interest applied monthly to account on outstanding balances

PRIMARY METERING DISCOUNT: applies to large general service customers whose service is metered on the primary side of the transformer. The 1% discount allows for transformer loses that would not normally be seen by the meter.

DIVERSITY CREDIT WINTER/SUMMER: this is a credit we receive from OPGI for large use demand and we pass on the credit to our Large Use customers

RESERVE CAPACITY CHARGE: a charge to ensure backup electrical capacity to customers who own their own generation plants

BACK-UP POWER DISTRIBUTION/ENERGY CHARGE: these are rates that will be used if a customer with his own generation requires backup power from us

RE-CONNECTION – REGULAR HOURS - when an account has been disconnected for non-payment of account or non application this charge will be applied to the account and paid for prior to reconnection during normal business hours

RECONNECTION – AFTER HOURS - when an account has been disconnected for non-payment of account or non application this charge will be applied to the account and paid for prior to reconnection during after normal business hours

NSF CHEQUE CHARGES – this fee is charged for all returned cheques from the bank unless it was at the fault of Bluewater Power

GOODS AND SERVICES TAX EXEMPTIONS – All ministries of the Ontario government are not subject to the payment of the Goods and Services Tax. Other areas where GST will not be applied are:

- Late interest charges
- Deposits
- Deposit interest
- Accounts Receivable refunds
- Deposit refunds
- Service to GST exempt customers

First Nations People residing on the reserve are GST exempt.
Un-incorporated business - natives on the reserve are GST exempt
Incorporated (Ltd) business – natives on the reserve are NOT GST exempt

Number: CL-CS– 009	**Date Issued:** November 1, 2000	**Date Revised:** May 7, 2007
Initiated by: Kathy Gadsby Manager of Market & Customer Service	**Authorized by:** Kathy Gadsby Manager of Market & Customer Service Alex Palimaka, Vice President Corporate Services & General Counsel	
Approved by: Janice McMichael-Dennis President & Chief Executive Officer		
Subject: SECURITY DEPOSITS, INTEREST, REFUNDS AND TRANSFERS		

Security deposits are required to reduce Bluewater Power's exposure to financial risk and to encourage prompt payment of the account; otherwise uncollectable amounts must be assessed against the revenue obtained from established customers.

RESIDENTIAL

A security deposit is required from all customers in the Residential classification.

The amount of the deposit to be provided to Bluewater Power shall be calculated using the property's average actual billing in the last 12 months prorated to 60 days. Where actual consumption is not available or not representative of typical consumption, reasonable estimates may be made by the utility. Where a customer has a payment history which discloses more than one disconnection notice in a relevant 12 month period, the distributor may use that customer's highest actual or estimated monthly load for the most recent 12 consecutive months within the past 2 years for the purposes of making the calculation of the maximum amount of security deposit.

The residential security deposit will be waived if one of the following conditions is met:

- The customer provides a letter of reference from the customer's previous hydro or gas utility in Canada, indicating the customer had a *good payment history*[1] for at least one year and the account was in the same name.
- The customer is a past customer of Bluewater Power with a proven *good payment history*[1] on file.
- The customer provides a credit check or consents to a credit check (at the customer's expense) that is satisfactory to Bluewater Power, in its reasonable discretion.
- A deposit will not be required of an existing residential customer as long as the customer maintains their established record of *good payment history*[1]. An existing customer may be required to provide a deposit upon the occurrence of events disqualifying them from a *good payment history*[1] or upon annual review identifying the same.

A residential rate class customer will qualify for refund of their security deposit when one consecutive year of *good payment history*[1] has been achieved.

GENERAL SERVICE <50KW

A security deposit is required from all customers in the General Service <50KW classification.

The amount of the deposit to be provided to Bluewater Power shall be calculated using the property's average actual billing in the last 12 months prorated to 60 days. Where actual consumption is not available or not representative of typical consumption, reasonable estimates may be made by the utility. Where a customer has a payment history which discloses more than one disconnection notice in a relevant 12 month period, the distributor may use that customer's highest actual or estimated monthly load for the most recent 12 consecutive months within the past 2 years for the purposes of making the calculation of the maximum amount of security deposit.

The general service <50KW security deposit will be waived if one of the following conditions is met:

- The customer provides a letter of reference from the customer's previous hydro or gas utility in Canada, indicating the customer had a *good payment history*[1] for at least one year and the account was in the same name.
- The customer is a past customer of Bluewater Power with a proven *good payment history*[1] on file.
- The customer provides a credit check or consents to a credit check (at the customer's expense) that is satisfactory to Bluewater Power, in its reasonable discretion.
- A deposit will not be required of an existing General Service <50KW customer as long as the customer maintains their established record of *good payment history*[1]. An existing customer may be required to provide a deposit upon the occurrence of events disqualifying them from a *good payment history*[1] or upon annual review identifying the same.

A general service <50KW rate class customer will qualify for refund of their security deposit when 60 consecutive months of *good payment history*[1] has been achieved.

GENERAL SERVICE >50KW and GENERAL SERVICE >50KW TOU

A security deposit is required from all customers in the General Service >50KW and General Service >50KW TOU classification.

- The amount of the deposit to be provided to Bluewater Power shall be calculated using the property's average actual billing in the last 12 months prorated to 30 days. Where actual consumption is not available or not representative of typical consumption, reasonable estimates may be made by the utility. Where a customer has a payment history which discloses more than one disconnection notice in a relevant 12 month period, the distributor may use that customer's highest actual or estimated monthly load for the most recent 12 consecutive months within the past 2 years for the purposes of making the calculation of the maximum amount of security deposit. Allowable reductions may be calculated, by credit rating, as stated in Section 2.4.13 of the Ontario Energy Board's Distribution System Code.

The general service >50KW and General Service >50KW TOU security deposit will be waived if one of the following conditions is met:

- The customer provides a letter of reference from the customer's previous hydro or gas utility in Canada, indicating the customer had an excellent payment history for at least one year and the account was in the same name.
- The customer is a past customer of Bluewater Power with a proven "*good payment history*"[1] on file.
- The customer provides a credit check or consents to a credit check (at the customer's expense) that is satisfactory to Bluewater Power, in its reasonable discretion.
- Waiver or reduction of a requested security deposit may also be attained where a credit rating from a recognized credit rating agency has been obtained at the customer's expense. A deposit will not be required of an existing General Service >50KW or General Service >50KW TOU customer as long as the customer maintains their established record of *good payment history*[1]. An existing customer may be required to provide a deposit upon the occurrence of events disqualifying them from a *good payment history*[1] or upon annual review identifying the same.

A general service general service >50KW and General Service >50KW TOU rate class customer will qualify for refund of their security deposit when 84 consecutive months of *good payment history*[1] has been achieved.

LARGE USE

A security deposit is required from all customers in the Large Use classification.

- The amount of the deposit to be provided to Bluewater Power shall be calculated using the property's average actual billing in the last 12 months prorated to 30 days. Where a customer has a payment history which discloses more than one disconnection notice in a relevant 12 month period, the distributor may use that customer's highest actual or estimated monthly load for the most recent 12 consecutive months within the past 2 years for the purposes of making the calculation of the maximum amount of security deposit. Allowable reductions may be calculated, by credit rating, as stated in Section 2.4.13 of the Ontario Energy Board's Distribution System Code. Allowable reductions will be calculated, by credit rating, as stated in Section 2.4.13 of the Ontario Energy Board's Distribution System Code.

The Large Use security deposit will be waived if one of the following conditions is met:

- The customer is a past customer of Bluewater Power with a proven *good payment history*[1] on file. Waiver or reduction of a requested security deposit may be attained where a credit rating from a recognized credit rating agency has been obtained at the customer's expense.
- A deposit will not be required of an existing Large Use customer as long as the customer maintains their established record of *good payment history*[1]. An existing customer may be required to provide a deposit upon the occurrence of events disqualifying them from a *good payment history*[1] or upon annual review identifying the same.

Bluewater Power shall return 50% of the paid deposit when 84 consecutive months of *good payment history*[1] has been achieved. Bluewater Power may return the full deposit as its sole discretion.

PRINCIPLES APPLICABLE TO ALL RATE CLASSES:

(1) ANNUAL REVIEW

If it is determined, upon annual review, that the amount of the security deposit should be adjusted upwards, this amount will become payable as of the due date of the customer's next regular bill. A review of all customer security deposits will be undertaken at least once in a calendar year. The review will be completed in conjunction with the anniversary date of the full payment of the security deposit. A review will determine whether Bluewater Power will return the deposit or whether the amount of the deposit is to be adjusted based on the maximum allowable amount.

(2) PAYMENT OF DEPOSIT

Residential Customer class:
Payment of a security deposit shall be cash or cheque, at the discretion of the customer.

Non-Residential Customer class:
Payment of a security deposit shall be cash, cheque or an automatically renewing, irrevocable letter of credit from a bank at the discretion of the customer.

(3) NON-PAYMENT OF DEPOSIT
Non-payment of a security deposit shall result in suspension of service following the established collection process.

The Customer Service Representative will add the pending deposit to the Security Deposits Receivable spreadsheet located on the Intranet to enable the Dunning Department to monitor the collection of pending deposits.

The Dunning Department will monitor the collection of pending deposits and only the Dunning Department Lead Hand or Manager of Market Services will have the authority to adjust deposit requirements and/or require deposits for existing customers.

(4) INTEREST & REFUNDS & TRANSFERS

All deposits on file are subject to interest to be applied to the account a minimum of once every 12 months or upon closure of an account. The annual rate of interest will be equal to the Bank of Canada published Prime Business Rate less 2% and will be updated quarterly.

Upon closure of an account the deposit will be refunded on the final bill and reapplied to the first bill of the new service location if the customer has not proven *good payment history*[1]. In the case where a larger security deposit is required the customer will be notified of the difference and billed accordingly.

(5) MAXIMUM SECURITY DEPOSIT

For calculation of the maximum security deposit amount, Bluewater Power may use the customer's highest actual or estimated billing information for the most recent 12 consecutive months within the past 24 months multiplied by the applicable billing cycle factor.
The bill cycle factor, as defined in the Ontario Energy Board Distribution System Code is 2.5 if the customer is billed monthly, 1.75 if the customer is billed bi-monthly or 1.5 if the customer is billed quarterly.

(6) RETAIL CONSOLIDATED BILLING

In the case of a customer that chooses to move to a retailer that offers in whole, or in part, retailer consolidated billing, any security deposit on hand shall be applied to the final bill in accordance with section 2.4.27 of the Distribution System Code.

(7) CUSTOMER REVIEWS

A customer may request a review of a security deposit 12 months after paying the deposit in full.

[1]*Good payment history* is defined as per Section 2.4.9 and 2.4.10 of the Ontario Energy Board Electricity Distribution System Code as follows:
"2.4.9 A distributor may require a security deposit from a customer who is not billed by a competitive retailer under retailer-consolidated billing unless the customer has a good payment history of 1 year in the case of a residential customer, 5 years in the case of a non-residential customer in a <50 kW demand rate class or 7 years in the case of a non-residential customer in any other rate class. The time period that makes up the good payment history must be the most recent period of time and some of the time period must have occurred in the previous 24 months. A distributor shall provide a customer with the specific reasons for requiring a security deposit from the customer.
2.4.10 For the purposes of section 2.4.9, a customer is deemed to have a good payment history unless, during the relevant time period set out in section 2.4.9, the customer has received more than one disconnection notice from the distributor, more than one cheque given to the distributor by the customer has been returned for insufficient funds, more than one pre-authorized payment to the distributor has been returned for insufficient funds or a disconnect / collect trip has occurred. If any of the preceding events occur due to an error by the distributor, the customer's good payment history shall not be affected."

RATE SCHEDULE

Effective May 1, 2007

RESIDENTIAL

Distribution Rate	per kWh	$0.0185
Monthly Service Charge per Customer		$13.90
Cost of Power Rate	per kWh	* See Electricity Options box
Transmission Connnection Charge	per kWh	$0.0050
Transmission Network Charge	per kWh	$0.0057
Wholesale Market Service Rate (incl.RRA)	per kWh	$0.0062
Debt Retirement Charge	per kWh	$0.0070
Standard Supply Service Administration Fee (SSS Customer only/mth)		$0.2500

GENERAL SERVICE <50kW

Distribution Rate	per kWh	$0.0150
Monthly Service Charge per Customer		$25.42
Cost of Power Rate	per kWh	* See Electricity Options box
Transmission Connection Charge	per kWh	$0.0045
Transmission Network Charge	per kWh	$0.0052
Wholesale Market Service Rate (incl.RRA)	per kWh	$0.0062
Debt Retirement Charge	per kWh	$0.0070
Standard Supply Service Administration Fee (SSS Customer only/mth)		$0.2500

GENERAL SERVICE >50kW (50 kW to 999 kW)

Distribution Rate	per kW	$1.8541
Monthly Service Charge per Customer		$330.82
Cost of Power Rate	per kWh	* See Electricity Options box
Transmission Connection Charge	per kW	$1.7882
Transmission Network Charge	per kW	$2.1218
Wholesale Market Service Rate (incl.RRA)	per kWh	$0.0062
Debt Retirement Charge	per kWh	$0.0070
Standard Supply Service Administration Fee (SSS Customer only/mth)		$0.2500

GENERAL SERVICE Intermediate (1000 to 4999 kW)

Distribution Rate	per kW	$0.8272
Monthly Service Charge per Customer		$3,084.55
Cost of Power Rate	per kWh	* See Electricity Options box
Transmission Connection Charge	per kW	$1.9603
Transmission Network Charge	per kW	$2.2535
Wholesale Market Service Rate (incl.RRA)	per kWh	$0.0062
Debt Retirement Charge	per kWh	$0.0070
Standard Supply Service Administration Fee (SSS Customer only/mth)		$0.2500

LARGE USE (> 5000 kW)

Distribution Rate	per kW	$1.0144
Monthly Service Charge per Customer		$18,021.42
Cost of Power Rate	per kWh	* See Electricity Options box
Transmission Connection Charge	per kW	$2.2417
Transmission Network Charge	per kW	$2.4952
Wholesale Market Service Rate (incl.RRA)	per kWh	$0.0062
Debt Retirement Charge	per kWh	$0.0070
Standard Supply Service Administration Fee (SSS Customer only/mth)		$0.2500

UNMETERED SCATTERED LOADS

Distribution Rate	per kWh	$0.0180
Monthly Service Charge per Connection		$12.58
Cost of Power Rate	per kWh	* See Electricity Options box
Transmission Connection Charge	per kWh	$0.0045
Transmission Network Charge	per kWh	$0.0052
Wholesale Market Service Rate (incl.RRA)	per kWh	$0.0062
Debt Retirement Charge	per kWh	$0.0070
Standard Supply Service Administration Fee (SSS Customer only/mth)		$0.2500

SENTINEL LIGHTING

Distribution Rate	per kW	$8.0993
Monthly Service Charge per Connection		$1.81
Cost of Power Rate	per kWh	* See Electricity Options box
Transmission Connection Charge	per kW	$1.4113
Transmission Network Charge	per kW	$1.6083
Wholesale Market Service Rate (incl.RRA)	per kWh	$0.0062
Debt Retirement Charge	per kWh	$0.0070
Standard Supply Service Administration Fee (SSS Customer only/mth)		$0.2500

STREET LIGHTING

Distribution Rate	per kW	$2.6538
Monthly Service Charge per Connection		$1.37
Cost of Power Rate	per kWh	* See Electricity Options box
Transmission Connection Charge	per kW	$1.3824
Transmission Network Charge	per kW	$1.6002
Wholesale Market Service Rate (incl.RRA)	per kWh	$0.0062
Debt Retirement Charge	per kWh	$0.0070
Standard Supply Service Administration Fee (SSS Customer only/mth)		$0.2500

MISCELLANEOUS CHARGES

Returned Cheque Charges + Actual Bank Charges		$15.00
Collection of Account Charges		$30.00
Disconnection/Re-Connection - Regular Hours		$65.00
Disconnection/Re-Connection - After Hours		$185.00
Meter Dispute Test/Dispute Involvement		$30.00
Special Meter Reading *(other reason)*		$30.00
New Account Setup		$10.00
Arrears Certificate/Lawyers Letters/ Tax Statements/Acct History		$15.00
Transformer Allowance Credit	per kW/mth	-$0.60
Primary Metering Allowance		-1%
Late Payment Interest Charge		1.5% per month
Loss Factor (Secondary Metered customers < 5000 kW)		1.0446

*** Electricity Options**

(1) Regulated Price Plan (RPP): Most customers are RPP customers. RPP pricing for the period May 1, 2007 to October 31, 2007 is:

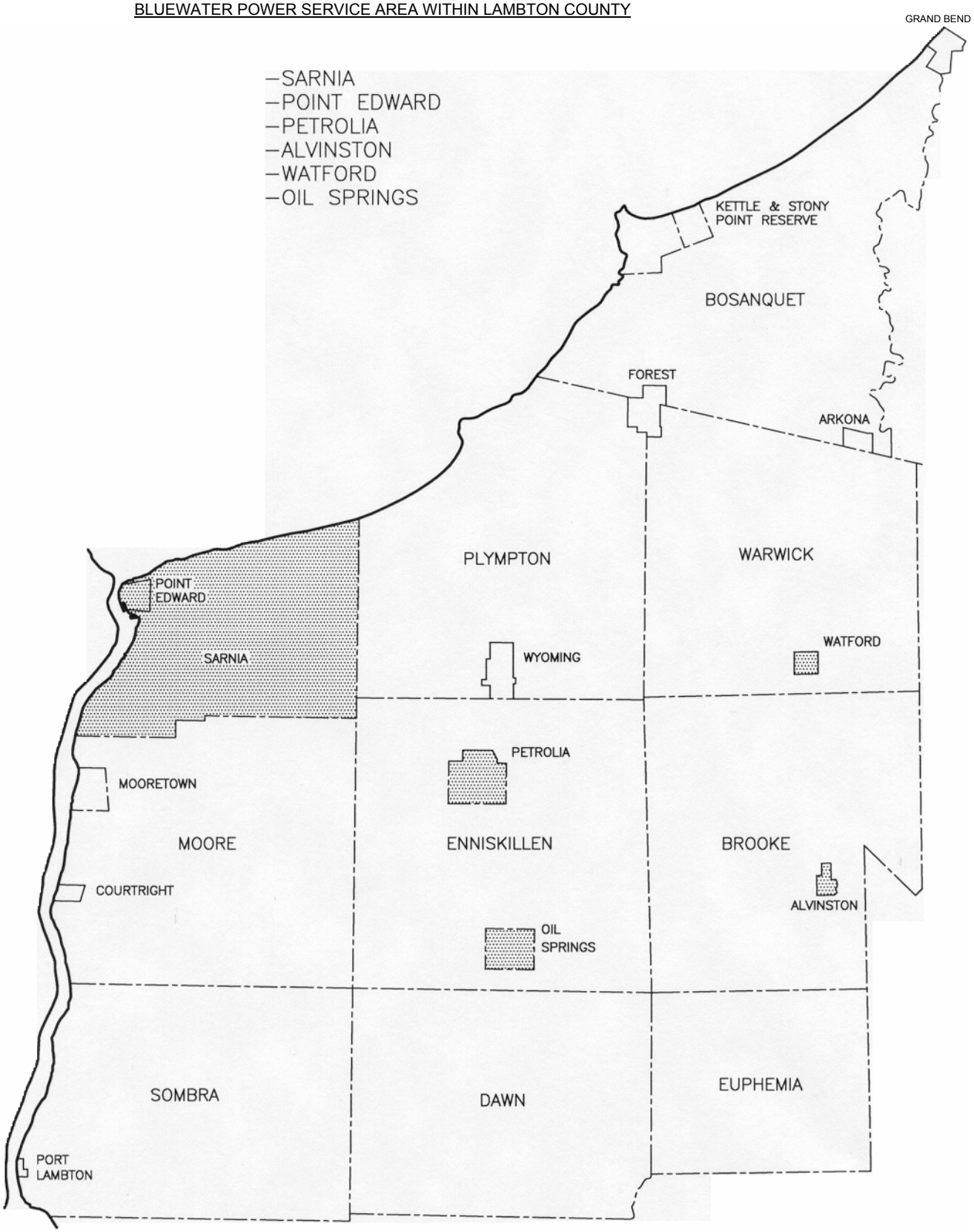
Tier 1 = 5.3 cents per kWh
Tier 2 = 6.2 cents per kWh

Residential customers are eligible for Tier 1 pricing for the first 600 kWh per month from May to October, and 1000 kWh per month from November to April; all other electricity is priced at Tier 2. Our average customer consumes 748 kWh per month. Non-residential customers who are eligible for the RPP plan receive 750 kWh per month at Tier 1 prices throughout the year.
NOTE: Customers who signed a Retail contract prior to December 9, 2002 continue to receive the protection of the regulated price plan.

(2) Retailer: Any customer can agree to buy their electricity from a retailer and they will pay the price negotiated with their retailer, provided the contract is dated later than December 9, 2002.

(3) Wholesale: Customers who do not fall in either category above will receive either the Weighted Average Price (WAP) or Hourly Weighed Average Price (HWAP).

BLUEWATER POWER SERVICE AREA WITHIN LAMBTON COUNTY



Electricity Distribution Licence

ED-2002-0517

Bluewater Power Distribution Corporation

Valid Until
March 31, 2023

Mark C. Garner
Secretary
Ontario Energy Board

Date of Issuance: October 15, 2003

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
26th. Floor
Toronto, ON M4P 1E4

Commission de l'Énergie de l'Ontario
C.P. 2319
2300, rue Yonge
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Toronto ON M4P 1E4

1 Definitions

In this Licence:

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

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

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

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

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

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

"**Licensee**" means: Bluewater Power Distribution Corporation;

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

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

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

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

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

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

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

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

2 Interpretation

18

19 2.1 In this Licence words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this licence where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day.

3 Authorization

20

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

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

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

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

4 Obligation to Comply with Legislation, Regulations and Market Rules

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

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

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

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

b) the Distribution System Code;

c) the Retail Settlement Code; and

d) the Standard Supply Service Code.

5.2 The Licensee shall:

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

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

6 Obligation to Provide Non-discriminatory Access

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

7 Obligation to Connect

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

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

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

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

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

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

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

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

8 Obligation to Sell Electricity

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

9 Obligation to Maintain System Integrity

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

10 Market Power Mitigation Rebates

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

54

11 Distribution Rates

55

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

56

12 Separation of Business Activities

57

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

58

13 Expansion of Distribution System

59

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

60

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

61

14 Provision of Information to the Board

62

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

63

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

64

15 Restrictions on Provision of Information

65

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

66

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

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

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

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

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

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

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

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

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

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

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

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

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

17 Term of Licence

17.1 This Licence shall take effect on October 15, 2003 and expire on March 31, 2023. The term of this Licence may be extended by the Board.

18 Fees and Assessments

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

19 Communication

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

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

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

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

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

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

20 Copies of the Licence

20.1 The Licensee shall:

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

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

96

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

97

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

98

1 The City of Sarnia as defined in Bill 35 of 1989, an Act respecting the amalgamation of the City of Sarnia and the Town of Clearwater.

99

2 The Town of Petrolia as of December 31, 1999.

100

3 The Village of Point Edward as defined in Schedule ‘A’ of zoning by-law # 9 of 1982.

101

4 The former Village of Alvinston as of December 31, 2000, now part of the Township of Brooke-Alvinston.

102

5 The former Village of Oil Springs as defined on Schedule ’A’ of zoning by-law #192 of 1986, plus all customers located south of Gum Bed Line and North of Aberfeldy Line between Kelly Road and Gypsie Flats Road.

103

6 The former Village of Watford as of December 31, 1997, now part of the Township of Warwick.

104

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

105

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

106

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

107

SCHEDULE 3 LIST OF CODE EXEMPTIONS

108

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

109

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

110

APPENDIX A MARKET POWER MITIGATION REBATES

111

1 Definitions and Interpretation

112

In this Licence,

113

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

114

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

115

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

116

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

117

2 Information Given to IMO

118

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

119

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

120

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

121

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

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

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

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

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

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

3 Pass Through of Rebate

127

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

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

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

131 c embedded distributors to whom the distributor distributes electricity.

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

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

134 "ONTARIO POWER GENERATION INC. rebate"

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

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

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

OFFER TO CONNECT

Between:

Bluewater Power Distribution Corporation
(hereinafter referred to as "Bluewater Power")

-and-

_____
(hereinafter referred to as the "Customer")

WHEREAS the Customer will be, or is, a distribution customer of Bluewater Power at the property known municipally as _____ and has requested that Bluewater Power provide new, or upgrade existing, electrical infrastructure of a capital nature ("System Expansion") in order to facilitate a development by the customer at said property (the "Project");

AND WHEREAS Bluewater Power has provided this Offer to Connect in response to that request in accordance with section 3.2 of the Distribution System Code ("DSC") and the Bluewater Power Conditions of Service.

NOW THEREFORE in consideration of the mutual covenants of the parties set out in this agreement, the sufficiency of which are hereby acknowledged as evidenced by the signatures below, the parties agree as follows:

(1) Terms included in this Offer to Connect shall have the following meaning:

a) "Actual Cost" shall mean the final cost of a System Expansion being the sum of all costs incurred by Bluewater Power and any Transfer Price paid to the Customer.
b) "Alternative Bid" shall mean that portion of the System Expansion that is contestable work and has been selected by the Customer to be performed by the Customer.
c) "Capital Contribution" shall mean that portion of the cost of the System Expansion that the Customer is required to pay, as determined and adjusted in accordance with this Agreement.
d) "Connection Date" shall be the date on which the System Expansion is substantially completed such that the Customer is receiving, or is capable of receiving, electricity, and such term shall serve the same purpose as the term "energization date" found in the DSC.
e) "Contestable Work" is that portion of the System Expansion that can be undertaken by the Customer as set out in Schedule "B".

f) “Customer Connection Horizon” is a maximum of five (5) years calculated from the Connection Date of the facilities.
g) “Distribution System Code” or “DSC” shall mean the Distribution System Code issued by the Ontario Energy Board (“OEB”), as amended from time-to-time, and published on the OEB’s website.
h) “Economic Evaluation” is the financial analysis required by section 3.2.1 of the DSC to determine the Capital Contribution of a Customer for a given System Expansion.
i) “Expansion Deposit” shall mean the maximum amount of deposit that could be required from a customer, being 100% of Project Revenues or total capital cost of the System Expansion as determined under Section 3.2.20 of the DSC; the “Actual Expansion Deposit” is the amount actually paid as determined under this Agreement.
j) “Non-Contestable Work” is that portion of the System Expansion that must be undertaken by Bluewater Power as set out in Schedule “B”.
k) “Projected Revenue” is a calculated amount representing the present value of forecast distribution revenue for Bluewater Power; in the case of residential, the amount is calculated based on the projected or actual number of connections; in the case of commercial, the amount is calculated based on the projected or actual load.
l) “Transfer Price” shall be the price at which assets constructed by the Customer under an Alternative Bid are transferred to Bluewater Power and shall be the lower of the cost to the Customer to construct (as evidenced by detailed invoices) or the amount set out in this Agreement for Contestable Work.
m) “Warranty” where work is performed by the Customer under an Alternative Bid, the Customer shall provide a warranty for two years beginning at the earlier of the end of the Customer Connection Horizon or the date on which the last forecasted connection (in the case of residential) or demand(in the case of commercial) has materialized.

(2) Attached to this Agreement and forming part hereof are the following schedules:

Schedule A:	Associated Drawings List
Schedule B:	Bluewater Power Estimate of Work
Schedule C:	Customer Information
Schedule D:	Economic Evaluation Analysis
Schedule E:	Payment Terms
Schedule F:	Alternative Bid Process

(3) The Customer has provided a drawing of the proposed development plan described in Schedule “A” in paper format as well as in AutoCad which it understands Bluewater Power relied upon to provide cost estimates for this Offer to Connect. In having submitted Schedule “A” for inclusion in this Offer to Connect, the Customer is stating that the plans set out in those drawings are unlikely to change.

(4) Bluewater Power has provided a preliminary design and estimate of the work required to service the Project based on the drawings in Schedule "A" and, in part, the Customer Information provided in Schedule "C". The estimate has been accepted by the Customer and is attached hereto as Schedule "B".

(5) Unless Bluewater Power objects in writing within 30 days of the Connection Date, all equipment and services installed under this Offer to Connect become the property of Bluewater Power upon their completion at the Transfer Price, which price is included as part of the capital cost in the Economic Evaluation Model for determination of the final Capital Contribution. Such transfer shall be free and clear of all mortgages, liens, demands, charges, pledges, adverse claims, rights, title, retention agreements, security interests, or other encumbrances of any nature and kind whatsoever, and the Customer shall indemnify and hold harmless Bluewater Power from any such claims or assertion, including the compensation of any legal expenses incurred in order to respond to such claims or assertions.

(6) The developer has provided Bluewater Power with details of the plan and schedule for development and the expected customer load information for the Project and that information is attached hereto as Schedule "C". The Customer understands that it is obligated to provide this information as accurately as possible and that the Economic Evaluation Analysis is only as accurate as the information provided by the Customer.

(7) Bluewater Power represents that it has performed the Economic Evaluation Analysis in accordance with the DSC and its Conditions of Service and that such analysis is attached hereto as Schedule "D".

(8) The Customer is required to make the payment in the manner set out in Schedule "E". Both parties agree to such further payments by the Customer, or rebates to the Customer, as may be determined as set out in Schedule "E". No further evaluation is required, or will be performed, outside of Schedule "E".

(9) Those items set out in Schedule "B" and identified as eligible for alternative bids, if any, may be carried out by contractors other than Bluewater Power. As required by Section 3.2.16(a) of the DSC, any Customer electing to pursue an alternative bid, must complete all of the contestable work. Schedule "F" outlines the process that must be followed if the Customer wishes to pursue an alternative bid.

(10) Payment of the amount identified in Schedule "E" is payable in accordance with that schedule but, in any event, is required before Bluewater Power will proceed with the procurement of material and plans for the installation of the facilities required herein.

(11) If any change to Schedule “A” or “C” is required by the Customer following execution of this Offer to Connect, the most current information will be utilized to prepare cost estimates and to re-run the Economic Evaluation model. This Agreement shall be amended only with the consent of both parties, acting reasonably, and the Customer may be required to pay directly for re-engineering fees outside of the Economic Evaluation process. Failing agreement on such revisions necessitated by a change to Schedule “A” or “C”, then this Offer to Connect shall be at an end in accordance with Section 12.

(12) If the Project does not go ahead for whatever reason, Bluewater Power shall refund the payment received from the Customer less any funds paid or payable by Bluewater Power on equipment and materials, as well as a charge representing Bluewater Power’s engineering fees and any labour expended to that date.

(13) This Offer to Connect is available for acceptance for 60 days following the date that this offer is made by Bluewater Power. Following 60 days, this Offer to Connect expires. The Customer acknowledges that no fees have been charged by Bluewater Power for the preparation of this Offer to Connect, however a subsequent Offer to Connect that is substantively similar to this Offer to Connect shall be subject to a prepaid administration fee of $500 plus G.S.T.

This Offer to Connect is made this _____ day of _____, _____.

Bluewater Power Distribution Corporation

Per: _____ (sign)

Name: _____ (print)

Title: _____

I have authority to bind the Corporation

The Customer, _____, hereby accepts this Offer to Connect and all terms contained herein on this _____ day of _____, _____ as follows:

- ❑ Option 1, where Bluewater Power performs all work on Schedule B, requires a Capital Contribution of $_____ (+ GST) and an Actual Expansion Deposit of $_____ (+ GST).

- ❑ Option 2, where the contractor completes that portion of work specifically noted on Schedule B, requires a Capital Contribution of $_____ (+ GST) and an Actual Expansion Deposit of $_____ (+ GST).

_____ (sign)
Witness

Per: _____

Name: _____ (print)

Title: _____

_____ (sign)
Witness

Per: _____

Name: _____ (print)

Address:

Phone Number: _____

Fax Number: _____

I/we have authority to bind the corporation.
(if not a corporation, then witnesses are required)

Schedule A: Associated Drawings

Drawing Number	Description	Date	Revision

Schedule B: Estimate of Work

Listed below is a description of all items associated with this upgrade/expansion work. Shown also are the estimated costs for each item and whether the item is eligible for the Alternative Bid Process, which is described in greater detail in Schedule F.

1. Non-Contestable Work

Item #	Description	Estimate	Alternative Bids
1	Material	$0.00	NO
2	Labour	$0.00	NO
3	Equipment	$0.00	NO
4	Civil Costs	$0.00	NO
	TOTAL	$ 0.00	

Description of Non-Contestable work Bluewater Power must perform:

1. Design and engineering specifications of the proposed expansion and connection
2. Installation of underground primary cables up the riser poles
3. Final connection of riser cables at riser poles
4. Make ready work on existing Bluewater Power assets
5. Numbering, signs and locks at transformers
6. Switching and or isolation of existing Bluewater Power facilities
7. Splicing cables to existing Bluewater Power primary cables
8. Any work involving existing Bluewater Power assets

2. Contestable Work

Item #	Description	Estimate	Alternative Bids
1	Material	$0.00	YES
2	Labour	$0.00	YES
3	Equipment	$0.00	YES
4	Civil Costs		
	- trenching	$0.00	YES
	- underground wiring	$0.00	YES
	TOTAL	$ 0.00	

Description of Contestable work:

1. Trenching
2. All transformer/switching vaults
3. Sand and granular padding
4. Supply and installation of grounding
5. Supply and installation of primary and secondary conductors
6. Duct, stakes and Big ‘O’
7. Labelling of secondary conductors
8. Training of secondary conductors
9. Transformers including inserts, elbows, fault indicators, secondary connectors and arrestors
10. Terminations at the transformer (elbows, fault indicators, grounding and secondary connections)
11. Termination of the primary cable
12. Any work not involving existing Bluewater Power assets.

3. Grand Total of Contestable and Non-Contestable Work

Non - Contestable Work	$ _____
Contestable Work	$ _____
Grand Total	$ _____

NOTES:

1. In the case of subdivision work, the Customer is 100% responsible for street lighting. The estimates above do not include streetlights, if any, which will be performed by Bluewater Power under separate arrangement.

2. This estimate is just an estimate and actual costs will be determined for the final analysis to determine the Capital Contribution.

Schedule C: Customer Information

Name of Development: _____

Residential:

Total Number of Lots (this Phase only):

Planned Connection Schedule (# lots/yr): Yr 1 Yr 2 Yr 3 Yr 4 Yr 5

Average size of Home: sq ft

General Service (<50kW demand):

Number of Connections:

Planned Connection Schedule

	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5
kW Demand: _____ Kw (per month)					
kWh (annual): _____ Kwh					

Service Voltage: volts, Three phase ____ Single Phase _____

General Service (>50kW demand):

Number of Connections:

Planned Connection Schedule:

	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5
kW Demand: _____ Kw (per month)					

Service Voltage: volts, Three phase ____ Single Phase _____

Schedule D: Economic Evaluation Analysis

1. Economic Evaluation is attached.

Schedule E: Payment Terms

Two types of payments are required from the Customer:

1. Capital Contribution:

The Customer shall pay Bluewater Power a Capital Contribution in the sum indicated on the signatory page of this Offer to Connect upon execution. Payment is to be made to "Bluewater Power" and delivered to the attention of "Bluewater Power Engineering".

Capital Contribution shall be re-evaluated as follows:

(1) For Residential Subdivisions, the Capital Contribution shall be re-evaluated within 90 days of the completion of the work based on Actual Costs, and the difference will either be invoiced to the Customer or credited, as applicable. Any payment required shall be due within 30 days, after which time it shall attract interest at the rate of 15% per annum, compounded monthly.

(2) For all other developments, the economic evaluation model set out in Schedule "D" shall be re-run on the first anniversary of the Connection Date using Actual Costs and actual demand/consumption (whichever is appropriate) during the first year. Any assumptions regarding demand/consumption in Schedule "C" for years two through five will be adjusted to reflect actual at the discretion of Bluewater Power, acting reasonably. For the sake of clarity, actual demand/consumption may result in a Customer being place in a different rate class on a go-forward basis in accordance with the standard practice of Bluewater Power and the economic evaluation will be re-run. The difference in Capital Contribution resulting from the re-evaluation of the economic evaluation model will either be invoiced to the Customer or credited, as applicable. Any payment required shall be due within 30 days, after which time it shall attract interest at the rate of 15% per annum, compounded monthly.

2. Actual Expansion Deposit:

The Customer shall also pay to Bluewater Power a deposit as an Actual Expansion Deposit in the sum indicated on the signatory page of this Offer to Connect upon execution. The Actual Expansion Deposit represents a portion of the Expansion Deposit Bluewater Power is entitled to collect and depends upon whether a Customer elects to pursue an Alternative Bid. Any Actual Expansion Deposit in the form of cash shall be returned to the Customer together with interest in accordance with Section 3.2.26 of the DSC. In recognition of the fact that Bluewater Power has only requested a portion of the Expansion Deposit to which it is entitled to collect, Bluewater Power shall not be limited to the Actual Expansion Deposit if the amount on deposit is not adequate to hold Bluewater Power whole with respect to load, connections or any matter relating to Warranty.

Where a Customer elects to pursue an Alternative Bid, the Actual Expansion Deposit shall be composed of three equal amounts as follows:

Deposit type	**Explanation**
Load Deposit	Required from all Customers to protect against the risk of the Customer failing to deliver the number of connections or load set out in Schedule "C"
Construction Deposit	Required only where a Customer chooses an Alternative Bid to protect against risks typically associated with construction
Warranty Deposit	Required only where a Customer chooses an Alternative Bid to protect against the risk of equipment or services failing during the Warranty Period

The Actual Expansion Deposit will be returned to the Customer as follows:

(1) Where the Customer has not elected to pursue an Alternative Bid and once the facilities are energized, the Actual Expansion Deposit will be returned in proportion to the actual connections (for residential developments) or actual demand (for commercial and industrial developments) that materialized that year. This annual calculation shall only be done for the duration of the customer Connection Horizon.

(2) Where the Customer has elected to pursue an Alternative Bid, the Actual Expansion Deposit will be returned in three phases as follows:

a) *Load Deposit:* same as above.
b) *Construction Deposit:* shall be returned in its entirety within 90 days of the Connection Date.
c) *Warranty Deposit:* shall be returned in its entirety within 90 days of the expiry of the Warranty Period.

Schedule F: Alternative Bid Process

For those items identified in Schedule B as Contestable Work, the Customer may seek an Alternative Bid from a contractor other than Bluewater Power on the following basis:

(1) The Customer is required to meet the expectations of a Customer set out in Section 3.2.16 of the DSC, including the obligation to complete all of the Contestable Work if they chose to pursue an Alternative Bid.

(2) Bluewater Power does not maintain a list of pre-qualified contractors. However, all contractors must meet the following criteria:
   a) EUSA qualified;
   b) WSIB certified and up-to-date;
   c) They must sign an agreement with Bluewater Power outlining the terms and conditions of their work, including bonding and insurance requirements.

(3) All work must be carried out in a manner acceptable to Bluewater Power, and must be constructed to Bluewater Power's standards and design, all as determined to the reasonable satisfaction of the on-site inspector for Bluewater Power.

(4) The Customer seeking Alternative Bids shall be responsible for all incremental costs of Bluewater Power required to facilitate the construction by the contractor selected by the Customer. These costs are in addition to the Capital Contribution and do not form part of the economic evaluation model. All such costs shall be invoiced either periodically or at the completion of the System Expansion, as determined by Bluewater Power. All costs shall be on a time and material basis and shall include, but are not be limited to, the following:

   a) engineering costs to review designs, specifications, contractor bids, contractor invoices or materials;
   b) preparation of blueprints;
   c) any and all dealings with the Customer or the Customer's contractor to ensure compliance with this Offer to Connect;
   d) on-site inspection to be required and carried out by Bluewater Power;
   e) materials may be supplied by Bluewater Power with an additional handling fee of 10% above the price indicated on Schedule "B", however Bluewater Power reserves the right to refer the Customer to another supplier for any reason, including but not limited to, materials being short in supply or insufficient personnel within the company's purchasing department.

(5) The Customer shall provide Bluewater Power with original bid documents as well as detailed invoices for its review. The costs of the selected Alternative Bid shall be borne directly by the Customer and all costs associated with the electrical distribution servicing shall be separately shown in all tenders to the reasonable satisfaction of Bluewater Power, such that Bluewater Power can ensure proper cost assignment.

(6) For the sake of clarity, the full Capital Contribution remains due and payable upon execution regardless of the Customer's intention to seek Alternative Bids. Upon completion of the work to the reasonable satisfaction of Bluewater Power, the Transfer Price, less the additional costs determined in accordance with section 3 of this Schedule "F", shall be refunded to the Customer within 30 days.

(7) The Customer shall provide a Warranty for all work performed under an Alternative Bid in accordance with the Distribution System Code. Such Warranty shall be satisfied by the Customer and, failing an adequate response in a reasonable time, the work shall be completed by Bluewater Power at the cost of the Customer to be satisfied through the Actual Expansion Deposit or through the Customer if insufficient funds exist on deposit to hold Bluewater Power whole.

BLUEWATER POWER DISTRIBUTION CORPORATION

Guidelines for Applicants Connecting Distributed Generation

Bluewater Power
Distribution Corporation

About Bluewater Power Distribution Corporation

Bluewater Power was incorporated on October 30, 2000 when the former Sarnia Hydro, Hydro Commission of the Village of Oil Springs, PUC of Petrolia, PUC of the Village of Point Edward, Watford PUC and the PUC of the Village of Alvinston merged into one company.

Bluewater Power is the largest electric utility in Lambton County and provides electricity to over 34,000 customers in Sarnia, Point Edward, Alvinston, Oil Springs, Petrolia and Watford. Bluewater Power distributes electricity to residential customers, large industries, international companies, financial institutions and commercial establishments. These customers are served by 91 full-time staff members from Bluewater Power's head office at 855 Confederation Street.

Bluewater Power's distribution system network consists of over 553.9 km of overhead plant and 202.6 km of underground plant, covering a service area of 178.14 sq. km.
Bluewater Power derives all its revenue from the distribution of electricity and related services.

For all Generation Connection inquiries please contact:

Bluewater Power Distribution Corporation
855 Confederation Street, PO Box 2140
Sarnia, ON, Canada N7T 7L6
Tel: (519) 337-8201

This document was prepared for Bluewater Power Distribution Corporation by Rodan Energy and Metering Solutions Inc. Rodan Energy & Metering Solutions Inc. is a leading provider of innovative metering and energy management solutions for power producers, consumers and distributors throughout North America.

Rodan is certified as an engineering firm by the Professional Engineers of Ontario and is specialized in market entry services for power producers in Ontario.

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Introduction

The goal of Local Distribution Companies (LDCs) is to provide safe, reliable, efficient delivery of electricity within their LDC's service area while being accountable to their shareholders…usually the Council and citizens of the municipality.

In the past, most electricity generation occurred within large centrally located plants which were connected to high voltage lines that transmitted electricity across the province to the locations where it would be used.

Technological improvements, regulatory policy reform and increased environmental awareness have created new opportunities for electricity to be generated in alternative ways by private and public companies on smaller scales closer to where it is used and increasingly by connecting the generation to lower voltage lines hence the use of the term distributed generation.

The Ontario government's policy to purchase electricity through what is known as the Standard Offer Program (SOP) creates an even greater opportunity for a significant increase in the interest and presence of distributed generation throughout the province. Your LDC has prepared this information package for those parties interested in learning more about connecting distributed electricity generation facilities to our electricity distribution system.

This package contains an overview of the Ontario electricity transmission system, the LDC's distribution system and safety, power quality, protection and other technical issues related to new generation.

This information package contains the following information:

- A description of the way electricity is typically generated, transmitted, and distributed in Ontario and the resulting technical considerations for prospective distributed generators.
- An overview of the options available for connecting different types of electricity generation facilities to an LDC's electrical distribution system and the different programs in Ontario through which generators can sell their electrical output.
- An overview of the technical, safety, and regulatory considerations that prospective distributed generators must be aware of.
- A description of the administrative process for connecting electricity generation facilities to an LDC's electrical distribution system.
- The Initial Consultation Request form that starts the connection process and other helpful resources for distributed generators.
- The Application Form to request a more detailed Connection Impact Assessment for a prospective generation developer
- Links to publicly available web sites where additional documents, information and self help materials on electricity generation, applicable standards, regulations, etc. are available.

Distributed generation is any type of electrical generator or static inverter producing alternating current that has the capability of Parallel Operation with the LDC Power distribution system, or is designed to operate separately from the LDC system and can supply a load that can also be fed by the LDC's system.

Although some distributed generation is intended to provide electricity solely for a customer's own use, such as stand-by or load displacement generation, this guide also covers the emerging role of distributed generation in supplying Ontario's generation needs through the sale of some or all of the electricity generated by exporting it through the LDC's electricity distribution system.

Distributed generation also varies in design and fuels from diesel or natural gas standby generators to natural gas co-generation to wind turbines, photovoltaic cells, biogas and hydroelectric generation. A further variable is size, from very small (micro) wind and photovoltaic units in the under 10 kilowatt (kW) range to generation in the multi megawatt (MW) range.

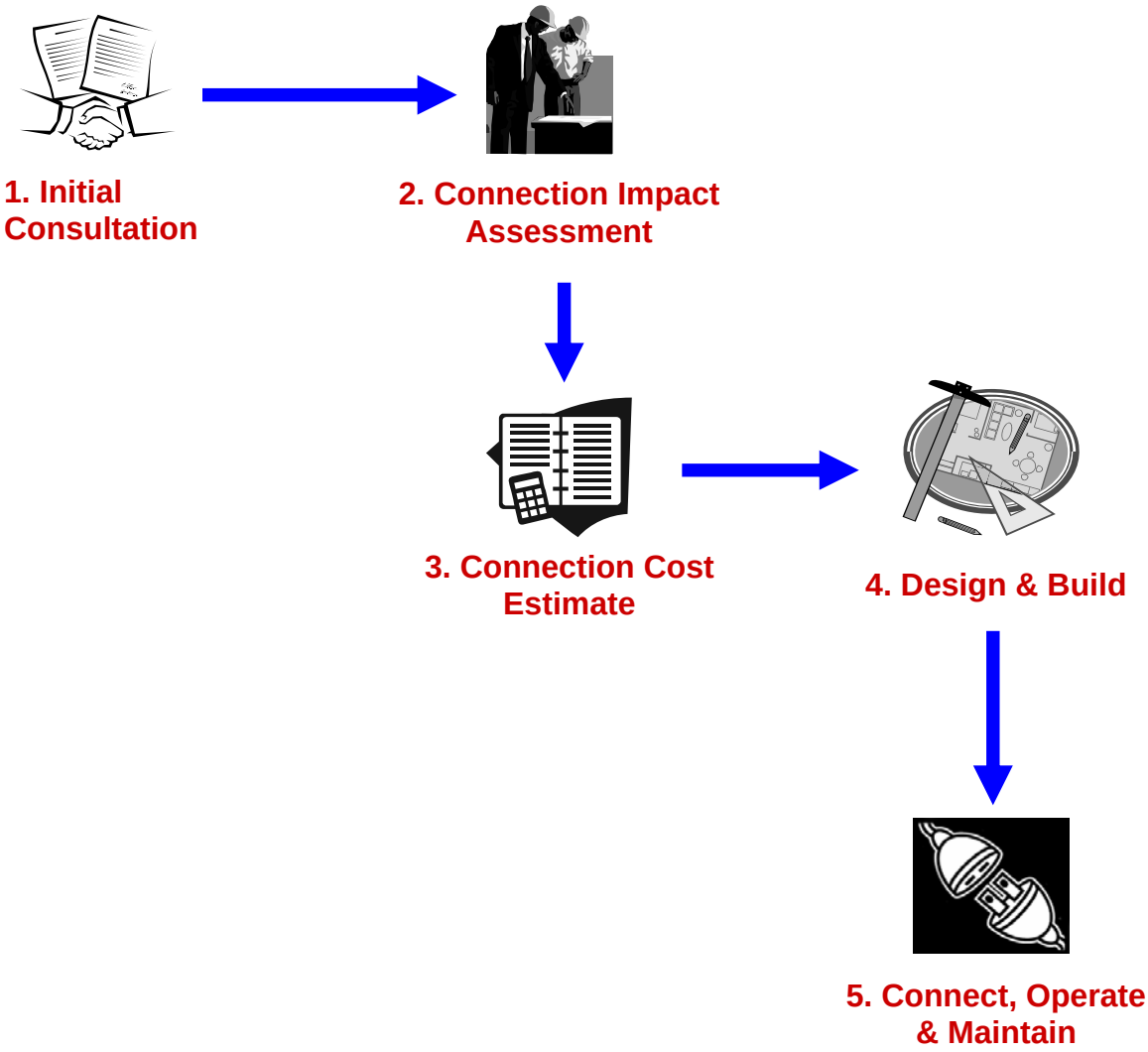
The variability and breadth of scope make it a challenge to provide information on connecting to an LDC's distribution system and those interested in connecting distributed generation may or may not have an appreciation of the technical requirements and the complexity of electrical delivery systems.

This information package is intended as a starting point for those interested in connecting distributed generation facilities to the distribution system. It provides high level outlines and simplifications of processes and regulations that are described in detail in a number of publicly available documents, the content of which will change from time to time. A list of some of these documents and the agencies that publish them is available in Appendix 2. It is recommended that anyone interested in connecting electricity generation to an LDC's distribution system read all relevant documentation carefully.

Should there be a conflict between this information package and the rules, regulations, and specific information as laid out in relevant documents regarding the connection of electricity generation facilities to a distribution system in Ontario, the rules, regulations, and specific documents shall take precedence.

Connection Process Flowchart

Connection Process



The process that the LDC will follow for connecting a distributed generator to the LDC's distribution system is detailed in the Ontario Energy Board's (OEB) Distribution System Code, Appendix F. (http://www.oeb.gov.on.ca/documents/dscappf_100304.pdf)

Connection Process Overview

Initial Consultation

LDC meets with the prospective Generator to discuss their plans, provide preliminary information on the connection options and explain the connection process. The Generator is required to complete and submit the Connection Review Application Form (Appendix 3) and provide other supporting documents to the LDC.

Connection Impact Assessment

After reviewing the Connection Review Application Form and other technical data submitted during the initial consultation, the project will then be discussed with the Generator in a face-to-face meeting. The aim of this meeting is to discuss issues of mutual interest early in the Generator's review of the feasibility of the project. The Generator is then required to submit a completed Generator Connection Assessment Review Form. (Appendix 4 for a generator of 10kW or less or Appendix 5 for a generator rated at between 10kW to 10MW).

Connection Cost Estimate

After all required assessments are complete (including assessment by Hydro One, if required), the scope of work required to connect new generation can be developed and estimates prepared. The Generator is required to make the appropriate payment to the LDC that could include fees for: processing and reviewing the application; technical review and impact assessment; and production and commissioning testing as necessary.

Design and Build

Once agreement of the scope, cost and timing are reached, the Generator is required to sign a Connection Cost Recovery Agreement. After submitting the agreement and payment, detailed design and construction may begin.

Connect, Operate and Maintain

After all of the required work and approvals are completed, the LDC and the Generator executes the Distribution Connection Agreement. This Agreement provides an outline of the connection as well as the roles and responsibilities of each party.

The Ontario Electricity Transmission & Distribution System

In general, Ontario's electricity system consists of large centrally located generating stations linked by high voltage transmission lines over long distances at 500 kV, 230 kV and 115 kV. As the electricity is moved around the province the voltage is reduced as the electricity gets closer to the point of end use. Transformer stations reduce the voltage to 27.6 kV and 44 kV lines which transfer the electricity to distribution stations that reduce voltage again down to as low as 4 kV for routing electricity around city streets.

It is likely that the location for distributed generation will be at the lower voltage levels and the ability of the distribution network to accommodate the distributed generation will depend on the "strength" of the network at that point and the normal loads that it supplies. A proxy for the "strength" of the network is the fault current.

The fault current is how much current that will flow when there is a fault on a network. The fault level at the end of a long electricity circuit is much lower than closer in to the upstream supply. At a low fault level site, the impact of the distributed generation can be great enough to disturb other local consumers. For this reason, it is sometimes necessary to reinforce the network, or connect the distributed generation to a higher voltage or stronger part of the network further away.

Higher-voltage systems such as the 230 kV or 500 kV transmission systems have high fault levels. In general, the lower the voltage, the weaker the system. The weaker the system the less distributed generation can be connected. LDC distribution systems operate at 27.6 kV, 44 kV, 12.5 kV, 8 kV and 4 kV. As a rule of thumb the voltage levels might have capacity for the maximum following amounts of distributed generation.

- 4 kV possibly between 500 kW and 1 MW
- 8 kV possibly between 1 MW and 3 MW
- 12 kV possibly between 3 MW to 5 MW
- 27.6 kV possibly between 6 MW and 10 MW
- 44 kV possibly between 15 MW and 20 MW

The above examples assume the presence of three-phase lines with adequate conductor size and inherent load levels. LDCs also have many single-phase lines, which would not be suitable for anything but the smallest distributed generation without upgrade. The actual capacity of LDC lines to accept distributed generation can only be determined by an engineering review.

The necessary protection systems to protect an LDC's distribution system from events that can occur with distributed generation connected will also vary by distributed generation size and distribution line characteristics. Therefore, similar units connected at different locations could have different protection requirements based on varying load conditions, as well as on the LDC's Hydro One feeder and transformer characteristics.

Depending on the size, type, fuel, and location of generation facilities, the Ministry of the Environment (MOE) may require that the customer carry out an environmental assessment. Please contact the MOE for more information.

Maps of the LDC distribution system are available to assist a potential distributed generation developer to determine the approximate capacity of an LDC line in the area of interest for distributed generation location.

Distinctions between types of Distributed Generation

There are a number of distinct types of generators as far as the distribution system is concerned: (a) solid-state or static inverters, (b) induction machines, and (c) synchronous machines.

Many smaller renewable energy systems produce grid quality AC power through an inverter and are therefore typically grouped together.

Induction and synchronous generators, on the other hand, are generally grouped together as "rotating machines," but their different configurations do give them different start-up and operational characteristics. For example, induction machines cannot operate in stand-alone mode and generally require the presence of the grid for rotor excitation and normally have a lagging power factor. Synchronous machines on the other hand can operate without the grid and can have a zero or leading power factor.

As a practical matter, it is much more difficult for inverter-based generators to power an island and inverters can feed far less current into a fault. This means that inverter-based and rotating generators are treated differently in the codes and standards, with very small inverter-based devices requiring less – if any – additional protection equipment.

Safety, Power Quality & Protection

Technical details are the heart of the interconnection process with safety, power quality, and system reliability being the primary utility concerns and responsibilities. Reference materials that determine the requirements for these interconnections have been prepared by a number of bodies and agencies including the OEB, IEEE, CSA and ESA. This section therefore addresses safety and technical issues in the abstract and how they can streamline the interconnection process. The goal here is to provide background and rationale, while not going into great technical detail, so where appropriate, references are given for those seeking additional details.

The OEB's Distribution System Code Appendix F.2 outlines the technical requirements for connecting a generator to an electricity distributor's system. We have identified specific sections of Appendix F.2 as it relates to safety, power quality and protection.

The link to the OEB DSC is at http://www.oeb.gov.on.ca/documents/dscappf_100304.pdf

A list of references where potential distributed generation developers can go to obtain more information can be found in Appendix 2.

Safety

Like any source of electricity, distributed generation systems have the potential to be dangerous to both people and property, and require protection devices to protect the distribution system, utility workers, utility customers and the general public. Large industrial customers have been generating power on-site for many years, but interconnecting photovoltaic, wind turbines, co-generation, microturbines, and other relatively small generation systems to operate in parallel with the grid at residential and commercial locations is an increasing and recent trend. Utilities are primarily concerned about the potential for distributed generation sources – not under their control – supplying energy to one of their lines that is otherwise thought to be de-energized. This is known as islanding.

Islanding

One of the most important issues for distributed generation is to avoid a condition known as islanding. Islanding is a situation where a portion of the utility system that contains both loads and a distributed generation source becomes separated from the remainder of the utility system but remains energized.

The primary concern is a situation where a fault occurs on the distribution system and automatic isolation of a utility protective device occurs. Since automatic reclosing is normally used on distribution systems to clear temporary faults it is essential that the distributed generation disconnects from the distribution system before the first automatic reclose occurs. The concern is that if the distributed generation does not disconnect fast enough a) the distributed generation may feed the fault; and b) when the utility

protective device(s) tries to reclose it will be closing back in on a line that is being supplied by distributed generation resulting in possible equipment damage, overloading or power quality issues.

Historically with central generation and transmission a utility could be sure that if an electrical circuit was isolated “upstream” and was not being fed from an alternative source that it was de-energized.

The utility may want to isolate the section of line for maintenance purposes and would normally do that through opening switches. While a utility can be sure that all of its own electricity sources are either shut down or isolated from the area that needs work they must now factor in distributed generation to ensure that it too is isolated and not supplying the line section.

Distributed generation creates a source of energy inputs to the utility system that the LDC does not control and if the distributed generation is potentially capable of islanding can backfeed electricity to the LDC’s distribution system.

Grounding

Distributed generators must be grounded in accordance with any equipment manufacturers’ requirements, the OESC and LDC requirements.

The distributed generation must not disrupt any coordination of ground fault protection or cause over-voltages that exceed the rating of equipment connected to the LDC distribution system.

Power Quality

Power quality is another significant technical concern for utilities and customer-generators. Utility power is consistently supplied at a standard voltage and frequency. In North America, residences receive single-phase alternating current (AC) power at 120/240 Volts at 60 cycles per second (60 Hz), and commercial buildings typically receive either 120/240 Volts single phase or three-phase power depending on the size of the building and the types of loads in the building.

Power quality is important because electronic devices and appliances have been designed to receive power at or near rated voltage and frequency standards and deviations may cause appliance malfunction or damage. Additional power quality considerations include harmonics, power factor, DC injection, and voltage flicker.

Each type of distributed generation device has its own output characteristics based on its technology therefore some will have more power quality issues than others.

Voltage Fluctuations and Voltage Regulation

Voltage fluctuations can result from a distributed generator connecting to or disconnecting from the utility system or because of its generation operating characteristics. The standards set certain limits, which must be achieved for events that occur within the distributed generation's operating cycle. Whether the utility actively or passively regulates their voltages to maintain an acceptable range, the presence of a distributed generation should have no detrimental impact on that regulation. The distributed generation must not try to regulate the voltage and frequency on the utility line but instead must follow the utility voltage and frequency and disconnect for any abnormality.

Ref: OEB DSC, F.2, Section 3

Voltage Unbalance

Utilities try to operate their three phase lines with voltages in the three phases balanced as closely as possible. The presence of a distributed generator should not contribute to additional voltage unbalance.

Ref: OEB DSC, F.2, Section 3.2

Frequency

As with voltage fluctuations frequency variations are a reliability and power quality issue. Distributed generation shall operate within the range of 59.3 to 60.5 Hz.

Ref: OEB DSC, F.2, Section 6.5

Harmonics

Harmonics generically refer to distortions in the voltage and current waveforms caused by the overlapping of the standard sinusoidal waveforms at 60 hertz (Hz) with waves at other frequencies that are other multiples of 60 Hz. Harmonics can be caused by the electronic equipment used in some distributed generators such as soft start units and inverters. Harmonics can cause equipment to fail or overheat and to degrade the service of other customers. Distributed generators must not impose harmonic distortions on the LDC's distribution system in excess of applicable standards.

Ref: OEB DSC, F.2, Section 10.2, CAN/CSA-C61000-3-6, IEEE 1547

Power Factor

Power factor is a measure of apparent power delivered when the voltage and current waveforms are out of synch. Power factor is the ratio of true electric power, as measured in kilowatts (kW), to the apparent power, as measured in kilovolt-amperes (kVA). The power factor can range from a worst case of zero when the current and voltage are completely out of synch to the optimal value of 100% when the current and voltage are entirely in synch. The terms "leading" and "lagging" refer to whether the current wave is

ahead of or behind the voltage wave and are a contributor to the efficiency or inefficiency of the utility's electrical system. Distributed generators connected to the distribution system must operate in the range 0.9 lagging to 0.95 leading power factor.

Ref: OEB DSC, F.2, Section 4

DC Injection

DC Injection is a potential issue for inverters where an inverter passes unwanted DC current into the AC or output side. This can be prevented by the incorporation of equipment and design to prevent or limit the effect.

Ref: OEB DSC, F.2, Section 10.3

Voltage Flicker

Somewhat like voltage fluctuations, voltage flicker refers to short-lived spikes or dips in the line voltage that are noticeable to the eye and annoying. It can occur when the outputs from a distributed generator vary for example with some wind turbines if the wind is gusting or turbulent.

Ref: OEB DSC, F.2, Section 10.1

Protection of Distributed Generation Facility

The distributed generation developer will be responsible for protecting its distributed generation facility equipment in such a manner that distribution system faults - such as outages, short circuits, automatic reclosing of distribution circuits, or other disturbances - do not damage the distributed generation facility equipment. The equipment protection shall also prevent the distributed generation facility from adversely affecting the distribution system's capability of providing reliable service to other customers.

Ref: OEB DSC, F.2, Section 2

Monitoring

For distributed generation greater than 250 kW the LDC may require remote monitoring of the distributed generation connection status, real power output, reactive power output and voltage at the point of generator connection. For distributed generation greater than 10 MW the monitoring must be in real time.

Ref OEB DSC F.2, Section 9

Standardized or Certified Equipment

While it is a requirement that the design for a distributed generation installation be approved by a professional engineer and that all equipment be CSA approved and inspected by the ESA, if the interface equipment used is a standard package or certified for use (by UL or CSA or some other recognized approving body) as is the case with some

inverters this will expedite and simplify the interconnection process. This is especially applicable at the lower distributed generation output levels and will reduce the amount of technical information required.

The safety, power quality and reliability of interconnected distributed generation is ensured through design, standards, inspection, testing and the provision of switches, breakers and protective relaying incorporated into the distributed generation or as auxiliary equipment. A brief summary is as follows:

- An interrupting device capable of interrupting the maximum available fault current at the distributed generation location. Ref OEB DSC F.2, Section 1
- An interconnection device that is manual, lockable, has visible disconnection and is accessible to LDC staff. Ref OEB DSC F.2, Section 1
- A generator disconnect device. Ref OEB DSC F.2, Section 1
- Anti islanding protection. Ref OEB DSC F.2, Section 6.1.2
- A protective relay that will operate the load interruption device with the following features
  - Over-voltage trip. Ref OEB DSC F.2, Section 1
  - Under-voltage trip. Ref OEB DSC F.2, Section 1
  - Over/underfrequency trip. Ref OEB DSC F.2, Section 6.5
  - Over current protection. Ref OEB DSC F.2, Section 6.4
  - Ground fault protection. Ref OEB DSC F.2, Section 2

- Reclosing co-ordination to ensure that the distributed generation ceases to energize prior to the reclosure of an upstream LDC device. Ref OEB DSC F.2, Section 6
- Power Factor correction (if required). Ref OEB DSC F.2, Section 4
- Synchronizing equipment that will limit voltage fluctuation, frequency variation and phase angle when the distributed generation parallels with the distribution system. Ref OEB DSC F.2, Section 3.2
- Transfer Trip may be required depending on the loading of the distribution feeder and the output rating of the distributed generation relative to the feeder loading.
- Feeder Relay Directioning to prevent inadvertent tripping of a protective device for faults not associated with the protection zone of the device.

Your LDC will provide three phase fault levels at the preliminary review stage. A protection co-ordination study will be required which may involve alternate supplies from different sources. Protection design and ratings should account for these variables.

Preliminary Review, Connection Impact Assessment, Technical Review

Generation Connection Process

The process that your LDC will follow for connecting a distributed generator to the LDC's distribution system is detailed in the OEB's Distribution System Code, Appendix F. The starting point is for potential distributed generation developers to complete the form attached as Appendix 3 and return it to the LDC.

Preliminary Review

In the very early stages where a distributed generation developer may be considering site selection, the LDC will provide a preliminary review and high level advice and guidance based on limited parameters such as:

- Potential sites
- Output capacity of distributed generation
- Fuel type
- Generator generic description and design type

Technical Review

Once a location has been determined, the distributed generation developer must complete an application form requesting a full Technical Review. The Technical Review will establish the LDC's requirements for the distributed generation at the specific location expanding on and supplementing the information provided for the CIA. The Technical Review will require the distributed generation developer to provide the following details of the project certified by a licensed professional engineer, along with three copies:

Distributed Generation Description

- Site
- Type of distributed generation
- Output including seasonal and daily variations
- Number of units initially and ultimately, if future expansion is applicable
- Time line for construction and commissioning

Single Line Electrical Diagrams (with ratings or sizes detailing)

- Point of connection to the distribution system
- Generator
- Generator disconnect device
- Protective relaying and functions
- Transformer
- Protective isolating device
- Generator breaker
- Manual interconnection disconnection device
- Voltage levels
- Fusing

Nameplate data or manufacturers specs on:

- Protective relays
- Synchronizing device
- Fault calculations, protective relay settings, fuse specification
- Short circuit and voltage drop studies
- Station service and battery system
- Grounding studies
- Load interrupter switch or circuit breaker
- Dedicated interconnection transformer
- Isolating device for interconnection
- Protection system and operating procedures including schematics

LDC Power Connection Impact Assessment

Where required, the LDC will perform a Connection Impact Assessment (CIA). The CIA looks at:

- the impact of the distributed generation on distribution system short circuit levels, load flows, current loading, voltage levels and voltage flicker under a variety of distribution system and distributed generation conditions to ensure there are no adverse effects.
- the preliminary design of the protection systems being proposed for the distributed generation to assess their adequacy to protect the public, utility employees working on the distribution system and distribution system equipment under a variety of fault and operational circumstances.
- whether a more detailed assessment and cost estimate of the connection feasibility is required.

The LDC will advise the distributed generation developer of the CIA results. If the impact of the distributed generation is within acceptable limits the LDC will advise the distributed generation developer that the next step in the connection process can be commenced. The distributed generation developer should not order any equipment or make

commitments to the project until the CIA has been satisfactorily completed and an Offer to Connect has been made.

Hydro One Impact Assessment

Distributed generation greater than 1 MW and less than 10 MW connected to an LDC's 27.6 kV or 44 kV system may have an impact on Hydro One's Transmission Facilities and will require their separate impact assessment.

Distributed generation greater than 10 MW and connected to an LDC's 27.6 kV or 44 kV distribution system will require a Customer Impact Assessment from Hydro One and an assessment of the impact on Hydro One's Transmission facilities.

IESO Impact Assessment

Distributed generation greater than 10 MW will require a transmission system impact assessment by the Independent Electricity System Operator.

Costs

The generator will be required to pay the LDC for the LDC's Connection Impact Assessment.

The LDC will charge actual costs for labour and materials for any distribution system upgrades or line extensions required including but not limited to increased transformer capacity requirement, primary or secondary conductor, line extensions, switches and associated distribution hardware.

Where the distributed generation is used for load displacement of existing load a standby charge may be applicable as approved by the OEB.

Timing

LDC's will comply with the timelines laid down in the OEB Distribution System Code but the elapsed time will only start when any payments required by the LDC have been paid by the distributed generator and all technical information or any other data required for reviews, assessments or studies have been received to the satisfaction of the LDC.

Metering

Metering requirements will be determined by the LDC and will depend on the type and size of generation and the load, if any, where the distributed generator is also a customer, at the distributed generation location. Where the distributed generator is

exporting power a bi-directional meter capable of measuring electricity received from and sent to the distribution system is required. All metering cabinets, instrument transformers, meters and if necessary a telephone line will be supplied by the Generator and owned by the LDC.

The metering shall be installed at the Demarcation Point of connection of the Distributed Generation Facility to the Distribution System. The point of demarcation for a Distributed Generation Facility is the primary live line clamp or lines switch that is installed on or at the LDC's Distribution line. If this is not practical, the LDC shall apply loss factors to the generation output in accordance with the loss factors applied for Retail settlements and billing. Appendix 6 shows the metering location and configuration options under the Standard Offer Program.

Any Generator has the right to be a participant in the IESO-controlled wholesale market for settlements. Participants in the wholesale market must meet the requirements as specified in Chapter 6 Wholesale Metering of the Market Rules. In general, the metering requirements for wholesale market participants are more stringent that those required for LDC retail revenue purposes. In both wholesale and retail markets, all meters and instrument transformers must be Measurement Canada approved and connected in accordance with Measurement Canada and OEB policies and procedures. However, in the wholesale market, the IESO requires that market participants engage the services of a Meter Service Provider (MSP) to install and maintain the metering system. In addition, the IESO specifies the number and types of meters that must be used for revenue purposes and requires the submission of an emergency instrument transformer restoration plan.

In 2005, the IESO revised the Market Rules to include relaxed polices for embedded generation facilities under 2 MVA or injecting less than 17 GWh per annum. These relaxed rules allow for the installation of a single meter only and no requirement to submit an emergency instrument transformer restoration plan.

Generation Connection Matrices

The range of potential distributed generation applications, sizes and fuels results in different circumstances under which they operate both technically and commercially. For example, a very small distributed generator fuelled by a renewable resource connected to a residential home may output to the distribution system but if the monthly energy output is less than total monthly customer energy consumption the owner may opt for net metering.

A similar distributed generator with energy output greater than the monthly energy consumption may opt for Standard Offer Contracts (SOC). A larger distributed generator fuelled by a non renewable resource may be used for load displacement and not export to the distribution system. Another larger distributed generator fuelled by a non renewable resource may export to the distribution system and while not eligible for SOC could receive the HOEP for the energy.

We have attempted to summarize the permutations and combinations in the matrices which are attached as Appendix 7. We believe the data to be accurate but we caution

that these matrices are the LDC's interpretation of rules and regulations that are in existence. Distributed generators should confirm applicability and eligibility in their own circumstances.

Approvals

Before any distributed generation can be connected to the LDC's distribution system it must have received as a minimum the following approvals plus any additional approvals identified in the Preliminary or Technical Reviews, or the Impact Assessments by the LDC and Hydro One:

- LDC Offer to Connect
- CSA or UL or recognized certification of all equipment installed
- ESA approval

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Appendix 1(a): Definitions

APPENDIX 1 (a)

Definitions

Applicant — The legally responsible person applying to an LDC to interconnect a distributed generation facility to the LDC's distribution system.

Application Review — A review by the LDC of the completed standard interconnection application form for interconnection, to determine if an engineering review or distribution system study is needed.

Back-up Power — Electric energy or capacity supplied by an LDC to replace energy ordinarily generated by distributed generation facility equipment during an unscheduled outage of the distribution system.

Certified Equipment — A generating, control or protective system that has been certified by a nationally recognized testing laboratory (NRTL) as meeting acceptable safety and reliability standards.

Commissioning Test — The initial process of documenting and verifying the performance of a distributed generation facility so that it operates in conformity with the design specifications.

Customer — Any person who is receiving electric service from an LDC's distribution system.

Designated Point of Contact — Each LDC shall designate one point of contact for all customer inquiries related to distributed generation facilities and from which interested parties can obtain a copy of interconnection guidelines - which include the appropriate application forms and interconnection agreements.

Distributed Generation (DG) Facility — A facility for the generation of electricity with a capacity of no more than 15 megawatts that is located near the point where the electricity will be used or is in a location that will support the functioning of the electric power distribution grid.

Distributed Generation Developer — same as Applicant.

Distribution Feeder/Line — An electric line from an LDC substation or other supply point to customers that is operated at 50 kV or less, or as determined by the LDC.

Distribution Substation — A facility that reduces the voltage of the electricity supply from sub transmission voltages less than 50 kV to even lower distribution voltages less than 50 kV.

Distribution System — All electrical wires, equipment, and other facilities owned or provided by an LDC that are normally operated at 50 kV or less.

Distribution System Code — A code issued by the Ontario Energy Board that prescribes the requirements for local distribution companies and customers who are

served by the distribution system. Specifically, Appendices F of the code outlines the procedures to be followed for processing and connecting distributed generation facilities and F.2 is an overview of the technical requirements.
http://www.oeb.gov.on.ca/documents/dscappf_100304.pdf

Distribution System Study — A study to determine if a distribution system upgrade is needed to accommodate the proposed distributed generation facility and to determine the cost of any such upgrade.

Engineering Review — A study that may be undertaken by an LDC, in response to its receipt of a completed standard application form for interconnection, to determine the suitability of the installation.

ESA – Electrical Safety Authority

Fault — An equipment failure, conductor failure, short circuit, or other condition resulting from abnormally high amounts of current from the power source.

HOEP — The Hourly Ontario Energy Price is an average of the market price set at each five-minute interval within that hour.

IEEE — Institute of Electrical and Electronics Engineers.

Impact Assessments — if warranted by the size, type, location or other factors impact assessments may be required by an LDC and in some cases Hydro One where the distribution lines connect to Hydro One transformer stations.

Independent Electricity System Operator (IESO) — An entity supervising the collective transmission facilities of a power region; the IESO is charged with nondiscriminatory coordination of market transactions, system-wide transmission operation, and network reliability.

Interconnection — The physical connection of a distributed generation facility to the distribution system so that parallel operation can occur.

Interconnection Agreement — a written set of operating procedures to specify how the distributed generator facility will interact with an LDC's distribution system and the responsibilities and accountabilities of the parties

Interconnection Disconnect Switch — A mechanical device used to disconnect a distributed generation facility from a distribution system. Also known as an isolation device.

Inverter — A machine, device or system that converts direct current power to alternating current power.

Islanding — A condition on the distribution system in which a distributed generation facility delivers power to customers using a portion of the distribution system that is electrically isolated from the remainder of the distribution system.

kV – kilovolt (1000 volts)

kW – kilowatt (1000 watts)

Local Distribution Company — A local distribution company or LDC manages and operates the electricity distribution system and currently bills for electricity services at the retail level in Ontario.

MW – megawatt (1000 kW)

Material Modification – Any modification that changes the maximum electrical output of a distributed generation facility or changes the interconnection equipment, including:
a) Changing from certified to non-certified devices.
b) Replacing a component with a component of different functionality or Underwriters Laboratories listing.
c) Changes to the Interconnection Point

Nationally Recognized Testing Laboratory — Any testing laboratory recognized by the ESA, or CSA as having an approved equipment accreditation program.

Net metering — An arrangement where distributed generation facilities can offset their associated load consumption and are compensated for any extra energy delivered to the electricity system. In Ontario, legislation permits distributed generation facilities using renewable resources with a capacity of 500 kW or less to be eligible for net metering.

OEB — Ontario Energy Board

Parallel Operation — The operation, for a finite time, of a distributed generation facility while the facility is connected to the energized distribution system.

Paralleling Equipment — The generating and protective equipment system that interfaces and synchronizes a distributed generation facility with the distribution system.

Point of Common Coupling — The point where the electrical conductors of the distribution system are connected to the customer's conductors and where any transfer of electric power between the customer and the distribution system takes place.

Point of Interconnection — The point where the distributed generation facility is electrically connected to the customer's electrical system.

Preliminary Review — A review at the feasibility stage to determine the suitability of a distributed generation site and the LDC's facilities available for connection

Protective Function — A function of a distributed generation facility, carried out using hardware and software, designed to prevent unsafe operating conditions from occurring before, during, and after the interconnection to a distribution system.

Supervisory Control and Data Acquisition (SCADA) — A system of remote control and telemetry used to monitor and control the electric system.

Switchgear — Components for switching, protecting, monitoring and controlling electric power systems.

Synchronize — The process of connecting two previously separated alternating current apparatuses after matching frequency, voltage, phase angles, etc. (e.g., paralleling a generator to the electric system).

Technical Review — a more comprehensive evaluation of the distributed generation proposal than the preliminary review to establish that the proposal and the equipment meet the technical guidelines for safety, power quality and reliability.

Telemetry — The transmission of distributed generation operating data using telecommunications techniques.

Transfer Switch — A switch designed so that it will disconnect the load from one power source and reconnect it to another source.

Transformer Station — A facility that reduces the voltage of the electricity supply from transmission voltages greater than 50 kV to distribution voltages less than 50 kV.

UL — Underwriters Laboratories.

Unit — same as distributed generation facility.

Appendix 1(b): Who's Who in Ontario Electricity

APPENDIX 1 (b)

Who's Who in Ontario Electricity

Sometimes it's difficult to figure out who's who and what they do in Ontario's electricity system. Here's a brief overview:

The Ontario Government and the Ontario Ministry of Energy	• Establish public policy; pass legislation and regulations relating to electricity. • Create other agencies IESO, OPA, OEB, etc., and establish raison d'etre for Hydro One, OPG and LDC's • Significant legislation: Electricity Act, 1998 and Regulations, Ontario Energy Board Act 1998, Electricity Restructuring Act 2004
Independent Electricity System Operator (IESO)	• The Independent Electricity System Operator (IESO) operates and manages Ontario's electricity system at the generation and transmission level. It does not design, build or own the system; it coordinates how the system interacts and performs and it monitors the performance, reliability and future adequacy of the system to provide electricity to Ontarians. The IESO creates electricity market rules, matches generation with load 24/7, establishes the Hourly Ontario Energy Price (HOEP) and settles wholesale electricity payments.
Ontario Power Authority (OPA)	• Although, the IESO operates the electricity system the Ontario Power Authority (OPA) forecasts, plans and is responsible for bringing new resources onto the system in the medium and long term so that the IESO has adequate resources to manage. It can also be involved in demand management, conservation and renewable energy activities as directed by its mandate and government.
Ontario Energy Board (OEB)	• The Ontario Energy Board (OEB) is the province's electricity regulator and is responsible for protecting the interests of consumers with respect to prices, reliability, adequacy and quality of electricity service and to promote economic efficiency of generation, transmission and distribution. The OEB approves the rates charged by transmitters (greater than 50 kV) and distributors (less than 50 kV) and creates codes and regulations for certain aspects of how transmitters and distributors conduct their business. • The OEB issues licenses for generators, transmitters, distributors, and retailers. • The OEB does not set rates for generation; that is a competitive process either through the Hourly Ontario Energy Price or third party contracts, but it has set prices for small consumers.

Ontario Power Generation (OPG)	• Ontario Power Generation (OPG) owns and operates most of Ontario's generating capacity. It is owned by the Province of Ontario.
Hydro One Networks (HONI)	• Hydro One is the province's largest transmission company and owns the provincial transmission grid. Hydro One also distributes electricity outside of the major urban centres. It supplies LDC's from TSs at 27.6 kV and 44 kV or DSs at lower voltages. Some distributed generation connected to Hydro One TSs or DSs will require co-ordination with Hydro One. Hydro One is owned by the Province of Ontario.
Electrical Safety Authority (ESA)	• The Electrical Safety Authority (ESA) is responsible for ensuring that electrical equipment is installed safely and meets required standards in accordance with the Ontario Electrical Safety Code.
Measurement Canada (MC)	• Measurement Canada (MC) is a federal agency of Industry Canada with the mandate of regulating meters and metering throughout the country. MC administers the Electricity and Gas Inspection Act. R.S. 1985, C.E-4.
Ontario Ministry of Environment (MOE)	• The Ontario Ministry of Environment (MOE) sets environmental standards for electricity projects in Ontario and ensures that generators, distributors and transmitters follow rules and standards when constructing and operating facilities.
Your LDC	• We are local distribution companies. We are regulated by the Ontario Energy Board and operate under all of the legislation, codes, rules and regulations set by the agencies, authorities and companies listed above. An LDC's core business is the distribution of electricity. Since we do not generate electricity and earn our revenue through transporting electricity across our wires we are impartial to the source of generation. LDC's are owned by their municipalities.

Appendix 2: Resource Links for Distributed Generators

APPENDIX 2

Resource Links for Distributed Generators

The Ontario Energy Board
http://www.oeb.gov.on.ca/index.html

Distribution System Code & Retail Settlement Code
http://www.oeb.gov.on.ca/html/en/industryrelations/rulesguidesandforms_regulatory.htm#electricity

Licensing Information for Generators
http://www.oeb.gov.on.ca/html/en/licences/applyforalicence.htm#electricity

The Ontario Power Authority
http://www.powerauthority.on.ca/

Requests for Proposals for Electricity Supply
http://www.ontarioelectricityrfp.ca/

Standard Offer Program for Renewable Energy
http://www.powerauthority.on.ca/Page.asp?PageID=924&SiteNodeID=132

Conservation Bureau & Conservation Requests for Proposals
http://www.conservationbureau.on.ca/

The Ontario Ministry of Energy
http://www.energy.gov.on.ca/

Information on Ontario's electricity markets, government programs, and the Net Metering Option.

Independent Electricity System Operator
http://www.ieso.ca/

Ontario's wholesale market operator – information about selling distributed energy generation to the grid at the Hourly Ontario Electricity Price.

Electrical Safety Authority
http://www.esa-safe.com/

Safe Generator Installation – Vital information for prospective distributed generators
http://www.esa-safe.com/GeneralPublic/sgi_001.php?s=22

Ontario Ministry of the Environment
http://www.ene.gov.on.ca/index.htm

Guide to Environmental Assessment Requirements for Electricity Projects
http://www.ene.gov.on.ca/envision/gp/4021e.pdf

Industry Associations and Other Resources

Ontario Sustainable Energy Association
http://www.ontario-sea.org

Power Connect – information for distributed generators
http://www.powerconnect.ca

Canadian Solar Industries Association
http://www.cansia.ca

Canadian Wind Energy Association
http://www.canwea.ca

Ontario Water Power Association
http://www.owa.ca

Association of Power Producers of Ontario
http://www.appro.org

Canadian Standards Association
http://www.csa.ca

Appendix 3

Connection Review Application Form

Appendix 3
Connection Review Application Form

Application for Preliminary Review of a request to connect Distributed Generation to Bluewater Power's Electrical Distribution System

1. Applicant's Contact Information (the party that will be contractually obligated for this generating facility)

Name _____

Company (if any) _____

Mailing Address _____

Phone Number (Main) _____ Cell _____

Fax Number _____ Email _____

2. Location of Interest for Distribution Generation

Street Address or Closest Location Description _____

_____

3. Generator Information

Generation Type: (Check One) ☐ Synchronous ☐ Induction ☐ Inverter ☐ Other:_____

Number of Phases: (Check One) ☐ Single Phase ☐ Three Phase

Primary Energy Source: Renewable:_____ Non Renewable_____
Type:_____

Do you intend to participate in any OPA programs? ☐ Yes ☐ No
Details: _____

Output capacity: _____ kW

Load displacement? ☐ Yes ☐ No Existing or New Load? _____

4. Other Information that may be relevant or assist in preliminary review. Use additional sheet if more information is required.

_____

_____

_____

_____

_____

*** Return this form to the LDC**

Appendix 4

Generator Connection Assessment Review Form

10 kW or Less

Appendix 4
Distributed Generation Application Form to connect 10 kW or less Bluewater Power's Electrical Distribution System

1. Applicant's Contact Information (the party that will be contractually obligated for this generating facility)

Name _____

Company (if any) _____

Mailing Address _____

Phone Number (Main) _____ Cell _____

Fax Number _____ Email _____

2. Location of the Generation System

Street Address _____

Lot _____

Concession _____

County _____

Bluewater Power Account Number (if any) _____

3. Applicant's Ownership Interest in the Generation System

☐ Owner ☐ Co-owner ☐ Lease ☐ Other

4. Primary Intent of the Generation System

☐ On-site Use of Power ☐ Net Metering ☐ Ontario Power Authority Standard Offer Program ☐ Other

5. Electricity Use, production and Purchases

(A) Anticipated annual electricity consumption of the facility or site _____ kWh/yr

(B) Anticipated annual electricity production of the generation system. _____ kWh/yr

(C) Anticipated annual electricity exports (i.e. (B) minus (A) _____ kWh/yr

Value will be negative if there are no net sales to the distribution system.

6. Installing Contractor Information

Contractor Name _____

Mailing Address _____

Name of Contractor Contact _____

Phone Number (Main) _____ Cell _____

Fax Number _____ Email _____

7. Requested In-Service Date _____

8. Provide One-Line Schematic Diagram of the System:

☐ Schematic is attached

Number of Pages _____

Appendix 4
Distributed Generation Application Form to connect 10 kW or less Bluewater Power's Electrical Distribution System

9. Generator Information (complete for each generator)

Manufacturer _____ Model No. _____

Version No. _____ Serial No. _____

Generation Type:

☐ Single Phase ☐ Three Phase ☐ Synchronous ☐ Induction ☐ Inverter ☐ Other:_____

Primary Energy Source:

Renewable:_____ Type:_____

Eligible for standard offer contract? ☐ Yes ☐ No

Non-Renewable _____ Type _____

NOTE: If there is more than one generator and/or inverter, attach an additional sheet describing each.

10. Site Plan Showing Location of the External Disconnect Switch (attach additional sheets as needed)

11. Design Requirements

a) Has the proposed distribution generation paralleling equipment been certified?

☐ Yes ☐ No

b) If not certified, does the proposed distributed generator meet the operating limits defined in Bluewater Power's DG Technical Specifications?

☐ Yes ☐ No

For items 12(a) and 12(b), if your answer is yes, please furnish details (e.g., copies of manufacturer's specifications). If your answer is no, it is recommended you contact the equipment manufacturer and determine the status.

Appendix 4
Distributed Generation Application Form to connect
10 kW or less Bluewater Power's Electrical Distribution System

Status of certification and compliance with operating limits where answer to 13 (a) and/or (b) is no.

_____
_____
_____
_____

12. Other Comments, Specifications and Exceptions (attach additional sheets if needed)

_____
_____
_____
_____
_____
_____

13. Applicant and Installer Signature

To the best of my knowledge, all the information provided in this Application Form is complete and correct.

Applicant Signature Date

_____

Installer Date

_____

*** Return this form to the LDC.**

Appendix 5

Generator Connection Assessment Review Form

10 kW to 10 MW

Appendix 5
Distributed Generation Connection Impact Assessment Review to connect 10kW – 10MW to Bluewater Power's Electrical Distribution System

Section 1: General Connection Information

Note: ALL of the information in "*Section 1: General Connection Information*" must be completed in full. Failure to provide complete information may delay the processing of the data.

All technical documents must be signed and sealed by a licensed Ontario Professional Engineer.

Date: (dd/mm/yyyy) _____ Contact Person Name: _____

Signature: _____

1. Project Name: _____

2. Project Dates: (dd/mm/yyyy)
Proposed Start of Construction: _____
Proposed In-Service: _____

3. Project Size:
Number of Units _____
Nameplate Rating of Each Unit (kW) _____
Number of Phases (1 or 3) _____
Proposed Total Capacity (kW) _____

4. Applicant Contact Information: (the party that will be contractually obligated for this generating facility)

Company Name _____
Street Address _____
Mailing Address (if different) _____
Representative Name _____
Representative Title _____
Phone Number (Main) _____ Cell _____
Fax Number _____ Email _____

5. Facility Contact Information: (where the generating facility will be installed)

Company Name _____
Street Address _____
Mailing Address (if different) _____
Representative Name _____
Representative Title _____
Phone Number (Main) _____ Cell _____
Fax Number _____ Email _____

6. Consultant:

Company _____

Street Address _____

Mailing Address (if different) _____

Representative Name _____

Representative Title _____

Phone Number (Main) _____ Cell _____

Fax Number _____ Email _____

7. Intent of Generation:

☐ Sale of Power ☐ Load Displacement

8. Project Type:

☐ Wind Turbine ☐ Hydraulic Turbine ☐ Steam Turbine ☐ Solar

☐ Diesel Engine ☐ Gas Turbine ☐ Fuel Cell ☐ Biomass

☐ Co-generation/CHP (Combined Heat & Power)

☐ Other (Please Specify) _____

9. Generator Facility Type:

Generation Facility Voltage (Volts): _____ ☐ AC ☐ DC

Type: Rotating generators: ☐ Synchronous ☐ Induction ☐ N/A

☐ Other (Please Specify) _____

Non-Rotating DC generation: ☐ Photovoltaic Arrays ☐ Fuel Cells ☐ Batteries

☐ Other (Please Specify) _____

10. Location and Site Plan:

Provide Site Plan with approximate line routings for connection to nearby Hydro One's facilities. The Site Plan should include roads, concession and lot numbers and nearby power lines.

Drawing / Sketch No. _____ Rev. _____

11. Location and Site Plan:

Proposed connection voltage to the LDC's distribution system (if known): _____ kV

Appendix 5
Distributed Generation Connection Impact Assessment Review to connect 10kW – 10MW to Bluewater Power's Electrical Distribution System

Section 2: Impact Assessment Information

Note:

(a) It is important that the Generator provides ALL the information requested below, if applicable. All information is required to complete the first step of the process to move to the new Queue structure. Indicate "Not Applicable" where appropriate.

(b) In certain circumstances the LDC may require additional information to conduct the Impact Assessment. Should this be the case the Generator will be duly advised.

Date: (dd/mm/yyyy) _____ Contact Person Name: _____

Signature: _____

1. Single Line Diagram (SLD):

Provide a SLD of the Generating Facility including the Interface Point/Point of Common Coupling ("PCC") to Hydro One's distribution system.

Drawing / Sketch No. _____ Rev. _____

☐ Attached
☐ Mailed Separately

2. Generator Facility Fault Contributions for Faults at the Interface Point/PCC

All values to be at the nominal connection voltage to Hydro One's distribution system, i.e. the high voltage side of the Facility interface (step-up) transformer.

Maximum Symmetrical (all generators online)

- Three phase fault (kA) _____
- Phase-to-phase fault (kA) _____
- Single Phase to ground fault (kA) _____

3. Generator Facility Characteristics:

a. Number of generating unit(s): _____

b. Manufacturer / Type or Model No.: _____

c. Rated capacity of each unit:

Gross:	_____	kW	_____	kVA
Net:	_____	kW	_____	kVA

If unit outputs are different, please fill in additional sheets to provide the information.

d. Type of generating unit: ☐ Synchronous ☐ Induction ☐ Static Power Converters (SPC)
☐ Other (Please Specify) _____

e. Rated frequency (Hz): _____

f. Number of phases: ☐ One ☐ Three

g. For Synchronous Units:

i) Generation facility voltage (kV): _____

ii) Rated current (A): _____

iii) Rated power factor of generating unit (s): _____ p.u.

iv) Power factor operating range. (Specify lag or lead): from _____ p.u. to _____ p.u.

v) Unsaturated reactances on: _____ kVA base, _____ kV base

Direct axis synchronous reactance, Xd _____ p.u.

Direct axis transient reactance, Xd' _____ p.u.

Direct axis subtransient reactance, Xd" _____ p.u.

vi) Time Constants:

Direct axis open circuit transient, T' _____ seconds

Direct axis open circuit subtransient, T" _____ seconds

vii) Provide a plot of generator capability curve: (MW output vs MVAR)

Document Number: _____ Rev. _____

☐ Attached
☐ Separate Mailing

viii) Generator Inertia constant (on machine base), if available

H = _____ seconds (generator only)

H = _____ seconds (generator & turbine)

h. For Induction Units:

i) Generation facility voltage (kV): _____

ii) Rated current (A): _____

iii) Rated power factor of generating unit (s): _____ p.u.

iv) Power factor operating range. (Specify lag or lead): from _____ p.u. to _____ p.u.

v) Unsaturated reactances on: _____ kVA base, _____ kV base

Direct axis synchronous reactance, Xd _____ p.u.

Direct axis transient reactance, Xd' _____ p.u.

Direct axis subtransient reactance, Xd" _____ p.u.

vi) Time Constants:

Direct axis open circuit transient, T' _____ seconds

Direct axis open circuit subtransient, T" _____ seconds

vii) Actual power factor at PCC (after p.f. correction):

Full output: _____ p.u.

No output: _____ p.u.

viii) Generator reactive power requirements:

Full output: _____ kVAR

No output: _____ kVAR

ix) Total power factor correction installed: _____ kVAR

Number of regulating steps: _____

Power factor correction switched per step: _____ kVAR

Power factor correction capacitors are automatically switched off when generator breaker open:

☐ Yes ☐ No

x) Maximum starting inrush current (multiple of full load current): _____ p.u.

xi) Generator Inertia constant (on machine base), if available

H = _____ seconds (generator only)

H = _____ seconds (generator & turbine)

i. For SPC / Inverter type units:

i. Manufacturer / Type or Model No.: _____ / _____

ii. Inverter AC output voltage: _____ Volts

iii. Inverter AC output current: _____ Amps

iv. Number of phases: ☐ One ☐ Three

v. Inverter output frequency: _____ Hz

vi. Type of inverter: ☐ Self-Commutated ☐ Line Commutated

☐ Other (Please Specify):

vii. Inverter rated power factor: _____ %

viii. Inverter power factor adjustment range, if applicable (specify lag or lead:

from _____ p.u. to _____ p.u.

ix. Are power factor correction capacitors used? ☐ Yes ☐ No

x. If yes, total power factor correction installed: _____ kVAR

xi. Number of capacitor steps:

xii. Are power factor correction capacitors automatically switched off when inverter breaker opens?

☐ Yes ☐ No

xiii. Is the inverter paralleling equipment and / or design pre-certified? ☐ Yes ☐ No

xiv. If yes, to which standard(s), e.g. CSA C22.2 No. 107.1-01, UL 1741: _____

xv. Maximum inrush current upon inverter start-up (multiple of full-load current): _____ p.u.

xvi. Modelling parameters recommended by SPC/Inverter/Converter Manufacturer.

Describe how your equipment should be modeled for load flow, voltage study and short circuit analysis.

_____

_____

_____

_____

4. Interface (Step-Up) Transformer Characteristics:

a. Transformer rating: _____ kVA

b. Manufacturer (if known): _____

c. Number of phases: ☐ Yes ☐ No

d. Nominal voltage of high voltage winding: _____ kV

e. Nominal voltage of low voltage winding: _____ kV

f. High voltage winding connection: _____

g. Grounding method of star connected high voltage winding neutral; if applicable

☐ Solid ☐ Ungrounded ☐ Impedance: R _____ X _____ ohms

h. Low voltage winding connection: _____

i. Grounding method of star connected low voltage winding neutral; if applicable

☐ Solid ☐ Ungrounded ☐ Impedance: R _____ X _____ ohms

j. Impedances on: _____ kVA base _____ kV base

R: _____ p.u. X: _____ p.u.

Note:

(a) The term "High Voltage", used above, refers to the connection voltage to Hydro One's distribution system, and "Low Voltage", used above, refers to the generation or any other intermediate voltage.

(b) Studies will be conducted at nominal voltages (i.e. tap changer at neutral position)

5. Intermediate Transformer Characteristics (if applicable):

a. Transformer rating: _____ kVA

b. Manufacturer (if known): _____

c. Number of phases: ☐ Yes ☐ No

d. Nominal voltage of high voltage winding: _____ KV

e. Nominal voltage of low voltage winding: _____ kV

f. High voltage winding connection: _____

g. Grounding method of star connected high voltage winding neutral; if applicable

☐ Solid ☐ Ungrounded ☐ Impedance: R _____ X _____ ohms

h. Low voltage winding connection: _____

i. Grounding method of star connected low voltage winding neutral; if applicable

☐ Solid ☐ Ungrounded ☐ Impedance: R _____ X _____ ohms

j. Impedances on: _____ kVA base _____ kV base

R: _____ p.u. X: _____ p.u.

Note:

(a) The term "High Voltage", used above, refers to the intermediate voltage that is input to the interface step-up transformer, and "Low Voltage", used above, refers to the generation voltage.

6. Generating Facility Load Information

a. Maximum continuous load:

- Total: _____ kVA _____ kW
- Generator Auxiliary Load Only: _____ kVA _____ kW

b. Maximum start up load: _____ kVA _____ kW

c. Largest motor size that would be started: _____ HP _____ kW

d. Maximum inrush current of the motor (multiple of full-load current): _____ p.u.

e. For load displacement generators:

- Max. present load at Generator's facility: _____ kVA _____ kW

- Max. future load at Generator's facility (excluding Auxiliary Loads):

_____ kVA _____ kW

- Indicate the means by which injection of power into Hydro One's system will be prevented.

_____

7. Operation Information:

- Mode of Operation: _____
- Annual Capacity Factor: _____ %
- Prospective number of annual scheduled starts / stops, and timing thereof: _____

8. Expected Monthly Generation, Consumption and Output From the Facility:

Expected:	Total Generation (a)		Total Internal Consumption (b)		Total Output (To the LDC's Distribution System) (a-b)*	
	kWh	Peak kW	kWh	Peak kW	kWh	Peak kW
January						
February						
March						
April						
May						
June						
July						
August						
September						
October						
November						
December						

* This value would be negative when the generators are not in operation or when the internal consumption exceeds generation.

Appendix 5
Distributed Generation Connection Impact Assessment Review to connect 10kW – 10MW to Bluewater Power's Electrical Distribution System

9. Protection Design, Philosophy and Logic

Either at the CIA stage or the design review stage it will be necessary to determine the protection philosophy, co-ordination and trip logic. If it is available now please provide it. If it is not, it can be deferred and submitted if the project goes ahead. Please do not feel inhibited by the space provided here. Use as much space and as many additional sheets as are required to describe how the Generator protection will deal with faults, outages, disturbances or other events on the distribution system and for the generator itself.

Protective Device	Range of Available Settings	Trip Time	Trip Set Point	Describe operation for disconnecting the generator or inverter in the event of a distribution system outage	Describe operation for disconnecting the generator or inverter in the event of a distribution system short circuit (three phase and single phase to ground)
27 Phase Undervoltage Instantaneous					
27 Phase Undervoltage					
50 Phase Instantaneous Overcurrent					
50Gground Instantaneous Overcurrent					
51 Phase Time Overcurrent					
51G Ground Time Overcurrent					
59 Phase Overvoltage Instantaneous					
59 Phase Overvoltage					
81 Under Frequency					
81 Over Frequency					
87 Transformer Differential					
Other					

Appendix 5
Distributed Generation Connection Impact Assessment Review to connect 10kW – 10MW to Bluewater Power's Electrical Distribution System

10. Other Comments, Specifications and Exceptions (attach additional sheets if needed)

_____

_____

_____

_____

11. Applicant and Project Design / Engineering Signature

To the best of my knowledge, all the information provided in this Application Form is complete and correct.

Applicant Signature Date

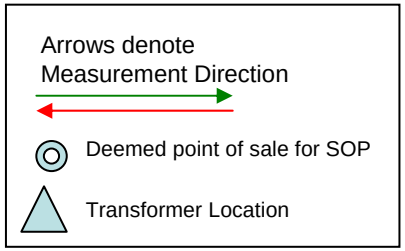
_____

Project Design / Engineering Date

_____

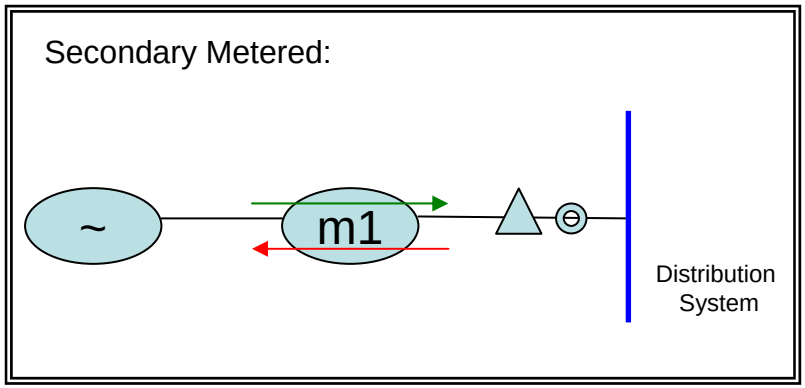
* **Return this form to the LDC.**

Appendix 6 : Standard Offer Program
Meter Configuration Options



Standard Offer Program
Meter Configuration Options

1. Pure Generator Customer



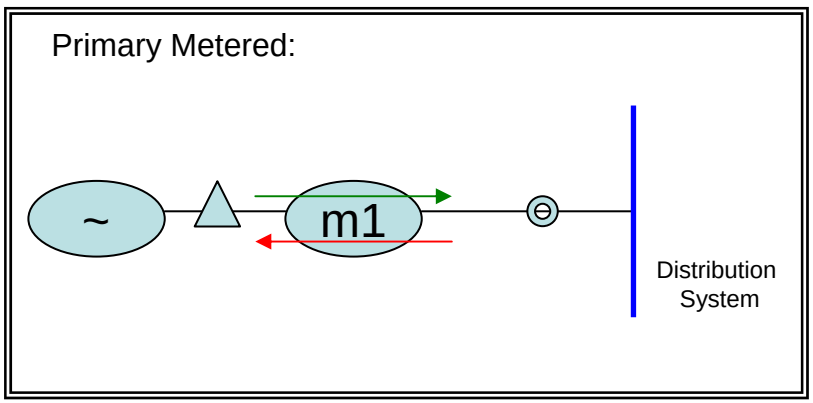
Settlements:

Energy delivered reduced by Site Specific Losses. Paid @ SOP Rate

(Kwh / (1+SSL)) x SOP Rate

Energy consumed increased by LDC approved loss factor. Billed at HOEP.

(Kwh x (1+LDCL)) x HOEP



Settlements:

Energy delivered- No adjustment required. Paid @ SOP Rate.

Kwh x SOP Rate

Energy consumed increased by LDC approved loss factor less 1% for primary metering discount. Billed @ HOEP.

(Kwh x (1+LDCL)) x .99 x HOEP

Note: Load Customer (Station Service) is also required to pay for additional energy related charges: WMSC, DRC, Network Service, Line & Transformation, and Distribution Variable Charges.

Note: Load Customer is also required to pay for additional energy related charges: WMSC, DRC, Network Service, Line & Transformation, and Distribution Variable Charges.

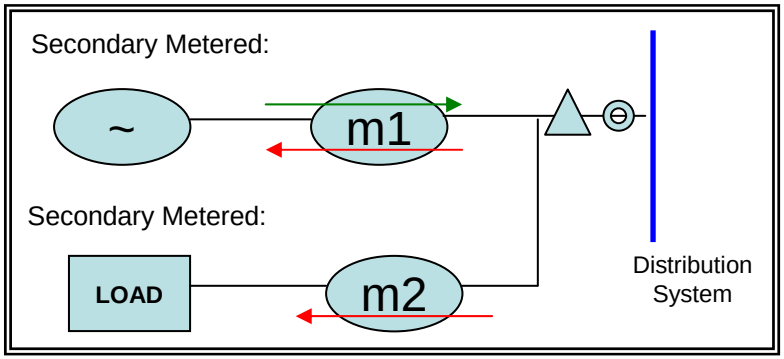
Arrows denote Measurement Direction

Deemed point of sale for SOP

Transformer Location

Standard Offer Program Meter Configuration Options

2. Generator and Load Customer – 2 Meters



Settlements - Generator:

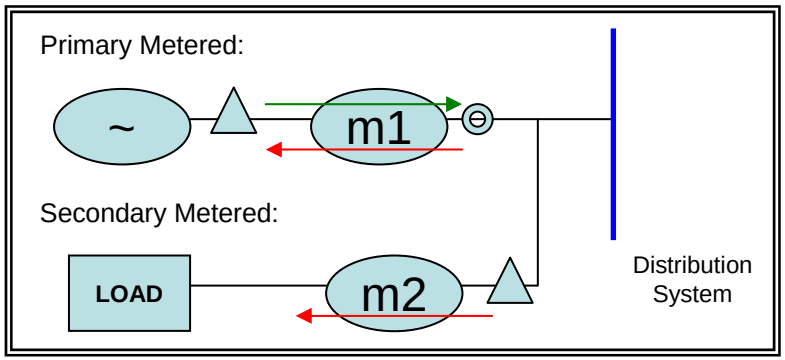
Energy delivered reduced by Site Specific Losses (Kwh / (1+SSL)) x SOP Rate

Energy consumed increased by LDC approved loss factor (Kwh x (1+LDCL)) x HOEP

Settlements - Load:

Energy consumed increased by LDC approved loss factor.

(Kwh x (1+LDCL)) x HOEP or (Kwh x (1+LDCL)) x RPP



Settlements - Generator:

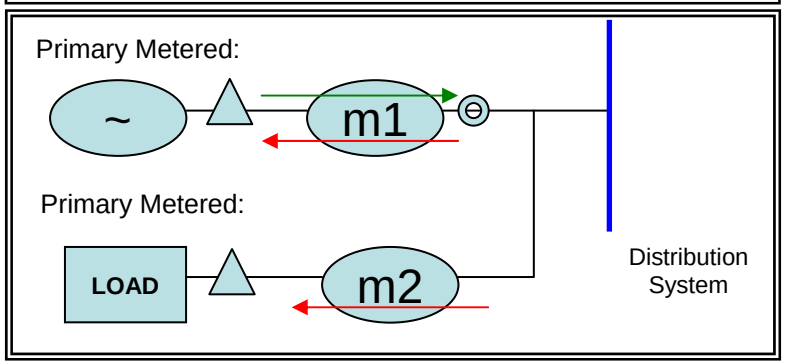
Energy delivered no adjustment required Kwh x SOP Rate

Energy consumed increased by LDC approved loss factor less 1% Primary Metering discount. (Kwh x (1+LDCL)) x .99 x HOEP

Settlements - Load:

Energy consumed increased by LDC approved loss factor.

(Kwh x (1+LDCL)) x HOEP or (Kwh x (1+LDCL)) x RPP



Settlements - Generator:

Energy delivered no adjustment required Kwh x SOP Rate

Energy consumed increased by LDC approved loss factor less 1% Primary Metering discount. (Kwh x (1+LDCL)) x .99 x HOEP

Settlements - Load:

Energy consumed increased by LDC approved loss factor less 1% Primary Metering Discount.

(Kwh x (1+LDCL)) x .99 x HOEP or (Kwh x (1+LDCL)) x .99 x RPP

Arrows denote Measurement Direction

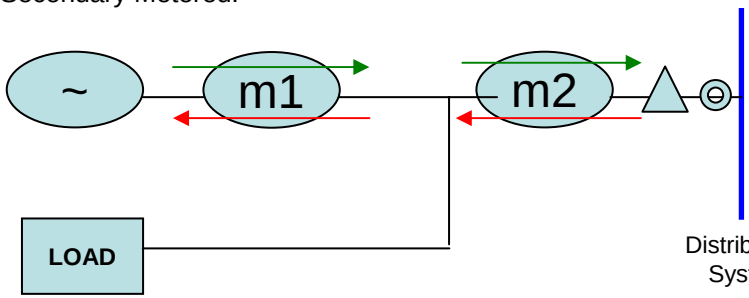
Deemed point of sale for SOP

Transformer Location

Standard Offer Program Meter Configuration Options

Embedded Generator and Load Customer (under exceptional circumstances only)
(See spreadsheet for calculation formulas and methodology)

Secondary Metered:



Settlements - Generator:

Energy delivered reduced by Site Specific Losses Energy consumed increased by LDC approved loss factor

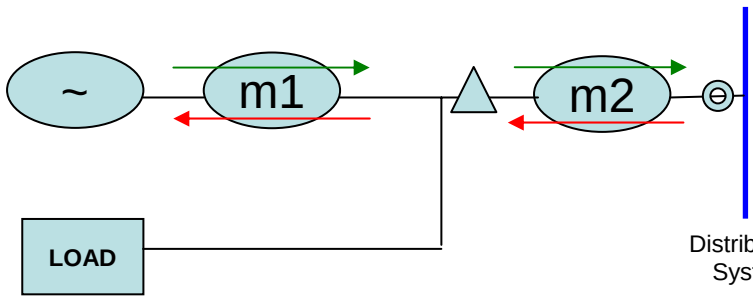
Settlements – Load:

Energy consumed increased by LDC approved loss factor.

Settlements – Load: (when m1 delivered coincident with m2 consumed or m2 consumed = 0 coincident with m1 delivered)

Energy consumed increased by LDC approved loss factor.

Primary Metered:



Settlements – Generator: (same as above)

Settlements – Load

Energy consumed increased by LDC approved loss factor.

Settlements – Load: (when m1 delivered coincident with m2 consumed or m2 consumed = 0 coincident with m1 delivered)

Energy consumed increased by LDC approved loss factor.

Note: Load Customer is also required to pay for additional energy related charges: WMSC, DRC, Network Service, Line & Transformation, and Distribution Variable Charges.

Arrows denote
Measurement Direction

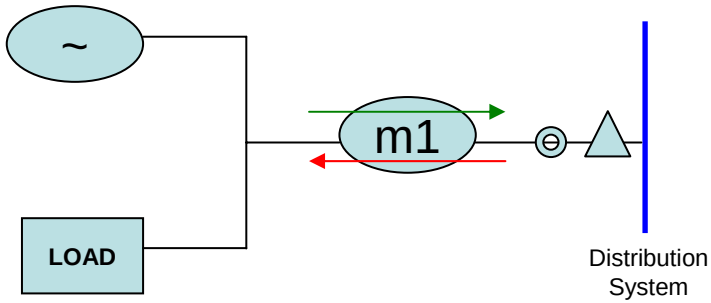
Deemed point of sale for SOP

Transformer Location

Standard Offer Program
Meter Configuration Options

4. Generator and Load Customer – 1 Meter (Simple Net Metering)

Secondary Metered:



Settlements:

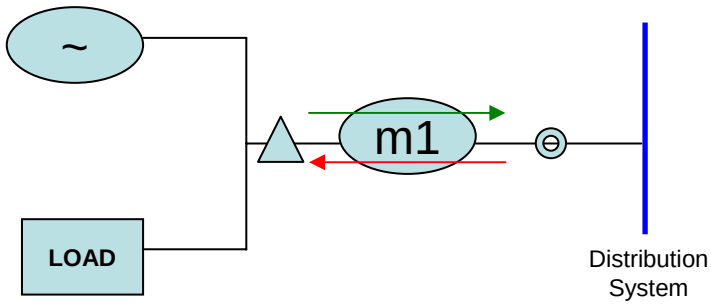
Energy delivered with no adjustment for Losses. (*O. Reg. 541/05, s. 8 (2)*)

Kwh x (RPP or HOEP) Rate

Energy consumed increased by LDC approved loss factor.

(Kwh x (1+LDCL)) x (RPP or HOEP) Rate

Primary Metered:



Settlements:

Energy delivered with no adjustment for losses. (*O. Reg. 541/05, s. 8 (2)*)

Kwh x (RPP or HOEP) Rate

Energy consumed increased by LDC approved loss factor less 1% for primary metering discount. Billed @ HOEP.

(Kwh x (1+LDCL)) x .99 x (RPP or HOEP) Rate

Note: Net Metering Regulations also require calculating credit to customer on Additional Charges: WMSC, DRC, Network Service, Line & Transformation, and Distribution Variable Charges.

Appendix 7(a): Interconnection Matrices (Summary Load Displacement)

Appendix 7 (a) Interconnection Matrices

SUMMARY LOAD DISPLACEMENT GENERATION

Description >	Embedded Load Displacement primarily for own use*****	Micro Embedded Load Displacement	Small Embedded Load Displacement	Mid Size Embedded Load Displacement	Large Embedded Load Displacement	Embedded Load Displacement Generation that displaces New Load
Fuel >	Fuel is solely from a renewable resource*	Non renewable resource	Non renewable resource	Non renewable resource	Non renewable resource	Non renewable resource
Size >	Less than 500 kW**	Less than 10 kW	10 kW to 500 kW connected at less than 15 kV	500 kW to 10 MW connected at less than 15 kV	Greater than 10 MW	Any size
			Up to 1 MW connected at greater than 15 kV	Greater than 1 MW to 10 MW connected at greater than 15 kV		
Net metering allowed**	Yes	No	No	No	No	No
Connection Agreement with LDC or Supply Authority Required	Yes	Yes	Yes	Yes	Yes	Yes
All equipment must be CSA approved or have ESA special approval	Yes	Yes	Yes	Yes	Yes	Yes
ESA Inspection Required	Yes	Yes	Yes	Yes	Yes	Yes
OEB Generation Licence Required if exporting to distribution system	No	Yes	Yes	Yes	Yes	Yes
IESO Market Participant***	No	No	No	No	No	No
Relay Protection required	Yes - Disconnect	Yes - Disconnect	Yes - Disconnect	Yes - Disconnect or Transfer Trip	Yes - Disconnect or Transfer Trip	Yes - Disconnect or Transfer Trip
Monthly Distribution Fixed Charge	No reduction	No reduction	No reduction	No reduction	No reduction	No reduction
Distribution Variable Charge	Net	Net	Net	Net	Net	Net
Commodity (Electricity) Charge paid for electricity delivered	Net (where eligible)	Gross	Gross	Gross	Gross	Gross
Commodity (Electricity) Charge received for generation		HOEP	HOEP	HOEP	HOEP	HOEP
Payment for generation received from		LDC	LDC	LDC	LDC	LDC
Regulatory Charges	Net	Net	Net	Net	Net	Net
Debt Retirement Charge	Net	Gross	Gross	Gross	Gross	Net
				500 kW to 1 MW		
Transmission Charges - Network	Net	Net	Net	Net	Net	Net
				Over 1 MW		Over 1 MW
Transmission Charges - Connection	Net	Gross	Gross	Gross	Gross	Gross
			Over 50 kW	Over 5 MW		Over 50 kW
Fixed Standby Charge****	No	No	Yes	Yes	Yes	Yes
Variable Standby Charge****	No	No	Yes	Yes	Yes	Yes

Notes:
* Wind, drop in water elevation, solar radiation, agricultural bio mass or any combination
** The LDC has a limit on its obligation to connect net metering on a first come, first served basis
*** Any generator has the right to be a market participant. Some may be required to be a market participant for technical reasons. Assumed for these smaller examples that generators would prefer to be embedded
**** If an OEB Rate Order exists
***** If distributed generator elects not to pursue standard offer contract.

Appendix 7(b): Interconnection Matrices (Summary Standard Offer Contracts)

Appendix 7 (b) Interconnection Matrices

SUMMARY STANDARD OFFER CONTRACTS (SOC)

Description >	Micro Embedded	Small Embedded	Mid Size
Fuel >	Fuel is solely from a renewable resource*	Fuel is solely from a renewable resource*	Fuel is solely from a renewable resource*
Size >	Less than 10 kW	10 kW to 500 kW connected at less than 15 kV	500 kW to 10 MW connected at less than 15 kV
		Up to 1 MW connected at greater than 15 kV	Greater than 1 MW to 10 MW connected at greater than 15 kV
Bi-directional Metering Required*****	Yes	Yes	Yes
Connection Agreement with LDC or Supply Authority Required	Yes	Yes	Yes
All equipment must be CSA approved or have ESA special approval	Yes	Yes	Yes
ESA Inspection Required	Yes	Yes	Yes
OEB Generation Licence Required	Yes	Yes	Yes
IESO Market Participant**	No	No	No
Commodity (Electricity) Charge received for generation	SOC	SOC	SOC
Payment for generation received from***	LDC	LDC	LDC
Relay Protection required	Yes - Disconnect	Yes - Disconnect	Yes - Disconnect or Transfer Trip
Monthly Distribution Fixed Charge****	No reduction	No reduction	No reduction

Notes:

* Wind, drop in water elevation, solar radiation, agricultural bio mass or any combination

** Any generator has the right to be an IESO Market Participant. Some may be required to be a Market Participant for technical reasons. Assumed for these smaller examples that generators would prefer to be embedded

*** While the payment will likely be received from the LDC the LDC will in turn settle with either the IESO or the OPA for the variance between the SOC price and the HOEP

**** Where the distributed generation is connected at the LDC's member distribution service account and is not a free standing facility

***** Bi-directional metering could also include two uni directional meters measuring power flow in and power flow out

Distribution Connection Agreement

The Connection Agreement is made this ____ day of _____, _____.

BETWEEN:

Bluewater Power Distribution Corporation (hereinafter called "Hydro") a corporation incorporated pursuant to the laws of the Province of Ontario and licensed by the Ontario Energy Board.

PARTY OF THE FIRST PART;

- and -
(Name of Customer)
(hereinafter called "Customer")

PARTY OF THE SECOND PART;

From time to time, the Hydro and Customer shall be individually referred to in this Agreement as "Party" and collectively as "Parties".

Whereas the Customer has applied to the Hydro for connection service;

Whereas the Parties are willing to enter into a Distribution Connection Agreement for the delivery of power by the Hydro to the Customer in accordance with the Hydro's Conditions of Electrical Service and on the terms and conditions of this Agreement.

The Parties hereto mutually agree as follows:

SECTION 1 - Definitions

For the purpose of this agreement and the attached schedules, the following definitions apply:

1.1 *"Agreement"* means this agreement together with Schedule 'A', 'B' and 'C' hereto, as amended from time to time by the written agreement of the Parties.

1.2 *"Power"* means electrical power including electrical energy delivered by the Hydro to supply the Customers internal load requirements.

1.3 *"Connection"* means the process of installing and activating connection assets in order to distribute electricity to a Customer.

1.4 *"Ownership"* means having the design authority and the replacement responsibility of the facilities.

1.5 *"Operating Control"* means the authority to perform, direct or authorize the operation of all devices under its control. Operating control is not synonymous with ownership. Operating Control is not synonymous with the actual execution of any switching operations.

1.6 *"Work Protection"* is the provision of a safe work environment for work. A guarantee that an isolated, or an isolated and de-energizing condition has been established for work.

1.7 *"Conditions of Electrical Service"* means the document developed by the Hydro in accordance with the Distribution System Code that describes the operating practices and connection rules for the Hydro.

1.8 *"Distribution System Code"* means the code, approved by the Ontario Energy Board, which establishes the obligations of the Hydro with respect to the services and terms of service to be offered to customers and retailers and provides technical operating standards of distribution systems.

1.9 *"Condition Guarantee"* means that a specified piece of equipment will remain in a given position or condition until the guarantee is surrendered.

SECTION 2 - Term of Agreement

2.1 This Agreement shall commence on the date of execution and shall continue in force and effect in perpetuity, with the provision that the Customer or the Hydro may terminate this Agreement by providing the other Party with written notice. Such notice will terminate this Agreement ninety days (90) following receipt of such notice.

2.2 This Agreement sets out the terms and conditions upon which the Hydro has agreed to offer, and the Customer has agreed to accept connection service.

SECTION 3 - Conditions of Electrical Service and the Distribution System Code

3.1 The Hydro "Conditions of Electrical Service", the Distribution System Code, and this Agreement establish the operating practices and connection rules for the Hydro and the Customer. The Parties hereby agree to be bound by, and act at all times in accordance with the Conditions of Electrical Service and the Distribution System Code and which hereby forms part of this Agreement.

SECTION 4 - Contact Information

4.1 Schedule 'A' of this Agreement details the specific Customer information required for connection to the Hydro Distribution System and provides names,

telephone numbers and addresses for any 'Notices' that may be required to be given by either Party to this Agreement.

4.2 Any formal written notice required by this Agreement shall be deemed given and received, when delivered to the Customer or the Hydro business address or, where a facsimile number is provided and the notice is transmitted electronically to the appropriate number as identified in Schedule 'A'.

SECTION 5 - Billing, Rates & Charges

5.1 Power is delivered by the Hydro to the Customer in accordance with this Agreement subject to the distribution rates and charges approved from time to time by the Ontario Energy Board for the classification of service that is applicable to the Customer.

5.2 The Hydro shall provide, install and maintain a meter installation, as per the Hydro's Conditions of Electrical Service, for the settlement and monthly billing purposes of the Customer. If at anytime the Customer registers with the Independent Electricity System Operator (IESO) as a Wholesale Market Participant, the Customer would then have the option of purchasing the metering installations and purchasing metering services through a registered Meter Service Provider (MSP).

5.3 In the event of a meter malfunction affecting billing data, the best alternative data will be used for billing purposes as agreed upon by the Customer and the Hydro. Best alternative data will generally be the historical records of Hydro or customer owned back-up meter records. If an agreement as to the best alternative data cannot be reached within 10 business days of the malfunction being identified, then an official meter dispute and billing audit process that would involve Measurement Canada would be the next procedural step.

SECTION 6 - Customer Financial Contributions

6.1 For new or expanded connection facilities, the customer financial contribution in aid of construction will be determined by the Economic Evaluation Process outlined in the Conditions of Electrical Service.

SECTION 7 - Space and Access

7.1 The Customer agrees to provide suitable space for the Hydro's meters, wires and where necessary, poles, cables, transformers and all other required appliances and

equipment on the said premises. The Customer also agrees that no one who is not an agent of the Hydro shall be permitted to remove, inspect or tamper with the said equipment, including Hydro seals.

7.2 The location of indoor and outdoor meters shall be readily accessible at all times to staff of the Hydro. A space of 1.2 metres (4 feet) clear of all obstructions shall be provided in front of the meter and service panel.

7.3 The Customers shall grant properly authorized agents of the Hydro reasonable access to the said premises for the purpose of reading, examining, preparing or removing their meters, wires, poles, cables, transformers and other appliances and equipment of the Hydro and for the inspection of all the Customer's appliances and wiring. The properly authorized Hydro agents shall comply with the Customer's requirements for access.

SECTION 8 - Liability and Indemnity

8.1 The obligations of the parties to one another and to third parties shall be governed by Section 2.2 at the Distribution System Code.

SECTION 9 - Ownership of Equipment

9.1 Schedule 'C' of the Agreement includes a description of the electrical service connection that the Hydro has agreed to supply to the Customer and a description of the service capacity that the Customer has installed.

9.2 All Hydro owned equipment, including the revenue metering equipment and instrument transformers shall continue to be vested in the Hydro, unless the Parties have specified otherwise in Schedule 'C' to this Agreement. If at anytime the Customer registers with the Independent Electricity System Operator (IESO) as a Wholesale Market Participant, the Customer would then have the option of purchasing the metering installations and purchasing metering services through a registered Meter Service Provider (MSP).

9.3 All Customer equipment and facilities shall continue to be vested in the Customer, unless the Parties have specified otherwise in Schedule 'C' to the Agreement.

SECTION 10 - Responsibility for Equipment

10.1 Meters, wires, poles, cables, transformers and all other appliances and equipment of the Hydro on the Customer premises shall be in the care and at the risk of the

Customer and if destroyed or damaged by fire or any other cause whatsoever other than ordinary wear and tear, the Customer shall pay to the Hydro the value of such meters, wires, poles, cables, transformers, appliances and equipment, or the cost of repairing or replacing same.

10.2 As of the date of this agreement, the only Hydro asset that resides on the Customer's property is the metering installation.

SECTION 11 - Operation of Equipment

11.1 The Customer will have operating control of the main high voltage disconnect devices _____. Any required operation of this device must be coordinated with the Hydro by providing the Hydro with five (5) working days notice for requests to operate this device. For the purpose of communicating between the Customer and the Hydro, name, position and telephone numbers, (work and home) will be maintained in Schedule 'A' which will be reviewed annually for accuracy. In the case of an emergency threatening life, the primary disconnect device, may be operated without prior notification. Post operating notification is mandatory.

11.2 The Hydro agrees to use reasonable diligence in providing a regular and uninterrupted supply of power, but does not guarantee a constant supply of power or the maintenance of unvaried frequency or voltage, and will not be liable in damages to the Customer by reason of any failure in respect thereof. It is the Customer's responsibility to provide for the protection of his equipment from voltage variations, transient operations and single phasing.

11.3 The Customer shall operate their equipment so as to avoid unacceptable harmonics, voltage flicker or voltage level being subjected onto the Hydro electrical distribution system. If the Hydro determines that the Customer's equipment or operation is causing the above conditions, the Customer is responsible to correct these in a timely manner.

11.4 Both the Hydro and the Customer agree to operate their equipment and systems in accordance with the terms of the Hydro's Conditions of Electrical Service and the Distribution System Code.

SECTION 12 - Maintenance

12.1 The Hydro and the Customer shall maintain their respective equipment in efficient condition with proper devices, according to the requirements and rules of the Electrical Safety Authority. If in the opinion of the Customer or the Hydro, maintenance is not properly performed, the identifying Party will notify the other in writing. The Customer shall inspect, test and monitor its facilities and

equipment connected to the Hydro's distribution system to ensure and maintain compliance with the Hydro's Conditions of Electrical Service and this Agreement.

SECTION 13 - Work Protection

13.1 When work is to be done by the Customer on apparatus that can be isolated by devices under the control of the Customer, the procedures and protection will be in accordance with the Customer practices and the Occupational Health and Safety Act of Ontario.

13.2 When the Customer requires isolation from the Hydro supply or isolation of a device under Hydro control, the Customer will request that the Hydro provide a Condition Guarantee.

SECTION 14 - Security Deposit

14.1 The Customer may be required to provide the Hydro with an Account Security Deposit, in accordance with the Conditions of Electrical Service. When billing history does not exist, an estimated deposit amount will be determined from the Customer's projected load and comparisons to existing similar businesses.

14.2 The Account Security Deposit will receive interest in accordance with the Distribution System Code, which will accrue on cash deposits on a monthly basis but is credited to the Customer's account only at the time the deposit is refunded or when applied to an outstanding account.

SECTION 15 - Disconnection

15.1 The Hydro has the right and/or obligation to disconnect the supply of electrical energy to the Customer for causes that are outlined in the Conditions of Electrical Service document.

15.2 The Customer hereby expressly authorizes and empowers the Hydro, at the Hydro's option, to remove Hydro Owned equipment installed for the supply of electrical power and to discontinue the supply of power and terminate this agreement whenever any of the causes for disconnection cannot be resolved or upon violation by the Customer of any of the terms and conditions of this agreement.

SECTION 16 - Force Majeure

16.1 For the purposes of this Agreement, "Force Majeure" means any act of God, labour disturbance, act of a public enemy, war, insurrection, riot, fire, storm or flood, earthquake, or explosion; any curtailment, order, regulation, or restriction imposed by governmental, military or lawfully established civilian authorities; or any other cause beyond a Party's reasonable control.

16.2 Subject to the items below, neither Party shall be held to have committed an event of default in respect of any obligation under this Agreement if prevented from performing that obligation, in whole or in part, because of a Force Majeure event.

16.3 If a Force Majeure event prevents a Party from performing any of its obligations under the Conditions of Electrical Service, Distribution System Code or this Agreement, that Party shall:

16.3.1 Promptly notify the other Party of the Force Majeure event and its assessment in good faith of the effect that the event will have on its ability to perform any of its obligations. If the immediate notice is not in writing, it shall be confirmed in writing as soon as reasonably practicable;

16.3.2 Not be entitled to suspend performance of any of its obligations under this Agreement to any greater extent or for any longer time than the Force Majeure event requires it to do;

16.3.3 Use its best efforts to mitigate the effects of the Force Majeure event, remedy its inability to perform, and resume full performance of its obligations;

16.3.4 Keep the other Party continually informed of its efforts; and

16.3.5 Provide written notice to the other Party when it resumes performance of any obligations affected by the Force Majeure event.

SECTION 17 - Divisibility of Agreement

17.1 If any term, covenant or condition of this Agreement, shall, to any extent, be invalid or unenforceable, the remainder of this Agreement shall remain in full force and effect, subject to any necessary adjustments to delete any of the above said invalid or unenforceable provisions.

SECTION 18 - Dispute Resolution

18.1 Except where this Agreement states otherwise, the dispute resolution procedures set forth in the Agreement shall apply to all disputes arising between the Customer and the Hydro regarding the Agreement and the Hydro's Conditions of Electrical Service and shall be the only means for resolving any such disputes.

18.2 For disputes involving electrical bills or meter read inaccuracies, the Customer is asked to refer first to the Customer's retailer. The dispute process between Retailer and Distributor shall be as per the Distribution System Code and all other relevant OEB Codes.

18.3 If the Customer is receiving Standard Supply Service from the Hydro, then the Customer must supply the complaint in written form addressed to the President of the Hydro. All disputes shall be processed in accordance with the Hydro's Customer Complaints Procedure.

SECTION 19 - Waiver

19.1 Failure by either Party to exercise any right or to enforce any remedy under this Agreement shall be limited to the particular instance. It shall not be deemed to waive any right or to limit the ability to enforce any remedy in other or similar instances, nor should it affect the validity of this Agreement.

SECTION 20 - Review and Revisions

20.1 Either Party may initiate a review or revisions by the Parties of this agreement at any time, however, both Parties, acting reasonably, must approve any changes hereto in writing.

SECTION 21 - Successor and Assigns

21.1 This Agreement and its attached schedules shall extend to and be binding upon and inure to the benefit of the Customer and the Hydro, and to their respective successors and assigns. In the event of a successor or assign, the Customer or the Hydro is required to give written notice to the other Party to this Agreement, identifying the name of the successor or assign and the date that the change comes into effect.

SECTION 22 - Acceptance of Agreement

Dated at _____ this _____day of _____, 20___.

We, the undersigned, agree to the above **Connection Agreement**

Name of Customer	Name of the Hydro
	Bluewater Power Distribution Corporation
(Signature of representative of Customer)	*(Signature of representative of the Hydro)*
	Brad Gray
Name (*please print*)	Name *(please print)*
	Vice President of Operations
Title	Title

SCHEDULE 'A'

Of Connection Agreement between
Bluewater Power Distribution Corporation
and
(Customer Name)

Contact Information:

The Hydro Account Number
Name (customer)
Service Address
Mailing Address
Business Telephone Number
Business Facsimile Number

Notices

Notice to the Hydro:

Contact: Bluewater Power Distribution Corporation
855 Confederation St., P.O. Box 2140
Sarnia, ON N7T 7L6

(*Name/Title*)
Bus. Tel: 519-XXX-XXXX
Home Tel: 519-XXX-XXXX
Bus. Fax: 519-XXX-XXXX
Cell Phone:

(*Name/Title*)
Bus. Tel: 519-XXX-XXXX, ext. XXX
Home Tel: 519-XXX-XXXX
Bus Fax: 519-XXX-XXXX
Cell Phone: 519-XXX-XXXX

Notice to the Customer:

Contact: (*Name/Title*)
Bus. Tel: 519-XXX-XXXX, ext. XXX
Home Tel: 519-XXX-XXXX
Bus Fax: 519-XXX-XXXX
Cell Phone: 519-XXX-XXXX

SCHEDULE 'B'

Of Connection Agreement between
Bluewater Power Distribution Corporation
and
(Customer Name)

Billing Rates & Charges

Classification of Service: _____

Load Profile

(*Customer Name*) monthly peak kW and energy load to be connected to the Hydro distribution system.

Please identify whether the following is **Historical data ____**. or **Forecasted data ____**.

	Net kWh	**Peak kW**
January		
February		
March		
April		
May		
June		
July		
August		
September		
October		
November		
December		

SCHEDULE 'C'

of Connection Agreement between
Bluewater Power Distribution Corporation
and
(Customer Name)

1. DESCRIPTION OF SERVICE

1.1 *(list specifics of electrical service.)*
e.g. – supply voltage (include phase/wires), service capacity, type of metering, telecommunications circuit (if required), location of service on customer property and any other specifics pertinent to the service connection.
Note: The above detail will be in an "Offer to Connect", however, there may be times when a Connection Agreement may be initiated without a prior Offer to Connect (e.g. customer moving into an existing facility).

2. OWNERSHIP OF EQUIPMENT

(list and identify the ownership of equipment for the Hydro and the Customer.)

2.1 (*Name of Customer*) owns:

2.1.1

2.2 (***Name of the Hydro*) owns:**

(identify who has operating control of key devices at interface with the Customer and the Hydro.)

3. OPERATING CONTROL

3.1 ***(Name of the Hydro)***

3.1.1

3.2 *(Name of the Customer)*

3.2.1

APPENDIX 1

(*Name of the Customer*) Drawings

Net Metering Application Form

This form is applicable to individual or multiple generating units at the customer's facility with total nameplate rating of 500 kW or less. Your generation facility must generate electricity from a renewable source that is wind, water, solar radiation, or agricultural biomass.

Inverter based generating units must not inject DC greater than 0.5% of the full rated output current at the point of connection of the generating units. The generated harmonic levels must not exceed those given in the CAN/CSA-C61000-3-6 Standards.

The following information is required for all net metered generators with total generation of up to 500 kW.

Date of Application: _____ (mm/dd/yyyy)

Proposed Generation In-Service Date: _____ (mm/dd/yyyy)

1. Project Information:

Location (Street Address / City / or Lot No. / Concession / Township / County, as applicable)

_____
_____
_____
_____

Owner

Company / Person: _____
Contact: _____
Mailing Address: _____
_____
_____
_____
Telephone: _____
Fax: _____
E-mail: _____

Engineering Consultant (Electrical)

Company / Person: _____
Contact: _____
Mailing Address: _____
_____
_____
_____
Telephone: _____
Fax: _____
E-mail: _____

2. Customer Status:

Are you an existing Bluewater Power Customer? ☐ Yes ☐ No

If yes, please provide your Bluewater Power 7-digit Account Number: _____

Are you a GST registrant? ☐ Yes ☐ No

If yes, please provide your GST registration number: _____

3. Project Size:

Total generation capacity _____ kW

Are all generating units of the same type / size? ☐ Yes ☐ No

4. Generation Type (check all that apply):

☐ Wind Turbine

☐ Hydraulic Turbine

☐ Solar / Photovoltaic Cells

☐ Biomass

☐ Other, please specify _____

5. Customer-Owned Step-up Interface Transformer (if applicable):

a. Transformer rating _____ kVA

b. High voltage winding connection ☐ delta ☐ star

Grounding method of star connected high voltage winding neutral
☐ Solid ☐ Ungrounded ☐ Impedance grounded: R _____ X _____ ohms

c. Low voltage winding connection ☐ delta ☐ star

Grounding method of star connected low voltage winding neutral
☐ Solid ☐ Ungrounded ☐ Impedance grounded: R _____ X _____ ohms

Note: The term "high voltage" refers to the connection voltage to Bluewater Power's distribution system and "low voltage" refers to the generator / inverter output voltage.

6. Generator / Inverter Information:

(For generation facilities installing more than one type of generator, complete section 6 and Appendix A)

a. Manufacturer: _____

b. Model No. _____

c. Number of phases ☐ Single Phase ☐ Three Phase

d. Nameplate rating: _____ kW

e. Generator / Inverter AC output voltage _____ Volts

f. Type of inverter: ☐ Self-commutated ☐ Line-commutated ☐ Other, please specify _____

g. Are power factor correction capacitors automatically switched off when generator breaker opens?
☐ Yes ☐ No

h. Is the generator / inverter paralleling equipment and / or design pre-certified and meets anti-islanding test requirements?
☐ Yes ☐ No

i. If answer to the above question is Yes, to which standard(s), e.g. CSA C22.2 No. 107.1-01, UL 1741, etc.?
_____

j. Method of synchronizing the generator / inverter to Bluewater Power's system

☐ Manual ☐ Automatic

k. Maximum inrush current upon generator or inverter connection (I_{inrush} / I_{rated})
_____ per unit

7. Grid Interface Controller (if applicable):

a. Manufacturer _____

b. Model No. _____

8. Single Line Diagram (only required for generators greater than 50 kW):

A Single Line Diagram (SLD) is required with this application form. The SLD should include, but not be limited to:

- Customer's electrical system showing major electrical equipment, their ratings, location of fault interrupting devices (circuit breakers, fuses)
- Generating unit(s) and their connection arrangement to Customer's electrical system
- Protection, metering and proposed tripping schemes
- Isolating / disconnecting device for the isolation of the generating unit(s) from the Bluewater Power system: suitably rated, accessible (to Bluewater Power personnel), visible, gang operated, lockable

- If applicable, information on customer owned step-up interface transformer: ratings, winding connections, grounding arrangements.

SLD Drawing Number: _____, Rev. _____

9. Location and Site Plan (only required for generators greater than 50 kW):

Provide a site plan (sketch) showing electric service entrance, step-down transformer, generator(s), / inverter(s) location, existing / new switchgear, location of the isolating / disconnecting device (for Bluewater Power usage), adjoining street name, and street address.

Drawing / Sketch No: _____, Rev. _____

Note: *Additional information may be required. Bluewater Power will inform you what additional information is required, if necessary.*

Applicant: _____ **Date:** _____
(Signature)

Please return this form by fax or mail to:

Net Metering Application – Attention: Mark Vanderheide
Bluewater Power Distribution Corporation
855 Confederation Street, PO Box 2140
Sarnia, Ontario N7T 7L6

Fax: (519) 332-3878

APPENDIX A: Generator / Inverter Information For Additional Turbines

(For generation facilities installing more than one type of generator)

a. Manufacturer: _____

b. Model No. _____

c. Number of phases ☐ Single Phase ☐ Three Phase

d. Nameplate rating: _____ kW

e. Generator / Inverter AC output voltage _____ Volts

f. Type of inverter: ☐ Self-commutated ☐ Line-commutated ☐ Other, please specify _____

g. Are power factor correction capacitors automatically switched off when generator breaker opens?
☐ Yes ☐ No

h. Is the generator / inverter paralleling equipment and / or design pre-certified and meets anti-islanding test requirements?
☐ Yes ☐ No

i. If answer to the above question is Yes, to which standard(s), e.g. CSA C22.2 No. 107.1-01, UL 1741, etc.?
_____

j. Method of synchronizing the generator / inverter to Bluewater Power's system

☐ Manual ☐ Automatic

k. Maximum inrush current upon generator or inverter connection (I_{inrush} / I_{rated})
_____ per unit

Net Metering Connection Agreement

In consideration of Bluewater Power Distribution Corporation ("Bluewater Power") agreeing to allow you to connect your 500 kW or smaller generation facility to Bluewater Power's distribution system, Bluewater Power requests that you understand and accept the following terms and conditions:

1.0 Eligibility

1.1 Your generation facility must generate electricity solely from solar radiation, wind, a drop in water elevation, an agricultural bio-mass resource or any combination of the foregoing.

1.2 The electricity generated by your generation facility must be primarily for your own use.

1.3 The maximum cumulative output capacity of the equipment used to generate electricity shall be no greater than 500 kW based on the rated maximum output capacity of the equipment.

1.4 You agree that the connection of your generation facility to Bluewater Power's distribution system shall also be bound by the requirements of the Ontario Energy Board *Distribution System Code* and Bluewater Power's Conditions of Service.

1.5 You are not participating in Ontario's Standard Offer Program.

2.0 Technical Requirements

2.1 You agree to have transfer and isolating capabilities installed on your generation facility if you wish to run it during a power outage affecting Bluewater Power's distribution system. You also agree that your generation facility must be disconnected from Bluewater Power's distribution system during such an outage.

2.2 You have installed an isolation device that meets the requirements of Section 84 of the *Ontario Electrical Safety Code* and agree that Bluewater Power may operate your isolation device as required for the maintenance and repair of the distribution system.

2.3 You agree to have regular scheduled maintenance performed on your generation facility in order to assure that connection devices, protection systems, and control systems are maintained in good working order and in compliance with all applicable laws, statutes, codes, licensing requirements, directives, rules, regulations, protocols, policies, orders, injunctions, rulings, awards, judgments, or decrees or any requirement or decision or agreement with or by any government or government department, commission, board, court authority or agency.

2.4 You agree to meet the requirements as outlined in the Technical Requirements for Generators Connecting to Bluewater Power's Distribution System as outlined in the *Distribution System Code Appendix F*. Additional requirements may be necessary to address unique situations, and Generators will be advised of any additional requirements at the appropriate assessment stage.

3.0 Liabilities

3.1 You covenant and agree that the design, installation, maintenance, and operation of your generation facility will not jeopardize the safety and security of both the generation facility and Bluewater Power's distribution system. This includes, but is not limited to, automatic disconnection of your generation facility from Bluewater Power's distribution system, as per Bluewater Power's generator protective relay settings, specified in Table 1 of this Agreement, in the event of a power outage affecting Bluewater Power's distribution system or any abnormal operation of Bluewater Power's distribution system. You acknowledge and agree that the protective relay settings of your generation facility are as specified in Table 1 of this Agreement.

3.2 You acknowledge and agree that in the event Bluewater Power, in its sole discretion, determines that your generation facility is damaging and/or is producing adverse effects on other Bluewater Power customers or on Bluewater Power's distribution system assets, you will disconnect your generation facility immediately from Bluewater Power's distribution system and correct the problem at your expense and you will indemnify and save harmless Bluewater Power for all of the

damages and/or adverse effects caused by the connection of your generation facility to Bluewater Power's distribution system.

3.3 Notwithstanding the generality of Section 3.2, you acknowledge and agree that in cases where your generation facility is connected to a Bluewater Power transformer that you are responsible for any and all damage to the Bluewater Power equipment caused by the operation of your generation facility.

4.0 Compensation and Billing

4.1 If you purchase electricity from Bluewater Power you agree that to be billed on a net metering basis the following applies:

- **4.1.1** Bluewater Power will not pay you for any excess generation that results in a net delivery of energy to Bluewater Power beyond a 12 month period.
- **4.1.2** Cumulative excess generation can only be carried over for a period of up to 12 months to offset your future electricity costs.
- **4.1.3** You will be billed monthly if your generation facility rating is above 10 kW as determined by Bluewater Power. You also agree that Bluewater Power may use your phone line to access your meter for billing purposes.
- **4.1.4** If your net consumption for a billing period is zero, or results in a credit, the delivery portion of your bill will not include kilowatt-hour based charges.

4.2 If you have a contract with an electricity retailer, you agree that the following applies:

- **4.2.1** You are billed under the bill-ready form of distributor-consolidated billing pursuant to the *Ontario Energy Board Retail Settlement Code*; and
- **4.2.2** You will not be eligible to be billed on a net metering basis unless the retailer confirms to Bluewater Power that you and the retailer have an agreement allowing you to return eligible electricity to the retailer for billing on a net metering basis.

4.3 If there is no scheduled meter read, you agree to provide meter readings to Bluewater Power in the manner and on the schedule specified by Bluewater Power to calculate your bill. You acknowledge in the event that we have not read your meter during the billing period or you have not provided suitable meter readings, Bluewater Power will bill you as if you have not consumed or returned any electricity. Once an actual meter read is performed, Bluewater Power will bill you on your actual consumption and credit you for electricity returned. To determine the month in which the value of your accrued electricity credits is reduced to zero, Bluewater Power will pro-rate the electricity you use and return based on the actual meter readings. For example, we would use your most recent actual meter reading and subtract it from your last actual meter reading to determine your average use and return per day during the billing period.

4.4 If you are a GST registrant, you are required to charge Bluewater Power for GST on the electricity you generated for input into Bluewater Power's distribution system. Bluewater Power is also required to bill you for GST on the amount of electricity you used from Bluewater Power's distribution system. Both amounts of GST will be shown on your bill. Bluewater Power is not permitted to "net" the amount of electricity you generated against what you used for the calculation and remittance of GST. Each month, if the GST charged by Bluewater Power exceeds the GST you charge Bluewater Power; you will pay the net amount of GST to Bluewater Power. However, if the GST charged by Bluewater Power is less than the GST you charge Bluewater Power, Bluewater Power will credit the net amount of GST against the other charges included on that bill. In each case, you will report the GST amount you charge Bluewater Power on Line 103 of the GST Return and, if you are eligible to claim GST paid to Bluewater Power as an input tax credit, the GST you are charged by Bluewater Power will be reported on Line 106. You will either pay the difference to the Receiver General when you file your GST return or claim a refund if your total credits exceed the taxes you collected. You may wish to consult your accountant about GST treatment.

4.5 If you are not a GST registrant, Bluewater Power is required to charge GST for the electricity you used from Bluewater Power's distribution system. Bluewater Power is not permitted to net the amount of electricity you generated against what you used for the calculation and remittance of GST.

5.0 Connection Costs

5.1 You agree to pay for the actual cost of modifications and upgrades to the distribution facilities required to connect your generation facility. The amount to be charged to construct the expansion to connect a generation facility to Bluewater Power's distribution system shall not exceed your share of the present value of the projected capital and ongoing maintenance costs for the equipment. Projected revenue and avoided costs from the generation facility shall be assumed to be zero. The methodology and inputs used to calculate this amount are presented in *Appendix B* of the *Distribution System Code*.

6.0 Future Charges

6.1 You agree to pay, if required, any current or future charges or tariffs as approved by the Ontario Energy Board with respect to the connection of your generation facility to Bluewater Power's distribution system.

7.0 Termination

7.1 You may terminate this Agreement at any time by providing Bluewater Power with 90 days prior written notice.

7.2 You agree that Bluewater Power reserves the right to terminate this Agreement on 30 days prior written notice:

(a) if Bluewater Power discontinues the Net Metering Program; or

(b) if you breach a term of this Agreement and do not remedy the breach within 30 days of receiving written notice from Bluewater Power of the breach.

7.3 You acknowledge and agree that upon termination of this Agreement, you must disconnect your generation facility from Bluewater Power's distribution system in a timely manner and to Bluewater Power's satisfaction.

7.4 Furthermore, you acknowledge and agree that if this Agreement is terminated, you may not be permitted to return eligible electricity to Bluewater Power for the purpose of being billed on a net metering basis for 12 months after the termination.

I understand, accept and agree to comply with and be bound by the above terms and conditions governing the connection of my generation facility to Bluewater Power's distribution system.

Customer Signature: _____ Date: _____

Customer Name: _____
(Please print)

For office use:	*Station*	_____	*Feeder*	_____	*Date Connected*	_____
Meter:	*Dual Register*	_____	*Interval Single Phase*	_____	*Interval Three Phase*	_____

Generator Protective Relay Settings

Table 1 – Inverter Based Generation

The following relay settings shall be used for inverters built to the CSA standard:

Source: CSA C22.2 No. 107.1-01 Table 16

System Voltage Vn = V nominal **V (Volts)**	Frequency **F (Hertz)**	Maximum number of cycles to disconnect	
		Seconds	Cycle
V < 0.5 Vn	60	0.1	6
0.5 Vn ≤ **V** < 0.88 Vn	60	2	120
1.10 Vn ≤ **V** < 1.37 Vn	60	2	120
V ≥ 1.37 Vn	60	0.033	2
Vn	**F** < 59.5*	0.1	6
Vn	**F** > 60.5	0.1	6

*The UL1741 & IEEE P1547 Standards use F < rated-0.7 i.e. 59.3 Hz.
To update if CSA C22.2 No. 107.1-01 is changed.

- If you are uncertain about your generation equipment's protective relay settings, please check with your generating equipment supplier.
- Automatic reconnect setting time for your generator is after five minutes of normal voltage and frequency on the Bluewater Power distribution system.

Note: **Keep a copy of this completed agreement for your use when the Bluewater Power field representative visits your site.**

Changes in Conditions of Services

Bluewater Power's Conditions of Services was filed with the OEB in 2007. There have been no changes to the Conditions of Services since the date of filing.

List of Witnesses and their Curriculum Vitae

Witnesses and curricula vitae will be provided prior to the determined hearing process.

Budget Directives (Capital and Operating)

Bluewater Power provides below the directives in relation to four major components of the budget process: revenue forecast, operating and maintenance expense forecast, payroll labour expense forecast and capital forecast. This budget information was compiled for both the bridge and test years.

Revenue Forecast

The revenue budget is comprised of three components: energy revenue, distribution revenue and other revenue.

The energy revenue for 2009 was forecast using the weather normalized load forecast as presented by the Elenchus Research Associates ("ERA") Report *Medium Term Weather Normalized Distribution System Load Forecast 2008 to 2009*, and is discussed in Exhibit 3, Tab 2, Schedule 1. A commodity price of $.0545 per kWh based on the OEB *Regulated Price Plan Report* dated April 11, 2008 has been assumed for the forecast.

Distribution revenue was forecast using the weather normalized volumes multiplied by both current approved distribution rates and by proposed rates in order to project distribution revenue for the 2009 test year.

Other revenue was reviewed on an item for item basis and other revenue was determined based on the most reliable historical indicator.

Payroll Labour Forecast

While payroll is ultimately included as an integral part of the operating and maintenance expense forecast, the payroll budget was completed separately due to its significance to the overall budget. The payroll labour was calculated by position by pay period and by the rate/hours expected to be realized during that pay period. A payroll accrual adjustment was made to ensure that the budgeted costs fall within the applicable forecast year.

Operating and Maintenance Expense Forecast

The operating and maintenance expenses for the bridge year and test year were forecast using a zero based methodology. Prior year experiences for many items strongly influence the budget after considerations of trending and one-time factors are taken into account. Each expense item was reviewed account by account for each of the forecast years. The O&M forecast can be found at Exhibit 4, Tab 2, Schedule 1.

Capital Budget

The capital budgeting process begins with a review of all ongoing and sustaining capital projects, followed by consideration of multi-year projects already underway. Any new non-recurring projects are considered individually as justified by the department proposing the project. Each capital project is reviewed on its own merit and special consideration is given to maintaining system reliability and accommodating future growth. Bluewater Power's asset management plan, as found at Exhibit 2, Tab 3, Schedule 9, is an integral part of the capital budgeting process.

The Planning and Design Department ("Design Services" or "Engineering") holds bi-weekly meetings to review on-going capital projects, operations and maintenance projects, and regular system reports. The meetings include staff representatives from the Lines Group, Purchasing Department ("Purchasing" or "Materials Management"), Meter Department and Field Technicians. The continuing dialogue helps to inform field and management staff regarding

future system improvements and helps to form the basis of Bluewater Power's budget preparation on an ongoing basis.

The approach in the Information Technology Department ("IT") follows a similarly disciplined process. The focus of capital spending is with maintaining the hardware and software infrastructure. Process improvements are driven either internally by the IT department or through request for changes from the operating groups. The capital plan can be found at Exhibit 2, Tab 3, Schedule 1.

Changes in Methodology

The only change in methodology is the change in the Capitalization Policy commencing January 1, 2009 as discussed at Exhibit 2, Tab 3, Schedule 8 – Capitalization Policy. That change in policy was not intended to increase the level of capitalization, but to recover a level of capitalization consistent with past practice. The purpose of the change in policy was to bring the capitalization practice more in line with the methodology employed broadly in the utility sector and to be compatible with methodologies approved previously by the OEB.

The only other item worth noting does not represent a change in methodology, but is an improvement to the utility's practices. Commencing in 2007, Bluewater Power implemented a more diligent and thorough practice of allocating costs associated with Non-Core Distribution Activities to Account 4380 as discussed in detail at "Exhibit 4, Tab 2, Schedule 7 – Non-Core Distribution Activities".

Finance

Financial Statements (2006)

The 2006 audited financial statements of Bluewater Power Distribution Corporation are attached as Exhibit 1, Tab 3, Schedule 1, Attachment 1.

Financial Statements of

BLUEWATER POWER DISTRIBUTION CORPORATION

Year ended December 31, 2006

KPMG LLP
Chartered Accountants
Box 976
21 King Street West Suite 700
Hamilton ON L8N 3R1

Telephone (905) 523-8200
Fax (905) 523-2222
Internet www.kpmg.ca

AUDITORS' REPORT

To the Shareholder of Bluewater Power Distribution Corporation

We have audited the balance sheet of Bluewater Power Distribution Corporation as at December 31, 2006 and the statements of earnings, retained earnings, and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2006 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Hamilton, Canada

March 23, 2007

KPMG LLP is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International, a Swiss cooperative. KPMG Canada provides services to KPMG LLP.

BLUEWATER POWER DISTRIBUTION CORPORATION

Balance Sheet

December 31, 2006, with comparative figures for 2005

	2006	2005 (restated)
Assets		
Current assets:		
Cash	$ 5,949,598	$ 7,778,391
Accounts receivable	6,404,180	2,109,810
Due from parent company	197,087	172,012
Unbilled revenue	10,080,741	10,551,761
Current recoverable regulatory assets (note 4)	808,292	2,185,173
Inventories	1,205,817	1,050,747
Prepaid expenses	424,471	395,742
	25,070,186	24,243,636
Property, plant and equipment (note 3)	37,396,966	37,199,221
Recoverable regulatory assets (note 4)	-	1,847,608
Future payment in lieu of income taxes (note 11)	2,480,000	2,480,000
	$ 64,947,152	$ 65,770,465
Liabilities and Shareholder's Equity		
Current liabilities:		
Due to Independent Electricity System Operator	$ 5,783,357	$ 6,721,559
Due to Hydro One	1,249,277	911,439
Accounts payable and accrued liabilities	1,918,114	2,995,306
Due to shareholders (note 13)	1,444,756	1,255,770
Payment in lieu of income taxes payable	543,015	323,688
Dividends payable	554,100	1,148,200
Deposits in aid of construction	485,204	638,789
	11,977,823	13,994,751
Due to shareholders (note 5)	19,377,604	19,377,604
Customer and other deposits	1,267,192	1,236,318
Employee future benefits (note 6)	4,985,307	4,479,596
Shareholder's equity:		
Share capital (note 9)	18,022,105	18,022,105
Retained earnings	9,317,121	8,660,091
	27,339,226	26,682,196
Commitments and contingencies (note 8)		
	$ 64,947,152	$ 65,770,465

See accompanying notes to financial statements.

On behalf of the Board: _____ Director

On behalf of the Board: _____ Director

BLUEWATER POWER DISTRIBUTION CORPORATION

Statement of Earnings and Retained Earnings

Year ended December 31, 2006, with comparative figures for 2005

	2006	2005
		(restated)
Gross revenue	$ 85,877,256	$ 94,639,063
Cost of power	71,104,272	81,291,542
Distribution margin	14,772,984	13,347,521
Regulatory assets recovered	2,165,864	3,022,266
Other operating revenues:		
Interest	260,408	63,054
Rental	98,159	105,131
Late payment charges	295,269	141,653
Carrying charges	15,789	214,262
Billables	1,169,356	1,315,580
Water and sewer billing	565,320	362,880
SSS administrative fees	84,137	85,362
Regulatory asset gain	-	1,629,251
Other (note 10)	336,979	263,773
	2,825,417	4,180,946
	19,764,265	20,550,733
Operating expenditures:		
Administration	10,145,634	9,672,034
Interest	1,468,652	1,434,273
Amortization of regulatory assets recovered	2,165,864	3,022,266
Amortization of property, plant and equipment	3,547,985	3,292,480
	17,328,135	17,421,053
Income before payments in lieu of income taxes	2,436,130	3,129,680
Payments in lieu of income taxes (recovery) (note 11):		
Current	1,225,000	380,000
Future	-	(800,000)
	1,225,000	(420,000)
Net income	1,211,130	3,549,680
Retained earnings, beginning of year	8,660,091	5,976,405
Prior period adjustment (note 2)	-	282,206
Dividends on common shares	(554,100)	(1,148,200)
Retained earnings, end of year	$ 9,317,121	$ 8,660,091

See accompanying notes to financial statements.

BLUEWATER POWER DISTRIBUTION CORPORATION

Statement of Cash Flows

Year ended December 31, 2006, with comparative figures for 2005

	2006	2005
		(restated)
Cash provided by (used in):		
Operating activities:		
Net income	$ 1,211,130	$ 3,549,680
Adjustments for:		
Amortization of property, plant and equipment	3,547,985	3,292,480
Amortization of regulatory assets recovered	2,165,864	3,022,266
Regulatory asset gain	-	(1,629,251)
Write-down of regulatory assets	-	343,564
Future payment in lieu of income taxes	-	(800,000)
Change in non-cash operating working capital (note 12)	(4,242,082)	1,714,976
Due from parent company	(25,075)	(12,768)
Due to shareholders	188,986	1,255,770
Dividends payable	(594,100)	848,200
Customer and other deposits	30,874	94,008
Employee future benefits	505,711	480,941
	2,789,293	12,159,866
Financing activities:		
Dividends on common shares	(554,100)	(1,148,200)
Funds received as contributed capital	352,158	487,788
	(201,942)	(660,412)
Investing activities:		
Additions to property, plant and equipment	(4,097,888)	(5,147,856)
Recoverable regulatory assets	(318,256)	(553,395)
	(4,416,144)	(5,701,251)
Increase (decrease) in cash	(1,828,793)	5,798,203
Cash, beginning of year	7,778,391	1,980,188
Cash, end of year	$ 5,949,598	$ 7,778,391
Supplemental cash flow information:		
Interest paid	$ 1,468,652	$ 1,434,273
Income taxes paid	1,147,003	414,584

See accompanying notes to financial statements.

BLUEWATER POWER DISTRIBUTION CORPORATION

Notes to Financial Statements

Year ended December 31, 2006

Bluewater Power Distribution Corporation (the "Corporation") was incorporated October 20, 2000 in accordance with the Ontario government's Electricity Competition Act (Bill 35). Assets of the Electric Utilities of the City of Sarnia, Town of Petrolia, Village of Point Edward, Village of Alvinston, Township of Warwick and Village of Oil Springs (the "Municipalities") were transferred to the Corporation on November 1, 2000. The Corporation distributes electricity in these municipalities and the beneficial ownership of the Corporation is held by these municipalities.

1. Significant accounting policies:

The financial statements have been prepared in accordance with generally accepted accounting principles in Canada consistently applied. The more significant accounting policies are summarized below:

(a) Revenue recognition:

Electricity distribution service charges comprises customer billings for electricity and distribution service charges less the cost of electricity purchases by the Corporation. Customer billings for electricity and distribution service charges are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading until the end of the fiscal year. The latter component is recorded as unbilled revenue.

(b) Use of estimates:

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and note disclosures related thereto. Due to the inherent uncertainty in making estimates, actual results could differ from estimates recorded in preparing these financial statements, including changes as a result of future regulatory decisions.

(c) Inventories:

Inventories consist principally of construction and maintenance materials. Inventories are stated at the lower of average cost and net realizable value.

BLUEWATER POWER DISTRIBUTION CORPORATION

Notes to Financial Statements (continued)

Year ended December 31, 2006

1. Significant accounting policies (continued):

(d) Property, plant and equipment and amortization:

Property, plant and equipment are recorded at amortized cost. Amortization is calculated on a straight-line basis over the estimated service life of the property, plant and equipment as follows:

Asset	Rate
Land rights	25 years
Buildings	60 years
Distribution and transmission systems	25 - 40 years
Equipment	5 years
Contributed capital	25 years

(e) Securities held as customer deposits:

The Ontario Energy Board (the "OEB") has released a ruling that requires Corporations to periodically review customers' deposits and where appropriate, return such deposits. During this review, Corporations may also request a deposit from customers based on certain criteria. At this time, the amount to be refunded cannot reasonably be determined and as such, the Corporation has not accrued a current liability.

The Corporation has a policy of paying interest on these deposits at a rate determined quarterly.

(f) Employee future benefits:

The Corporation pays certain medical and life insurance benefits, under unfunded defined benefit plans, on behalf of its retired employees. These estimated post-retirement costs are recognized in the period in which the employees rendered their services to the Corporation.

(g) Pension plan:

The Corporation provides a pension plan for its employees though the Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund"), and provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. The fund is a contributory defined benefit pension plan.

(h) Related party transactions:

Transactions with related parties represent the culmination of the earnings process and are measured at the exchange amount.

BLUEWATER POWER DISTRIBUTION CORPORATION

Notes to Financial Statements (continued)

Year ended December 31, 2006

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1. Significant accounting policies (continued):

(i) Contributed capital:

Contributed capital arises from development charges which are provided or paid for by developers and is recorded as a reduction of the capital cost of related fixed assets.

(j) Financial instruments:

The Corporation's financial instruments consist of accounts receivable, due from parent company, unbilled revenue, due to Independent Electricity System Operator, due to Hydro One, accounts payable and accrued liabilities, due to shareholders and dividends payable. Management is of the opinion that the fair values of all financial assets and liabilities are not materially different from their carrying values due to the short term maturity of these instruments. The carrying value of the shareholder notes approximates its fair value as debt bears interest at rates comparable to current market rates.

(k) Financial effects of distribution rate regulation:

The financial results presented are in accordance with generally accepted accounting principles and within that framework the Company accounts for the impact of regulatory actions in the following manner:

a) Regulatory Decisions to Adjust Distribution Rates

In the event that a regulatory decision is rendered, providing regulatory approval and certainty to the recognition of an asset, or creation of a liability, and culminating in an adjustment to Company distribution rates, such occurrences are immediately reflected in the Company's accounts.

b) Regulatory Direction and Practice

In the absence of a regulatory decision impacting rates, and where the Company is required by regulatory accounting practice or direction to accumulate balances for future rate recovery or create liabilities for future discharge, those amounts are recorded in accordance with that regulatory direction. Management assesses the future uncertainty with respect to the final regulatory disposition of those amounts, and to the extent required, makes accounting provisions to reduce the deferred balances accumulated or to increase the recorded liabilities. Upon rendering of the final regulatory decision adjusting distribution rates, the provisions are adjusted to reflect the final impact of that decision, and such adjustment is reflected in net earnings for the period.

Amounts currently confirmed by final regulatory decision, and amounts currently accounted for in the absence of final regulatory decision together with related provisions for future uncertainty, are more fully described in note 4 to the financial statements.

BLUEWATER POWER DISTRIBUTION CORPORATION

Notes to Financial Statements (continued)

Year ended December 31, 2006

2. Prior period adjustment:

Prior year's figures have been restated to amortize contributed capital over the life of the related asset.

3. Property, plant and equipment:

	Cost	Accumulated amortization	2006 Net book value	2005 Net book value
Land	$ 445,817	$ -	$ 445,817	$ 445,817
Land rights	283,160	251,125	32,035	43,483
Buildings	4,049,962	1,584,934	2,465,028	2,350,114
Distribution and transmission systems	65,943,944	34,018,219	31,925,725	31,840,555
Equipment	14,106,140	9,031,875	5,074,265	4,830,757
Contributed capital	(3,050,765)	(504,861)	(2,545,904)	(2,311,505)
	$ 81,778,258	$ 44,381,292	$ 37,396,966	$ 37,199,221

During the year, the Corporation received $352,158 (2005 - $487,788) of contributed capital.

BLUEWATER POWER DISTRIBUTION CORPORATION

Notes to Financial Statements (continued)

Year ended December 31, 2006

4. Recoverable regulatory assets:

	2006	2005
Pre-market opening cost of power variances	$ 3,436,806	$ 3,297,352
Qualifying transition costs recoverable	4,180,256	4,232,167
Post-market opening retail settlement variances	1,212,092	2,358,260
	8,829,154	9,887,779
Less: accumulated amounts recovered through rates	(8,020,862)	(5,854,998)
Remaining amount recoverable	808,292	4,032,781
Less current portion (due within the next twelve months)	(808,292)	(2,185,173)
	$ -	$ 1,847,608

Regulatory assets represent costs incurred by the Corporation for the purpose of supporting the deregulation of the electricity industry in Ontario. These amounts have been accumulated pursuant to regulation underlying the Electricity Act ("EA") and deferred in anticipation of their future recovery in electricity distribution service charges.

Qualifying transitional costs recoverable - represent specific and incremental costs to the Corporation for systems and process changes to support the opening of the competitive electricity market in Ontario on May 1, 2002 ("Market Opening").

Pre-market opening cost of power variance - represent the excess of the cost of the commodity electricity to the Corporation over the amount billed to its customers prior to Market Opening.

Post-market opening retail settlement variances - represent amounts that have accumulated since Market Opening and comprise:

(a) Variances between amounts charged by the Independent Electricity System Operator ("IESO") for the operation of the wholesale electricity market and grid, various wholesale market settlement charges and transmission charges, and the amounts billed to customers by the Corporation based on the OEB approved wholesale market service rate; and

4. Recoverable regulatory assets (continued):

Post-market opening retail settlement variances - represent amounts that have accumulated since Market Opening and comprise (continued):

(b) Variances between the amounts charged by the IESO to allow for purchases of electricity and the amounts billed to customers by the Corporation based on OEB approved rates; and

(c) Deferred payments in lieu of taxes ("PILs") - represent variances that result from the difference between OEB approved PILs recoverable in electricity distribution services charges and the actual amount of these charges to customers that relates to the recovery of PILs.

Conservation and Demand Management expenditures and recoveries

In May of 2004, the Minister of Energy granted approval to all distributors to apply to the regulator for an increase in their 2005 distribution rates, conditional on a commitment by the Company to reinvest an equivalent amount in conservation and demand management initiatives. The Company received approval to collect $657,600 to be spent on conservation and demand management programs over the period ending September 30, 2007. To date the Company has spent $657,710 (2005 - $362,532) on conservation and demand management activities.

5. Due to shareholders:

	2006	2005
Subordinate promissory note payable to shareholders, bearing interest at 7.25%, with interest payable in quarterly installments, with no specified repayment terms for principle amounts. Shareholders can demand payment with eighteen months written notice	$ 19,377,604	$ 19,377,604

The promissory note payable to shareholders is unsecured, subordinated and due eighteen months following demand for payment and was non-interest bearing prior to October 1, 2001. The rate of interest payable by the Corporation, commencing October 1, 2001, is the maximum amount prescribed by the OEB in its publication Electricity Distribution Rate Handbook as its "Deemed Debt Cost Rates". The Deemed Debt Cost Rate applicable to the Corporation is 7.25%.

The Corporation incurred interest expense in respect of the promissory note payable to shareholders of $1,404,876 (2005 - $1,404,876).

BLUEWATER POWER DISTRIBUTION CORPORATION

Notes to Financial Statements (continued)

Year ended December 31, 2006

6. Employee future benefits:

The Company pays certain health, dental and life insurance benefits on behalf of its retired employees. In measuring the Company's accrued benefit obligation, a discount rate of 5.0% (2005 – 5.0%) was assumed by the actuaries. A 3.0% (2005 – 3.0%) salary increase for life insurance coverage was assumed. The Company's liability at December 31, for this plan, is as follows:

	2006	2005
Accrued benefit obligation	$ 6,873,425	$ 6,505,224

The transition obligation has been amortized over the average remaining service life of current employees, which is eleven years. This results in a liability on the balance sheet at year end as follows:

	2006	2005
Accrued benefit liability	$ 4,985,307	$ 4,479,596

Other information about the Company's plan for the year ended December 31, is as follows:

	2006	2005
Service cost	$ 226,706	$ 215,911
Interest cost	331,838	314,301
Benefits paid	190,344	190,182

7. Pension plan:

The Corporation participates in the OMERS, a multi-employer plan, on behalf of its employees. The plan is a contributory defined benefit pension plan. Contributions in 2006 were 6.5% (2005 - 6.0%) for employee earnings below the year's maximum pensionable earnings and 9.6% (2005 - 8.8%) thereafter. The Corporation contributed $423,474 (2005 - $358,572) to the OMERS pension plan during the year ended December 31, 2006.

8. Commitments and contingencies:

The Corporation has letters of credit aggregating $7,635,650 (2005 - $7,700,000) in favour of the IESO as security for the Corporation's purchase of electricity through the IESO. The Corporation also has letters of credit aggregating $600,000 (2005 - $600,000) in favour of Hydro One as security for the Corporation's purchase of electricity through Hydro One. At year-end, no amounts were drawn on these letters of credit.

A class action claiming $500,000,000 in restitutionary payments plus interest was served on the former Toronto Hydro-Electric Commission, continuing as Toronto Hydro Corporation, on November 18, 1998. The action was initiated against the former Toronto Hydro-Electric Commission as the representative of the Defendant Class consisting of all municipal electric utilities in Ontario which have charged late payment charges on overdue utility bills at any time after April 1, 1981.

The claim is that late payment penalties result in municipal electric utilities receiving interest at effective rates in excess of 60% per year, which is illegal under Section 347(1)(b) of the Criminal Code. The Municipal Electric Association is undertaking the defence of this class action. At this time, it is not possible to quantify the effect, if any, on the financial statements of the Corporation. Consequently, no provision has been made in these financial statements with respect to any possible losses that may arise as a result of this matter.

9. Share capital:

The authorized share capital consists of an unlimited number of common shares. Any invitation to the public to subscribe for shares of the Corporation is prohibited.

The share capital of the Corporation is as follows:

	2006	2005
Authorized:		
Unlimited common shares		
Issued and outstanding:		
10,000 common shares	$ 18,022,105	$ 18,022,105

BLUEWATER POWER DISTRIBUTION CORPORATION

Notes to Financial Statements (continued)

Year ended December 31, 2006

10. Other revenue:

Other revenue from operations comprises of:

	2006	2005
Change in occupancy	$ 50,679	$ 50,342
Service agreement revenue	45,352	40,907
Consolidated billing charges	25,903	23,207
Collection charges	58,810	54,847
Gain on disposal	5,952	40,550
Sale of scrap material	81,161	25,128
Miscellaneous	69,122	28,792
	$ 336,979	$ 263,773

11. Payment in lieu of income taxes:

The provision for payment in lieu ("PILs") varies from amounts which would be computed by applying the Corporation's combined statutory income tax rate as follows:

	2006	2005
Basic tax rate of 36.1% applied to income before PILs (36.1% rate used in 2005)	$ 880,000	$ 1,092,000
Corporate minimum tax (recovery)	-	(144,000)
Tax effect of non-deductible expenses	23,000	14,000
Effect of changes to substantively enacted tax rates	342,000	-
Tax benefit of goodwill recognized for PIL's purposes	-	(1,057,000)
Other	(20,000)	(325,000)
Tax provision (recovery)	$ 1,225,000	$ (420,000)

Future income tax assets of $2,480,000 (2005 - $2,480,000) have been recorded at year end based on substantively enacted income tax rates. Such future income tax assets relate in part to the tax basis of depreciable capital assets and intangible assets in excess of amounts recorded for accounting purposes, and in part to the timing differences between the recognition of revenue and expenses for accounting and income tax purposes.

BLUEWATER POWER DISTRIBUTION CORPORATION

Notes to Financial Statements (continued)

Year ended December 31, 2006

12. Change in non-cash operating working capital:

	2006	2005
Accounts receivable	$ (4,294,370)	$ 911,036
Unbilled revenue	471,020	(1,470,249)
Inventories	(155,070)	(85,665)
Prepaid expenses	(28,729)	4,414
Current recoverable regulatory assets	1,376,881	650,770
Accounts payable and accrued liabilities	(1,077,192)	879,835
Due to Independent Electricity System Operator	(938,202)	495,252
Due to Hydro One	337,838	169,992
Payment in lieu of income taxes payable	219,327	107,230
Deposits in aid of construction	(153,585)	52,361
	$ (4,242,082)	$ 1,714,976

13. Related party transactions:

The balance owing has arisen as a result of water billing services on behalf of certain shareholders. During the course of the year, the Corporation earned $565,320 (2005 - $362,880) relating to the provision of these services.

14. Credit risks:

Credit risk is the risk that a counterparty will fail to discharge its obligation to the Corporation reducing the expected cash inflow from Corporation assets recorded at the balance sheet date. Credit risk can be concentrated in debtors that are similarly affected by economic or other conditions.

The Corporation has assessed that there are no significant concentrations of credit risk other than the present uncertainty relating to the recovery of regulatory assets. The final regulatory amount recoverable will be assessed in future years by the regulator after the audit of those costs.

15. Comparative amounts:

Certain 2005 comparative figures have been reclassified to conform with the financial presentation adopted per the current year.

Financial Statements (2007)

The 2007 audited financial statements of Bluewater Power Distribution Corporation are attached as Exhibit 1, Tab 3, Schedule 2, Attachment 1.

Financial Statements of

BLUEWATER POWER DISTRIBUTION CORPORATION

Year ended December 31, 2007

KPMG LLP
Chartered Accountants
115 King Street South
2nd Floor
Waterloo ON N2J 5A3

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AUDITORS' REPORT

To the Shareholders of Bluewater Power Distribution Corporation

We have audited the balance sheet of Bluewater Power Distribution Corporation as at December 31, 2007 and the statements of earnings and retained earnings, and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2007 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

London, Canada

March 14, 2008

KPMG LLP is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International, a Swiss cooperative.

BLUEWATER POWER DISTRIBUTION CORPORATION

Balance Sheet

December 31, 2007, with comparative figures for 2006

	2007	2006
Assets		
Current assets:		
Cash	$ 4,062,078	$ 5,949,598
Accounts receivable	7,110,608	6,404,180
Due from related companies	1,029,240	197,087
Unbilled revenue	10,505,927	10,080,741
Current regulatory balances recoverable (note 4)	470,601	1,879,700
Inventories	1,215,089	1,205,817
Prepaid expenses	443,117	424,471
	24,836,660	26,141,594
Property, plant and equipment (note 3)	37,770,012	37,396,966
Future payment in lieu of income taxes (note 11)	2,380,000	2,480,000
	$ 64,986,672	$ 66,018,560
Liabilities and Shareholders' Equity		
Current liabilities:		
Power purchases payable	$ 6,759,210	$ 7,032,634
Accounts payable and accrued liabilities	2,508,329	1,756,165
Due to shareholders (note 13)	1,497,573	1,444,756
Payment in lieu of income taxes payable	173,455	543,015
Dividends payable	620,857	554,100
Deposits in aid of construction	787,096	445,204
	12,346,520	11,775,874
Due to shareholders (note 5)	19,377,604	19,377,604
Long term regulatory balances payable (note 4)	4,327,327	1,071,408
Customer and other deposits	1,350,725	1,307,192
Hydro One low voltage payable	83,158	161,949
Employee future benefits (note 6)	5,508,399	4,985,307
Shareholders' equity:		
Share capital (note 9)	18,022,105	18,022,105
Retained earnings	3,970,834	9,317,121
	21,992,939	27,339,226
Commitments and contingencies (note 8)		
	$ 64,986,672	$ 66,018,560

See accompanying notes to financial statements.

On behalf of the Board:

_____ Director _____ Director

BLUEWATER POWER DISTRIBUTION CORPORATION

Statement of Earnings and Retained Earnings

Year ended December 31, 2007, with comparative figures for 2006

	2007	2006
Gross revenue	$ 87,450,745	$ 85,877,256
Cost of power	72,009,498	71,104,272
Distribution margin	15,441,247	14,772,984
Regulatory assets recovered	1,879,700	2,165,864
Other operating revenues:		
Interest	349,695	260,408
Rental	134,346	98,159
Late payment charges	276,666	295,269
Billables	2,177,485	1,169,356
Water and sewer billing (note 13)	602,863	565,320
SSS administrative fees	84,311	84,137
OPA revenue	720,801	-
Other revenue (note 10)	307,413	336,979
	4,653,580	2,809,628
	21,974,527	19,748,476
Operating expenditures:		
Administration	11,545,244	10,129,845
Interest	1,460,010	1,468,652
Amortization of regulatory assets recovered	1,879,700	2,165,864
Amortization of property, plant and equipment	3,847,903	3,547,985
	18,732,857	17,312,346
Income before payments in lieu of income taxes	3,241,670	2,436,130
Payments in lieu of income taxes (note 11):		
Current	1,500,000	1,225,000
Future	100,000	-
	1,600,000	1,225,000
Net income	1,641,670	1,211,130
Retained earnings, beginning of year	9,317,121	8,660,091
Dividends on common shares	(6,987,957)	(554,100)
Retained earnings, end of year	$ 3,970,834	$ 9,317,121

See accompanying notes to financial statements.

BLUEWATER POWER DISTRIBUTION CORPORATION

Statement of Cash Flows

Year ended December 31, 2007, with comparative figures for 2006

	2007	2006
Cash provided by (used in):		
Operating activities:		
Net income	$ 1,641,670	$ 1,211,130
Adjustments for:		
Amortization of property, plant and equipment	3,847,903	3,547,985
Amortization of regulatory assets recovered	1,879,700	2,165,864
Future payment in lieu of income taxes	100,000	-
Changes in non-cash operating working capital (note 12)	(708,460)	(5,564,346)
Due from related companies	(832,153)	(25,075)
Due to shareholders	52,817	188,986
Dividends payable	66,757	(594,100)
Customer and other deposits	43,533	70,874
Employee future benefits	523,092	505,711
	6,614,859	1,507,029
Financing activities:		
Dividends on common shares	(6,987,957)	(554,100)
Hydro One low voltage payable	(78,791)	(94,617)
Funds received as contributed capital	637,880	352,158
Increase in regulatory liabilities	2,785,318	1,058,625
	(3,643,550)	762,066
Investing activities:		
Additions to property, plant and equipment	(4,858,829)	(4,097,888)
Decrease in cash	(1,887,520)	(1,828,793)
Cash, beginning of year	5,949,598	7,778,391
Cash, end of year	$ 4,062,078	$ 5,949,598
Supplemental cash flow information:		
Interest paid	$ 1,460,010	$ 1,468,652
Income taxes paid	1,994,644	1,147,003

See accompanying notes to financial statements.

BLUEWATER POWER DISTRIBUTION CORPORATION

Notes to Financial Statements

Year ended December 31, 2007

Bluewater Power Distribution Corporation (the "Corporation") was incorporated October 20, 2000 in accordance with the Ontario government's Electricity Competition Act (Bill 35). Assets of the Electric Utilities of the City of Sarnia, Town of Petrolia, Village of Point Edward, Village of Alvinston, Township of Warwick and Village of Oil Springs (the "Municipalities") were transferred to the Corporation on November 1, 2000. The Corporation distributes electricity in these municipalities and the beneficial ownership of the Corporation is held by these municipalities.

1. Significant accounting policies:

The financial statements have been prepared in accordance with generally accepted accounting principles in Canada consistently applied. The more significant accounting policies are summarized below:

(a) Revenue recognition:

Electricity distribution service charges comprises customer billings for electricity and distribution service charges less the cost of electricity purchases by the Corporation. Customer billings for electricity and distribution service charges are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading until the end of the fiscal year. The latter component is recorded as unbilled revenue.

(b) Inventories:

Inventories consist principally of construction and maintenance materials. Inventories are stated at the lower of average cost and net realizable value.

(c) Property, plant and equipment:

Property, plant and equipment are recorded at cost. Amortization is calculated on a straight-line basis over the estimated service life of the property, plant and equipment as follows:

Asset	Rate
Land rights	25 years
Buildings	60 years
Distribution and transmission systems	25 - 40 years
Equipment	5 years
Contributed capital	25 years

BLUEWATER POWER DISTRIBUTION CORPORATION

Notes to Financial Statements (continued)

Year ended December 31, 2007

1. Significant accounting policies (continued):

(d) Customer and other deposits:

The Ontario Energy Board (the "OEB") has released a ruling that requires Corporations to periodically review customers' deposits and where appropriate, return such deposits. During this review, Corporations may also request a deposit from customers based on certain criteria. At this time, the amount to be refunded cannot reasonably be determined and as such, the Corporation has not accrued a current liability.

The Corporation has a policy of paying interest on these deposits at a rate determined quarterly.

(e) Employee future benefits:

The Corporation pays certain medical and life insurance benefits, under unfunded defined benefit plans, on behalf of its retired employees. These estimated post-retirement costs are recognized in the period in which the employees rendered their services to the Corporation.

(f) Pension plan:

The Corporation provides a pension plan for its employees though the Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund (the “Fund"), and provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. The Fund is a contributory defined benefit pension plan. As this is a multi-employer plan, no liability is recorded on the Corporation’s books.

(g) Related party transactions:

Transactions with related parties represent the culmination of the earnings process and are measured at the exchange amount.

(h) Contributed capital:

Contributed capital arises from development charges which are provided or paid for by developers and is recorded as a reduction of the capital cost of related fixed assets.

BLUEWATER POWER DISTRIBUTION CORPORATION

Notes to Financial Statements (continued)

Year ended December 31, 2007

1. Significant accounting policies (continued):

(i) Financial effects of distribution rate regulation:

The financial results presented are in accordance with generally accepted accounting principles and within that framework the Corporation accounts for the impact of regulatory actions in the following manner:

(i) Regulatory decisions to adjust distribution rates:

In the event that a regulatory decision is rendered, providing regulatory approval and certainty to the recognition of an asset, or creation of a liability, and culminating in an adjustment to the Corporation's distribution rates, such occurrences are immediately reflected in the Corporation's accounts.

(ii) Regulatory direction and practice:

In the absence of a regulatory decision impacting rates, and where the Corporation is required by regulatory accounting practice or direction to accumulate balances for future rate recovery or create liabilities for future discharge, those amounts are recorded in accordance with that regulatory direction. Management assesses the future uncertainty with respect to the final regulatory disposition of those amounts, and to the extent required, makes accounting provisions to reduce the deferred balances accumulated or to increase the recorded liabilities. Upon rendering of the final regulatory decision adjusting distribution rates, the provisions are adjusted to reflect the final impact of that decision, and such adjustment is reflected in net earnings for the period.

Amounts currently confirmed by final regulatory decision, and amounts currently accounted for in the absence of final regulatory decision together with related provisions for future uncertainty, are more fully described in note 4 to the financial statements.

(j) Use of estimates:

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and note disclosures related thereto. Due to the inherent uncertainty in making estimates, actual results could differ from estimates recorded in preparing these financial statements, including changes as a result of future regulatory decisions.

BLUEWATER POWER DISTRIBUTION CORPORATION

Notes to Financial Statements (continued)

Year ended December 31, 2007

2. Change in accounting policy:

On January 1, 2007, the Corporation adopted the following new accounting standards issued by the Canadian Institute of Chartered Accountants:

(i) Section 1530, "*Comprehensive Income*", establishes standards for reporting and displaying comprehensive income. Comprehensive income is defined as the change in equity from transactions and other events from non-owner sources. Other comprehensive income refers to items recognized in comprehensive income but that are excluded from net income calculated in accordance with Canadian generally accepted accounting policies.

(ii) Section 3251, "*Equity*", establishes standards for the presentation of equity in the reporting period.

(iii) Section 3855, "*Financial Instruments - Recognition and Measurement*", establishes standards for recognizing and measuring financial instruments, namely financial assets, financial liabilities and derivatives.

(iv) Section 3861 "*Financial Instrument - Disclosure and Presentation*", establishes standards for presentation and disclosure of financial instruments, namely financial assets, financial liabilities and derivatives.

(v) Section 3865, "*Hedges*", establishes standards for which hedge accounting is permissible and how it may be applied.

Under these new standards, all financial instruments are required to be initially measured at fair value and classified into one of the following five categories: held for trading, held-to-maturity investments, loans and receivables, available-for-sale financial assets or other financial liabilities. Subsequent measurement and recognition of changes in fair value of financial instruments depend on their initial classification.

The Corporation has implemented the following classifications:

(i) Held-for-trading:

Cash is designated as "Financial Assets Held for Trading". These financial assets are marked-to-market through net earnings at each period end.

(ii) Loans and receivables:

Accounts receivable, and unbilled revenue are classified as "Loans and Receivables". After their initial fair value measurement, they are measured at amortized cost using the effective interest rate method.

BLUEWATER POWER DISTRIBUTION CORPORATION

Notes to Financial Statements (continued)

Year ended December 31, 2007

2. Change in accounting policy:

(iii) Other financial liabilities:

Accounts payable and accrued liabilities and Power purchases payable are designated as "Other Financial Liabilities". After their initial fair value measurement, they are measured at amortized cost using the effective interest rate method.

These accounting policy changes were adopted on a prospective basis with no restatement of prior period financial statements. No adjustment was required to be recorded in retained earnings upon adoption of these standards.

3. Property, plant and equipment:

	Cost	Accumulated amortization	2007 Net book value	2006 Net book value
Land	$ 445,817	$ -	$ 445,817	$ 445,817
Land rights	283,160	262,574	20,586	32,035
Buildings	4,239,676	1,644,977	2,594,699	2,465,028
Distribution and transmission systems	69,186,990	36,472,929	32,714,061	31,925,725
Equipment	15,514,950	10,464,014	5,050,936	5,074,265
Contributed capital	(3,688,645)	(632,558)	(3,056,087)	(2,545,904)
	$ 85,981,948	$ 48,211,936	$ 37,770,012	$ 37,396,966

During the year, the Corporation received $637,880 (2006 - $352,158) of contributed capital.

4. Regulatory balances recoverable (payable):

	2007	2006
Regulatory balances approved for recovery in rates	$10,371,162	$ 10,397,946
Qualifying costs to be recovered in future rates	385,448	373,203
Retail settlement variances to be settled in future rates	(4,712,774)	(1,941,995)
	6,043,836	8,829,154
Less: accumulated amounts recovered through rates	(9,900,562)	(8,020,862)
Remaining amount recoverable (payable)	(3,856,726)	808,292
Less current portion, recoverable within the next twelve months	470,601	1,879,700
	$ (4,327,327)	$ (1,071,408)

BLUEWATER POWER DISTRIBUTION CORPORATION

Notes to Financial Statements (continued)

Year ended December 31, 2007

4. Regulatory balances recoverable (payable) (continued):

Regulatory assets approved by the OEB for recovery in rates represent costs incurred by the Corporation for the purpose of supporting the deregulation of the electricity industry in Ontario.

Qualifying costs are amounts that have been accumulated pursuant to regulation underlying the Electricity Act ("EA") and deferred in anticipation of their future recovery in electricity distribution service charges.

Retail settlement variances represent amounts that have been accumulated since January 1, 2005 and comprise:

(a) Variances between amounts charged by the Independent Electricity System Operator ("IESO") for the operation of the wholesale electricity market and grid, various wholesale market settlement charges and transmission charges, and the amounts billed to customers by the Corporation based on the OEB approved wholesale market service rate; and

(b) Variances between the amounts charged by the IESO and Hydro One to allow for purchases of electricity and the amounts billed to customers by the Corporation based on OEB approved rates; and

(c) Variances between the amounts incurred by the Corporation for the OEB mandated smart meter implementation and the amounts billed to customers by the Corporation based on OEB approved rates.

5. Due to shareholders:

	2007	2006
Subordinate promissory note payable to shareholders, bearing interest at 7.25%, with interest payable in quarterly installments, with no specified repayment terms for principal amounts. Shareholders can demand payment with twelve months written notice	$ 19,377,604	$ 19,377,604

The promissory note payable to shareholders is unsecured, subordinated and due twelve months following demand for payment and was non-interest bearing prior to October 1, 2001. The rate of interest payable by the Corporation, commencing October 1, 2001, is the maximum amount prescribed by the OEB in its publication Electricity Distribution Rate Handbook as its "Deemed Debt Cost Rates". The Deemed Debt Cost Rate applicable to the Corporation is 7.25%.

The Corporation incurred interest expense in respect of the promissory note payable to shareholders of $1,404,876 (2006 - $1,404,876).

BLUEWATER POWER DISTRIBUTION CORPORATION

Notes to Financial Statements (continued)

Year ended December 31, 2007

6. Employee future benefits:

The Corporation pays certain health, dental and life insurance benefits on behalf of its retired employees. In measuring the Corporation's accrued benefit obligation, the actuary calculated the obligation utilizing the following assumptions provided by management:

	2007	2006
Discount rate	5%	5%
Salary increase	3%	3%
Health care costs declining by 1% per year until 5% ultimate rate reached	8%	9%
Dental	5%	5%

The transition obligation has been amortized over the average remaining service life of current employees, which is eleven years. This results in a liability on the balance sheet at year end as follows:

	2007	2006
Accrued benefit obligation	$ 7,263,098	$ 6,873,425
Less: Unrecognized loss	(1,754,699)	(1,888,118)
Accrued benefit liability	$ 5,508,399	$ 4,985,307

Other information about the Corporation's plan for the year ended December 31 is as follows:

	2007	2006
Service cost	$ 238,042	$ 226,706
Interest cost	350,597	331,838
Benefits paid	(198,967)	(190,344)
Actuarial loss	133,420	137,511
	$ 523,092	$ 505,711

7. Pension plan:

The Corporation participates in the OMERS, a multi-employer plan, on behalf of its employees. The plan is a contributory defined benefit pension plan. Contributions in 2007 were 6.5% (2006 - 6.5%) for employee earnings below the year's maximum pensionable earnings and 9.6% (2006 – 9.6%) thereafter. The Corporation contributed $449,935 (2006 - $423,474) to the OMERS pension plan, on behalf of its employees, during the year ended December 31, 2007.

BLUEWATER POWER DISTRIBUTION CORPORATION

Notes to Financial Statements (continued)

Year ended December 31, 2007

8. Commitments and contingencies:

(i) The Corporation has letters of credit aggregating $6,281,038 (2006 - $7,635,650) in favour of the IESO as security for the Corporation's purchase of electricity through the IESO. The Corporation also has letters of credit aggregating $600,000 (2006 - $600,000) in favour of Hydro One as security for the Corporation's purchase of electricity through Hydro One. At year end, no amounts were drawn on these letters of credit.

(ii) A class action claiming $500,000,000 in restitutionary payments plus interest was served on the former Toronto Hydro-Electric Commission, continuing as Toronto Hydro Corporation, on November 18, 1998. The action was initiated against the former Toronto Hydro-Electric Commission as the representative of the Defendant Class consisting of all municipal electric utilities ("MEU") in Ontario, of which the Corporation is a successor MEU, which have charged Late Payment charges on overdue utility bills at any time after April 1, 1981.

The claim is that late payment penalties result in municipal electric utilities receiving interest at effective rates in excess of 60% per year, which is illegal under Section 347(1)(b) of the Criminal Code. This action is at a preliminary stage. Pleadings have closed but examinations for discovery have not been conducted and the classes have not been certified. The Electricity Distributors Association is undertaking the defense of this class action on behalf of the Defendant Class.

(ii) On April 22, 2004, in a decision in a class action commenced against The Consumers' Gas Company Limited (now Enbridge Gas Distribution Inc.), the Supreme Court of Canada ruled that Consumers' Gas was required to repay that portion of certain late payment charges collected by it from its customers that were in excess of the interest limit stipulated in section 347 of the Criminal Code. Although the claim related to charges collected by Consumers' Gas after the enactment of section 347 of the Criminal Code in 1981, the Supreme Court limited recovery to charges collected after the action was initiated in 1994. 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 Consumers' Gas.

The Corporation is not a party to the Consumers' Gas class action, however, it is anticipated that the above noted class action will now proceed for determination in light of the reasons of the Supreme Court in the Consumers' Gas class action.

The Defendant Class may have defences available to it in this action that were not disposed of by the Supreme Court in the Consumers' Gas class action. Also, the determination of whether the late payment charges collected by the Corporation from its customers were in excess of the interest limit stipulated in section 347 of the Criminal Code is fact specific in each circumstance.

At this time, given the preliminary status of this action, it is not possible to quantify the effect, if any, on the financial statements of the Corporation. Consequently, no provision has been made in these financial statements with respect to any possible losses that may arise as a result of this matter.

BLUEWATER POWER DISTRIBUTION CORPORATION

Notes to Financial Statements (continued)

Year ended December 31, 2007

9. Share capital:

The authorized share capital consists of an unlimited number of common shares. Any invitation to the public to subscribe for shares of the Corporation is prohibited.

The share capital of the Corporation is as follows:

	2007	2006
Authorized:		
Unlimited common shares		
Issued and outstanding:		
10,000 common shares	$ 18,022,105	$ 18,022,105

10. Other revenue:

Other revenue from operations comprises of:

	2007	2006
Change in occupancy	$ 50,022	$ 50,679
Service agreement revenue	44,024	45,352
Consolidated billing charges	24,519	25,903
Collection charges	69,071	58,810
Gain on disposal of equipment	4,152	5,952
Sale of scrap material	58,976	81,161
Miscellaneous	56,649	69,122
	$ 307,413	$ 336,979

11. Payment in lieu of income taxes:

The provision for payment in lieu ("PILs") varies from amounts which would be computed by applying the Corporation's combined statutory income tax rate as follows:

	2007	2006
Basic tax rate of 36.1% applied to income before PILs (36.1% rate used in 2006)	$ 1,171,000	$ 880,000
Tax effect of non-deductible expenses	23,000	23,000
Effect of changes to substantively enacted tax rates	439,000	342,000
Other	(33,000)	(20,000)
Tax provision	$ 1,600,000	$ 1,225,000

BLUEWATER POWER DISTRIBUTION CORPORATION

Notes to Financial Statements (continued)

Year ended December 31, 2007

11. Payment in lieu of income taxes (continued):

Future income tax assets of $2,380,000 (2006 - $2,480,000) have been recorded at year end based on substantively enacted income tax rates. Such future income tax assets relate in part to the tax basis of depreciable capital assets and intangible assets in excess of amounts recorded for accounting purposes, and in part to the timing differences between the recognition of revenue and expenses for accounting and income tax purposes.

12. Changes in non-cash operating working capital:

	2007	2006
Accounts receivable	$ (706,428)	$ (4,294,370)
Unbilled revenue	(425,186)	471,020
Inventories	(9,272)	(155,070)
Prepaid expenses	(18,646)	(28,729)
Accounts payable and accrued liabilities	752,164	(982,575)
Power purchases payable	(273,424)	(600,364)
Payment in lieu of income taxes payable	(369,560)	219,327
Deposits in aid of construction	341,892	(193,585)
	$ (708,460)	$ (5,564,346)

13. Related party transactions:

The balance owing has arisen as a result of water billing services on behalf of certain shareholders. During the course of the year, the Corporation earned $602,863 (2006 - $565,320) relating to the provision of these services. Over the course of the year, the change in the balance payable to related parties arose during the normal course of business.

14. Credit risks:

Credit risk is the risk that a counterparty will fail to discharge its obligation to the Corporation reducing the expected cash inflow from Corporation assets recorded at the balance sheet date. Credit risk can be concentrated in debtors that are similarly affected by economic or other conditions.

The Corporation has assessed that there are no significant concentrations of credit risk other than the present uncertainty relating to the recovery of regulatory assets. The final regulatory amount recoverable will be assessed in future years by the regulator after the audit of those costs.

BLUEWATER POWER DISTRIBUTION CORPORATION

Notes to Financial Statements (continued)

Year ended December 31, 2007

15. Financial instruments:

The Corporation's financial instruments consist of accounts receivable, due from related companies, unbilled revenue, power purchases payable, accounts payable and accrued liabilities, due to shareholders and dividends payable. Management is of the opinion that the fair values of all financial assets and liabilities are not materially different from their carrying values due to the short-term maturity of these instruments. The fair value of the shareholder notes is not readily determinable due to the related party nature of this instrument.

16. Comparative amounts:

Certain of the 2006 comparative figures have been reclassified to conform with the financial statement presentation adopted in the current year.

Pro Forma Statements (2008 and 2009)

The 2008 and 2009 Pro Forma financial statements of Bluewater Power Distribution Corporation are attached as Exhibit 1, Tab 3, Schedule 3, Attachment 1 and Exhibit 1, Tab 3, Schedule 3, Attachment 2, respectively.

2008 Pro-Forma Trial Balance

Account Grouping	Account Description	Final Projection
1050-Current Assets	1005-Cash	2,129,369
	1100-Customer Accounts Receivable	5,115,000
	1104-Accounts Receivable - Recoverable Work	1,000,000
	1110-Other Accounts Receivable	1,500,000
	1120-Accrued Utility Revenues	11,100,000
	1130-Accumulated Provision for Uncollectible Accounts--Credit	(115,000)
	1180-Prepayments	450,000
	1200-Accounts Receivable from Associated Companies	300,000
1100-Inventory	1330-Plant Materials and Operating Supplies	1,250,000
1200-Other Assets and Deferred Charges	1508-Other Regulatory Assets	675,232
	1525-Miscellaneous Deferred Debits	512
	1548-LV Apr 1'08 to Oct 31/'0 Hydro One RAR 2005 variance (holding account only)	39,964
	1550-LV Variance Account	(34,349)
	1555-Smart Meters Capital Variance Account	(184,910)
	1556-Smart Meters OM&A Variance Account	40,687
	1562-Deferred Payments in Lieu of Taxes	(272,710)
	1565-Conservation and Demand Management Expenditures and Recoveries	
	1566-CDM Contra Account	
	1580-RSVAWMS	(1,811,251)
	1584-RSVANW	115,743
	1586-RSVACN	(393,008)
	1588-RSVAPOWER	(2,826,460)
	1590-Recovery of Regulatory Asset Balances	(148,276)
1450-Distribution Plant	1805-Land	445,817
	1806-Land Rights	283,160
	1820-Distribution Station Equipment - Normally Primary below 50 kV	5,636,213
	1830-Poles, Towers and Fixtures	1,208,153
	1835-Overhead Conductors and Devices	26,137,702
	1840-Underground Conduit	146,974

2008 Pro-Forma Trial Balance

Account Grouping	Account Description	Final Projection
	1845-Underground Conductors and Devices	18,759,860
	1850-Line Transformers	13,073,086
	1855-Services	282,505
	1860-Meters	6,999,687
1500-General Plant	1908-Buildings and Fixtures	4,637,699
	1915-Office Furniture and Equipment	719,927
	1920-Computer Equipment - Hardware	3,400,871
	1925-Computer Software	5,334,806
	1930-Transportation Equipment	3,393,184
	1935-Stores Equipment	80,604
	1940-Tools, Shop and Garage Equipment	731,070
	1945-Measurement and Testing Equipment	229,399
	1955-Communication Equipment	160,396
	1960-Miscellaneous Equipment	835,038
	1970-Load Management Controls - Customer Premises	464,917
	1980-System Supervisory Equipment	1,201,410
1550-Other Capital Assets	1995-Contributions and Grants - Credit	(4,270,397)
	2055-Construction Work in Progress--Electric	
1600-Accumulated Amortization	2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	(51,074,012)
	2120-Accumulated Amortization of Electric Utility Plant - Intangibles	(873,253)
1650-Current Liabilities	2205-Accounts Payable	(1,450,000)
	2210-Current Portion of Customer Deposits	(800,000)
	2215-Dividends Declared	(96,549)
	2220-Miscellaneous Current and Accrued Liabilities	(250,000)
	2240-Accounts Payable to Associated Companies	(1,500,000)
	2250-Debt Retirement Charges(DRC) Payable	(500,000)
	2252-Transmission Charges Payable	(7,500,000)
	2290-Commodity Taxes	(50,000)
	2292-Payroll Deductions / Expenses Payable	(75,000)
	2294-Accrual for Taxes, Payments in Lieu of Taxes, Etc.	(175,000)
1700-Non-Current Liabilities	2306-Employee Future Benefits	(6,202,814)
	2320-Other Miscellaneous Non-Current Liabilities	(21,442)
	2335-Long Term Customer Deposits	(1,200,000)
	2350-Future Income Tax - Non-Current	2,380,000
	2425-Sub account of 1588 Global Adjustment (holding account only)	209,918
1800-Long-Term Debt	2520-Other Long Term Debt	(19,377,604)
1850-Shareholders' Equity	3005-Common Shares Issued	(13,413,553)
	3010-Contributed Surplus	(4,608,552)
	3045-Unappropriated Retained Earnings	(3,970,834)
	3046-Balance Transferred From Income	(370,478)
	3049-Dividends Payable-Common Shares	3,096,549
3000-Sales of Electricity	4006-Residential Energy Sales	(19,232,422)

2008 Pro-Forma Trial Balance

Account Grouping	Account Description	Final Projection
	4020-Energy Sales to Large Users	(21,574,205)
	4025-Street Lighting Energy Sales	(604,461)
	4030-Sentinel Lighting Energy Sales	(47,410)
	4035-General Energy Sales	(37,313,912)
	4050-Revenue Adjustment	
	4062-Billed WMS	
	4066-Billed NW	
	4068-Billed CN	
	4075-Billed-LV	(164,987)
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	(15,789,653)
	4082-Retail Services Revenues	(68,097)
	4084-Service Transaction Requests (STR) Revenues	(5,091)
3100-Other Operating Revenues	4210-Rent from Electric Property	(132,498)
	4225-Late Payment Charges	(212,950)
	4235-Miscellaneous Service Revenues	(129,300)
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	(289,755)
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.	94,058
	4355-Gain on Disposition of Utility and Other Property	(44,261)
	4375-Revenues from Non-Utility Operations	
	4380-Expenses of Non-Utility Operations	
	4390-Miscellaneous Non-Operating Income	(25,000)
3200-Investment Income	4405-Interest and Dividend Income	123,604
3350-Power Supply Expenses	4705-Power Purchased	62,352,337
	4708-Charges-WMS	5,949,214
	4710-Cost of Power Adjustments	
	4714-Charges-NW	4,638,339
	4716-Charges-CN	4,688,440
	4730-Rural Rate Assistance Expense	1,144,080
	4750-Charges-LV	164,987
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	648,444
	5010-Load Dispatching	197,415
	5012-Station Buildings and Fixtures Expense	
	5015-Transformer Station Equipment - Operation Supplies and Expenses	
	5017-Distribution Station Equipment - Operation Supplies and Expenses	400
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	229,370

2008 Pro-Forma Trial Balance

Account Grouping	Account Description	Final Projection
	5035-Overhead Distribution Transformers- Operation	1,300
	5040-Underground Distribution Lines and Feeders - Operation Labour	260,994
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	231,928
	5055-Underground Distribution Transformers - Operation	
	5065-Meter Expense	273,300
	5070-Customer Premises - Operation Labour	56,379
	5075-Customer Premises - Materials and Expenses	30,171
	5085-Miscellaneous Distribution Expense	299,785
	5095-Overhead Distribution Lines and Feeders - Rental Paid	29,376
3550-Distribution Expenses - Maintenance	5114-Maintenance of Distribution Station Equipment	4,500
	5120-Maintenance of Poles, Towers and Fixtures	12,000
	5125-Maintenance of Overhead Conductors and Devices	75,470
	5145-Maintenance of Underground Conduit	
	5150-Maintenance of Underground Conductors and Devices	16,000
	5155-Maintenance of Underground Services	4,900
	5160-Maintenance of Line Transformers	24,000
	5175-Maintenance of Meters	3,540
3650-Billing and Collecting	5305-Supervision	109,523
	5310-Meter Reading Expense	129,818
	5315-Customer Billing	813,915
	5320-Collecting	232,243
	5330-Collection Charges	750
	5335-Bad Debt Expense	84,500
3700-Community Relations	5410-Community Relations - Sundry	36,400
	5415-Energy Conservation	35,376
	5420-Community Safety Program	103,633
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	738,263

2008 Pro-Forma Trial Balance

Account Grouping	Account Description	Final Projection
	5610-Management Salaries and Expenses	180,016
	5615-General Administrative Salaries and Expenses	1,176,415
	5620-Office Supplies and Expenses	2,000
	5630-Outside Services Employed	212,442
	5635-Property Insurance	161,843
	5645-Employee Pensions and Benefits	2,053,952
	5655-Regulatory Expenses	281,665
	5660-General Advertising Expenses	10,000
	5665-Miscellaneous General Expenses	652,365
	5675-Maintenance of General Plant	81,424
3850-Amortization Expense	5705-Amortization Expense - Property, Plant, and Equipment	4,045,269
3900-Interest Expense	6005-Interest on Long Term Debt	1,404,877
	6035-Other Interest Expense	56,820
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	290,000
4000-Income Taxes	6110-Income Taxes	815,684
	6115-Provision for Future Income Taxes	
4100-Extraordinary & Other Items	6205-Donations	

2009 Pro-Forma Trial Balance

Account Grouping	Account Description	Final Projection
1050-Current Assets	1005-Cash	(266,726)
	1100-Customer Accounts Receivable	5,524,200
	1104-Accounts Receivable - Recoverable Work	1,000,000
	1110-Other Accounts Receivable	1,500,000
	1120-Accrued Utility Revenues	11,988,000
	1130-Accumulated Provision for Uncollectible Accounts--Credit	(115,000)
	1180-Prepayments	450,000
	1200-Accounts Receivable from Associated Companies	300,000
1100-Inventory	1330-Plant Materials and Operating Supplies	1,250,000
1200-Other Assets and Deferred Charges	1505-LRAM and SSM (holding account only)	2,918
	1508-Other Regulatory Assets	13,200
	1510-Preliminary Survey and Investigation Charges	0
	1515-Emission Allowance Inventory	0
	1516-Emission Allowances Withheld	0
	1518-RCVARetail	0
	1520-Power Purchase Variance Account	0
	1525-Miscellaneous Deferred Debits	10
	1530-Deferred Losses from Disposition of Utility Plant	0
	1540-Unamortized Loss on Reacquired Debt	0
	1545-Development Charge Deposits/ Receivables	0
	1548-LV Apr 1'08 to Oct 31/'0 Hydro One RAR 2005 variance (holding account only)	41,299
	1550-LV Variance Account	(740)
	1555-Smart Meters Capital Variance Account	(190,678)
	1556-Smart Meters OM&A Variance Account	41,967
	1560-Deferred Development Costs	0
	1562-Deferred Payments in Lieu of Taxes	(280,402)

2009 Pro-Forma Trial Balance

Account Grouping	Account Description	Final Projection
	1563-Account 1563 - Deferred PILs Contra Account	0
	1565-Conservation and Demand Management Expenditures and Recoveries	0
	1566-CDM Contra Account	0
	1570-Qualifying Transition Costs	0
	1571-Pre-market Opening Energy Variance	0
	1572-Extraordinary Event Costs	0
	1574-Deferred Rate Impact Amounts	0
	1580-RSVAWMS	(38,367)
	1582-RSVAONE-TIME	0
	1584-RSVANW	2,494
	1586-RSVACN	(7,323)
	1588-RSVAPOWER	(56,426)
	1590-Recovery of Regulatory Asset Balances	(3,229,643)
	1592-2006 PILs/Taxes Variance	0
1450-Distribution Plant	1805-Land	445,817
	1806-Land Rights	283,160
	1820-Distribution Station Equipment - Normally Primary below 50 kV	5,766,704
	1830-Poles, Towers and Fixtures	1,941,647
	1835-Overhead Conductors and Devices	27,247,131
	1840-Underground Conduit	243,952
	1845-Underground Conductors and Devices	19,329,938
	1850-Line Transformers	13,518,588
	1855-Services	445,964
	1860-Meters	7,697,717
1500-General Plant	1908-Buildings and Fixtures	5,705,016
	1915-Office Furniture and Equipment	723,963
	1920-Computer Equipment - Hardware	3,866,633
	1925-Computer Software	7,501,976
	1930-Transportation Equipment	3,728,644
	1935-Stores Equipment	80,604
	1940-Tools, Shop and Garage Equipment	799,543

2009 Pro-Forma Trial Balance

Account Grouping	Account Description	Final Projection
	1945-Measurement and Testing Equipment	229,399
	1955-Communication Equipment	160,396
	1960-Miscellaneous Equipment	835,038
	1970-Load Management Controls - Customer Premises	464,917
	1980-System Supervisory Equipment	1,201,410
1550-Other Capital Assets	1995-Contributions and Grants - Credit	(4,997,587)
1600-Accumulated Amortization	2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	(55,136,817)
	2120-Accumulated Amortization of Electric Utility Plant - Intangibles	(938,418)
1650-Current Liabilities	2205-Accounts Payable	(1,450,000)
	2210-Current Portion of Customer Deposits	(800,000)
	2215-Dividends Declared	(884,091)
	2220-Miscellaneous Current and Accrued Liabilities	(250,000)
	2240-Accounts Payable to Associated Companies	(1,500,000)
	2250-Debt Retirement Charges(DRC) Payable	(500,000)
	2252-Transmission Charges Payable	(7,500,000)
	2290-Commodity Taxes	(50,000)
	2292-Payroll Deductions / Expenses Payable	(75,000)
	2294-Accrual for Taxes, Payments in Lieu of Taxes, Etc.	(175,000)
1700-Non-Current Liabilities	2306-Employee Future Benefits	(6,742,660)
	2335-Long Term Customer Deposits	(1,200,000)
	2350-Future Income Tax - Non-Current	2,380,000
	2425-Sub account of 1588 Global Adjustment (holding account only)	4,458
1800-Long-Term Debt	2520-Other Long Term Debt	(19,377,604)
1850-Shareholders' Equity	3005-Common Shares Issued	(13,413,553)
	3010-Contributed Surplus	(4,608,552)
	3045-Unappropriated Retained Earnings	(1,163,932)
	3046-Balance Transferred From Income	(2,652,274)
	3049-Dividends Payable-Common Shares	884,091
3000-Sales of Electricity	4006-Residential Energy Sales	(19,369,549)
	4020-Energy Sales to Large Users	(21,690,586)
	4025-Street Lighting Energy Sales	(610,004)
	4030-Sentinel Lighting Energy Sales	(47,359)
	4035-General Energy Sales	(37,192,784)
	4075-Billed-LV	(189,602)
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	(20,792,082)
	4082-Retail Services Revenues	(68,097)
	4084-Service Transaction Requests (STR) Revenues	(5,091)
3100-Other Operating Revenues	4210-Rent from Electric Property	(136,320)
	4225-Late Payment Charges	(225,433)
	4235-Miscellaneous Service Revenues	(135,840)

2009 Pro-Forma Trial Balance

Account Grouping	Account Description	Final Projection
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	(361,084)
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.	92,578
	4355-Gain on Disposition of Utility and Other Property	(30,051)
3200-Investment Income	4405-Interest and Dividend Income	243,636
3350-Power Supply Expenses	4705-Power Purchased	62,444,763
	4708-Charges-WMS	5,958,032
	4714-Charges-NW	4,655,750
	4716-Charges-CN	4,705,961
	4730-Rural Rate Assistance Expense	1,145,775
	4750-Charges-LV	189,602
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	944,384
	5010-Load Dispatching	208,989
	5012-Station Buildings and Fixtures Expense	100
	5014-Transformer Station Equipment - Operation Labour	26,000
	5017-Distribution Station Equipment - Operation Supplies and Expenses	420
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	231,369
	5035-Overhead Distribution Transformers- Operation	1,965
	5040-Underground Distribution Lines and Feeders - Operation Labour	899,617
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	306,371
	5065-Meter Expense	437,516
	5075-Customer Premises - Materials and Expenses	43,220
	5085-Miscellaneous Distribution Expense	404,711
	5095-Overhead Distribution Lines and Feeders - Rental Paid	30,690
3550-Distribution Expenses - Maintenance	5114-Maintenance of Distribution Station Equipment	7,275
	5120-Maintenance of Poles, Towers and Fixtures	14,300
	5125-Maintenance of Overhead Conductors and Devices	83,520
	5150-Maintenance of Underground Conductors and Devices	16,900

2009 Pro-Forma Trial Balance

Account Grouping	Account Description	Final Projection
	5155-Maintenance of Underground Services	5,145
	5160-Maintenance of Line Transformers	26,000
	5175-Maintenance of Meters	4,500
3650-Billing and Collecting	5305-Supervision	124,802
	5310-Meter Reading Expense	148,146
	5315-Customer Billing	887,684
	5320-Collecting	233,138
	5330-Collection Charges	788
	5335-Bad Debt Expense	102,885
3700-Community Relations	5410-Community Relations - Sundry	52,000
	5415-Energy Conservation	45,540
	5420-Community Safety Program	119,331
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	962,527
	5610-Management Salaries and Expenses	209,019
	5615-General Administrative Salaries and Expenses	1,713,680
	5620-Office Supplies and Expenses	2,860
	5625-Administrative Expense Transferred Credit	(543,487)
	5630-Outside Services Employed	178,675
	5635-Property Insurance	166,076
	5645-Employee Pensions and Benefits	1,986,471
	5655-Regulatory Expenses	437,711
	5660-General Advertising Expenses	21,000
	5665-Miscellaneous General Expenses	724,793
	5675-Maintenance of General Plant	91,788
3850-Amortization Expense	5705-Amortization Expense - Property, Plant, and Equipment	4,358,109
3900-Interest Expense	6005-Interest on Long Term Debt	1,404,876
	6035-Other Interest Expense	56,820
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	297,750
4000-Income Taxes	6110-Income Taxes	1,322,854

Cost of Power Projections

Cost of power projections were calculated using the Regulated Price Plan ("RPP") commodity price as indicated in the *Regulated Price Plan Pricing Report May 1, 2008 to April 30, 2009* as issued by the OEB on April 11, 2008. The RPP price in the report is $.0545 per kWh.

The rates for the Retail Transmission Network charge, Retail Transmission Connection charge, Wholesale Market Service rate, Debt Retirement Charge and SSS Administration fee are all as approved in Bluewater Power's 2008 IRM rate application EB-2007-0862. The current rates are detailed in Exhibit 1, Tab 1, Schedule 4.

The estimated pass through charges for 2008 and 2009 are detailed in Exhibit 1, Tab 3, Schedule 4, Attachment 1.

Low Voltage Charges

Bluewater Power is an embedded distributor to Hydro One Networks Inc. ("Hydro One") and as such incurs costs for low voltage ("LV") services. The LV costs for 2008 are projected to be $164,987 which is based on 2008 actual invoice data from January to June 2008 and the remainder of 2008 is forecast using 2007 data.

On April 1, 2008 Bluewater Power received notice from Hydro One that the LV rates are proposed to change November 1, 2008. As a result, Bluewater Power has projected the 2009 LV charges at the Hydro One proposed rates. The projected charges for 2009 are $189,602. The calculation is detailed in Exhibit 1, Tab 3, Schedule 4, Attachment 2.

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Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

Pass Through Charges

Electricity (Commodity)		**Customer**	**Revenue**	**Expense**	**2008**	*rate ($/kWh):*	**$0.05450**
		Class Name	**USA #**	**USA #**	**Volume**		**Amount**
	kWh	Residential	4006	4705	273,966,122		14,931,154
	kWh	General Service <50 kW	4035	4705	124,066,473		6,761,623
	kWh	General Service 50 to 999 kW	4035	4705	223,339,526		12,172,004
	kWh	General Service 1,000 to 4,999 kW	4035	4705	188,461,164		10,271,133
	kWh	Large	4020	4705	321,506,745		17,522,118
	kWh	Unmetered Scattered Load	4035	4705	3,095,156		168,686
	kWh	Sentinel Lighting	4030	4705	709,420		38,663
	kWh	Street Lighting	4025	4705	8,934,965		486,956
		TOTAL			**1,144,079,571**		**62,352,337**
Transmission - Network		**Customer**	**Revenue**	**Expense**		**2008**	
		Class Name	**USA #**	**USA #**	**Volume**	**Rate**	**Amount**
	kWh	Residential	4006	4714	273,966,122	$0.0047	1,287,641
	kWh	General Service <50 kW	4035	4714	124,066,473	$0.0043	533,486
	kW	General Service 50 to 999 kW	4035	4714	590,129	$1.7399	1,026,765
	kW	General Service 1,000 to 4,999 kW	4035	4714	397,831	$1.8479	735,152
	kW	Large	4020	4714	493,030	$2.0461	1,008,789
	kWh	Unmetered Scattered Load	4035	4714	3,095,156	$0.0043	13,309
	kW	Sentinel Lighting	4030	4714	1,635	$1.3188	2,156
	kW	Street Lighting	4025	4714	23,656	$1.3122	31,041
		TOTAL			**402,634,032**		**4,638,339**

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Bluewater Power Distribution Corporation (

2009 EDR Application (ED-2008-0221)

Pass Through Charges

Electricity (Commodity)	**Customer**	**2009**	*rate ($/kWh):*	**$0.05450**
	Class Name	**Volume**		**Amount**
kWh	Residential	275,919,502		15,037,613
kWh	General Service <50 kW	124,835,762		6,803,549
kWh	General Service 50 to 999 kW	223,932,369		12,204,314
kWh	General Service 1,000 to 4,999 kW	185,691,188		10,120,170
kWh	Large	323,391,044		17,624,812
kWh	Unmetered Scattered Load	2,266,760		123,538
kWh	Sentinel Lighting	708,493		38,613
kWh	Street Lighting	9,030,349		492,154
	TOTAL	**1,145,775,469**		**62,444,763**
Transmission - Network	**Customer**		**2009**	
	Class Name	**Volume**	**Rate**	**Amount**
kWh	Residential	275,919,502	$0.0047	1,296,822
kWh	General Service <50 kW	124,835,762	$0.0043	536,794
kW	General Service 50 to 999 kW	593,516	$1.7399	1,032,658
kW	General Service 1,000 to 4,999 kW	398,767	$1.8479	736,882
kW	Large	493,510	$2.0461	1,009,771
kWh	Unmetered Scattered Load	2,266,760	$0.0043	9,747
kW	Sentinel Lighting	1,637	$1.3188	2,159
kW	Street Lighting	23,562	$1.3122	30,918
	TOTAL	**404,533,016**		**4,655,750**

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Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

Pass Through Charges

Transmission - Connection	**Customer Class Name**	**Revenue USA #**	**Expense USA #**	**2008 Volume**	**Rate**	**Amount**
kWh	Residential	4006	4716	273,966,122	$0.0048	1,315,037
kWh	General Service <50 kW	4035	4716	124,066,473	$0.0043	533,486
kW	General Service 50 to 999 kW	4035	4716	590,129	$1.6988	1,002,511
kW	General Service 1,000 to 4,999 kW	4035	4716	397,831	$1.8623	740,881
kW	Large	4020	4716	493,030	$2.1296	1,049,957
kWh	Unmetered Scattered Load	4035	4716	3,095,156	$0.0043	13,309
kW	Sentinel Lighting	4030	4716	1,635	$1.3407	2,192
kW	Street Lighting	4025	4716	23,656	$1.3133	31,067
	TOTAL			**402,634,032**		**4,688,440**
Wholesale Market Service	**Customer Class Name**	**Revenue USA #**	**Expense USA #**	**2008 Volume**	*rate ($/kWh):*	**$0.00520 Amount**
kWh	Residential	4006	4708	273,966,122		1,424,624
kWh	General Service <50 kW	4035	4708	124,066,473		645,146
kWh	General Service 50 to 999 kW	4035	4708	223,339,526		1,161,366
kWh	General Service 1,000 to 4,999 kW	4035	4708	188,461,164		979,998
kWh	Large	4020	4708	321,506,745		1,671,835
kWh	Unmetered Scattered Load	4035	4708	3,095,156		16,095
kWh	Sentinel Lighting	4030	4708	709,420		3,689
kWh	Street Lighting	4025	4708	8,934,965		46,462
	TOTAL			**1,144,079,571**		**5,949,214**

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Bluewater Power Distribution Corporation (

2009 EDR Application (ED-2008-0221)

Pass Through Charges

Transmission - Connection	**Customer**	**2009**		
	Class Name	**Volume**	**Rate**	**Amount**
kWh	Residential	275,919,502	$0.0048	1,324,414
kWh	General Service <50 kW	124,835,762	$0.0043	536,794
kW	General Service 50 to 999 kW	593,516	$1.6988	1,008,265
kW	General Service 1,000 to 4,999 kW	398,767	$1.8623	742,624
kW	Large	493,510	$2.1296	1,050,979
kWh	Unmetered Scattered Load	2,266,760	$0.0043	9,747
kW	Sentinel Lighting	1,637	$1.3407	2,195
kW	Street Lighting	23,562	$1.3133	30,944
	TOTAL	**404,533,016**		**4,705,961**
Wholesale Market Service	**Customer**	**2009**	*rate ($/kWh):*	**$0.00520**
	Class Name	**Volume**		**Amount**
kWh	Residential	275,919,502		1,434,781
kWh	General Service <50 kW	124,835,762		649,146
kWh	General Service 50 to 999 kW	223,932,369		1,164,448
kWh	General Service 1,000 to 4,999 kW	185,691,188		965,594
kWh	Large	323,391,044		1,681,633
kWh	Unmetered Scattered Load	2,266,760		11,787
kWh	Sentinel Lighting	708,493		3,684
kWh	Street Lighting	9,030,349		46,958
	TOTAL	**1,145,775,469**		**5,958,032**

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Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

Pass Through Charges

Rural Rate Protection	**Customer**	**Revenue**	**Expense**	**2008**	*rate ($/kWh):*	**$0.00100**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**
kWh	Residential	4006	4730	273,966,122		273,966
kWh	General Service <50 kW	4035	4730	124,066,473		124,066
kWh	General Service 50 to 999 kW	4035	4730	223,339,526		223,340
kWh	General Service 1,000 to 4,999 kW	4035	4730	188,461,164		188,461
kWh	Large	4020	4730	321,506,745		321,507
kWh	Unmetered Scattered Load	4035	4730	3,095,156		3,095
kWh	Sentinel Lighting	4030	4730	709,420		709
kWh	Street Lighting	4025	4730	8,934,965		8,935
	TOTAL			**1,144,079,571**		**1,144,080**
Debt Retirement Charge	**Customer**	**Revenue**	**Expense**	**2008**	*rate ($/kWh):*	**$0.00700**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**
	TOTAL					
Low Voltage Charges	**Customer**	**Revenue**	**Expense**	**2008**		
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**
	TOTAL (Input amount)	4075	4750		164,987	**164,987**
GRAND TOTAL						**78,937,397**

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Bluewater Power Distribution Corporation (

2009 EDR Application (ED-2008-0221)

Pass Through Charges

Rural Rate Protection		**Customer**	**2009**	*rate ($/kWh):*	**$0.00100**
		Class Name	**Volume**		**Amount**
	kWh	Residential	275,919,502		275,920
	kWh	General Service <50 kW	124,835,762		124,836
	kWh	General Service 50 to 999 kW	223,932,369		223,932
	kWh	General Service 1,000 to 4,999 kW	185,691,188		185,691
	kWh	Large	323,391,044		323,391
	kWh	Unmetered Scattered Load	2,266,760		2,267
	kWh	Sentinel Lighting	708,493		708
	kWh	Street Lighting	9,030,349		9,030
		TOTAL	**1,145,775,469**		**1,145,775**
Debt Retirement Charge		**Customer**	**2009**	*rate ($/kWh):*	**$0.00700**
		Class Name	**Volume**		**Amount**
		TOTAL			
Low Voltage Charges		**Customer**		**2009**	
		Class Name	**Volume**		**Amount**
		TOTAL (Input amount)		189,602	**189,602**
GRAND TOTAL					**79,099,884**

Bluewater Power proposed 2009 LV Charges from Hydro One Networks Inc.

From	To	Hydro One Meter Number	Location	KW ON		Shared Line Charge (using HONI proposed rate)	Shared Low Voltage Dist Station (Oil Springs and Alvinston)	Monthly meter charge for cust not owning their meters.	Fixed Monthly Charge	Total monthly charge
					RATE	$ 0.58	$ 1.24	$ 553	$ 188	
12/28/2007	01/26/2008	4102870W1	Alvinston	1112.64		$ 645.33	$ 1,379.67	$ 553	$ 188	
		0000840W1	Pet PME3	4500.72		$ 2,610.42		$ 553	$ 188	
		6200230W3	WatT-2	2317.35		$ 1,344.06		$ 553	$ 188	
		6200430W1	Petrolia	4095.84		$ 2,375.59		$ 553	$ 188	
		4103010W1	Oil Springs	758.78		$ 440.09	$ 940.89	$ 553	$ 188	
		4192430W1	Petrolia	1834.56		$ 1,064.04		$ 553	$ 188	$ 15,246.10
01/29/2008	02/26/2008	4102870W1	Alvinston	1106.16		$ 641.57	$ 1,371.64	$ 553	$ 188	
		0000840W1	Pet PME3	4692.24		$ 2,721.50		$ 553	$ 188	
		6200230W3	WatT-2	2303.7		$ 1,336.15		$ 553	$ 188	
		6200430W1	Petrolia	3988.32		$ 2,313.23		$ 553	$ 188	
		4103010W1	Oil Springs	768.47		$ 445.71	$ 952.90	$ 553	$ 188	
		4192430W1	Petrolia	5513.76		$ 3,197.98		$ 553	$ 188	$ 17,426.68
02/27/2008	03/28/2008	4102870W1	Alvinston	1003.44		$ 582.00	$ 1,244.27	$ 553	$ 188	
		0000840W1	Pet PME3	4665.36		$ 2,705.91		$ 553	$ 188	
		6200230W3	WatT-2	2194.5		$ 1,272.81		$ 553	$ 188	
		6200430W1	Petrolia	3847.2		$ 2,231.38		$ 553	$ 188	
		4103010W1	Oil Springs	732.09		$ 424.61	$ 907.79	$ 553	$ 188	
		4192430W1	Petrolia	4949.28		$ 2,870.58		$ 553	$ 188	$ 16,685.34
03/29/2008	04/28/2008	4102870W1	Alvinston	830.16		$ 481.49	$ 1,029.40	$ 553	$ 188	
		0000840W1	Pet PME3	4304.16		$ 2,496.41		$ 553	$ 188	
		6200230W3	WatT-2	1941.45		$ 1,126.04		$ 553	$ 188	
		6200430W1	Petrolia	3521.28		$ 2,042.34		$ 553	$ 188	
		4103010W1	Oil Springs	587.3		$ 340.63	$ 728.25	$ 553	$ 188	
		4192430W1	Petrolia	1703.52		$ 988.04		$ 553	$ 188	$ 13,678.62
04/29/2008	05/28/2008	4102870W1	Alvinston	680.16		$ 394.49	$ 843.40	$ 553	$ 188	
		0000840W1	Pet PME3	3788.4		$ 2,197.27		$ 553	$ 188	
		6200230W3	WatT-2	1738.8		$ 1,008.50		$ 553	$ 188	
		6200430W1	Petrolia	3386.88		$ 1,964.39		$ 553	$ 188	
		4103010W1	Oil Springs	562.04		$ 325.98	$ 696.93	$ 553	$ 188	
		4192430W1	Petrolia	1518.72		$ 880.86		$ 553	$ 188	$ 12,757.83
05/29/2008	06/27/2008	4102870W1	Alvinston	1072.32		$ 621.95	$ 1,329.68	$ 553	$ 188	
		0000840W1	Pet PME3	5619.6		$ 3,259.37		$ 553	$ 188	
		6200230W3	WatT-2	2365.65		$ 1,372.08		$ 553	$ 188	
		6200430W1	Petrolia	5046.72		$ 2,927.10		$ 553	$ 188	
		4103010W1	Oil Springs	874.45		$ 507.18	$ 1,084.32	$ 553	$ 188	
		4192430W1	Petrolia	2076.48		$ 1,204.36		$ 553	$ 188	$ 16,752.02
06/27/2007	07/26/2007	4102870W1	Alvinston	1101		$ 638.58	$ 1,365.24	$ 553	$ 188	
		0000840W1	Pet PME3	4954		$ 2,873.32		$ 553	$ 188	
		6200230W3	WatT-2	2481		$ 1,438.98		$ 553	$ 188	
		6200430W1	Petrolia	5006		$ 2,903.48		$ 553	$ 188	
		4103010W1	Oil Springs	850		$ 493.00	$ 1,054.00	$ 553	$ 188	
		4192430W1	Petrolia	2745		$ 1,592.10		$ 553	$ 188	$ 16,804.70
07/26/2007	08/29/2007	4102870W1	Alvinston	1165		$ 675.70	$ 1,444.60	$ 553	$ 188	
		0000840W1	Pet PME3	5036		$ 2,920.88		$ 553	$ 188	
		6200230W3	WatT-2	2605		$ 1,510.90		$ 553	$ 188	
		6200430W1	Petrolia	5476		$ 3,176.08		$ 553	$ 188	
		4103010W1	Oil Springs	861		$ 499.38	$ 1,067.64	$ 553	$ 188	
		4192430W1	Petrolia	2153		$ 1,248.74		$ 553	$ 188	$ 16,989.92
08/29/2007	09/27/2007	4102870W1	Alvinston	1002		$ 581.16	$ 1,242.48	$ 553	$ 188	
		0000840W1	Pet PME3	4925		$ 2,856.50		$ 553	$ 188	
		6200230W3	WatT-2	2494		$ 1,446.52		$ 553	$ 188	
		6200430W1	Petrolia	5080		$ 2,946.40		$ 553	$ 188	
		4103010W1	Oil Springs	784		$ 454.72	$ 972.16	$ 553	$ 188	
		4192430W1	Petrolia	2163		$ 1,254.54		$ 553	$ 188	$ 16,200.48

From	To	Hydro One Meter Number	Location	KW ON		Shared Line Charge (using HONI proposed rate)	Shared Low Voltage Dist Station (Oil Springs and Alvinston)	Monthly meter charge for cust not owning their meters.	Fixed Monthly Charge	Total monthly charge
					RATE	$ 0.58	$ 1.24	$ 553	$ 188	
09/27/2007	10/27/2007	4102870W1	Alvinston	1073		$ 622.34	$ 1,330.52	$ 553	$ 188	
		0000840W1	Pet PME3	4581		$ 2,656.98		$ 553	$ 188	
		6200230W3	WatT-2	1982		$ 1,149.56		$ 553	$ 188	
		6200430W1	Petrolia	4559		$ 2,644.22		$ 553	$ 188	
		4103010W1	Oil Springs	776		$ 450.08	$ 962.24	$ 553	$ 188	
		4192430W1	Petrolia	1629		$ 944.82		$ 553	$ 188	$ 15,206.76
10/27/2007	11/27/2007	4102870W1	Alvinston	962		$ 557.96	$ 1,192.88	$ 553	$ 188	
		0000840W1	Pet PME3	4593		$ 2,663.94		$ 553	$ 188	
		6200230W3	WatT-2	2124		$ 1,231.92		$ 553	$ 188	
		6200430W1	Petrolia	3907		$ 2,266.06		$ 553	$ 188	
		4103010W1	Oil Springs	648		$ 375.84	$ 803.52	$ 553	$ 188	
		4192430W1	Petrolia	1703		$ 987.74		$ 553	$ 188	$ 14,525.86
11/27/2007	12/28/2007	4102870W1	Alvinston	1099		$ 637.42	$ 1,362.76	$ 553	$ 188	
		0000840W1	Pet PME3	4698		$ 2,724.84		$ 553	$ 188	
		6200230W3	WatT-2	2298		$ 1,332.84		$ 553	$ 188	
		6200430W1	Petrolia	4196		$ 2,433.68		$ 553	$ 188	
		4103010W1	Oil Springs	833		$ 483.14	$ 1,032.92	$ 553	$ 188	
		4192430W1	Petrolia	4956		$ 2,874.48		$ 553	$ 188	$ 17,328.08
						$ 109,910.29	$ 26,340.09	$ 39,816.00	$ 13,536.00	
					Estimated for 2009					**$ 189,602.38**

Uses 2007 and 2008 actual invoice data, along with Hydro One proposed rates to be effective Nov 1, 2008

Reconciliation between Financial Statements and Financial Results Filed

OM&A

$	11,545,244	"Administration" expense on 2007 audited financial statements
	(156,210)	Carrying charges expense grouped with USoA 4405
	(298,710)	Non-utility: Water billing related expenses grouped with USoA 4380
	(623,220)	Non-utility: OPA program related expenses grouped with USoA 4380
	(1,081,050)	Non-utility: civil and billable related expenses grouped with USoA 4380
	(29,348)	Donations grouped in USoA 6205
	(278,911)	Property and capital taxes grouped with USoA 6105
	9,077,795	Sum of all 5xxx USoA accounts, except 5705 Amortization Expense
		(agrees to 2007 trial balance filed earlier in 2008)
	(155,017)	Adjustment to USoA 5060: reallocated to USoA 4330
	3,420	Adjustment to USoA 5665: reallocated from USoA 6105
	(7,608)	Adjustments to various USoA accounts: reallocated to USoA 4380
$	8,918,590	Revised sum of all 5xxx USoA accounts, except 5705 Amortization Expense
		(agrees to 2007 trial balance filed with this rate application)

REVENUE

$	15,441,247	"Distribution margin" on 2007 audited financial statements
	4,653,580	"Other operating revenues" on 2007 audited financial statements
	20,094,827	Total revenues on 2007 audited financial statements
	(156,210)	Carrying charges expense grouped with USoA 4405
	(2,382,014)	Non-utility expenses grouped with USoA 4380
	88,954	Interdepartmental Rents grouped with USoA 4205
	17,645,557	Sum of all 4xxx USoA accounts
		(agrees to 2007 trial balance filed earlier in 2008)
	(155,017)	Adjustment to USoA 5060: reallocated to USoA 4330
	(7,609)	Adjustments to various USoA accounts: reallocated to USoA 4380
$	17,482,931	Revised sum of all 4xxx USoA accounts
		(agrees to 2007 trial balance filed with this rate application)

Proposed Accounting Treatment for Long-Lived Assets

The following information relates to the accounting treatment of long-lived assets. Long-lived assets include property, plant and equipment and intangibles that are subject to amortization.

Property, plant and equipment are stated at cost and are removed from the accounts at the end of their estimated average service lives, except in those instances where specific identification allows their removal at retirement or disposition. Gains or losses at retirement or disposition of such assets are credited or charged to “Other Income” in the Statement of Income. In the event that facts and circumstances indicate that property, plant and equipment may be impaired, an evaluation of recoverability is performed. For purposes of such an evaluation, the estimated future discounted cash flows associated with the asset are compared to the carrying amount of the asset to determine if a write-down is required.

The impairment loss is measured as the amount by which the carrying amount of the assets exceeds its fair value.

Compliance with the Uniform System of Accounts

This application has been prepared and filed in compliance with the Uniform System of Accounts ("USofA") and the Accounting Procedures Handbook ("APH"). The only departure from the APH relates to the accounting treatment of carrying charges. That departure is necessary to create consistency between the treatment of carrying charges in the 2006 EDR (EB-2005-0340) application and this application.

The 2006 EDR application included $629,814 in carrying charge revenue credited to Account 4405 – Interest and Dividend Income. That credit represented carrying charges that were charged during the historic test year of 2004 for the Transition Costs Deferral Account as well as Pre-market Opening and Post-market Opening Variance Accounts. That accounting treatment was in accordance with the guidance provided on page 13 of Article 480 of the APH with respect to transition costs, as well as page 29 of Article 490 of the APH with respect to all variance accounts. The carrying charge revenue in the 2004 historic test year was included in rates approved as part of the 2006 EDR and created a revenue offset that served to benefit ratepayers with reduced rates.

During the 2009 projected test year, Bluewater Power anticipates a cost of $243,636 representing carrying charges to be accrued with respect to all deferral and variance accounts in the calendar year 2009. The guidance provided at page 37 of Article 490 of the APH would require that these costs be assigned to Account 6035 – Other Interest Expense. As a cost of debt, however, the cost assigned to Account 6035 would be excluded from this rate application and replaced with deemed interest costs. The cost of the carrying charges would, therefore, not be recovered through rates. The decision to apply deemed debt in this way is to avoid an unjustified and presumably unintentional inconsistency that would be created by technical compliance with the APH. Where carrying charges are <u>earned</u> on deferral/variance accounts representing amounts owed by ratepayers they serve as an offset to revenue requirement whereas carrying charges that are <u>owed</u> on deferral/variance accounts representing amounts owed to ratepayers are excluded from revenue requirement since actual interest costs are replaced by deemed interest costs.

Since technical compliance with the APH would not result in just and reasonable rates, as a result of this potential discriminatory disparity, Bluewater Power has proposed a consistent treatment whereby carrying charges are booked to Account #4405 whether they are a debit or a credit. In this application we have included a debit to Account #4405 in the amount of $243,636 representing carrying charges to be accrued in the test year on amounts owed to ratepayers. Bluewater Power is not seeking to recover the foregone revenue of approximately $1.8 million as a result of the 2006 EDR application; rather, Bluewater Power is simply seeking consistency in treatment of carrying charges for this application.

Accounting Orders

There are no accounting orders issued to Bluewater Power.

Prospectus, information and recent share issue update

This is not applicable to Bluewater Power.

Extraordinary Events

Extraordinary Circumstances

There are no extraordinary circumstances applicable to Bluewater Power that affect this rate application.

RATE BASE

Overview

Rate Base Overview

Bluewater Power's forecasted rate base for the 2009 test year is $53,158,483.

The rate base underlying Bluewater Power's revenue requirement includes a forecast of net fixed assets, plus a working capital allowance. Net fixed assets are gross assets in service minus accumulated depreciation and contributed capital. The amounts added to rate base in the test year are calculated as the average of 2008 and 2009 net fixed asset additions.

The following items will be discussed in the upcoming schedules:

- Schedule 2 contains the Rate Base Summary Table 2.1.2.1
- Schedule 3 contains the Annual Variance Analysis with the main drivers of the variance;
    - Description of sustaining capital expenditures vs. non-routine capital expenditures
    - Allowance for working capital, segregated by the portion of the working capital related to cost of power expenses, and the portion related to OM&A expenses.

The additions to rate base related to both system growth and improvements to existing systems. Bluewater Power has been making a focused effort to reinvest in its distribution infrastructure and to improve system reliability. As discussed in the Asset Management Plan at Exhibit 2, Tab 3, Schedule 9, Bluewater Power tracks the causes of outages and uses that information as part of its capital planning process. This approach to capital planning helps Bluewater Power to respond to outage causes and maintain reliability. Bluewater Power's reliability statistics are shown in Table 2.1.1.1 below.

Table 2.1.1.1 – Annual Reliability Indices

Outage Information (Excluding Loss of Supply)	**2007**	**2006**	**2005**	**3 Yr Average**
# of Customers Involved in Outages	88,118	90,775	152,052	110,315
# of Customers * 12 months	424,596	424,596	414,108	421,100
# of Hours of Interruption (min./60)	94,414	81,646	112,219	96,093
# of Interruptions	400	336	410	382
Outage Ratios:				
SAIDI	2.67	2.31	3.25	2.74
SAIFI	2.49	2.57	4.41	3.15
CAIDI	1.07	0.90	0.74	0.90

Rate Base Summary Table

Table 2.1.2.1 below details the actual rate base for 2007, as well as the projected rate base for 2008 and 2009. The annual variance is displayed, and the variance is discussed in Exhibit 2, Tab 1, Schedule 3.

Table 2.1.2.1

	2009 Projection	2008 Projection	Var $		2008 Projection	2007 Actual	Var $
Net Capital Assets in Service:							
Opening Balance	37,944,816	37,626,977	317,839		37,626,977	37,364,171	262,806
Ending Balance	41,145,335	37,944,816	3,200,519		37,944,816	37,626,977	317,839
Average Balance	39,545,075	37,785,896	1,759,179		37,785,896	37,495,574	290,323
Working Capital Allowance	13,613,408	13,308,482	304,926		13,308,482	12,180,537	1,127,945
Total Rate Base	**53,158,483**	**51,094,378**	**2,064,105**		**51,094,378**	**49,676,110**	**1,418,268**

Annual Variance Analysis on Rate Base

Bluewater Power's rate base materiality threshold as prescribed by the Filing Guidelines is approximately $350,000. As illustrated by the Rate Base Summary Table 2.1.2.1, the annual variances in Bluewater Power's rate base (both actual and forecasted) exceed the materiality threshold for each year. Written explanations for these rate base variances are set out in the following sections.

2007 Historic compared to 2008 Bridge

As illustrated by the Rate Base Summary Table 2.1.2.1, Bluewater Power's 2008 rate base is forecasted to be approximately $51.1 million, approximately $1.4 million more than its actual 2007 rate base.

Approximately $1.13 million (80%) of the $1.4 million rate base variance from 2007 to 2008 is attributable to an increase in working capital allowance. This increase in Bluewater Power's working capital allowance is almost entirely attributable (92%) to an increase in cost of power, as illustrated by Table 2.1.3.1 below and in more detail at Exhibit 2, Tab 4, Schedule 2, Attachment 1.

The remainder of the rate base variance $0.29 million (20%) can be attributed to capital projects, however it should be noted that the variance in Bluewater Power's capital expenditures from 2007 to 2008 will fall below Bluewater Power's materiality threshold of approximately $350,000. For a list of Bluewater Power's capital projects in 2007 and 2008, please refer to Exhibit 2, Tab 3, Schedule 1**.** For descriptions of capital projects that exceed $100,000 in any year, please refer to Exhibit 2, Tab 3, Schedule 6. For a variance analysis of gross assets on an account basis, please refer to Exhibit 2, Tab 2, Schedule 3.

2008 Bridge compared to 2009 Test

Bluewater Power's rate base in the 2009 test year is forecasted to be approximately $53.16 million, an increase of approximately $2.06 million from Bluewater Power's forecasted 2008 rate base.

This increase is almost entirely attributable (85%) to capital expenditures in the test year. The increase in Bluewater Power's 2008 to 2009 capital expenditures is primarily caused by the following three "non-routine" capital projects, all of which are described at Exhibit 2, Tab 3, Schedule 6:

- the building renovations/expansion project;
- the SAP upgrade project;
- the Modeland transmission station meter upgrade project.

The remaining 15% of the 2008 to 2009 rate base variance is attributable to an increase in working capital allowance, as illustrated in Table 2.1.3.1.

Allowance for Working Capital

The proposed working capital allowance for the 2009 test year is $13,613,408, calculated as 15% of OM&A and cost of power. Table 2.1.3.1 illustrates the OM&A and cost of power components of Bluewater Power's working capital allowance from 2007 to 2009:

Table 2.1.3.1

	2007 Actual	2008 Projected	2009 Projected
Power Supply Expenses	$72,009,497	$78,937,397	$79,099,884
WCA @ 15%	$10,801,425	$11,840,610	$11,864,983
Annual WCA Variance (Power)		$1,039,185	$24,373
% Variance		8.8%	0.2%
OM&A	$9,194,081	$9,785,815	$11,656,169
WCA @ 15%	$1,379,112	$1,467,872	$1,748,425
Annual WCA Variance (OM&A)		$88,760	$280,553
Annual % Variance		6.0%	16.0%
Total WCA	**$12,180,537**	**$13,308,482**	**$13,613,408**
Total WCA Variance		$1,127,945	$304,926
Variance due to Power Supply Expenses		$1,039,185	$24,373
% Variance due to Power Supply		92.1%	8.0%
Variance due to OM&A		$88,760	$280,553
% Variance due to OM&A		7.9%	92.0%

It is apparent from this table that Bluewater Power's working capital allowance is forecast to increase significantly from 2007 to 2008, primarily caused by an increase in cost of power. Please refer to Exhibit 2, Tab 4, Schedule 2, Attachment 1 for the calculation of working capital allowance on an account basis from 2007 to 2009.

Fixed Assets

Fixed Asset Continuity Statements

The fixed asset continuity statements are attached as Exhibit 2, Tab 2, Schedule 1, Attachment 1.

Capital Asset Continuity Statements

** Asset retirements and other changes*	2006 EDR Approved	Variance to 2006 Actual			2006 Balance
		Additions	Ret./Other *	Amortization	
1805-Land					
Gross Assets	445,817				445,817
Accumulated Amortization					
Net Book Value	445,817				445,817
1806-Land Rights					
Gross Assets	283,160				283,160
Accumulated Amortization	(221,619)			(29,507)	(251,125)
Net Book Value	61,541			(29,507)	32,035
1808-Buildings and Fixtures					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1810-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1815-Transformer Station Equipment - Normally Primary above 50 kV					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	4,421,144	247,437	646,111		5,314,692
Accumulated Amortization	(2,251,875)			(275,789)	(2,527,663)
Net Book Value	2,169,269	247,437	646,111	(275,789)	2,787,029
1830-Poles, Towers and Fixtures					
Gross Assets		203,424	103,114		306,538
Accumulated Amortization				(13,471)	(13,471)
Net Book Value		203,424	103,114	(13,471)	293,067

Capital Asset Continuity Statements

** Asset retirements and other changes*	2006 EDR Approved	Variance to 2006 Actual			2006 Balance
		Additions	Ret./Other *	Amortization	
1835-Overhead Conductors and Devices					
Gross Assets	22,528,705	788,215	1,118,943		24,435,863
Accumulated Amortization	(10,746,858)			(2,262,108)	(13,008,965)
Net Book Value	11,781,847	788,215	1,118,943	(2,262,108)	11,426,898
1840-Underground Conduit					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1845-Underground Conductors and Devices					
Gross Assets	16,336,461	367,560	1,068,742		17,772,763
Accumulated Amortization	(6,971,481)			(1,617,703)	(8,589,184)
Net Book Value	9,364,980	367,560	1,068,742	(1,617,703)	9,183,579
1850-Line Transformers					
Gross Assets	10,514,427	665,389	711,204		11,891,020
Accumulated Amortization	(5,079,269)		(6)	(1,080,906)	(6,160,181)
Net Book Value	5,435,158	665,389	711,198	(1,080,906)	5,730,839
1855-Services					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1860-Meters					
Gross Assets	5,625,800	186,909	410,359		6,223,068
Accumulated Amortization	(3,212,663)			(506,092)	(3,718,755)
Net Book Value	2,413,137	186,909	410,359	(506,092)	2,504,313
1905-Land					
Gross Assets					
Accumulated Amortization					
Net Book Value					

Capital Asset Continuity Statements

** Asset retirements and other changes*	2006 EDR Approved	Variance to 2006 Actual			2006 Balance
		Additions	Ret./Other *	Amortization	
1906-Land Rights					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1908-Buildings and Fixtures					
Gross Assets	3,737,050	176,607	136,305		4,049,962
Accumulated Amortization	(1,426,051)			(158,883)	(1,584,934)
Net Book Value	2,310,999	176,607	136,305	(158,883)	2,465,028
1910-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1915-Office Furniture and Equipment					
Gross Assets	539,755	56,181	88,218		684,154
Accumulated Amortization	(472,937)			(58,839)	(531,776)
Net Book Value	66,818	56,181	88,218	(58,839)	152,378
1920-Computer Equipment - Hardware					
Gross Assets	1,985,558	372,081	546,346		2,903,985
Accumulated Amortization	(1,410,824)			(584,266)	(1,995,091)
Net Book Value	574,734	372,081	546,346	(584,266)	908,894
1925-Computer Software					
Gross Assets	1,868,201	525,770	1,550,889		3,944,860
Accumulated Amortization	(511,803)			(1,302,288)	(1,814,091)
Net Book Value	1,356,398	525,770	1,550,889	(1,302,288)	2,130,769
1930-Transportation Equipment					
Gross Assets	2,585,010	269,708	263,305		3,118,023
Accumulated Amortization	(2,278,476)		(342,051)	(389,038)	(3,009,565)
Net Book Value	306,534	269,708	(78,746)	(389,038)	108,458

Capital Asset Continuity Statements

** Asset retirements and other changes*	2006 EDR Approved	Variance to 2006 Actual			2006 Balance
		Additions	Ret./Other *	Amortization	
1935-Stores Equipment					
Gross Assets	42,591	37,420	593		80,604
Accumulated Amortization	(31,169)			(11,243)	(42,413)
Net Book Value	11,422	37,420	593	(11,243)	38,191
1940-Tools, Shop and Garage Equipment					
Gross Assets	546,958	53,192	50,762		650,911
Accumulated Amortization	(447,580)			(56,776)	(504,356)
Net Book Value	99,377	53,192	50,762	(56,776)	146,555
1945-Measurement and Testing Equipment					
Gross Assets	194,133	14,464	20,802		229,399
Accumulated Amortization	(185,753)			(14,281)	(200,034)
Net Book Value	8,380	14,464	20,802	(14,281)	29,366
1950-Power Operated Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1955-Communication Equipment					
Gross Assets	142,724	2,480	15,192		160,396
Accumulated Amortization	(110,071)			(15,222)	(125,293)
Net Book Value	32,653	2,480	15,192	(15,222)	35,103
1960-Miscellaneous Equipment					
Gross Assets	493,304	93,071	73,501		659,876
Accumulated Amortization	(452,651)			(63,687)	(516,338)
Net Book Value	40,653	93,071	73,501	(63,687)	143,538
1965-Water Heater Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					

Capital Asset Continuity Statements

** Asset retirements and other changes*	2006 EDR Approved	Variance to 2006 Actual			2006 Balance
		Additions	Ret./Other *	Amortization	
1970-Load Management Controls - Customer Premises					
Gross Assets	418,852		46,065		464,917
Accumulated Amortization	(379,695)			(48,633)	(428,328)
Net Book Value	39,157		46,065	(48,633)	36,589
1975-Load Management Controls - Utility Premises					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1980-System Supervisory Equipment					
Gross Assets	985,837	5,184	185,199		1,176,220
Accumulated Amortization	(440,001)			(108,692)	(548,694)
Net Book Value	545,836	5,184	185,199	(108,692)	627,527
1985-Sentinel Lighting Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1990-Other Tangible Property					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1995-Contributions and Grants - Credit					
Gross Assets	(2,049,843)		(1,000,923)		(3,050,765)
Accumulated Amortization				504,861	504,861
Net Book Value	(2,049,843)		(1,000,923)	504,861	(2,545,904)
2005-Property Under Capital Leases					
Gross Assets					
Accumulated Amortization					
Net Book Value					

Capital Asset Continuity Statements

** Asset retirements and other changes*	2006 EDR Approved	Variance to 2006 Actual			2006 Balance
		Additions	Ret./Other *	Amortization	
TOTAL					
Gross Assets	**71,645,644**	**4,065,093**	**6,034,725**		**81,745,463**
Accumulated Amortization	**(36,630,775)**		**(342,056)**	**(8,092,563)**	**(45,065,394)**
Net Book Value	**35,014,869**	**4,065,093**	**5,692,669**	**(8,092,563)**	**36,680,069**

Capital Asset Continuity Statements

** Asset retirements and other changes*	2006 Balance	2007 Changes			2007 Balance
		Additions	Ret./Other *	Amortization	
1805-Land					
Gross Assets	445,817				445,817
Accumulated Amortization					
Net Book Value	445,817				445,817
1806-Land Rights					
Gross Assets	283,160				283,160
Accumulated Amortization	(251,125)			(11,448)	(262,574)
Net Book Value	32,035			(11,448)	20,586
1808-Buildings and Fixtures					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1810-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1815-Transformer Station Equipment - Normally Primary above 50 kV					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	5,314,692	89,774	0		5,404,466
Accumulated Amortization	(2,527,663)			(125,677)	(2,653,340)
Net Book Value	2,787,029	89,774	0	(125,677)	2,751,126
1830-Poles, Towers and Fixtures					
Gross Assets	306,538	384,496	1		691,035
Accumulated Amortization	(13,471)			(19,035)	(32,506)
Net Book Value	293,067	384,496	1	(19,035)	658,529

Capital Asset Continuity Statements

** Asset retirements and other changes*	2006 Balance	2007 Changes			2007 Balance
		Additions	Ret./Other *	Amortization	
1835-Overhead Conductors and Devices					
Gross Assets	24,435,863	650,518	(0)		25,086,381
Accumulated Amortization	(13,008,965)			(920,856)	(13,929,821)
Net Book Value	11,426,898	650,518	(0)	(920,856)	11,156,560
1840-Underground Conduit					
Gross Assets		71,215	0		71,215
Accumulated Amortization				(2,849)	(2,849)
Net Book Value		71,215	0	(2,849)	68,366
1845-Underground Conductors and Devices					
Gross Assets	17,772,763	575,045	0		18,347,808
Accumulated Amortization	(8,589,184)			(684,423)	(9,273,607)
Net Book Value	9,183,579	575,045	0	(684,423)	9,074,201
1850-Line Transformers					
Gross Assets	11,891,020	803,622	(0)		12,694,642
Accumulated Amortization	(6,160,181)			(478,622)	(6,638,803)
Net Book Value	5,730,839	803,622	(0)	(478,622)	6,055,839
1855-Services					
Gross Assets		143,665	0		143,665
Accumulated Amortization				(3,162)	(3,162)
Net Book Value		143,665	0	(3,162)	140,503
1860-Meters					
Gross Assets	6,223,068	524,711	0		6,747,779
Accumulated Amortization	(3,718,755)			(220,086)	(3,938,841)
Net Book Value	2,504,313	524,711	0	(220,086)	2,808,938
1905-Land					
Gross Assets					
Accumulated Amortization					
Net Book Value					

Capital Asset Continuity Statements

** Asset retirements and other changes*	2006 Balance	2007 Changes			2007 Balance
		Additions	Ret./Other *	Amortization	
1906-Land Rights					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1908-Buildings and Fixtures					
Gross Assets	4,049,962	189,714	0		4,239,676
Accumulated Amortization	(1,584,934)			(60,043)	(1,644,977)
Net Book Value	2,465,028	189,714	0	(60,043)	2,594,699
1910-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1915-Office Furniture and Equipment					
Gross Assets	684,154	27,251	(0)		711,405
Accumulated Amortization	(531,776)			(30,141)	(561,917)
Net Book Value	152,378	27,251	(0)	(30,141)	149,488
1920-Computer Equipment - Hardware					
Gross Assets	2,903,985	353,265	0		3,257,250
Accumulated Amortization	(1,995,091)			(336,821)	(2,331,912)
Net Book Value	908,894	353,265	0	(336,821)	925,338
1925-Computer Software					
Gross Assets	3,944,860	451,110	1		4,395,971
Accumulated Amortization	(1,814,091)			(725,420)	(2,539,512)
Net Book Value	2,130,769	451,110	1	(725,420)	1,856,459
1930-Transportation Equipment					
Gross Assets	3,118,023	292,958	(17,258)		3,393,723
Accumulated Amortization	(3,009,565)		(17,258)	(207,679)	(3,234,502)
Net Book Value	108,458	292,958	(34,516)	(207,679)	159,221

Capital Asset Continuity Statements

** Asset retirements and other changes*	2006 Balance	2007 Changes			2007 Balance
		Additions	Ret./Other *	Amortization	
1935-Stores Equipment					
Gross Assets	80,604				80,604
Accumulated Amortization	(42,413)			(6,493)	(48,905)
Net Book Value	38,191			(6,493)	31,699
1940-Tools, Shop and Garage Equipment					
Gross Assets	650,911	41,396	(0)		692,307
Accumulated Amortization	(504,356)			(26,189)	(530,545)
Net Book Value	146,555	41,396	(0)	(26,189)	161,762
1945-Measurement and Testing Equipment					
Gross Assets	229,399				229,399
Accumulated Amortization	(200,034)			(3,527)	(203,560)
Net Book Value	29,366			(3,527)	25,839
1950-Power Operated Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1955-Communication Equipment					
Gross Assets	160,396				160,396
Accumulated Amortization	(125,293)			(5,649)	(130,942)
Net Book Value	35,103			(5,649)	29,454
1960-Miscellaneous Equipment					
Gross Assets	659,876	124,656	(0)		784,532
Accumulated Amortization	(516,338)			(45,872)	(562,211)
Net Book Value	143,538	124,656	(0)	(45,872)	222,321
1965-Water Heater Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					

Capital Asset Continuity Statements

** Asset retirements and other changes*	2006	2007 Changes			2007
	Balance	Additions	Ret./Other *	Amortization	Balance
1970-Load Management Controls - Customer Premises					
Gross Assets	464,917				464,917
Accumulated Amortization	(428,328)			(14,264)	(442,592)
Net Book Value	36,589			(14,264)	22,325
1975-Load Management Controls - Utility Premises					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1980-System Supervisory Equipment					
Gross Assets	1,176,220	25,190	(0)		1,201,410
Accumulated Amortization	(548,694)			(47,342)	(596,035)
Net Book Value	627,527	25,190	(0)	(47,342)	605,375
1985-Sentinel Lighting Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1990-Other Tangible Property					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1995-Contributions and Grants - Credit					
Gross Assets	(3,050,765)		(637,880)		(3,688,645)
Accumulated Amortization	504,861			127,697	632,558
Net Book Value	(2,545,904)		(637,880)	127,697	(3,056,087)
2005-Property Under Capital Leases					
Gross Assets					
Accumulated Amortization					
Net Book Value					

Capital Asset Continuity Statements

** Asset retirements and other changes*	2006 Balance	2007 Changes			2007 Balance
		Additions	Ret./Other *	Amortization	
TOTAL					
Gross Assets	**81,745,463**	**4,748,586**	**(655,136)**		**85,838,913**
Accumulated Amortization	**(45,065,394)**		**(17,258)**	**(3,847,902)**	**(48,930,554)**
Net Book Value	**36,680,069**	**4,748,586**	**(672,395)**	**(3,847,902)**	**36,908,359**

Capital Asset Continuity Statements

** Asset retirements and other changes*	2007 Balance	2008 Changes			2008 Balance
		Additions	Ret./Other *	Amortization	
1805-Land					
Gross Assets	445,817				445,817
Accumulated Amortization					
Net Book Value	445,817				445,817
1806-Land Rights					
Gross Assets	283,160				283,160
Accumulated Amortization	(262,574)			(1,193)	(263,767)
Net Book Value	20,586			(1,193)	19,393
1808-Buildings and Fixtures					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1810-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1815-Transformer Station Equipment - Normally Primary above 50 kV					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	5,404,466	231,747			5,636,213
Accumulated Amortization	(2,653,340)			(130,291)	(2,783,631)
Net Book Value	2,751,126	231,747		(130,291)	2,852,582
1830-Poles, Towers and Fixtures					
Gross Assets	691,035	517,118			1,208,153
Accumulated Amortization	(32,506)			(38,033)	(70,539)
Net Book Value	658,529	517,118		(38,033)	1,137,614

Capital Asset Continuity Statements

** Asset retirements and other changes*	2007 Balance	2008 Changes			2008 Balance
		Additions	Ret./Other *	Amortization	
1835-Overhead Conductors and Devices					
Gross Assets	25,086,381	1,051,321			26,137,702
Accumulated Amortization	(13,929,821)			(948,992)	(14,878,813)
Net Book Value	11,156,560	1,051,321		(948,992)	11,258,889
1840-Underground Conduit					
Gross Assets	71,215	75,759			146,974
Accumulated Amortization	(2,849)			(4,364)	(7,213)
Net Book Value	68,366	75,759		(4,364)	139,761
1845-Underground Conductors and Devices					
Gross Assets	18,347,808	412,052			18,759,860
Accumulated Amortization	(9,273,607)			(709,385)	(9,982,992)
Net Book Value	9,074,201	412,052		(709,385)	8,776,868
1850-Line Transformers					
Gross Assets	12,694,642	378,444			13,073,086
Accumulated Amortization	(6,638,803)			(502,061)	(7,140,864)
Net Book Value	6,055,839	378,444		(502,061)	5,932,222
1855-Services					
Gross Assets	143,665	138,840			282,505
Accumulated Amortization	(3,162)			(8,524)	(11,686)
Net Book Value	140,503	138,840		(8,524)	270,819
1860-Meters					
Gross Assets	6,747,779	251,908			6,999,687
Accumulated Amortization	(3,938,841)			(228,463)	(4,167,304)
Net Book Value	2,808,938	251,908		(228,463)	2,832,383
1905-Land					
Gross Assets					
Accumulated Amortization					
Net Book Value					

Capital Asset Continuity Statements

** Asset retirements and other changes*	2007 Balance	2008 Changes			2008 Balance
		Additions	Ret./Other *	Amortization	
1906-Land Rights					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1908-Buildings and Fixtures					
Gross Assets	4,239,676	398,023			4,637,699
Accumulated Amortization	(1,644,977)			(65,146)	(1,710,123)
Net Book Value	2,594,699	398,023		(65,146)	2,927,576
1910-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1915-Office Furniture and Equipment					
Gross Assets	711,405	8,522			719,927
Accumulated Amortization	(561,917)			(30,811)	(592,728)
Net Book Value	149,488	8,522		(30,811)	127,199
1920-Computer Equipment - Hardware					
Gross Assets	3,257,250	143,621			3,400,871
Accumulated Amortization	(2,331,912)			(348,948)	(2,680,860)
Net Book Value	925,338	143,621		(348,948)	720,011
1925-Computer Software					
Gross Assets	4,395,971	938,835			5,334,806
Accumulated Amortization	(2,539,512)			(856,415)	(3,395,927)
Net Book Value	1,856,459	938,835		(856,415)	1,938,879
1930-Transportation Equipment					
Gross Assets	3,393,723	504,440	(504,979)		3,393,184
Accumulated Amortization	(3,234,502)		309,940	(177,184)	(3,101,746)
Net Book Value	159,221	504,440	(195,039)	(177,184)	291,438

Capital Asset Continuity Statements

** Asset retirements and other changes*	2007 Balance	2008 Changes			2008 Balance
		Additions	Ret./Other *	Amortization	
1935-Stores Equipment					
Gross Assets	80,604				80,604
Accumulated Amortization	(48,905)			(6,218)	(55,123)
Net Book Value	31,699			(6,218)	25,481
1940-Tools, Shop and Garage Equipment					
Gross Assets	692,307	38,763			731,070
Accumulated Amortization	(530,545)			(26,233)	(556,778)
Net Book Value	161,762	38,763		(26,233)	174,292
1945-Measurement and Testing Equipment					
Gross Assets	229,399				229,399
Accumulated Amortization	(203,560)			(3,527)	(207,087)
Net Book Value	25,839			(3,527)	22,312
1950-Power Operated Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1955-Communication Equipment					
Gross Assets	160,396				160,396
Accumulated Amortization	(130,942)			(5,592)	(136,534)
Net Book Value	29,454			(5,592)	23,862
1960-Miscellaneous Equipment					
Gross Assets	784,532	50,506			835,038
Accumulated Amortization	(562,211)			(47,276)	(609,487)
Net Book Value	222,321	50,506		(47,276)	225,551
1965-Water Heater Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					

Capital Asset Continuity Statements

** Asset retirements and other changes*	2007 Balance	2008 Changes			2008 Balance
		Additions	Ret./Other *	Amortization	
1970-Load Management Controls - Customer Premises					
Gross Assets	464,917				464,917
Accumulated Amortization	(442,592)			(13,112)	(455,704)
Net Book Value	22,325			(13,112)	9,213
1975-Load Management Controls - Utility Premises					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1980-System Supervisory Equipment					
Gross Assets	1,201,410				1,201,410
Accumulated Amortization	(596,035)			(48,054)	(644,089)
Net Book Value	605,375			(48,054)	557,321
1985-Sentinel Lighting Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1990-Other Tangible Property					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1995-Contributions and Grants - Credit					
Gross Assets	(3,688,645)	(581,752)			(4,270,397)
Accumulated Amortization	632,558			154,553	787,111
Net Book Value	(3,056,087)	(581,752)		154,553	(3,483,286)
2005-Property Under Capital Leases					
Gross Assets					
Accumulated Amortization					
Net Book Value					

Capital Asset Continuity Statements

** Asset retirements and other changes*	2007	2008 Changes			2008
	Balance	Additions	Ret./Other *	Amortization	Balance
TOTAL					
Gross Assets	**85,838,913**	**4,558,147**	**(504,979)**		**89,892,081**
Accumulated Amortization	**(48,930,554)**		**309,940**	**(4,045,269)**	**(52,665,883)**
Net Book Value	**36,908,359**	**4,558,147**	**(195,039)**	**(4,045,269)**	**37,226,198**

Capital Asset Continuity Statements

** Asset retirements and other changes*	2008 Balance	2009 Changes			2009 Balance
		Additions	Ret./Other *	Amortization	
1805-Land					
Gross Assets	445,817				445,817
Accumulated Amortization					
Net Book Value	445,817				445,817
1806-Land Rights					
Gross Assets	283,160				283,160
Accumulated Amortization	(263,767)			(14,292)	(278,059)
Net Book Value	19,393			(14,292)	5,101
1808-Buildings and Fixtures					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1810-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1815-Transformer Station Equipment - Normally Primary above 50 kV					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	5,636,213	130,491			5,766,704
Accumulated Amortization	(2,783,631)			(141,591)	(2,925,222)
Net Book Value	2,852,582	130,491		(141,591)	2,841,482
1830-Poles, Towers and Fixtures					
Gross Assets	1,208,153	733,494			1,941,647
Accumulated Amortization	(70,539)			(62,282)	(132,821)
Net Book Value	1,137,614	733,494		(62,282)	1,808,826

Capital Asset Continuity Statements

** Asset retirements and other changes*	2008	2009 Changes			2009
	Balance	Additions	Ret./Other *	Amortization	Balance
1835-Overhead Conductors and Devices					
Gross Assets	26,137,702	1,109,429			27,247,131
Accumulated Amortization	(14,878,813)			(853,578)	(15,732,391)
Net Book Value	11,258,889	1,109,429		(853,578)	11,514,740
1840-Underground Conduit					
Gross Assets	146,974	96,978			243,952
Accumulated Amortization	(7,213)			(7,704)	(14,917)
Net Book Value	139,761	96,978		(7,704)	229,035
1845-Underground Conductors and Devices					
Gross Assets	18,759,860	570,078			19,329,938
Accumulated Amortization	(9,982,992)			(728,401)	(10,711,393)
Net Book Value	8,776,868	570,078		(728,401)	8,618,545
1850-Line Transformers					
Gross Assets	13,073,086	445,502			13,518,588
Accumulated Amortization	(7,140,864)			(522,231)	(7,663,095)
Net Book Value	5,932,222	445,502		(522,231)	5,855,493
1855-Services					
Gross Assets	282,505	163,459			445,964
Accumulated Amortization	(11,686)			(14,360)	(26,046)
Net Book Value	270,819	163,459		(14,360)	419,918
1860-Meters					
Gross Assets	6,999,687	698,030			7,697,717
Accumulated Amortization	(4,167,304)			(248,155)	(4,415,459)
Net Book Value	2,832,383	698,030		(248,155)	3,282,258
1905-Land					
Gross Assets					
Accumulated Amortization					
Net Book Value					

Capital Asset Continuity Statements

** Asset retirements and other changes*	2008	2009 Changes			2009
	Balance	Additions	Ret./Other *	Amortization	Balance
1906-Land Rights					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1908-Buildings and Fixtures					
Gross Assets	4,637,699	1,067,317			5,705,016
Accumulated Amortization	(1,710,123)			(73,139)	(1,783,262)
Net Book Value	2,927,576	1,067,317		(73,139)	3,921,754
1910-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1915-Office Furniture and Equipment					
Gross Assets	719,927	4,036			723,963
Accumulated Amortization	(592,728)			(29,182)	(621,910)
Net Book Value	127,199	4,036		(29,182)	102,053
1920-Computer Equipment - Hardware					
Gross Assets	3,400,871	465,762			3,866,633
Accumulated Amortization	(2,680,860)			(360,020)	(3,040,880)
Net Book Value	720,011	465,762		(360,020)	825,753
1925-Computer Software					
Gross Assets	5,334,806	2,167,170			7,501,976
Accumulated Amortization	(3,395,927)			(1,082,787)	(4,478,714)
Net Book Value	1,938,879	2,167,170		(1,082,787)	3,023,262
1930-Transportation Equipment					
Gross Assets	3,393,184	565,599	(230,139)		3,728,644
Accumulated Amortization	(3,101,746)		230,139	(200,330)	(3,071,937)
Net Book Value	291,438	565,599		(200,330)	656,707

Capital Asset Continuity Statements

** Asset retirements and other changes*	2008	2009 Changes			2009
	Balance	Additions	Ret./Other *	Amortization	Balance
1935-Stores Equipment					
Gross Assets	80,604				80,604
Accumulated Amortization	(55,123)			(48,254)	(103,377)
Net Book Value	25,481			(48,254)	(22,773)
1940-Tools, Shop and Garage Equipment					
Gross Assets	731,070	68,473			799,543
Accumulated Amortization	(556,778)			(29,590)	(586,368)
Net Book Value	174,292	68,473		(29,590)	213,175
1945-Measurement and Testing Equipment					
Gross Assets	229,399				229,399
Accumulated Amortization	(207,087)			(3,527)	(210,614)
Net Book Value	22,312			(3,527)	18,785
1950-Power Operated Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1955-Communication Equipment					
Gross Assets	160,396				160,396
Accumulated Amortization	(136,534)			(8,987)	(145,521)
Net Book Value	23,862			(8,987)	14,875
1960-Miscellaneous Equipment					
Gross Assets	835,038				835,038
Accumulated Amortization	(609,487)			(50,873)	(660,360)
Net Book Value	225,551			(50,873)	174,678
1965-Water Heater Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					

Capital Asset Continuity Statements

** Asset retirements and other changes*	2008	2009 Changes			2009
	Balance	Additions	Ret./Other *	Amortization	Balance
1970-Load Management Controls - Customer Premises					
Gross Assets	464,917				464,917
Accumulated Amortization	(455,704)			(11,739)	(467,443)
Net Book Value	9,213			(11,739)	(2,526)
1975-Load Management Controls - Utility Premises					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1980-System Supervisory Equipment					
Gross Assets	1,201,410				1,201,410
Accumulated Amortization	(644,089)			(48,054)	(692,143)
Net Book Value	557,321			(48,054)	509,267
1985-Sentinel Lighting Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1990-Other Tangible Property					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1995-Contributions and Grants - Credit					
Gross Assets	(4,270,397)	(727,190)			(4,997,587)
Accumulated Amortization	787,111			180,967	968,078
Net Book Value	(3,483,286)	(727,190)		180,967	(4,029,509)
2005-Property Under Capital Leases					
Gross Assets					
Accumulated Amortization					
Net Book Value					

Capital Asset Continuity Statements

** Asset retirements and other changes*	2008	2009 Changes			2009
	Balance	Additions	Ret./Other *	Amortization	Balance
TOTAL					
Gross Assets	**89,892,081**	**7,558,628**	**(230,139)**		**97,220,570**
Accumulated Amortization	**(52,665,883)**		**230,139**	**(4,358,109)**	**(56,793,853)**
Net Book Value	**37,226,198**	**7,558,628**		**(4,358,109)**	**40,426,717**

Gross Assets Table

The gross assets table is attached as Exhibit 2, Tab 2, Schedule 2, Attachment 1.

Gross Capital Assets (ending balances)

Gross Capital Asset Account	2009 Projection	2008 Projection	Var $	2008 Projection	2007 Actual	Var $
1805-Land	445,817	445,817		445,817	445,817	
1806-Land Rights	283,160	283,160		283,160	283,160	
1808-Buildings and Fixtures						
1810-Leasehold Improvements						
1815-Transformer Station Equipment - Normally Primary above 50 kV						
1820-Distribution Station Equipment - Normally Primary below 50 kV	5,766,704	5,636,213	130,491	5,636,213	5,404,466	231,747
1830-Poles, Towers and Fixtures	1,941,647	1,208,153	**733,494**	1,208,153	691,035	**517,118**
1835-Overhead Conductors and Devices	27,247,131	26,137,702	**1,109,429**	26,137,702	25,086,381	**1,051,321**
1840-Underground Conduit	243,952	146,974	96,978	146,974	71,215	75,759
1845-Underground Conductors and Devices	19,329,938	18,759,860	**570,078**	18,759,860	18,347,808	**412,052**
1850-Line Transformers	13,518,588	13,073,086	**445,502**	13,073,086	12,694,642	**378,444**
1855-Services	445,964	282,505	163,459	282,505	143,665	138,840
1860-Meters	7,697,717	6,999,687	**698,030**	6,999,687	6,747,779	251,908
1905-Land						
1906-Land Rights						
1908-Buildings and Fixtures	5,705,016	4,637,699	**1,067,317**	4,637,699	4,239,676	**398,023**
1910-Leasehold Improvements						
1915-Office Furniture and Equipment	723,963	719,927	4,036	719,927	711,405	8,522
1920-Computer Equipment - Hardware	3,866,633	3,400,871	**465,762**	3,400,871	3,257,250	143,621
1925-Computer Software	7,501,976	5,334,806	**2,167,170**	5,334,806	4,395,971	**938,835**
1930-Transportation Equipment	3,728,644	3,393,184	335,460	3,393,184	3,393,723	(539)
1935-Stores Equipment	80,604	80,604		80,604	80,604	
1940-Tools, Shop and Garage Equipment	799,543	731,070	68,473	731,070	692,307	38,763
1945-Measurement and Testing Equipment	229,399	229,399		229,399	229,399	
1950-Power Operated Equipment						
1955-Communication Equipment	160,396	160,396		160,396	160,396	
1960-Miscellaneous Equipment	835,038	835,038		835,038	784,532	50,506
1965-Water Heater Rental Units						
1970-Load Management Controls - Customer Premises	464,917	464,917		464,917	464,917	
1975-Load Management Controls - Utility Premises						

Gross Capital Assets (ending balances)

Gross Capital Asset Account	2007 Actual	2006 EDR	Var $
1805-Land	445,817	445,817	
1806-Land Rights	283,160	283,160	
1808-Buildings and Fixtures			
1810-Leasehold Improvements			
1815-Transformer Station Equipment - Normally Primary above 50 kV			
1820-Distribution Station Equipment - Normally Primary below 50 kV	5,404,466	4,421,144	**983,322**
1830-Poles, Towers and Fixtures	691,035		**691,035**
1835-Overhead Conductors and Devices	25,086,381	22,528,705	**2,557,676**
1840-Underground Conduit	71,215		71,215
1845-Underground Conductors and Devices	18,347,808	16,336,461	**2,011,347**
1850-Line Transformers	12,694,642	10,514,427	**2,180,215**
1855-Services	143,665		143,665
1860-Meters	6,747,779	5,625,800	**1,121,979**
1905-Land			
1906-Land Rights			
1908-Buildings and Fixtures	4,239,676	3,737,050	**502,626**
1910-Leasehold Improvements			
1915-Office Furniture and Equipment	711,405	539,755	171,650
1920-Computer Equipment - Hardware	3,257,250	1,985,558	**1,271,692**
1925-Computer Software	4,395,971	1,868,201	**2,527,770**
1930-Transportation Equipment	3,393,723	2,585,010	**808,713**
1935-Stores Equipment	80,604	42,591	38,013
1940-Tools, Shop and Garage Equipment	692,307	546,958	145,350
1945-Measurement and Testing Equipment	229,399	194,133	35,266
1950-Power Operated Equipment			
1955-Communication Equipment	160,396	142,724	17,672
1960-Miscellaneous Equipment	784,532	493,304	291,228
1965-Water Heater Rental Units			
1970-Load Management Controls - Customer Premises	464,917	418,852	46,065
1975-Load Management Controls - Utility Premises			

Gross Capital Assets (ending balances)

Gross Capital Asset Account	2009 Projection	2008 Projection	Var $	2008 Projection	2007 Actual	Var $
1980-System Supervisory Equipment	1,201,410	1,201,410		1,201,410	1,201,410	
1985-Sentinel Lighting Rental Units						
1990-Other Tangible Property						
1995-Contributions and Grants - Credit	(4,997,587)	(4,270,397)	**(727,190)**	(4,270,397)	(3,688,645)	**(581,752)**
2005-Property Under Capital Leases						
TOTAL	**97,220,570**	**89,892,081**	**7,328,489**	**89,892,081**	**85,838,913**	**4,053,168**

Variances in excess of the below-noted materiality threshold appear in ***bold***

Net Fixed Assets	*37,944,816*		*37,626,976*	
Materiality Threshold		*379,448*		*376,270*

Gross Capital Assets (ending balances)

Gross Capital Asset Account	2007 Actual	2006 EDR	Var $
1980-System Supervisory Equipment	1,201,410	985,837	215,573
1985-Sentinel Lighting Rental Units			
1990-Other Tangible Property			
1995-Contributions and Grants - Credit	(3,688,645)	(2,049,843)	**(1,638,803)**
2005-Property Under Capital Leases			
TOTAL	**85,838,913**	**71,645,644**	**14,193,269**

Variances in excess of the below-noted materiality threshold appear in ***bold***

Net Fixed Assets *37,364,171*
Materiality Threshold *373,642*

Materiality/Variance Analysis on Gross Assets

Included in this schedule are variance explanations of gross assets on an account basis. The balances shown below for gross asset accounts are cumulative in nature and none of the accounts include depreciation. Depreciation is discussed separately in this application. Moreover, the gross asset accounts are not offset to reflect contributed capital. Contributed capital, in totality, is presented in a separate account found in a table at the end of this analysis.

Therefore, the variance from one year to the next reflects gross expenditures in the year that have been allocated to each account. It is important to note that “variances” indicated below do not reflect varied spending from one year to the next. Since capital accounts are cumulative, any expenditure tracked to an account will appear as a “variance”. For example, if $1 were recorded year after year in the same account, although annual spending would remain constant every year, the account would show a “variance” of $1 every year. Accordingly, this analysis helps to indicate where expenditures have been focused for this utility, but the specific expenditures contributing to the variance are addressed in detail by Project ID number at Exhibit 2, Tab 3, Schedule 6 - Materiality Analysis on Capital Additions for those projects exceeding $100,000 in the year. Reference is provided to that schedule in the tables below referring the reader to the appropriate justification where one of the specified projects is contributing to the variance. For a summary listing of projects by Project ID number (i.e. UT1, UT2, etc), please refer to Exhibit 2, Tab 3, Schedule 1.

2008 Bridge Year Compared to 2009 Test Year

Asset Account	2008 Bridge	2009 Test	Variance Amount	Variance %
1830 - Poles, Towers and Fixtures	1,208,153	1,941,647	733,494	61%

Explanation:

Of this variance, $266,469 (36%) relates to routine sustaining investment necessary to sustain the distribution assets of Bluewater Power. The remaining contributors to the variance are related to non-routine projects identified as follows:

27.6 kV Neutral Program	UT5	$	146,820	(Exh 2, Tab 3, Sch 6)
27.6 kV Feeder - Petrolia	UT7	$	14,682	
4 kV Load Conversion	UT9	$	4,894	
27.6 kV Lines Upgrade	UT21	$	58,728	
Overhead Line - Back Lot Re-Build	UT30	$	74,878	
27.6 kV Feeder Extensions	UT32	$	55,058	(Exh 2, Tab 3, Sch 6)
8 kV Load Conversions	UT34	$	33,842	
Asset Condition Assessment	UT40	$	54,495	(Exh 2, Tab 3, Sch 6)
Transmission Station meter upgrade - Modeland	M7	$	23,628	(Exh 2, Tab 3, Sch 6)

Asset Account	2008 Bridge	2009 Test	Variance Amount	Variance %
1835 - Overhead Conductors and Devices	26,137,702	27,247,131	1,109,429	4%

Explanation:

Of this variance, $543,809 (49%) relates to routine sustaining investment necessary to sustain the distribution assets of Bluewater Power. The remaining contributors to the variance are related to non-routine projects identified as follows:

27.6 kV Load Break Switch Replacement	UT3	$	48,940	
27.6 kV Feeder - Petrolia	UT7	$	83,198	
4 kV Load Conversion	UT9	$	21,534	
27.6kV Lines Upgrade	UT21	$	34,258	
Animal Protection	UT29	$	103,940	(Exh 2, Tab 3, Sch 6)
Overhead Line - Back Lot Re-Build	UT30	$	7,635	
27.6 kV Feeder Extensions	UT32	$	67,293	(Exh 2, Tab 3, Sch 6)
8 kV Load Conversions	UT34	$	39,568	
Remote Load Break Switches	UT39	$	75,880	
Modeland TS/St. Andrews Upgrades	UT40	$	54,495	(Exh 2, Tab 3, Sch 6)
Transmission Station meter upgrade - Modeland	M7	$	28,879	(Exh 2, Tab 3, Sch 6)

Asset Account	2008 Bridge	2009 Test	Variance Amount	Variance %
1845 - Underground Conductors and Devices	18,759,860	19,329,938	570,078	3%

Explanation:

Of this variance, $440,694 (77%) relates to routine sustaining investment necessary to sustain the distribution assets of Bluewater Power. The remaining contributors to the variance are related to non-routine projects identified as follows:

Fault Indicators - Underground	UT26	$	18,970	
Manhole Structure Re-builds	UT27	$	25,465	
Modeland TS/St. Andrews Upgrades	UT40	$	54,495	(Exh 2, Tab 3, Sch 6)
Transmission Station meter upgrade - Modeland	M7	$	30,454	(Exh 2, Tab 3, Sch 6)

Asset Account	2008 Bridge	2009 Test	Variance Amount	Variance %
1850 - Line Transformers	13,073,086	13,518,588	445,502	3%

Explanation:

Of this variance, $227,652 (51%) relates to routine sustaining investment necessary to sustain the distribution assets of Bluewater Power. The remaining contributors to the variance are related to non-routine projects identified as follows:

4 kV Load Conversion	UT9	$	71,452	
27.6 kV Lines Upgrade	UT21	$	4,894	
Overhead Line - Back Lot Re-Build	UT30	$	15,367	
Substation Transformer Replacements	UT44	$	126,137	(Exh 2, Tab 3, Sch 6)

Asset Account	2008 Bridge	2009 Test	Variance Amount	Variance %
1860 - Meters	6,999,687	7,697,717	698,030	10%

Explanation:

Of this variance, $255,917 (37%) relates to routine investment necessary to sustain the distribution assets of Bluewater Power. The remaining contributors to the variance are related to non-routine projects identified as follows:

Transmission Station meter upgrade - Modeland	M7	$	442,112	(Exh 2, Tab 3, Sch 6)

Asset Account	2008 Bridge	2009 Test	Variance Amount	Variance %
1908 - Buildings and Fixtures	4,637,699	5,705,016	1,067,317	23%

Explanation:

Of this variance, $204,002 (19%) relates to routine investment necessary to sustain the distribution assets of Bluewater Power. The remaining contributors to the variance are related to non-routine projects identified as follows:

Building Renovation	O5	$	863,315	(Exh 2, Tab 3, Sch 6)

Asset Account	2008 Bridge	2009 Test	Variance Amount	Variance %
1920 - Computer Equipment - Hardware	3,400,871	3,866,633	292,726	14%

Explanation:

Of this variance, $315,762 (68%) relates to routine investment necessary to sustain the distribution assets of Bluewater Power. The remaining contributors to the variance are related to non-routine projects identified as follows:

SAP Upgrade	IT18	$	150,000	(Exh 2, Tab 3, Sch 6)
Data Centre Network Replacement	IT19	$	173,036	(Exh 2, Tab 3, Sch 6)

Asset Account	2008 Bridge	2009 Test	Variance Amount	Variance %
1925 - Computer Software	5,334,806	7,501,976	2,167,170	41%

Explanation:

Of this variance, $711,836 (33%) relates to routine investment necessary to sustain the distribution assets of Bluewater Power. The remaining contributors to the variance are related to non-routine projects identified as follows:

GIS	UT45	$	160,189	(Exh 2, Tab 3, Sch 6)
SAP Upgrade	IT18	$	1,295,145	(Exh 2, Tab 3, Sch 6)

Asset Account	2008 Bridge	2009 Test	Variance Amount	Variance %
1995 - Contributions and Grants - Credit	(4,270,397)	(4,997,587)	(727,190)	17%

Explanation:

This variance is based on historical amounts and trends which are expected to continue in the test year. Contributions are mainly related to sub-division development.

2007 Actual Year Compared to 2008 Bridge Year

Asset Account	2007 Actual	2008 Bridge	Variance Amount	Variance %
1830 - Poles, Towers and Fixtures	691,035	1,208,153	517,118	75%

Explanation:

Of this variance, $242,618 (47%) relates to projects identified as necessary to sustain the distribution assets of Bluewater Power. The remaining contributors to the variance are related to non-routine projects identified as follows:

27.6kV Neutral Program	UT5	$	40,000	
27.6 kV Feeder - Petrolia	UT7	$	18,750	(Exh 2, Tab 3, Sch 6)
4 kV Load Conversion	UT9	$	4,000	
27.6 kV Lines Upgrade	UT21	$	60,000	(Exh 2, Tab 3, Sch 6)
Overhead Line - Back Lot Re-Build	UT30	$	61,200	
27.6 kV Feeder Extensions	UT32	$	67,500	(Exh 2, Tab 3, Sch 6)
8 kV Load Conversions	UT34	$	23,050	

Asset Account	2007 Actual	2008 Bridge	Variance Amount	Variance %
1835 - Overhead Conductors and Devices	25,086,381	26,137,702	1,051,321	4%

Explanation:

Of this variance, $511,781 (49%) relates to projects identified as necessary to sustain the distribution assets of Bluewater Power. The remaining contributors to the variance are related to non-routine projects identified as follows:

27.6kV Load Break Switch Replacement	UT3	$	50,000	
27.6 kV Feeder - Petrolia	UT7	$	106,250	(Exh 2, Tab 3, Sch 6)
4 kV Load Conversion	UT9	$	17,600	
27.6 kV Lines Upgrade	UT21	$	35,000	(Exh 2, Tab 3, Sch 6)
Animal Protection	UT29	$	50,000	
Overhead Line - Back Lot Re-Build	UT30	$	6,240	
27.6 kV Feeder Extensions	UT32	$	82,500	(Exh 2, Tab 3, Sch 6)
8 kV Load Conversions	UT34	$	26,950	
Remote Load Break Switches	UT39	$	60,000	
Elimination of Load Transfers	UT41	$	105,000	(Exh 2, Tab 3, Sch 6)

Asset Account	2007 Actual	2008 Bridge	Variance Amount	Variance %
1845 - Underground Conductors and Devices	18,347,808	18,759,860	412,052	2%

Explanation:

Of this variance, $377,352 (92%) relates to routine investment necessary to sustain the distribution assets of Bluewater Power. The remaining contributors to the variance are related to non-routine projects identified as follows:

Fault Indicators - Underground	UT26	$	20,000
Manhole Structure Re-builds	UT27	$	14,700

Asset Account	2007 Actual	2008 Bridge	Variance Amount	Variance %
1850 - Line Transformers	12,694,642	13,073,086	378,444	3%

Explanation:

Of this variance, $207,484 (55%) relates to projects identified necessary to sustain the distribution assets of Bluewater Power. The remaining contributors to the variance are related to non-routine projects identified as follows:

4 kV Load Conversion	UT9	$	58,400	
Transformer Replacements (PCB Units)	UT19	$	50,000	
27.6 kV Lines Upgrade	UT21	$	5,000	(Exh 2, Tab 3, Sch 6)
Overhead Line - Back Lot Re-Build	UT30	$	12,560	
Elimination of Load Transfers	UT41	$	45,000	(Exh 2, Tab 3, Sch 6)

Asset Account	2007 Actual	2008 Bridge	Variance Amount	Variance %
1908 - Buildings and Fixtures	4,239,676	4,637,699	398,023	9%

Explanation:

Of this variance, $213,023 (54%) relates to routine investment necessary to sustain the distribution assets of Bluewater Power. The remaining contributors to the variance are related to non-routine projects identified as follows:

Building Renovation	O5	$	185,000	(Exh 2, Tab 3, Sch 6)

Asset Account	2007 Actual	2008 Bridge	Variance Amount	Variance %
1925 - Computer Software	4,395,971	5,334,806	938,835	21%

Explanation:

Of this variance, $828,835 (88%) relates to routine investment necessary to sustain the distribution assets of Bluewater Power. The remaining contributors to the variance are related to non-routine projects identified as follows:

SCADA Projects	UT20	$	10,000	
CYME Gateway	UT42	$	100,000	(Exh 2, Tab 3, Sch 6)

Asset Account	2007 Actual	2008 Bridge	Variance Amount	Variance %
1995 - Contributions and Grants - Credit	(3,688,645)	(4,270,397)	(581,752)	16%

Explanation:

This variance is based on historical amounts and trends which are expected to continue in the bridge year. Contributions are mainly related to sub-division development.

Accumulated Depreciation Table

The accumulated depreciation table is attached as Exhibit 2, Tab 2, Schedule 4, Attachment 1.

Accumulated Amortization (ending balances)

Gross Capital Asset Account	2009 Projection	2008 Projection	Var $	2008 Projection	2007 Actual	Var $
1805-Land						
1806-Land Rights	(278,059)	(263,767)	(14,292)	(263,767)	(262,574)	(1,193)
1808-Buildings and Fixtures						
1810-Leasehold Improvements						
1815-Transformer Station Equipment - Normally Primary above 50 kV						
1820-Distribution Station Equipment - Normally Primary below 50 kV	(2,925,222)	(2,783,631)	(141,591)	(2,783,631)	(2,653,340)	(130,291)
1830-Poles, Towers and Fixtures	(132,821)	(70,539)	(62,282)	(70,539)	(32,506)	(38,033)
1835-Overhead Conductors and Devices	(15,732,391)	(14,878,813)	**(853,578)**	(14,878,813)	(13,929,821)	**(948,992)**
1840-Underground Conduit	(14,917)	(7,213)	(7,704)	(7,213)	(2,849)	(4,364)
1845-Underground Conductors and Devices	(10,711,393)	(9,982,992)	**(728,401)**	(9,982,992)	(9,273,607)	**(709,385)**
1850-Line Transformers	(7,663,095)	(7,140,864)	**(522,231)**	(7,140,864)	(6,638,803)	**(502,061)**
1855-Services	(26,046)	(11,686)	(14,360)	(11,686)	(3,162)	(8,524)
1860-Meters	(4,415,459)	(4,167,304)	(248,155)	(4,167,304)	(3,938,841)	(228,463)
1905-Land						
1906-Land Rights						
1908-Buildings and Fixtures	(1,783,262)	(1,710,123)	(73,139)	(1,710,123)	(1,644,977)	(65,146)
1910-Leasehold Improvements						
1915-Office Furniture and Equipment	(621,910)	(592,728)	(29,182)	(592,728)	(561,917)	(30,811)
1920-Computer Equipment - Hardware	(3,040,880)	(2,680,860)	(360,020)	(2,680,860)	(2,331,912)	(348,948)
1925-Computer Software	(4,478,714)	(3,395,927)	**(1,082,787)**	(3,395,927)	(2,539,512)	**(856,415)**
1930-Transportation Equipment	(2,353,320)	(2,383,129)	29,809	(2,383,129)	(2,515,885)	132,756
1935-Stores Equipment	(103,377)	(55,123)	(48,254)	(55,123)	(48,905)	(6,218)
1940-Tools, Shop and Garage Equipment	(586,368)	(556,778)	(29,590)	(556,778)	(530,545)	(26,233)
1945-Measurement and Testing Equipment	(210,614)	(207,087)	(3,527)	(207,087)	(203,560)	(3,527)
1950-Power Operated Equipment						
1955-Communication Equipment	(145,521)	(136,534)	(8,987)	(136,534)	(130,942)	(5,592)
1960-Miscellaneous Equipment	(660,360)	(609,487)	(50,873)	(609,487)	(562,211)	(47,276)
1965-Water Heater Rental Units						
1970-Load Management Controls - Customer Premises	(467,443)	(455,704)	(11,739)	(455,704)	(442,592)	(13,112)
1975-Load Management Controls - Utility Premises						

Accumulated Amortization (ending balan

Gross Capital Asset Account	2007 Actual	2006 EDR	Var $
1805-Land			
1806-Land Rights	(262,574)	(221,619)	(40,955)
1808-Buildings and Fixtures			
1810-Leasehold Improvements			
1815-Transformer Station Equipment - Normally Primary above 50 kV			
1820-Distribution Station Equipment - Normally Primary below 50 kV	(2,653,340)	(2,251,875)	**(401,465)**
1830-Poles, Towers and Fixtures	(32,506)		(32,506)
1835-Overhead Conductors and Devices	(13,929,821)	(10,746,858)	**(3,182,964)**
1840-Underground Conduit	(2,849)		(2,849)
1845-Underground Conductors and Devices	(9,273,607)	(6,971,481)	**(2,302,126)**
1850-Line Transformers	(6,638,803)	(5,079,269)	**(1,559,534)**
1855-Services	(3,162)		(3,162)
1860-Meters	(3,938,841)	(3,212,663)	**(726,178)**
1905-Land			
1906-Land Rights			
1908-Buildings and Fixtures	(1,644,977)	(1,426,051)	(218,926)
1910-Leasehold Improvements			
1915-Office Furniture and Equipment	(561,917)	(472,937)	(88,980)
1920-Computer Equipment - Hardware	(2,331,912)	(1,410,824)	**(921,088)**
1925-Computer Software	(2,539,512)	(511,803)	**(2,027,709)**
1930-Transportation Equipment	(2,515,885)	(2,278,476)	(237,409)
1935-Stores Equipment	(48,905)	(31,169)	(17,736)
1940-Tools, Shop and Garage Equipment	(530,545)	(447,580)	(82,965)
1945-Measurement and Testing Equipment	(203,560)	(185,753)	(17,807)
1950-Power Operated Equipment			
1955-Communication Equipment	(130,942)	(110,071)	(20,871)
1960-Miscellaneous Equipment	(562,211)	(452,651)	(109,560)
1965-Water Heater Rental Units			
1970-Load Management Controls - Customer Premises	(442,592)	(379,695)	(62,897)
1975-Load Management Controls - Utility Premises			

Accumulated Amortization (ending balances)

Gross Capital Asset Account	2009 Projection	2008 Projection	Var $	2008 Projection	2007 Actual	Var $
1980-System Supervisory Equipment	(692,143)	(644,089)	(48,054)	(644,089)	(596,035)	(48,054)
1985-Sentinel Lighting Rental Units						
1990-Other Tangible Property						
1995-Contributions and Grants - Credit	968,078	787,111	180,967	787,111	632,558	154,553
2005-Property Under Capital Leases						
TOTAL	**(56,075,235)**	**(51,947,265)**	**(4,127,970)**	**(51,947,265)**	**(48,211,936)**	**(3,735,329)**

Variances in excess of the below-noted materiality threshold appear in ***bold***

Net Fixed Assets	*37,944,816*		*37,626,976*	
Materiality Threshold		*379,448*		*376,270*

Accumulated Amortization (ending balan

Gross Capital Asset Account	2007 Actual	2006 EDR	Var $
1980-System Supervisory Equipment	(596,035)	(440,001)	(156,034)
1985-Sentinel Lighting Rental Units			
1990-Other Tangible Property			
1995-Contributions and Grants - Credit	632,558		**632,558**
2005-Property Under Capital Leases			
TOTAL	**(48,211,936)**	**(36,630,775)**	**(11,581,161)**

Variances in excess of the below-noted materiality threshold appear in ***bold***

Net Fixed Assets	*37,364,171*	
Materiality Threshold		*373,642*

Materiality Analysis on Accumulated Depreciation

Depreciation rates used by Bluewater Power have not changed during the period of this analysis. The depreciation rates applied by Bluewater Power are outlined in Exhibit 2, Tab 3, Schedule 5 and are consistent with those outlined in Appendix B of the *2006 Distribution Rate Handbook.*

Depreciation follows directly from capital investment. To that extent, all material variances in depreciation outlined in the following schedules have the same justification as the corresponding investment in gross capital assets. Therefore, the reader is referred to the explanations found in Exhibit 2, Tab 2, Schedule 3 for variance explanations relating to Gross Assets.

Table 2.2.5.1 demonstrates that depreciation has increased steadily over the past several years at Bluewater Power indicating an increased level of spending on capital projects. Another contributing factor to the increase in the level of amortization is the increased level of capital spending in the areas of Information Technology; items falling under the category of "Computer Equipment Hardware" and "Computer Software" have a 5 year lifespan for depreciation purposes compared to 25 to 30 years for "Distribution Plant" and 5 to 10 years for "General Plant".

Table 2.2.5.1 - Depreciation on an Annual Basis

($000's)	2007 Actual	2008 Bridge Year	2009 Test Year
Depreciation & Amortization	3,847.9	4,045.3	4,358.1

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Capital Plan

Capital Plan by Project

The three year detailed capital plan by project is found at Exhibit 2, Tab 3, Schedule 1, Attachment 1.

Although Bluewater Power's materiality threshold for capital projects is approximately $350,000, written explanations of capital projects that exceed $100,000 in any year are set out at Exhibit 2, Tab 3, Schedule 6 – Materiality Analysis on Capital Additions. All amounts in the table represent capital additions that were or will be in-service within the year under which they fall.

In 2007, Bluewater Power completed 63 capital projects at a cost of $4,858,828. Twelve of these capital projects exceeded $100,000, and accounted for $3,089,150 (64%) of the total capital budget. The remaining 51 projects have an average cost of $25,648.

In 2008, Bluewater Power completed or will complete 57 capital projects at a cost of $5,139,900. Thirteen of these capital projects are forecasted to exceed $100,000, and accounted for $3,040,500 (59%) of the total. The remaining 44 projects have an average cost of $24,184.

In 2009, Bluewater Power will complete 49 capital projects at a cost of $8,286,810. Twenty of these capital projects are forecasted to exceed $100,000, and account for $6,656,798 (80%) of the total. The remaining 29 projects have an average cost of $28,104.

Capital Expenditures

The following table numerically summarizes Bluewater Power's capital expenditures from 2007 to 2009:

Table 2.3.1.1

	2007 Actual	2008 Budget	2009 Budget
Operations	$ 3,387,683	$ 3,823,000	$ 4,277,313
Metering	$ 521,844	$ 185,000	$ 711,245
Information Technology	$ 776,909	$ 893,000	$ 2,431,744
Other	$ 172,393	$ 238,900	$ 865,517
Total	$ 4,858,829	$ 5,139,900	$ 8,285,819
Variance		*$ 281,071*	*$ 3,145,919*

These categories of capital expenditures are discussed below.

Operations

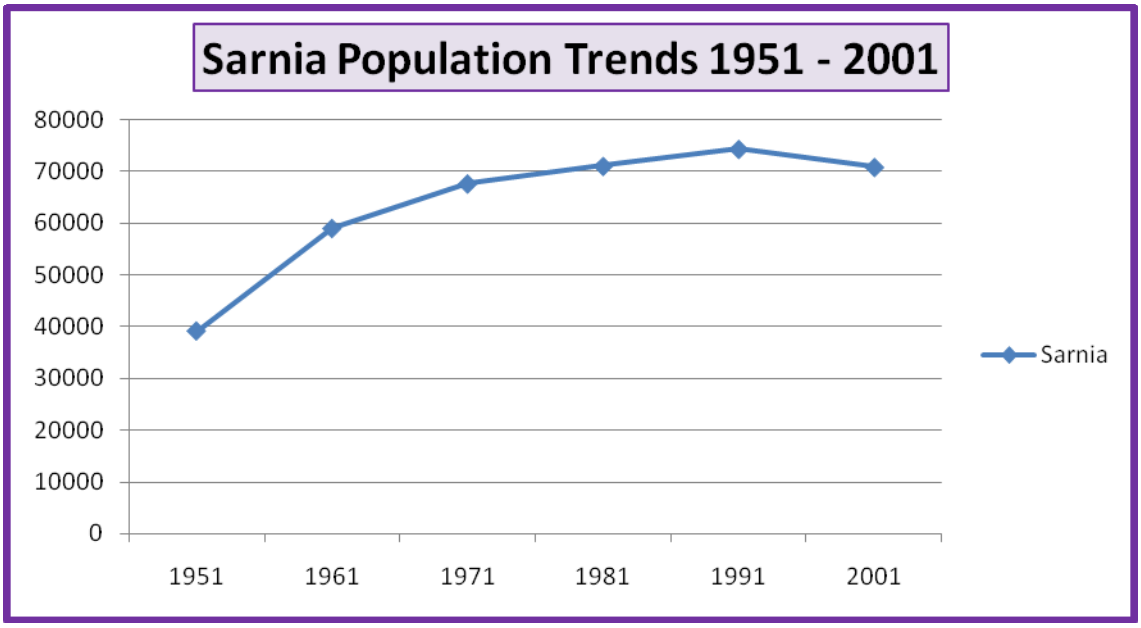
Bluewater Power's capital investments in operations (i.e. poles, conductor, transformers, etc.) can generally be classified into two categories: (i) sustaining capital investment (operations); and (ii) non-routine capital investment (operations). Both of these categories are described below.

Sustaining Capital Investment (Operations):

Sustaining capital investment refers to baseline investment that is made every year to maintain Bluewater Power's system reliability as well as to accommodate the typical growth of Bluewater Power's system.

Sarnia's population increased rapidly from approximately 40,000 to 70,000 (75% increase) between 1950 and 1970 as shown in Table 2.3.1.2. Consequently, the heaviest period of capital growth was during this time frame, meaning that a significant portion of Bluewater Power's operating assets (i.e. poles, conductor, transformers, etc.) are between 40 and 60 years of age.

Table 2.3.1.2



Bluewater Power estimates that the average age of its operating assets is between 20-30 years, as a result of Bluewater Power's efforts to update its infrastructure through its ongoing sustaining capital investments since 1970. As illustrated in Table 2.3.1.3, from 2007 to 2009, Bluewater Power's sustaining capital investment in operating assets has remained relatively stable at approximately $2.5 million/year.

Table 2.3.1.3

	2007 Actual	2008 Budget	2009 Budget
Sustaining Capital Investment	$2,404,673	$2,496,000	$2,711,762

The typical engineering life of distribution system components is 40 to 50 years. Therefore, Bluewater Power's distribution system is nearing its end of life. If Bluewater Power does not increase its sustaining capital investment in operating assets going forward, it will be required to make significant investments between 2020 and 2030. To avoid this last-minute catch-up scenario, commencing in 2010, Bluewater Power intends to work toward increasing its sustaining capital investment in operating assets to approximately $4 million per year.

Non-Routine Capital Investment (Operations):

Non-routine capital investment in operations refers to investment in capital projects that are non-recurring to address a particular operational need beyond routine sustaining capital investment. Non-routine operating projects may occur in a single year (a "single-year project") or over a number of years (a "multi-year project"). This type of investment fluctuates from year-to-year depending on capital needs identified as part of Bluewater Power's Asset Management Plan described in Exhibit 2, Tab 3, Schedule 9.

Bluewater Power's multi-year and single year capital projects (operations) are listed at Exhibit 2, Tab 3, Schedule 1, and those greater than $100,000 in any given year are described at Exhibit 2, Tab 3, Schedule 6.

Metering

The following types of meters are used by Bluewater Power:

- *Single-phase meters*: Bluewater Power owns approximately 3,635 single-phase meters used for residential and some small commercial customers;
- *Network meters:* Bluewater Power owns approximately 1,247 network meters used for multi-unit buildings (i.e., apartment buildings);
- *Polyphase meters:* Bluewater Power owns approximately 2,136 polyphase meters used for commercial and industrial customers; and
- *Wholesale meters:* Bluewater Power currently owns eight wholesale meters that are connected to Hydro One's transmission system.

Bluewater Power typically spends approximately $175,000 per year in sustaining capital for its meters. This sustaining capital is primarily attributable to the routine re-sealing/replacement of single-phase meters as described at Exhibit 2, Tab 3, Schedule 6 (project M1). Fluctuations in Bluewater Power's meter capital expenditures (i.e. in 2007 and in 2009) are directly attributable to the non-discretionary replacement of wholesale meters in Hydro One's stations, described at Exhibit 2, Tab 3, Schedule 6 (projects M7 and M3). All of Bluewater Power's metering capital projects in 2007, 2008 and 2009 are listed at Exhibit 2, Tab 3, Schedule 1.

Bluewater Power has not included any smart meter capital costs in this application, although it is requesting that its smart meter rate adder be increased from $0.26 to $1.00 at Exhibit 5, Tab 1, Schedule 4.

Information Technology

Bluewater Power's information technology ("IT") capital costs remain relatively stable from year to year. The $1,538,744 increase from 2008 ($893,000) to 2009 ($2,431,744) is almost entirely attributable to one IT capital project in 2009 budgeted at $1,445,145. This project is an upgrade of Bluewater Power's current integrated, SAP ERP system and is described at Exhibit 2, Tab 3, Schedule 6 (project IT18). All of Bluewater Power's IT capital projects in 2007, 2008 and 2009 are listed at Exhibit 2, Tab 3, Schedule 1.

Other

Those capital expenditures that do not fit within operations, metering or information technology are included in the "Other" category. The large increase in this category from 2008 to 2009 is almost entirely attributable to Bluewater Power's building renovation project described at Exhibit 2, Tab 3, Schedule 6 (project O5).

	BLUEWATER POWER CAPITAL PLAN BY PROJECT				
Project ID	Project Name	Sustaining & Ongoing (S), Non-Routine (N)	2009 Budget	2008 Budget	2007 Actuals
	Operations/Design Services				
UT1	Furniture	N	-	2,000	2,000
UT2	Substation Building Improvement Program	S	106,970	60,000	37,732
UT3	27.6 Load Break Switch Replacement	N	48,940	50,000	47,555
UT4	Street Widening	S	53,274	60,000	12,833
UT5	27.6kV Neutral Program	N	146,820	40,000	24,512
UT6	Sub #2 Conversion - Phase III	N	-	100,000	48,208
UT7	27.6 Feeder - Petrolia Program	N	97,880	125,000	32,623
UT8	Alvinston/Oil Springs Capital Items	S	19,576	20,000	12,814
UT9	4KV Load Conversion	N	97,880	80,000	91,861
UT10	Pt Edward upgrades	S	48,940	40,000	47,610
UT11	Tools	S	44,000	20,000	22,417
UT12	Vehicle Replacements	S	528,000	450,000	261,891
UT13	New Connections	S	978,799	800,000	1,166,879
UT14	Strategic Transformer Inventory	S	163,485	150,000	232,686
UT15	5kV Protective Relay Replacement	N	81,940	80,000	52,354
UT16	Safety Related Projects	S	11,000	5,000	6,884
UT17	Cross Arm/Cap & Pin Insulator Replacement	S	97,880	80,000	72,047
UT18	Wood Pole Replacement Program	S	97,880	100,000	108,219
UT19	Transformer Replacements (PCB Units)	N	-	50,000	94,146
UT20	SCADA Projects	N	-	10,000	17,954
UT21	27.6kV Lines Upgrades	N	97,880	100,000	102,828
UT22	Perch DS Conversion	N	-	-	68,958
UT23	Watford	S	77,334	30,000	31,357
UT24	Load Balancing	S	47,425	20,000	17,542
UT25	CEO Contingency Fund	S	212,425	200,000	194,899
UT26	Fault Indicators - Underground	N	18,970	20,000	15,984
UT27	Manhole Structure Re-builds	N	51,970	30,000	20,700
UT28	Service Centre	S	53,485	97,000	87,112
UT29	Animal Protection	N	103,940	50,000	22,421
UT30	Overhead Line - Back Lot Rebuild	N	97,880	80,000	62,556
UT31	18M11 Recloser	N	-	-	4,951
UT32	27.6 Kv Feeder Extensions	N	122,350	150,000	-
UT33	Reclosers (other types)	N	-	-	129,336
UT34	8 kv Load Conversion	N	73,410	50,000	32,140
UT35	Transformer Cover Replacements	S	24,470	20,000	24,157
UT36	Harbour Rd. & Seaway Rd. Upgrades	N	-	-	71,561
UT37	Vault 'K'-Riser installation	N	-	-	40,362
UT38	Storm Restoration	S	146,820	150,000	67,594
UT39	Remote Load Break Switches	N	75,880	60,000	-
UT40	Asset Condition Assessment	N	163,485	-	-
UT41	Elimination of Load Transfers	N	-	150,000	-
UT42	Cyme Gateway	N	-	100,000	-
UT43	Management Labour	S	-	194,000	-
UT44	Substation Transformer #9 Replacement	N	126,137	-	-
UT45	Geographical Information System (GIS)	N	160,189	-	-
	Total Operations/Design Services		**4,277,313**	**3,823,000**	**3,387,683**
		S	**2,711,762**	**2,496,000**	**2,404,673**
		N	**1,565,550**	**1,327,000**	**983,010**
			4,277,313	**3,823,000**	**3,387,683**

Project ID	Project Name	Sustaining & Ongoing (S), Non-Routine (N)	2009 Budget	2008 Budget	2007 Actuals
	Metering				
M1	Single Phase Meters	S	96,706	100,000	114,558
M2	Poly Phase Meters	S	55,365	60,000	66,535
M3	St. Andrews Meter Upgrade	N	-	-	313,813
M4	New Meters	S	27,500	20,000	19,321
M5	Traffic Room Organization	N	-	-	3,736
M6	Metering Tools	S	6,600	5,000	3,881
M7	Trans Station Meter Upgrade - Modeland	N	525,074	-	-
	Total Metering		**711,245**	**185,000**	**521,844**
		S	**186,171**	**185,000**	**204,295**
		N	**525,074**	**-**	**317,549**
			711,245	**185,000**	**521,844**
	Information Technology				
IT1	Corporate IT Security	S	48,462	40,000	37,069
IT2	Customer Self-Service	N	-	-	12,780
IT3	Data Centre Lifecycle	S	265,379	202,500	212,938
IT4	Deloitte/SAP AMO	S	-	144,000	70,483
IT5	Computer Infrastructure Lifecycle	S	118,777	60,000	58,741
IT6	Recurring Systems Developments & Enhancements	S	60,267	100,000	125,228
IT7	Legislated Business Application Upgrades	S	198,625	140,000	76,113
IT8	Software-Upgrades and Additions	S	107,036	75,000	74,172
IT9	GIS Developments	S	-	2,500	-
IT10	Microsoft SQL	N	-	-	37,503
IT11	Server OS Upgrades	N	-	-	24,826
IT12	Blackberry	N	-	-	20,756
IT13	SAP Performance Optimization	N	-	-	1,478
IT14	GIS - (Various)	N		-	24,822
IT15	Data Backup and Restore	S	-	47,000	-
IT16	Document Management	S	15,018	37,000	-
IT17	IT Management Tools	S	-	45,000	-
IT18	SAP Upgrade	N	1,445,145	-	-
IT19	Data Center Network Lifecycle Replacement	N	173,036	-	-
	Total Information Technology		**2,431,744**	**893,000**	**776,909**
		S	**813,563**	**893,000**	**654,744**
		N	**1,618,180**	**-**	**122,165**
			2,431,744	**893,000**	**776,909**
	Other Projects				
O1	Other Projects (all below $100,000)	N	2,202	53,900	144,239
O5	Building Renovations/Expansion	N	863,315	185,000	28,154
	Total Other Projects	**N**	**865,517**	**238,900**	**172,393**
	Grand Total		**8,285,818**	**5,139,900**	**4,858,829**
		S	**3,711,497**	**3,574,000**	**3,263,712**
		N	**4,574,321**	**1,565,900**	**1,595,117**
			8,285,818	**5,139,900**	**4,858,829**
	The projects highlighted are discussed at Exhibit 2, Tab 3, Schedule 6 - Materiality Analysis on Capital Additons.				

Summary of Asset Additions

Table 2.3.2.1 details the gross asset additions for each of 2008 and 2009. The average of 2008 and 2009 forms the gross asset additions to be included in the calculation of rate base.

Table 2.3.2.1

USoA Account	Description	2008 Bridge Year	2009 Test Year	Grand Total
1805	Land	$ 0	$0	$0
1806	Land Rights	$0	$0	$0
1820	Distribution Station	$231,747	$130,491	$362,238
1830	Poles, Towers, Fixtures	$517,118	$733,494	$1,250,612
1835	Overhead	$1,051,321	$1,109,429	$2,160,750
1840	Underground Conduit	$75,759	$96,978	$172,738
1845	Underground Conductors, Devices	$412,052	$570,078	$982,130
1850	Transformers	$378,444	$445,502	$823,946
1855	Services Underground	$138,840	$163,459	$302,300
1860	Meters	$251,908	$698,030	$949,938
1908	Building	$398,023	$1,067,317	$1,465,340
1915	Office Equip	$8,522	$4,036	$12,558
1920	Computer Equip - Hardware	$143,621	$465,762	$609,383
1925	Computer Equip - Software	$938,835	$2,167,170	$3,106,005
1930	Transportation Equipment	$504,440	$565,599	$1,070,039
1935	Stores	$0	$0	$0
1940	Tools	$38,763	$68,473	$107,236
1945	Measure & Testing Equipment	$0	$0	$0
1955	Communication Equipment	$0	$0	$0
1960	New Era	$50,506	$	$50,506
1970	Load Mgmt Customer Premises	$0	$0	$0
1980	Scada	$0	$0	$0
	Total	**$5,139,900**	**$8,285,819**	**$13,425,719**

Summary of Asset Retirements

In 2007, 2008 and 2009, Bluewater Power did not nor will it retire any utility assets that have remaining book value. Bluewater Power strives to retire utility assets at the end of their useful life, which typically exceeds their accounting life.

Leave to Construction (under Section 92)

Bluewater Power does not have any projects that require a Leave to Construction.

Fixed Assets and Associated Depreciation Rates

USoA		Straight Line	Straight Line
Account	Account Description	Life - Years	Rate
1805	Distribution Plant - Land	N/A	N/A
1806	Distribution Plant - Land Rights/Easements	25	4.0%
1820	Distribution Plant - Distribution Stn. Equip. < 50KV	30	3.3%
1830	Distribution Plant - Poles, Towers and Fixtures	25	4.0%
1835	Distribution Plant - Overhead Conductors, Devices	25	4.0%
1840	Distribution Plant - Underground Conduit	25	4.0%
1845	Distribution Plant - Underground Conductors, Devices	25	4.0%
1850	Distribution Plant - Line Transformers	25	4.0%
1855	Distribution Plant - Services Underground	25	4.0%
1860	Distribution Plant - Meters	25	4.0%
1908	General Plant - Building/Fixtures	60	1.7%
1915	General Plant - Office Furniture/Equipment	10	10.0%
1920	Computer Equipment Hardware	5	20.0%
1925	Computer Software	5	20.0%
1930	General Plant - Transportation Equipment - heavy	8	12.5%
1930	General Plant - Transportation Equipment - light	5	20.0%
1935	General Plant - Stores Equipment	10	10.0%
1940	General Plant - Tools and Garage Equipment	10	10.0%
1945	General Plant - Measure and Testing Equipment	10	10.0%
1955	General Plant - Communication Equipment - FM	10	10.0%
1960	General Plant - Miscellaneous Equipment	5	20.0%
1970	General Plant - Load Mgt Customer Premises	10	10.0%
1980	General Plant - System Supervisory Equipment	25	4.0%

The amortization rates used by Bluewater Power are the same as the rates found in Appendix B of the rate handbook. These rates have not changed since the approval of the 2006 EDR application. They reflect a rational and systematic allocation of cost over future periods appropriate to the nature of the property, plant and equipment.

Materiality Analysis on Capital Additions

Bluewater Power's materiality threshold for capital projects prescribed by the Filing Guidelines is approximately $350,000. Despite this materiality threshold, Bluewater Power has provided descriptions for capital projects that exceed a threshold of $100,000 in 2007, 2008 and 2009.For a complete list of capital projects (both below and above $100,000), please refer to Exhibit 2, Tab 3, Schedule 1, Attachment 1.

As set out in the Capital Plan by Project at Exhibit 2, Tab 3, Schedule 1, Bluewater Power's capital expenditures can be categorized as follows: operations; meters; information technology; and other. Within each of these categories, capital expenditures can be described as either (i) ongoing sustaining capital investment; or (ii) non-routine capital investment.

Ongoing sustaining capital investment refers to baseline investment that is made every year to maintain Bluewater Power's system reliability and to accommodate the typical growth of Bluewater Power's system. Included in this category are non-discretionary projects such as new customer connections and relocation of plant in conjunction with municipal street widenings.

Non-routine capital investment refers to investment in capital projects that are non-recurring to address a particular need beyond routine sustaining capital investment. Non-routine capital projects may occur in a single year ("single-year projects") or over a number of years ("multi-year projects"). For multi-year projects, only those portions of the projects that come into service in a particular year are included in that year's rate base.

The project descriptions below are organized based on these categorizations.

Description	**Project Identifier**
I. Operations	
i. Sustaining Capital Investment (Operations)	
Substation Building Improvement Program	UT2
Vehicle Replacements	UT12
New Connections	UT13
Strategic Transformer Inventory	UT14
Cross Arm/Cap & Pin Insulator Replacement	UT17
Wood Pole Replacement Program	UT18
CEO Contingency Fund	UT25
Service Centre	UT28
Storm Restoration	UT38
Management Labour	UT43
ii. Non-Routine Capital Investment (Operations)	
27.6 kV Neutral Program	UT5
Sub #2 Conversion - Phase 3	UT6
27.6 kV Feeder – Petrolia Program	UT7
27.6 kV Lines Upgrade	UT21
Animal Protection	UT29
Over-head Line Back Lot Re-Build	UT30
27.6 kV Feeder Extension	UT32
Reclosures	UT33
Voltage Conversion Program	UT9 and UT34
Asset Condition Assessment	UT40
Elimination of Long Term Load Transfers	UT41
CYME Gateway	UT42

Substation Transformer #9 Replacement	UT44
Geographic Information System	UT45
II. METERS	
i. Sustaining Capital Investment (Meters)	
Single Phase Meters	M1
ii. Non-Routine Capital Investment (Meters)	
Transmission Station Meter Upgrade – St. Andrews	M3
Transmission Station Meter Upgrade – Modeland	M7
III. INFORMATION TECHNOLOGY	
i. Sustaining Capital Investment (IT)	
Data Centre Lifecycle	IT3
Deloitte/SAP AMO	IT4
Computer Infrastructure Lifecycle	IT5
Recurring Systems Developments & Enhancements	IT6
Legislated Business Application Upgrades	IT7
Software-upgrades and additions	IT8
ii. Non-Routine Capital Investment (IT)	
SAP Upgrade	IT18
Data Centre Network Replacement	IT19
IV. OTHER	
Building Renovations/Expansion	O5

1

I. OPERATIONS

i. Sustaining Capital Investment (Operations)

Substation Building Improvement Program (UT2)

Improvements at Bluewater Power's 4 kV and 8 kV substation buildings is an ongoing sustaining program that is required to keep Bluewater Power's substation buildings in reasonable condition. Many of Bluewater Power's 4 kV and 8 kV substations are located within subdivisions (i.e. in some cases, residential homes are located adjacent to a substation). Examples of this ongoing sustaining capital work include:

- Replacement of old and/or defective siding, windows, doors, painting, fences, roof/shingles;
- Professional assessment and repair of deteriorating exterior finish;
- Battery replacements at various substations;
- Substation fan control upgrades to cool equipment when necessary.

Bluewater Power has typically spent approximately $37,000 per year on this sustaining capital work; however this amount is not enough to maintain the 4 kV and 8 kV substations. They are in need of additional capital investment, particularly in regard to old and/or defective siding, windows, doors, painting, fences and roof/shingles.

2009 Expenditures (budgeted): $106,970

In addition to the regular sustaining capital work described above, the following substations with deteriorating exteriors require repair in 2009:

- MS #1 Water Street Substation (stucco exterior is deteriorating) – this is an historic landmark in Sarnia; and
- MS#30 Centre Street Substation (brick exterior crumbling and shifting).

The exterior repair work for MS#1 and MS#30 is scheduled to commence in January, 2009 and will be complete in 2009.

Vehicle Replacements (UT12)

Bluewater Power has a comprehensive fleet management system. Using software developed by Bluewater Power (the “Access Data Base”),Bluewater Power tracks kilometers driven, litres of fuel per kilometer, corrective maintenance, planned maintenance and required testing for each vehicle in its fleet. This management system assists in maximizing the useful life of Bluewater Power’s vehicles.

Several factors come into play when Bluewater Power makes a decision to replace a vehicle. Data is utilized that has been collected in regard to engine hours, kilometers traveled, operator feedback, operator safety and consideration of whether the vehicle design continues to meet Bluewater Power’s requirements.

When the analysis indicates that a vehicle is below Bluewater Power’s standard for safety, economic viability or intended work design, a proposal is prepared requesting the purchase of a new vehicle.

Bluewater Power works from a five year capital plan to prepare for vehicle budgeting. For the purchase of large fleet vehicles a team comprised of users, a mechanic and a management supervisor is created to review the products of different manufacturers and request estimated costs early in a budget year. Following budget approval from the Bluewater Power Board of Directors the team moves into deeper analysis, utilizing demonstration vehicles, visiting and discussing reliability, warrantee response and overall vehicle satisfaction with other LDCs who have purchased similar equipment.

The Materials Management Department prepares an RFP based on team results and sends it out to the chosen manufacturers who have met the desired vehicle criteria. The contract is awarded based on the manufacturer meeting the required specifications, cost and overall support from the team.

2007 Expenditures (actual): $261,891

	Proposed New Vehicle	Replacing Vehicle	Cost
1	Single bucket for Operations Department	None	$243,210
2	Kubota Lawn Tractor	None	$8,640
3	UtilEquip dump trailer	None	$10,041
		Total	**$261,891**

1. A new single bucket truck was added to the Operations fleet. The new truck is utilized for service work, emergency work and installing ropes and equipment for large capital projects. The new truck improved efficiencies at Bluewater Power by having a faster, more fuel efficient vehicle performing work that was historically done by a truck that was designed for heavier lifting projects. It filled a void that was growing with commercial and residential growth.

2. Purchasing a lawn tractor that could be utilized specifically for the main service centre allowed an older lawn tractor to be located at a large Bluewater Power substation at Maxwell and Front Street. This eliminated the need to trailer the machine back and forth and improved lawn aesthetics of an old substation that is in a high traffic tourist area of Sarnia.

3. Due to the increasing number of underground utilities and pipelines associated with the Sarnia chemical industry, Bluewater Power has been utilizing a day lighting contractor for excavation of pole holes, anchors etc. Day lighting companies use high pressure water to excavate, eliminating the damage that is caused by augers and power drilling equipment. When an excavation is complete, native top soil is removed and granular fill must be used as backfill around the poles. Bluewater Power must haul the required fill and a hydraulic dump trailer was the most efficient means.

2008 Expenditures (budgeted): $450,000

	Proposed New Vehicle	Replacing Vehicle	Cost
1	Double bucket material handler	1994 Freightliner double bucket material handler	$425,000
2	Station Wagon	Dodge Van	$25,000
		Total	**$450,000**

1. Bluewater Power purchased a double bucket material handler that has a working height of 90 ft. The new truck replaced a double bucket material handler that had 62 ft. of working height. Bluewater Power line crews were increasingly encountering situations where they required more working height and side reach (off road distribution circuits) to complete work safely and efficiently. The new truck has a versatile design with extra lifting capacity.

2. The new station wagon was purchased for the Meter Department to replace an end of life van. The station wagon met the work requirements of the department had a lower capital cost and an approximate 30% improved fuel efficiency over a like for like replacement.

2009 Expenditures (budgeted): approximately $528,000

The following five vehicles are proposed for 2009:

	Proposed New Vehicle	Replacing Vehicle	Cost
1	Single bucket material handler for Operations Department	2000 Freightliner single bucket truck	$286,000
2	Minivan for Meter Department	1995 Dodge Van	$27,500
3	Minivan for Service Representative (may serve double duty for materials mgmt)	2000 Dodge Van	$27,500
4	Minivan or small pickup truck for Engineering Department	2001 Dodge Pick up truck	$22,000
5	Combination Boom and Dump Box	N/A	$165,000
		Total	**$528,000**

1. Single bucket material handler for Operations Line Department: Bluewater Power currently owns a single bucket truck that is eight years old and has reached the end of its useful life; 150,000 km, 8,700 Engine Hours, 4,000 PTO hours. The bucket truck is being utilized to service Bluewater Power's rural customers; it is on the road more than other Bluewater Power vehicles during regular and after hour emergencies. Bluewater Power has determined, due to continuous operation, maintenance records and exposure, the truck will reach the end of useful life in 2009. Replacement of the vehicle is necessary for Bluewater Power to service its rural customers.

2. Mini-van for Operations Meter Department: Bluewater Power currently owns a full sized panel van that is being replaced because of age; 160,000 km. The van is used in all aspects of meter services.

3. Minivan or small pickup truck for Meter Department Field Representative: Bluewater Power currently owns a 4X4 Dodge pickup truck for the Meter Department Customer Service Representative. The truck will be replaced due to mileage (230,000 km) and increased repair costs. The truck will be replaced with a fuel efficient vehicle.

4. Minivan or small pickup truck to be utilized by the Engineering Department: Bluewater Power currently has a 2001 Dodge pickup truck that will be moved to a vehicle pool that has been approved by senior management to be utilized when necessary by Stores Department, Control Room and Lines. This will better utilize the truck and provide a more fuel efficient vehicle for the Engineering Department.

5. Combination Boom and Dump Box:. Bluewater Power does not have a vehicle that can lift heavy transformers, concrete vaults and large wire reels. As a result Bluewater Power has relied on the rental of cranes which has increased proportionally with residential and commercial customer growth. The necessity for heavy lifts often occurs after regular working hours during emergencies and it can be difficult to secure a lift vehicle. The dump portion of the vehicle will be used to haul fill and gravel. Bluewater Power regularly employs water excavating companies to expose cables, install poles and anchors due to a heavy concentration of chemical plants and resulting pipelines. The liability and safety implications associated with damaging underground plant have necessitated the shift in company excavating processes. This new process removes native soil so there is a continuous need to haul stone and fill. Therefore the new vehicle will serve two purposes both of which will enhance customer service and reliability.

New Connections (UT13)

Bluewater Power continually adds new residential and commercial customers as required in order to meet ongoing demand. New connections include the following:

- New subdivision and subdivision expansions
- New residential services
- New commercial/industrial services

Bluewater Power is obligated to connect new customers in accordance with the *Electricity Act, 1998*, as well as its distribution license (ED-2002-0517). This expense is non-discretionary.

As indicated in the following table, Bluewater Power's customer connection expenses have been relatively stable since 2005. Consistent with Bluewater Power's customer forecast at Exhibit 3, Tab 2, Schedule 4, Bluewater Power forecasts its connection costs to slightly increase in the test year. As well, the Bluewater Bridge Authority (the governing body overseeing the twin international bridges in Sarnia) will be upgrading its electrical service in 2009 which will increase customer connection expenses in the 2009 test year. Therefore, it is likely that Bluewater Power's customer connection costs will be more consistent with the historic average than the 2008 cost. For these reasons, Bluewater Power believes that its 2009 forecast for customer connections is reasonable.

	2009 Budget	2008 Budget	2007 Actual	2006 Actual	2005 Actual
New Connections (OEB Requirements)	$978,799	$800,000	$1,166,879	$877,619	$1,015,760

Strategic Transformer Inventory (UT14)

Bluewater Power's strategic transformer inventory is a critical component of its capital asset program. It enables the utility to respond to transformer failures due to end-of-life or storms. The strategic spare inventory is maintained by purchasing new transformers when and as required and by refurbishing existing transformers brought out of service, where possible. The strategic reserve does not include transformers purchased directly for capital programs (they may flow through this capital account, but they are budgeted for elsewhere) but includes only transformers required for end of life or storms.

Funding of the strategic transformer inventory enhances customer reliability by ensuring an adequate level of inventory to replace transformers reasonably anticipated to require replacement in the year. The history of this utility as a merger representing six hydro-electric commissions, the largest of which was itself a merger with former Ontario Hydro territory means that a broad range of transformers are required in order to ensure proper levels of back-ups for emergencies.

The program has become increasingly critical as shortages in world supplies of essential metals have stretched delivery times of transformers from twelve weeks to up-to sixteen weeks. These same supply issues, as well as rising costs, have meant an increased focus by Bluewater Power on refurbishing a transformers versus buying a new transformer where economically justified and technically viable. Therefore, although efforts are underway to reduce costs, a reduction in the strategic reserve would create an unacceptable level of risk to customer reliability.

	2009 Budget	2008 Budget	2007 Actual	2006 Actual	2005 Actual
Transformers	$163,485	$150,000	$232,686	$175,740	$176,628

Cross Arm/Cap & Pin Insulator Replacement (UT17)

Bluewater Power's distribution facilities are primarily comprised of wood poles, wood cross-arms and porcelain insulators. These designs have served the utility industry well, however, with aging it is apparent that the weak link in the structural elements of the design is the wood cross-arm, as well as in the porcelain insulators that support the conductor.

The condition of cross-arms is affected by the following:

1. The quality of the original materials;
2. insect damage;
3. splitting due to weathering or loads; and
4. rot or insect infestations of the material.

Bluewater Power depends on a visual evaluation of the cross-arms to determine whether they are adequate to remain in service. However, defects in insulators are not easily identifiable. Defects in insulators can lead to mechanical failures where these insulators could cause overhead conductors to come into contact with each other, resulting in damage to equipment and a subsequent outage. Further, defective insulators pose a safety risk to staff working on overhead poles. Bluewater Power has determined that certain 35 kV Ohio Brass horizontal post insulators manufactured from porcelain can fail prematurely by breaking off. Bluewater Power began to use a 35 kV epoxy style insulator in the early 1990s to replace porcelain.

Historically Bluewater Power did not track the age of its porcelain insulators. Therefore, Bluewater Power believes that it is prudent to replace all of its porcelain insulators with epoxy style insulators in conjunction with cross-arm replacements and other programs as described below.

In 2007, Bluewater Power estimated that it has approximately 13,000 insulators installed on its overhead network, of which approximately 7,000 are porcelain horizontal post insulators.

To date Bluewater Power has replaced porcelain insulators and cross-arms on critical circuits that serve critical customers. The current practice is to change, at minimum, all insulators on the pole the crew is working on (on average three per pole) as well as the cross-arms if found defective. Bluewater Power has selected a polymeric insulator (the insulator is lighter in weight and installation time is quicker, which is much more cost effective).

The cross-arm/insulator replacement is an ongoing sustaining program that is necessary to maintain the safety and reliability of Bluewater Power's distribution system. This activity is typically carried out in conjunction with other programs in order to maximize efficiencies. For example, it is common for these assets to be replaced in conjunction with Bluewater Power's 4 kV and 8 kV voltage conversion program, with pole replacements and with system expansions.

Cross-arm and porcelain insulator replacement will occur as part of this program under the following conditions:

- cross-arms are replaced at the end of useful life (due to factors mentioned above); and
- porcelain insulators are replaced when replacing cross-arms or in conjunction with other work as described above.

2009 Expenditure (budgeted): approximately $100,000

In 2009, Bluewater Power is forecasting the cost of this program to be $97,880. Bluewater Power's forecasted cost for 2008 is $80,000, and Bluewater Power's actual expenditures were approximately $72,000 in 2007. The reason for the forecasted increase in 2009 is that Bluewater Power will be performing more voltage conversions in 2009 than in 2008 and 2007. It is more efficient and cost-effective for Bluewater Power to replace its porcelain insulators and end-of-life cross arms in conjunction with those programs.

Bluewater Power inspections have also determined that increased emphasis must be placed on the replacement of cross arms and insulators due to the level of deterioration.

Wood Pole Replacement Program (UT18)

Bluewater Power has an ongoing sustaining program for the replacement of wood poles that have deteriorated and are in a position to fail, especially during adverse weather conditions. This program allowed Bluewater Power to develop a leading indicator in 2007 that will track testing/inspections compared to the number of poles changed throughout the year.

Each year, one-third (5,267) of Bluewater Power's wood pole assets are targeted for inspection. A visual inspection of the pole is first carried out in order to identify defects such as cracks, split tops, lightning strikes, shrinkage, discoloration and pole feathering toward the top of the pole. Any defects found are recorded in a pole inspection report; from the report a non-destructive resistance test is performed to check the structural integrity of the pole. The procedure is accomplished by boring a 1.5 to 3.0 mm diameter meter drill at a 45 degree angle to a boring depth of approximately 38 mm, which can identify 90% of the rotting that occurs at or just below ground level. Specialized equipment records the data, which can be read immediately or printed at a later date, thus ensuring a permanent record of pole inspections. This type of testing not only improves the predictability of pole failures, but also exceeds legislated safety and reliability requirements for pole inspection and prevents the expense and customer inconvenience of unplanned pole replacements.

Bluewater Power's pole replacement program is an ongoing sustaining program. Bluewater Power typically replaces 25 to 30 wood poles each year.

2007 Expenditures (actual): $108,219

In 2007, 25 end-of-life poles were replaced.

2008 Expenditures (budgeted): $100,000

As of May, 2008, 19 end-of-life poles were replaced. Bluewater Power forecasts that approximately 30 poles will be replaced by the end of 2008.

2009 Expenditures (budgeted): approximately $100,000

Bluewater Power estimates that 25 to 30 end-of-life poles will be replaced in 2009.

CEO Contingency Fund (UT25)

The CEO Contingency Fund has been created to capture unforeseen capital costs that arise during the course of the year that require an immediate response. The fund has been used, for example, to make major repairs to power line vehicles that have been required within the budget year. The budget has also been utilized to purchase job-specific equipment that has been required within the budget year.

Having the contingency fund has allowed the Bluewater Power senior management team to provide more conservative and accurate capital budget figures during the annual budget processes knowing that funds for unforeseen expenditures can be accessed with the approval from the President and CEO. The fund was utilized almost in its entirety in 2007 and is on track to be fully utilized in 2008.

	2009 Budget	2008 Budget	2007 Actual
Contingency Fund	$212,425	$200,000	$194,899

Storm Restoration (UT38)

Historically, Bluewater Power tracked storm damage costs in its OM&A budget, even for capital investments. Since 2007, Bluewater Power has implemented an annual capital budget to accommodate electrical plant replacement costs that occur as a result of storm damage. The new process allows better tracking through the SAP work order system by tracking individual work orders that settle to the capital budget. The new process accurately captures storm related costs and capital upgrades that result from replacement. The capital budget value is an estimate of average annual costs associated with storm damage combined with practical knowledge of staff.

Bluewater Power 2007 actual capital costs related to storm damage were $67,594. The field experts at Bluewater Power believe that storm damage in 2007 due to hostile weather was unusually low compared to previous years. Bluewater Power has witnessed a remarkable change in weather patterns in 2008, resulting in numerous thunderstorms accompanied by high winds.

2008 and 2009 Expenditures (budgeted): approximately $150,000/year

In light of the weather patterns in 2008, Bluewater Power has budgeted approximately $150,000 for storm related costs in 2008 and 2009.

UT43 – Capitalization of Management Labour – 2008

In 2007 and 2008, Bluewater Power applied a loaded labour rate to the direct capital hours charged to capital projects. The loaded labour rate in 2007 and 2008 included both benefits and overhead. It was determined in 2007 that the loaded labour rate for overhead did not include an allocation of management time. Accordingly, commencing in 2007, certain applicable management employees recorded a fixed number of hours per week based on estimates of time spent on capital projects that were not directly charged to a project. For example, senior managers do not charge any direct labour to capital projects but it was determined that 10% represented a reasonable allocation of senior management costs based on time spent planning, approving and overseeing capital projects (some senior managers have more time allocated based on estimates of their time spent on capital projects). As a further example, supervisors do charge direct labour to capital projects but the majority of their hours do not get allocated to capital; therefore, a further amount of between 25% and 50% of their time is allocated through this methodology.

	2009 Budget	2008 Budget	2007 Actual
Capital	$0	$194,000	$164,479

Calculations for 2007 Actuals

4 senior managers @ 10% of hours worked	$ 37,807
1 senior manager @ 25% of hours worked	$ 25,505
3 supervisors @ 25% of hours worked	$ 65,461
1 supervisor @ 50% of hours worked	$ 35,706
	$164,479

Calculations for 2008 Budget

3 senior managers @ 10% of hours worked	$ 25,767
1 senior manager @ 25% of hours worked	$ 23,447
4 supervisors @ 25% of hours worked	$ 96,701
1 supervisor @ 50% of hours worked	$ 48,085
	$194,000

Calculations for 2009 Budget

As discussed in Exhibit 2, Tab 3, Schedule 8 – Capitalization Policy, the methodology for calculating the amount to be capitalized for indirect labour and overhead has been changed. The capitalized management time that would have otherwise been included in this capital account now forms part of the capitalization rate of 10% that is added to each capital project managed internally. For a complete discussion of this issue, please refer to Exhibit 2, Tab 3, Schedule 8 – Capitalization Policy.

ii. Non-Routine Capital Investments (Operations)

27.6 kV Neutral Program (UT5)

Bluewater Power's 27.6 kV Neutral Program is a multi-year program that involves installing a larger neutral conductor from its distribution stations along each 27.6/16 kV feeder. Bluewater Power's circuits were converted from a delta to a wye system during the 1980's and 1990's. The neutral conductor used was the existing 4 kV neutral conductor, which was not adequate enough to accommodate the new fault currents that were present on a wye system. Under fault conditions, large fault levels can be delivered along each feeder which: (i) can create large ground fault currents and could cause a step potential hazard; and (ii) would result in slow clearing times and affect reliability and power quality. These issues were identified in a 1999 report prepared by Elecsar Engineering Limited (further explained as part of the Asset Management Plan found in Exhibit 2, Tab 3, Schedule 9) as follows:

> "*Over the years, the system has grown and some things have not kept pace with the changes. The 27.6 kV delta system, with distribution stations throughout the city to step down the voltage and distribute to customers. The distribution systems from all these stations, at this time, had a limited ground fault capability (450 Amps). These systems were made up of 4160 Wye connected feeders going out to the streets to be stepped down by transformers for distribution to houses. A small neutral was strung along the streets and care was taken to balance the load between the phases to ensure very small current unbalance would flow in the neutral*."

These Distribution Stations were becoming overloaded therefore the choice was made to change to a Wye connected 27.6/16 kV system and supply distribution transformers directly from the primary feeder, rather than increase the size or number of these feeders. Feeders from the main transformer stations were placed into service. However, instead of installing a neutral for all feeders, the existing 4 kV neutral was used. If the system was balanced again, the neutral would carry very little current. Along with this, each time a 16 kV single phase transformer was installed the neutral would be grounded at this point and there would be a shared path for ground currents.

Over time, a new neutral should have been pulled back to the station. This has happened very slowly or not at all, therefore there are now feeders in the system with small neutrals and large unbalanced loads.

Large imbalances present a serious problem. At least 10,000 Amps of ground current can be delivered on these feeders in a fault condition and with the small conductor, it is not possible to deliver this magnitude of current. This situation could result in high ground fault currents that could cause step potential to the public. In addition, there could be slow clearing faults that could cause extended voltage reductions until relays would time out and trip breakers to clear them. This could cause lengthy unplanned outages to customers.

Bluewater Power has replaced neutral conductors in areas of concern and eliminated the step potential hazard. Commencing in 2009, Bluewater Power plans to commence a multi-year program to replace its remaining neutral conductors to improve reliability and power quality. Bluewater Power estimates that the entire program will take approximately 5 to 7 years to complete at a cost of approximately $150,000 per year.

2009 Expenditure (budgeted): $146,820

Bluewater Power will commence work at Hydro One's transmission stations and work systematically along each feeder. However, Bluewater Power will depart from this strategy where crews are working on or in the vicinity of 4 kV neutral conductors in order to achieve efficiencies and cost savings.

Substation #2 Conversion (UT6)

2008 Expenditure (budgeted): $100,000

In 2003 Bluewater Power started a multi-year project to replace a utility owned Substation #2 (a 4kV station) located on St. Andrews Street in Sarnia. The project was originally scheduled as a six year project; however the entire project will be completed in five years, reaching completion in 2008. The project consists of the elimination of all 4 kV feeders from the station by way of conversion to nearby 27.6 kV circuits as well as all associated switchgear, relays, transformers and cables from the site.

27.6 kV Feeder – Petrolia Program (UT7)

The south-west part of the Town of Petrolia is undergoing significant development with the construction of approximately 200 to 300 new residential homes. To date, approximately 100 homes have been completed (which are customers of Bluewater Power), and construction in the area will continue until 2012. Currently, south-west Petrolia is being served by 4 kV facilities. In order to accommodate the new load the 4 kV feeder from Bluewater Power's substation MS#31 must be replaced with a 27.6 kV line. Failure to do so will result in the overloading of Bluewater Power's 4 kV system in south-west Petrolia as the new homes are completed.

This program is a multi-year program that is separate from Bluewater Power's Voltage Conversion Program because of its magnitude and because the development does not coincide with the timing of Bluewater Power's Voltage Conversion Program (i.e., this program is scheduled to be completed by 2012 to coincide with the completion of the residential development).

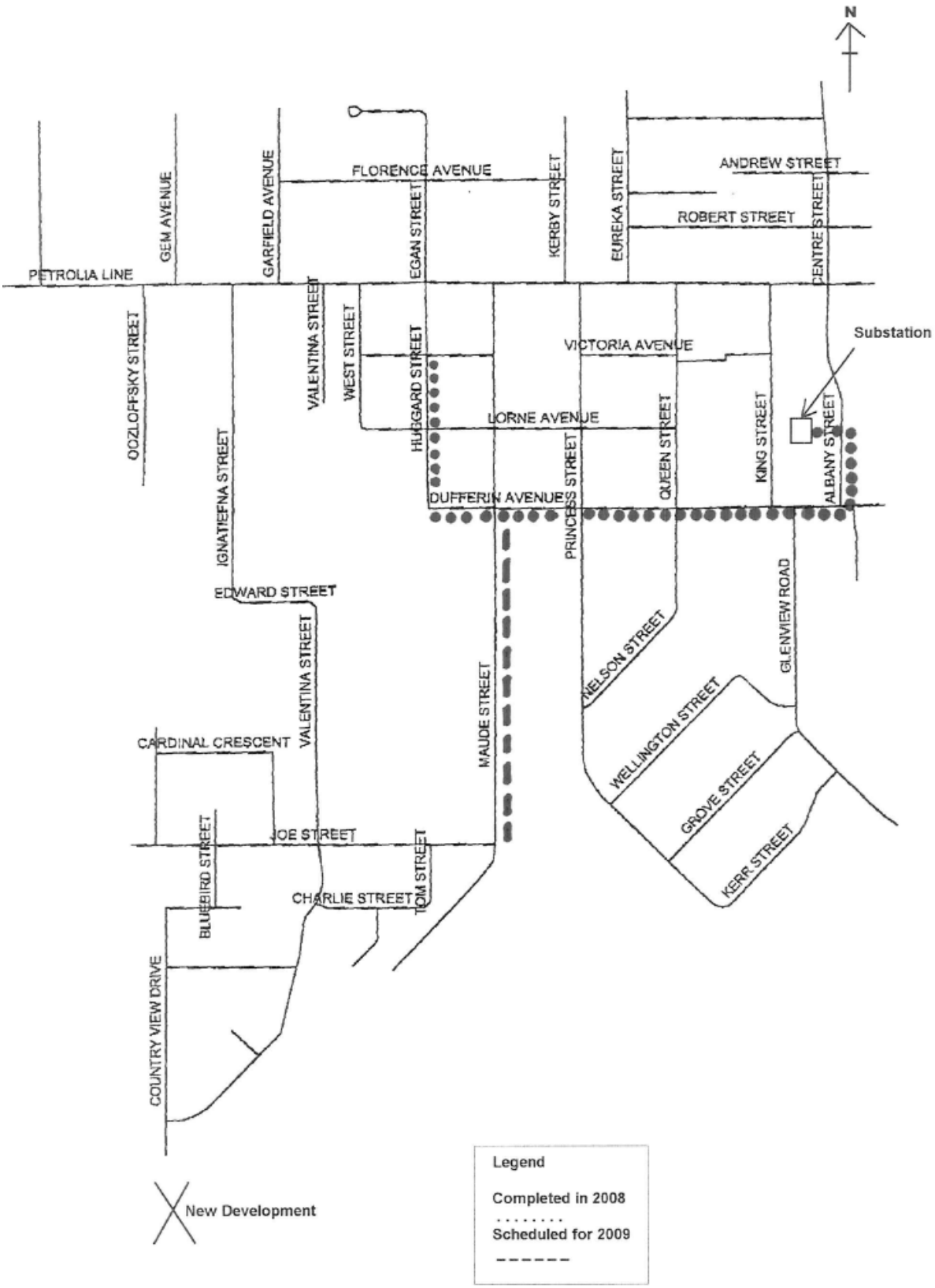
2008 Expenditure (budgeted): $125,000

As illustrated by the map set out below, in 2008 Bluewater Power will convert approximately 1.4 km of its 4 kV system as part of this multi-year program. This conversion will occur from Bluewater Power's substation MS#31 on Albany Street, south to Dufferin Avenue and include a portion of Huggard Street. The facilities constructed in 2008 will be in-service in that year.

2009 Expenditure (budgeted): approximately $100,000

In 2009, Bluewater Power plans to carry-out this program south along Maude Street. The facilities constructed in 2009 will be in-service in that year.

South-West Petrolia



27.6 kV Lines Upgrade (UT21)

Due to regular system growth and to address future load growth, 27.6 kV lines/feeders are re-built (conductors are upgraded) to ensure capacity is available for existing and new customers. The 27.6 kV Line Upgrade program is utilized to increase conductor size where Bluewater Power has identified load on circuits that is about to exceed conductor capacity. Installing larger conductors allows additional load growth and also improves reliability and efficiencies.

The program is also used to upgrade feeder sizes between key circuits to allow flexibility when switching load from feeder to feeder during emergency outages and scheduled upgrades. This allows Bluewater Power to provide a more secure, redundant electricity supply to customers in instances where a feeder outage occurs. Recent developments that have led to expenditures on this project include the expansion of the University of Western's technical centre located at Modeland Road and Wellington Street, new residential development around the Modeland and Michigan Road area, and Bluewater Power's 8 kV voltage conversion in the area (if a feeder goes down, Bluewater Power must be able to divert load to the same sized feeder).

2007 Expenditures (actual): $102,828

In 2007, Bluewater Power's capital expenditures for this program were $102,828. Bluewater Power completed feeder upgrades in the Indian Road corridor that feeds large industry, which helped improve reliability and flexibility to industrial customers.

Upgrades were also completed to a section of line on Williams Drive to provide a back-up supply that would allow further system upgrades to a section of line on Churchill Road. The section of line that was upgraded increased redundancy to an important distribution supply on Williams Drive.

2008 Expenditures (budgeted): $100,000

In 2008, Bluewater Power will upgrade the feeders in central Sarnia on Modeland Road from Confederation Street to Wellington Street.

2009 Expenditures (budgeted): approximately $100,000

In 2009, Bluewater Power will upgrade the feeders in central Sarnia on Modeland Road from Wellington Street to Michigan Avenue.

Animal Protection (UT29)

Animal interference with distribution facilities is a major concern for Bluewater Power and is the third leading cause of power outages at Bluewater Power. The number of large outages on Bluewater Power's system caused by animal interference is illustrated by the following table:

Large Outage Causes	2005	2006	2007	2008*
Animal Interference	8	6	12	11

* forecast

In order to reduce outages and facility damage caused by animal interference, Bluewater Power has implemented a multi-year capital program from 2006 to 2013 to install:

- 3M Guthrie guards on transformer bushings;
- Pole wrap on key poles that house lightning arresters, transformers, metering units, air brakes etc. because that is the most likely equipment for animals to go phase to ground or phase to phase.
- "Plastic Rodent Barrier" PVC product from Polymershapes.
- Protective switch covers through Lineman's Testing "Salisbury Cutout Switch Covers" model 21899.
- 3M Greenline on outdoor substation bus bar and switches.

Bluewater Power estimates that the cost associated with large outages caused by animal interference is at least $15,000 per outage.

2009 Expenditures (budgeted): $103,940

Bluewater Power's approach to installing animal protection is to perform this work in conjunction with other programs or to start at a substation and work along the feeders. Due to the sensitivity of customers being supplied from the St. Andrews transformer station installation (i.e., large industrial customers) Bluewater Power plans to complete animal protection work in 2009 on the six feeders leaving St. Andrews transformer station that supply those customers.

Over-head Line Back Lot Re-Build (UT30)

Bluewater Power has three residential neighborhoods servicing 680 customers that are serviced by back lot distribution circuits. Back lot distribution circuits were built in the 1950's and 1960's on right of ways that ran along the back lots of subdivisions, often to avoid boulevard trees and to decrease the number of distribution circuits required on residential streets (one back lot distribution circuit services two streets). Bell telephone and cable television companies utilized the same infrastructure to feed customers.

In 2006 Bluewater Power started a multi-year capital program to re-build lines in areas where overhead back lot lines exist. It is important to re-build the lines, otherwise reliability and public safety will be jeopardized. Back lot construction also requires line staff to climb poles or utilize ladders on mid-span service connections which is an additional reason for the poles to be sound and reliable.

Bluewater Power converted one entire back-lot subdivision over a four year period in the late 1990's to front lot underground service. Based on that experience, Bluewater Power has determined that the average cost per residence makes it uneconomic to convert the remainder of Bluewater Power's back-lot construction to front lot underground service. The fiscally responsible approach is to rebuild existing construction due to the location of secondary attachment points, joint use customers and electrical services at the rear of every house. Re-building back-lot construction is a timely process from a planning and implementation perspective. The work is labour intensive and requires continuous dialogue with affected customers to gain access to rear lots and organize outages. The majority of all back-lot construction is joint use with Bell telephone and cable companies which requires additional coordination. Bluewater Power has learned new techniques and gained new efficiencies through the first two years of this capital program.

2009 Expenditures (budgeted): approximately $100,000

In 2009 Bluewater Power will be concentrating efforts on Landsdowne Avenue north of Confederation Road, south of Wellington Street.

27.6 kV Feeder Extensions (UT32)

This program was put into place in 2008 to extend various 27.6 kV feeders to develop feeder ties where 27.6 kV feeders do not exist. Due to increasing system growth in 2008 along Blackwell Side Road, it was necessary to extend the 27.6 kV feeder to coincide with residential development. Any feeder extensions (where feeder ties are created) increase reliability for customers as redundancy is created, thus increasing the security of supply to the area where plant extension took place.

2008 Expenditures: $150,000 (budgeted)

As explained above, Bluewater Power will carry out this program along Blackwell Side Road in 2008.

2009 Expenditures: $122,350 (budgeted)

Bluewater Power will carry out this program in 2009 to decrease high-voltage feeder exposure for south Sarnia industrial customers and to improve redundancy.

Reclosures (UT33)

This project was limited to the year 2007.

2007 Expenditure (actuals): $129,336

In 2007 Bluewater Power purchased four automatic electronic recloser/load break switches at a total cost of $ 129,336. The switches are installed in various areas to reduce outages through automation. The switches allow the utility to sectionalize feeders when a fault occurs, thus reducing outage times. The switches improve reliability as the switches are equipped with a recloser function and with load break capability (the recloser function provides the capability to re-close automatically and restore supply once any fault is cleared).

Voltage Conversion Program (UT9 and UT34)

Bluewater Power has been replacing and reinforcing its 4 kV and 8 kV systems over a number of years. As a result, Bluewater Power's existing 4 kV and 8 kV facilities are generally able to accommodate current capacity. However, since the 27.6 kV system transforms the 4 kV and 8 kV systems (i.e. steps the voltage level down to 4 kV and 8 kV), any loading changes and any feeder configuration changes on the 27.6 kV side of transformers will have a direct effect on both the 4 kV and 8 kV systems and vice versa (one system always affects the other feeder when loadings become unbalanced).

Therefore, Bluewater Power has concluded that it would be prudent to proactively replace its 4 kV and 8 kV facilities starting in 2009 as part of a long-term multi-year program (i.e., over the next 15 to 20 years). The benefits associated with this program include:

- alleviation of capacity concerns
- reduction in system line losses
- reduction in peak demand
- improved reliability
- improved feeder end voltage levels
- improved redundant supplies.

2009 Expenditure (budgeted): $171,290

The areas that Bluewater Power intends to convert in 2009 are: (i) the London Line area (21F2 converted to 96M23); (ii) various 4 kV and 8 kV loads from MS #10 to the 18M13 feeder; and (iii) the Blackwell Side Rd./Lakeshore Rd. area. These areas were prioritized based on substation loading, condition of distribution assets and 27.6 kV feeder capacity.

In regard to (iii) above, Lakeshore Road from Murphy Road east in Sarnia is of particular interest for conversion. It is heavily forested and the residential load is high due to the larger size of homes. Reliability data indicates outages in this area are beginning to increase. Due to customer sensitivity regarding tree trimming in this area Bluewater Power has been reluctant to move into conversion. Bluewater Power has been trimming trees with the knowledge that new construction and in some cases higher poles will be required to convert. Bluewater Power is prepared to start rebuilding in a strategic manner.

Asset Condition Assessment (UT40):

2009 Expenditure (budgeted): $163,485

Bluewater Power has undertaken an Asset Condition Assessment ("ACA") focusing on its main feeders out of both the Modeland Transmission Station and the St. Andrew's Transmission Station. The report will require physical inspections of feeders, substations and associated equipment, as well as load studies utilizing Bluewater Power's GIS, SCADA and CYME software programs.

Although Bluewater Power undertook a formal ACA in 1999 and has a thorough Asset Management Plan in place, Bluewater Power believes a thorough system analysis is required, particularly given increasing demands on the system to meet increasingly higher standards of power quality. In that regard, Bluewater Power has several large customers in the chemical business and power quality issues are not only costly but they lead to significant environmental issues. Therefore, the focus of these efforts will not only be to assess system conditions, but to also identify potential solutions to reliability and power quality issues that have been identified and closely followed in 2008. The report will be used to improve system reliability and power quality, as well as to identify any potential new directions for Bluewater Power's capital spending.

The preliminary work on the ACA has been underway since the third quarter of 2008 and the final report is expected to be completed by third quarter of 2009. It is anticipated that the majority of cost will be related to hiring third-party consultants, although there are likely to be costs paid to Hydro One in order to provide information required to carry out this study.

Elimination of Long Term Load Transfers (UT41)

2008 Expenditure (Budgeted) - $150,000

Bluewater Power delivers electricity to customers outside of its licensed service territory under long standing load transfer agreements. Similarly, there are customers within Bluewater Power service territory that are being served by Hydro One Networks Inc. ("Hydro One") mainly because their facilities are in closer proximity to these customers than the Bluewater Power facilities.

Section 6.5 of the Distribution System Code mandates that the load transfer arrangements must be eliminated by January 31, 2009. In order to comply with the code requirements, Bluewater Power has been working with Hydro One to devise a load transfer elimination plan.

A joint plan has been completed by both parties in which each transfer customer was assessed to determine the best course of action required to eliminate the load transfer arrangement. In summary, Hydro One will surrender 32 customers and Bluewater Power will surrender 12 customers and retain 4 customers.

The budget of $150,000 was set for the cost of new construction to service customers to be retained, as well as the anticipated costs of acquiring Hydro One assets acquired through this process. This project is on track to be completed by December 31, 2008.

CYME Gateway (UT42)

This project relates to the year 2008 only.

2008 Expenditure (budgeted): $100,000

Bluewater Power Design Services group in conjunction with a consultant currently performs feeder fault analysis, voltage drop calculations and fuse coordination using a program called CYME. Currently the program is used by a consultant hired by Bluewater Power to perform the above mentioned functions. At the end of 2008 the consultant will be retiring and it will be necessary to bring the program back to the Design Services group. In order for the Design Services group to carry out the program, additional software is required called the CYME Gateway. The CYME Gateway will enable the CYME program to integrate with the Geographic Information Systems (GIS) and extract up to date distribution data from GIS into CYME. The data that is extracted would include feeder maps and feeder loads to perform all feeder fault analysis, voltage drop calculations and fuse coordination on the utility system. This investment will save consulting dollars, but it will also permit staff to undertake beneficial studies in-house that would have been cost prohibitive if utilizing outside consultants.

Substation Transformer #9 Replacement (UT44)

Station transformers are identified for replacement based on oil testing. Oil samples are sent annually to a laboratory to perform tests that indicate the integrity of the core, the oil, and to study gas build ups. Annual test data are added to a historic data base for each specific station transformer; it is the compilation of data over the life of the transformer that proactively identifies transformers for replacement or repair.

Bluewater Power maintains a small inventory of station transformers to be used during emergencies. Bluewater Power does not have a mobile transformer unit therefore it is imperative that Bluewater Power carefully tracks the health of its station transformers and replace them on a proactive basis. The decision to replace a transformer is backed by historic tests and inspection of various components that are vital to a transformer (to identify conditions such as rust, leaks and broken bushings). This type of proactive program maintains reliability and avoids waiting for a failure to replace a transformer.

2009 Expenditure (budgeted): $126,137

In 2009, substation #9 (located at the corner of Wellington and Lansdowne Streets) will be approaching its end of life and will be targeted for replacement. The transformer is 1960's vintage; oil analysis is beginning to indicate a deterioration of the paper insulation in the core of the transformer. This particular substation transformer feeds 1,204 residential and commercial customers in the City of Sarnia.

Geographic Information System ("GIS") (UT45):

This project relates to the year 2009 only.

2009 Expenditure (budgeted): $160,189

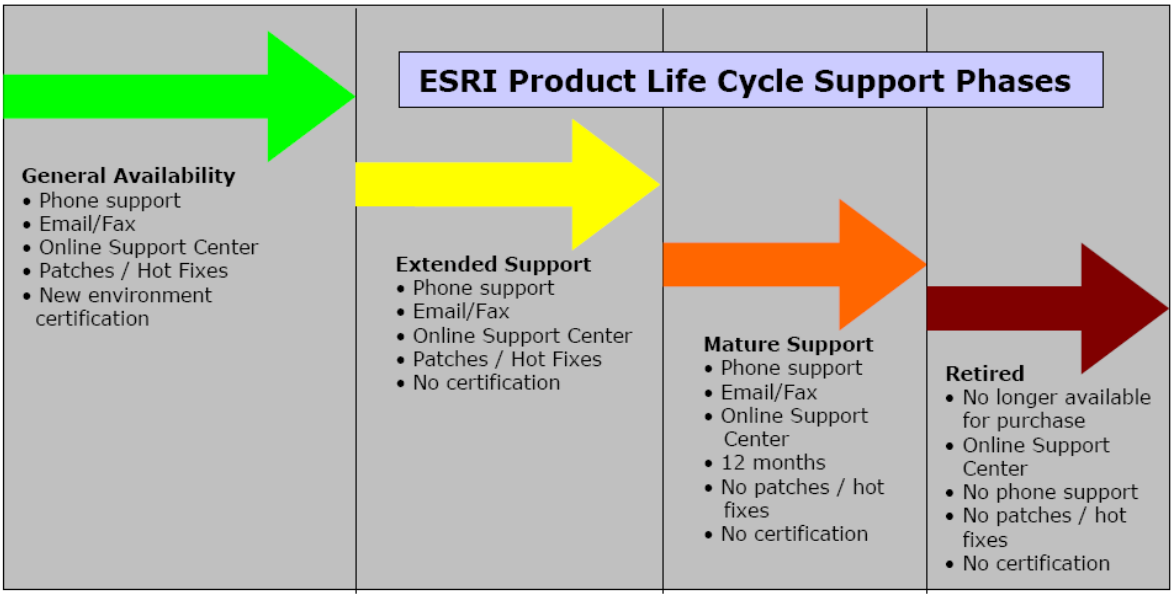
As explained in Bluewater Power's Asset Management Plan at Exhibit 2, Tab 3, Schedule 9, Bluewater Power employs a GIS for automated mapping, as a facilities management tool, and as a geographic representation of Bluewater Power's infrastructure.

Bluewater Power's GIS is an integral part of its asset management plan. At present, Bluewater Power has ESRI ArcGIS 9.0 implemented. While it meets many requirements of its current usage, there are a growing number of limitations, some of which are described below. As a result, Bluewater Power is proposing an upgrade to the latest version.

As illustrated below, the existing implementation of ESRI ArcGIS 9.0 is in a 'Mature Support' phase and is planned to enter the "Retired" phase effective December 2008. A 'Retired' version is no longer available for purchase, has no phone support, will not have patches or hot fixes available and has limited online knowledge base support.

This version retains a number of custom developed programs that have been in place since the original implementation of ArcGIS in 1999. While these programs are used today they are costly to maintain and often break down whenever a patch or upgrade is applied. The new version of the software includes the functionality these custom programs have, but do so in a more effective manner and within the product itself.

As well, Bluewater Power's current GIS is unable to archive data. For example, OEB reporting requires information pertaining to previous year, and currently in order to provide the information, anything built in the current year must be manually removed which takes time and creates the possibility of errors. In addition, further applications which are built for later releases cannot be added to the current GIS.



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Version	Release Date	General Availability	Extended Support	Mature Support	Retired	Notes
9.3	June 2008	X				
9.2	Nov 2006	X				**ArcGIS 9.2 will be moved to 'Extended Support' status effective 9/01/2008.**
9.1	May 2005		X Aug 2007			**ArcGIS 9.1 will be moved to 'Mature Support' status effective 9/01/ 2008.**
9.0	May 2004			X May 2005		**ArcGIS 9.0 will be retired effective December 2008.**
8.3	Feb 2003			X May 2005		**ArcGIS 8.3 will be retired effective 9/01/2008**
8.2	Apr 2002				X May 2005	This is a retired version
8.1.2	Jan 2002				X May 2004	This is a retired version
8.1	Apr 2001				X May 2004	This is a retired version
8.0.2	Mar 2000				X Apr 2003	This is a retired version
8.0.1	Dec 1999				X Jul 2002	This is a retired version

2

3

4

Bluewater Power is proposing to upgrade its GIS to the latest version, 9.3. With this upgrade, each of the limitations noted above will be corrected. Full support will be available (under "General Availability"), the custom programs will be eliminated, and archiving capabilities will be implemented. As well, Bluewater Power will receive improved usability, stability and performance taking advantage of additional data types, functionality and workflows. In addition, the proposed upgrade includes a program called Responder which is a powerful, versatile and effective tool for processing and documenting outages, as well as allowing for a better allocation of resources during an outage. It reduces outage time by allowing personnel to quickly locate an outage, correlate information, analyze the network and dispatch a crew to the correct location (automating current manual entries). Responder provides for historical information and outage documentation, and allows personnel to archive data and report on performance indexes. Call center staff can view real-time outage maps and reports while fielding customer calls. Responder gives an overall picture of the outage status which can be shared with the public on a website. Overall, Responder maximizes reliability, minimizes outages, improves customer satisfaction, reduces costs and improves safety.

Bluewater Power considered the alternative of building a custom application, but dismissed this alternative because it would be difficult and expensive to implement, maintain and update.

Bluewater Power expects that there will be improved customer service and efficiency savings resulting from the proposed GIS upgrade. The savings will be reflected in improved outage management and thus a reduction in outage time. The proposed system will allow Bluewater Power to better utilize resources through a quicker response time and better time management.

II. METERS

i. Sustaining Capital Investment (Meters)

Single Phase Meters (M1)

Bluewater Power has approximately 31,500 single phase meters that are used for residential and small commercial customers. These meters are inspected as part of meter reading every two months for residential meters and every month for small commercial customers. Meter seal expiry dates are tracked in Bluewater Power's SAP system.

Bluewater Power maintains an inventory of single phase meters for the purpose of changing-out meters that require re-sealing or replacement. The seal period is 12 years for new single phase meters and 10 years for resealed single phase meters. Failure to maintain meters in accordance with the *Electricity and Gas Inspection Act* is an offence.

2007 Expenditure (actual): $114,558

2,020 single phase meters were resealed or replaced in 2007.

2008 and 2009 Expenditures (budgeted): approximately $100,000

Bluewater Power has budgeted $100,000 in both 2008 and 2009 to be consistent with its typical annual investment in this sustaining capital program. These costs are unavoidable. In particular, despite the pending implementation of Smart Meters there are no exemptions or extensions available to postpone this expenditure. Bluewater Power does, however, utilize resealing of meters to the greatest extent possible in order to control costs.

ii. Non-Routine Capital Investment (Meters)

Bluewater Power has been forced to invest in upgrades to wholesale meters and associated feeders in order to comply with regulations. Those investments took place in 2007 with respect to the St. Andrews TS and are required for 2009 at the Modeland TS.

Transmission Station Meter Upgrade - St Andrews (M3)

2007 Expenditure (actual): $313,813

The Independent Electricity System Operator's Market Rules (the "Market Rules") requires owners of metering installations at the date of market opening to continue acting as meter service provider until the expiry of the first meter seal in the metering installation. There were two metering installations in Hydro One's St. Andrew's transmission station that fell into this transitional obligation. In 2007**,** the first meter seals expired on the metering installations, thereby ending Hydro One's obligation to continue acting as Bluewater Power's meter service provider. Since Hydro One was no longer Bluewater Power's meter service provider, it required Bluewater Power to remove its metering installation from its transmission station.

There are six feeders leaving the St. Andrew's transmission station that supply Bluewater Power. Bluewater Power's wholesale power was historically metered at the two buses in the station by the two metering installations. However, in order to meter Bluewater Power's wholesale power outside of the St. Andrew's transmission station (i.e., beyond the buses), each of the six feeders had to be individually metered. Therefore, Bluewater Power was required to install six wholesale metering installations outside the station, one for each feeder leaving the station.

The relocated metering installations were in-service in 2007. A break-down of the $313,813 expenditure is as follows:

	2007
Materials	$263,579
Internal Labour	$50,234
Total	**$313,813**

Transmission Station Meter Upgrade - Modeland (M7)

2009 Expenditure (budget): $525,074

The basis for this expenditure is the same as that described in project M3 above. The Market Rules required owners of metering installations at the date of market opening to continue acting as meter service provider until the expiry of the first meter seal in the metering installation. There are two metering installations in Hydro One's Modeland Road transmission station that fell into this transitional obligation. In 2003**,** the first meter seals expired on the metering installations, thereby ending Hydro One's obligation to continue acting as Bluewater Power's meter service provider. The metering installations were re-sealed, and Hydro One agreed to allow Bluewater Power to keep them in its Modeland transmission station until 2009.

Therefore, in 2009 Bluewater Power will be required to install metering installations outside the Modeland transmission station on each of the nine feeders that leave the station.

This project is scheduled to commence in 2009. The re-located metering installation will be in-service in 2009. A break-down of the budgeted amount is as follows:

	2009
Materials	$375,000
Third Party Costs	$50,000
Internal Labour	$100,074
Total	**$525,074**

III. INFORMATION TECHNOLOGY

i. Sustaining Capital Investment (IT)

Data Centre Lifecycle (IT3)

For the past number of years, Bluewater Power has included this budget, which deals with the routine lifecycle and management of products and services associated with the datacentre. It includes servers, network gear, UPS, environmentals (such as cooling and fire suppression), and other data centre equipment and related software replacement lifecycles.

The data centre services and equipment are implemented and upgraded on a lifecycle basis. Depending on the type and use of the equipment the lifecycle is 3 to 8 years. Generally, the plan is dictated by age of equipment, access to improved technology and workload volumes of Bluewater Power IT Staff. These projects are carried out throughout the year depending on project work schedule, and product pricing and availability. Each instance is managed through a variety of project management tools depending on the project scope and complexity.

These projects need to continue on a regular basis to keep with current technology, workload management and technology efficiencies. Delay or cancellation of these efforts will put Bluewater Power's datacenter and IT business offerings at risk.

2009 Budget	2008 Budget	2007 Actual
$265,379	$202,500	$212,938

Deloitte/SAP AMO (IT4)

Bluewater Power is currently engaged in a multi-year Application Maintenance Outsourcing (AMO) agreement with Deloitte Consulting. The purpose of this agreement is for Deloitte to provide development expertise to assist Bluewater Power in the ongoing sustainability of SAP. Under this agreement, Deloitte works with Bluewater Power IT and Business functional staff to develop and maintain the SAP asset. Projects will vary in size and scope based on business and technical need. Examples range from development of ABAP (SAP's development language) queries and reports, to implementation of wholesale settlement, and large customer, complex billing. These efforts extend throughout each year.

SAP is a multi-disciplinary product whereby expertise is typically limited to certain functions only, such as ABAP or Basis (the technical management function of SAP) or CCS (the functional module of SAP called Customer Care and Service) functional design, etc. Since it is not economical for Bluewater Power to hire expertise for these multiple functions, we have chosen to engage in this multi-year agreement under which we have access to expertise in each of the SAP disciplines. Further, in order to have this external expertise which retains a consistent familiarity and understanding of Bluewater Power's SAP environment through regular SAP developers and consistent process, this model serves best. It is critical that Bluewater Power is able to sustain its SAP investment and this solution provides the most effective and efficient result in both time and cost, which this model allows for.

This agreement is planned to expire in 2008. Subsequently it is not budgeted for in 2009 with the expectation that most development in this area will be managed through the SAP upgrade project.

2009 Budget	2008 Budget	2007 Actual
-	$144,000	$70,483

Computer Infrastructure Lifecycle (IT5)

This ongoing, sustaining budget item is for the replacement of all desktop/laptop PCs and technical office equipment. Bluewater Power operates on a 4-year lifecycle approach to PCs and most other office equipment. This enables standardization of product and service and generally keeps a consistent financial impact to budgets. In addition to lifecycle, this budget accommodates any additions to staff or role changes requiring new PCs or other office equipment.

As part of normal PC and technical office equipment lifecycle, Bluewater Power rolls out new PCs to 25% of its staff annually. As well, this budget item deals with the change-out of equipment such as printers, fax machines, data projectors and other IT related desktop type equipment.

By way of process, the primary PC lifecycle is researched and quoted by early second quarter for rollout and implementation by the end of the second quarter. Other equipment, such as printers are evaluated based on workload, access to best fit technology and available pricing opportunities.

In order to maintain healthy and efficient end user PCs and technology, Bluewater Power believes it must be regularly managed with proper lifecycles. This approach enables efficient use of Bluewater Power IT staff and ensures reliable and efficient end user capabilities. Delaying or not performing such efforts will lead to equipment failure, backlog and ultimately higher costs.

Note, while most years have a generally consistent spend in this budget, because some items, such as fax machines, and data projectors are not life-cycled in a 4-year approach, there will be years where this budget is higher. The 2009 budget is such a year in part due to the planned replacement of corporate fax machines and data projectors.

2009 Budget	2008 Budget	2007 Actual
$118,777	$60,000	$58,741

Recurring Systems Developments & Enhancements (IT6)

The Bluewater Power Information Technology environment is a complex system of hardware and software provisioning as a service to and a benefit for the business. Because of this there are many smaller projects and efforts that occur which extend the life of these assets, but which do not incur the purchase of products, materials or services from external vendors. Examples might include the rollout of a software product which is downloadable and free, but which takes time and effort to install on all PCs across the company. Other examples would be the time and effort taken to change out the hard drives in a Storage Area Network (SAN), which would come as part of an existing maintenance agreement. Still another example would be the time and effort required to develop a custom software application which improves the efficiency of business process, but which is done entirely in-house on an ad-hoc basis.

As a result, this budget item is made up entirely of IT Staff labour. It should be noted that the amount tends to vary each year based on the number of labour intensive projects that are planned. The 2009 budget is lower than recent years primarily because of the availability of IT Staff, whose time will be consumed more in other projects.

2009 Budget	2008 Budget	2007 Actual
$60,267	$100,000	$125,228

Legislated Business Application Upgrades (IT7)

Bluewater Power budgets money to accommodate changes in regulation and legislation that require changes to IT related systems and functions. Some examples of this have been Bill 100, rebates, price changes, etc. In addition to adopting required, legislated change, this enables Bluewater Power to invest in small and sometimes ad-hoc development projects to constantly improve business process through technology.

The process around this is always to assess the change in legislation or regulation and to identify where any or all of the effort can be done by Bluewater Power staff. If not possible, and depending on the nature of the change and the product it impacts, appropriate external assistance is sought out. These projects are implemented at various times throughout each year. Each instance is managed through a variety of project management tools depending on project scope and complexity.

Because, by the very nature of regulatory and legislated change, the amount of money spent in this budget item varies from year to year and even within a given budget year. However, it is critical to include this item so that Bluewater Power can remain compliant with new regulations and legislations which affect change to the primary business systems, and to enable continuous improvement programs which drive up operational efficiency.

Note that the 2009 budget year is somewhat higher than previous years primarily due to the projected cost of ad hoc development requirements, which were formerly performed under a multi-year application management outsourcing agreement. That agreement has expired and will not be renewed as a multi-year agreement. However some of the services provided under it are expected to be required to sustain business systems in 2009.

2009 Budget	2008 Budget	2007 Actual
$198,625	$140,000	$76,113

Software Upgrades and Additions (IT8)

Bluewater Power uses a number of software products that are expanded or upgraded on an occasional basis. These are primarily desktop software products and all Bluewater Power desktop software is purchased through this budget item. Examples of this include (but are not limited to) Microsoft Office, Microsoft Project, Adobe Acrobat, and AutoCAD. Additional software requirements for new staff adds or role changes are covered in this budget item as well. These projects are generally carried out throughout each year, and their implementation or rollout is managed through a variety of project management tools depending on project scope and complexity.

Employee efficiency is largely impacted by software that is current and functions well. Ensuring these tools are available and up to date allow Bluewater Power staff to remain efficient both internally and in interactions with business partners outside Bluewater Power. It is essential that Bluewater Power remain compliant with licensing requirements for all software in use at Bluewater Power and this budget item allows for that.

It is important to note that this budget item will vary in amount from year to year depending on projected software requirements. For example, AutoCAD is costly but may not be upgraded for a number of years, thus having a "lumpy" impact on the budgeted amount. The 2009 budget includes requirements for a growing number of software licenses, upgrades on some key applications and accommodation for additional role changes requiring new software.

2009 Budget	2008 Budget	2007 Actual
$107,036	$75,000	$74,172

ii. Non-Routine Capital Investment (IT)

Data Centre Network Replacement (IT19)

Within the IT Infrastructure at Bluewater Power, there exists a system of various network routers, switches and other gear primarily including products from Cisco, Netgear, and McData. It's critical to have properly functioning network gear in order to provide efficient IT services. However, this existing network equipment is aging, approaching end of life, and in need of being replaced. It is currently 7 to 10 years old and, because of network and data transaction growth, it's being taxed at much higher demands than it was designed to handle. It is Bluewater Power's intent to replace all this aging equipment within this budget item.

The plans are to engage a third party network services and equipment provider to assess current IT network related issues and to recommend product replacement and an overall solution. This project will be managed by both internal and external project managers. While preliminary research has been carried out for budgetary purposes, a full assessment will be carried out in Q1 and Q2 with intended implementation to occur in Q3 of 2009.

2009 Expenditure (budgeted): $173,036

The budget amount for this project in 2009 is $173,036.

SAP Upgrade (IT18)

Background

Bluewater Power uses an Enterprise Resource Planning system (ERP) as its primary business software application. An ERP system is a business support system that maintains a single database that contains the data needed for a variety of business functions. The common database integrates every department of Bluewater Power's business (i.e. customer information and billing, meter reads data warehousing, wholesale and retail settlement, financial reporting, accounts payable and receivable, supply chain management, plant maintenance, and operations work management) and allows the business to store and retrieve information in real-time.

Bluewater Power's current ERP system utilizes SAP's R3 4.7 Enterprise, which is an upgrade of Bluewater Power's 2002 implementation of SAP. This upgrade was made in 2004 and from a software perspective is now outdated. It is normal practice for businesses to upgrade software approximately every five years in order to accommodate software vendor changes, advancing business conditions, maturing software functionality and to ensure a stable IT environment.

For the reasons set out below, Bluewater Power is proposing to upgrade its current SAP ERP system from Version 4.7 to 6.0.

Limitations of the Existing System

Limitations of Bluewater Power's existing system, which justify the need for the proposed upgrade are as follows:

SAP User Interface – the existing user interface is called EC20. This is an original version of the end user interface screen from which all SAP transactions take place. It is no longer supported by SAP. As such, the product can only be supported by external consultants which are difficult to find and costly. The interface has limited functionality, is very inefficient and not user friendly. Some examples include:

1. Customer Service Reps are not able to access all customer information through the interface. This results in Customer Service Reps manually searching for information to compile for the customer, subsequently leaving customers with lengthy wait times. Occasionally, it is not possible for Customer Service Reps to retrieve this information and, Bluewater Power's IT professionals are required to access the data through the use of coding not available to Customer Service Reps.
2. The system is not able to auto-populate data fields that are generic or standard in nature. As a result, Customer Service Reps have to manually enter data every time a specific process is done. This leads to errors in customer accounts and inconsistencies in data which lead to issues such as billing errors.
3. EC20 requires significant technical resources. This causes the system to sometimes run slowly, and often times, end users (especially Customer Service Reps) have to wait long periods between screens while attending to the needs of customers.

Reporting – the reporting function in Bluewater Power's existing system is limited in that all reports require that new code be developed by qualified external consultants. These reports are highly specific and do not allow for change without additional costs. The need to produce new or altered reports is constant, thus requiring these costly efforts. There are also many examples of this reporting where the result is less than optimal, often requiring significant manual intervention whereby information is compiled by a number of people, exported to Microsoft Excel and manipulated to meet reporting requirements. Some examples include:

1. Quarterly and Annual Ontario Energy Board (OEB) reports are created by collecting information from 3 to 5 different staff members who generate smaller reports from SAP. These are exported to Microsoft Excel and data is manipulated in order to create reports that display the information required by the OEB. This introduces the possibility for errors to occur and also creates issues for Bluewater Power's external financial auditors with respect to quality, reliability and accuracy of data and process.
2. The Ontario Power Authority (OPA) program in 2007 to promote conservation by reducing electricity consumption by 10% or greater from the prior year's similar time period required the development of a report that ended up taking significant development work at a cost that was higher than the industry average. This was primarily due to the process whereby reports have to be developed in the existing SAP system.
3. Management reports detailing department financial information are not readily available or have not been created because of the cost involved. This results in less than optimal access to timely information and inefficiencies of involving others to generate such information.

Financial Accounting – International Financial Reporting Standards (IFRS) is a new financial accounting requirement that needs to be in place in Canada for the beginning of the 2011 calendar year. However, in order to meet the requirements for a comparative year, it will need to be in place for the start of 2010. This new standard is not currently developed in the existing version of SAP implemented at Bluewater Power. Due to the nature of the required changes, this will be a project requiring significant effort in order to ensure compliance. In order for this to successfully be implemented in time, Bluewater Power will have to complete the project in 2009.

Credit and Collections – Currently, the credit and collections function, known as 'Dunning,' is less than optimal in the existing ERP system. The current version offering has not allowed for the process to be automated. This forces the Dunning Reps to carry out significant manual efforts, even making it necessary to track specific accounts outside the SAP system on Microsoft Excel spreadsheets. This has created issues for Customer Service Reps not having access to necessary account information. It also introduces opportunity for errors to occur, potentially impacting customer credit worthiness. In addition, because some of the tracking data is a manual effort, the Finance department is not able to provide auditors with timely access to 30, 60, 90 day account insight into account balances for validating bad debt expense at year end.

Retail Settlement – When SAP was implemented at Bluewater Power the product was not mature enough to accommodate Retail Settlement functions. In order to enable this critical business functionality, custom code, referred to internally as, 'The Hook,' was developed. While this enabled Bluewater Power to meet the requirements of the Retail Settlement Code, it was limiting in functionality and many manual processes were necessary to put in place. In addition to these inefficiencies, whenever any patches, fixes or upgrades are applied to SAP, it causes The Hook functionality to break. Fixes and patches are critical to the stability of the system. However, the breaking of The Hook has caused an increase in time to complete changes and has added significant internal and external costs.

SAP Support Structure – Solution Manager is a new tool that as of April 2009, SAP is directing its customers to use as the interface required by SAP in order to perform any support, maintenance, patches or upgrades. It is the way in which SAP will interact with its customer base. Without Solution Manager, Bluewater Power will no longer be able to connect with SAP to implement patches and updates, or receive online support which is a requirement to maintain a stable system.

Alternatives Considered to Address These Limitations

Alternative #1: SAP Upgrade

SAP continues to develop its ERP product offering with the latest release named SAP ERP 6.0. This new release has introduced a significant change in the platform and direction of the core SAP application. Now, based on the SAP NetWeaver technology platform, it provides the market with a service-enabled application landscape based on a flexible technology platform and open standards. This Services Oriented Architecture (SOA) and web centric platform introduces an 'enhancement packages' system making it possible to utilize development advances and to model business processes in a cost-effective manner. Bluewater Power would begin the upgrading to SAP ERP 6.0 in late January or early February, 2009. It is expected that the length of the project will extend up to six months. The strategy to implement the upgrade will be to hire an external SAP business integration partner that will provide project management, along with functional and technical expertise in the planning and execution of upgrading to SAP ERP 6.0. They, in turn with Bluewater Power staff will perform all aspects of the upgrade within the confines of a very detailed scope of work.

Addressing the Existing Limitations

SAP ERP 6.0 includes a number of enhancements over the current implemented version of SAP at Bluewater Power. Of these enhancements, many deal with the limitations identified above, and are addressed below.

SAP User Interface – Implementing the new version of SAP brings with it the Contact Information Center or CIC. This product has built in processes for all utility transactions and is the preferred interface for SAP Utility clients. The new user interface will be one of the most significant changes in the upgrade. It is highly intuitive, user friendly and significantly more efficient through which to do business. This is especially true for Customer Service Representatives who are dealing directly with customer inquiries and transactions and need to respond in a timely manner. They will have full access to the information they require and be able to better serve the customers of Bluewater Power. As well, because of the newly designed technology platform, the CIC operates in a much more efficient manner technically. This will address the existing issues of wait times between screens.

Reporting – The new implementation of SAP will take advantage of SAP's Business Warehouse and Business Objects components. These tools enable SAP users to collect, analyze and report on data without the need for proprietary and highly specific code development. This will give users more flexibility in creating and generating reports and will reduce the costs associated with these developments.

Financial Accounting – SAP ERP 6.0 has addressed the issues of IFRS and implements with new general ledger structures designed to accommodate this mandatory compliance requirement. Implementing these changes as part of an upgrade project will streamline the required changes and allow Bluewater Power to meet the tight timelines of compliancy.

Credit and Collections – Upgrading to SAP ERP 6.0 will allow Bluewater Power to take advantage of enhanced Dunning (late payment/credit management) functionality. The added functionality will enable the collections process to be fully automated, thus reducing manual workarounds that exist today and ensuring highly accurate processing of customer related credit issues. Because this functionality will be fully automated, it will allow for the Finance Department to access necessary information for auditors and demonstrate a more credible process.

Retail Settlement – The maturity of SAP ERP 6.0 has functionality that will eliminate the need for 'The Hook.' This will improve processes related to retail settlement, making them more streamlined and less error prone. In addition, because this functionality will be inherent to the SAP product and not custom code, the functionality will not break when necessary patches and fixes are applied to the system. This will greatly improve the stability of the system and lead to lower cost of ownership.

SAP Support Structure – As part of the SAP ERP 6.0 upgrade, Solution Manager functionality will be implemented. This interface will allow Bluewater Power to retain its necessary interaction with SAP for the performance of support, patches, fixes and software enhancement packages.

Additional Benefits of Upgrade

SAP delivers more than 300 enhancements in its SAP ERP 6.0 release. While not all of these will directly benefit Bluewater Power, there will be many platform structure and minor enhancements that will. A high level summary chart of its benefits follows:

Activity	Benefit
Increased productivity	• Improve cost control through integrated management of key business processes across your organization
	• Improve operational efficiency by extending the reach of business processes throughout and beyond the enterprise
	• Accelerate response to market changes and competitive challenges
Reduced costs through	• Improve process standardization, efficiency, and adaptability by utilizing enterprise service-oriented architecture
increased flexibility	• Gain access to transactions, information, and collaborative activities across a broad business community
	• Add specific functionality as needed to support evolving business requirements
	• Protect and leverage existing investments in SAP® solutions
Optimized IT spending	• Cut IT costs by tightly integrating and optimizing core business processes
	• Reduce capital outlay by eliminating the need to purchase third-party software
	• Lower costs by standardizing enterprise software on a single integration platform
	• Enable faster, more cost-effective business expansion by eliminating the complexity of managing homegrown or heterogeneous software applications
Faster, higher ROI	• Use rapid implementation techniques that cost less than half of what traditional approaches cost
	• Gain rapid access to needed functionality through preset defaults and prepackaged, industry specific versions
	• Enhance the value of existing software investments by increasing their use throughout the enterprise
Innovation without disruption	• Take advantage of new functionality through SAP ERP enhancement packages rather than upgrades
	• Implement functionality to support business processes incrementally as your business requires an evolutionary approach that protects your existing IT investments and reduces costs

In addition to those benefits, timeliness of an upgrade is significant to Bluewater Power for the following reasons.

SAP Technical Maintenance Schedule – The current implemented version of SAP has standard maintenance coverage by SAP through April 2009. This is a driver for upgrading to ERP 6.0 as the ability to get critical support from SAP becomes more costly and more difficult. That is to say, upgraded customers are given priority beyond the expiration of standard maintenance and the cost for that reduced coverage increases by an additional 4%. Upgrading to ERP 6.0 enables SAP regular support without the additional cost and greatly reduces the risk of having a critical outage scenario whereby acceptable business resumption times may be in jeopardy.

Smart Metering – Given the timeline in place to implement smart metering at Bluewater Power, it is significant that the SAP upgrade occur in 2009, prior to that rollout. While the existing implementation of SAP can accommodate the adoption of smart metering, there would have to be significant interface developments and changes to make it happen successfully. These same changes will be required with the upgraded version of SAP, so it is intrinsically more valuable to perform these efforts only once on the upgraded version.

Upgrading to SAP ERP 6.0 will be a great benefit to Bluewater Power and its customers. It will increase efficiency, lower the total cost of ownership and increase the stability of its Information Technology platform.

Alternative #2: Custom Development

Choosing not to upgrade the existing version of SAP will lead to a patchwork of custom developed code cobbled together, prone to error and both difficult and costly to maintain. This approach would not mitigate the limiting functionality of the current system nor would it lead to a sustainable platform on which to do business. For these reasons, custom development of the existing version of SAP was dismissed by Bluewater Power. Examples below demonstrate the impact of this approach.

1. The cost to maintain the custom developed "Hook" increases each year for a number of reasons. The original code was written by a consultant no longer available. Since it is custom, attempts to further develop it by other programmers increases complexity and reduces stability. As well, it takes longer to disseminate and develop, increasing cost. Finally, given the climate of regulatory change, it has demonstrated to be a product that requires regular change.
2. Credit and collections practices are flawed in the current version. There have been two attempts to develop SAP to accommodate the processes in place for this practice. These efforts have only been somewhat successful. While it does not warrant additional cost and time for further investment in correcting this shortcoming, the need for the process does not diminish. Therefore a number of alternative work-arounds have been put in place, but these are cobbled together (including emails, excel spreadsheets, intranet postings, etc.) and become increasingly more difficult to manage as data grows.
3. Getting information out and making sense of that data is critical. While there have been many reports developed for BWP, the requirements for reporting data constantly changes. The current custom development approach is very costly and highly specific. As a result some reports are specifically developed and others are cobbled together from other reports which contain some of the information, but which can be extracted into various formats, including Excel. Again, these alternatives grow and become unmanageable. Other reports are costly and have limited future value.

As these few examples demonstrate, business requirements do not stop because of limitations in software. Rather, other methods are created or developed to accommodate the need. While these may suffice in the immediate to meet an obligation, deadline or regulation, they quickly grow, become limited in scope, are costly and soon become unmanageable.

Cost of Upgrade to SAP 6.0

Bluewater Power's approach to upgrading SAP will continue to take a path whereby the most effective and efficient implementation and project processes will be followed. Bluewater Power will ensure that costs are held to the lowest possible while gaining the maximum investment impact to the organization. In order to achieve that, Bluewater Power will utilize its more than six years experience with SAP, and see to it that a number of best practices are undertaken. Some of these will include a full project scoping, engagement of an SAP qualified and recommended systems integrator, use of Bluewater Power internal expertise wherever possible, adoption of SAP recommended implementation procedures, and development and execution of a detailed project plan.

The following chart displays a breakdown of the projected cost of the project.

SAP Upgrade Cost Breakdown	
	Total
Consulting	$1,050,000
Expenses	$185,000
Internal Labour	$135,145
SAP Licensing	$75,000
Total	**$1,445,145**

These costs are a high level summary based on internal project assessments and input from independent SAP consulting firms. The costs would include an upgrade of the current system to SAP ERP 6.0 and address the limitations as identified above.

Bluewater Power will engage a third party qualified SAP Implementation partner, complete an in-depth project scope, and develop a project charter and a detailed project plan for implementation during calendar year 2009. This project will be managed by both internal and

external project managers and in both the preparation stages and throughout the project, Bluewater Power will adopt project management industry best practices.

Conclusion

Bluewater Power has analyzed the limitations of its current ERP system, identified the options available to mitigate those limitations and identified what is necessary to remain a competitive, compliant and viable organization with a stable IT platform. The result of that effort is a recommendation to upgrade its current SAP implementation to SAP ERP 6.0. Upgrading to this latest version will bring significant organizational benefits by extending the functionality and improving the performance of the SAP ERP software, ultimately leading to improved customer service and benefit. This solution is a long term investment in a reliable and sustainable product that will best meet the needs of Bluewater Power.

An independent technology assessment completed by SJH Consulting on the proposed SAP upgrade is attached as Exhibit 2, Tab 3, Schedule 6, Attachment 1. The conclusion drawn by SJH Consulting is that Bluewater Power should upgrade its SAP to version 6.0.

ii. Non-Routine Capital Investment

Building Renovations/Expansion (O5)

The head office of Bluewater Power is located at 855 Confederation Street in Sarnia, Ontario. The original office building was constructed in 1967 with a building addition completed in 1990. In the 18 years since this last construction both staff and equipment have grown as Bluewater Power has adjusted to meet both market and customer demands. As of 2008, Bluewater Power has reached a position where it is in need of expanded facilities. As discussed below, employees are doubled up in office space and also sitting in hallways, and valuable vehicles and equipment are being stored outdoors. In order to address this problem, Bluewater Power is in the process of bringing its facilities up to date in a series of separate and deliberate steps as part of a multi-year program. To complete this total project in one step would require a significant investment of both capital and resources. Bluewater Power believes it is more prudent to phase-in a series of smaller building projects to address its needs.

Current Constraints

Bluewater Power has identified a space shortage within many areas including (i) offices, (ii) equipment bay space, and (iii) vehicle/employee parking.

(i) Office Space

Since the last building addition in 1990 Bluewater Power staff numbers have grown. This staff growth was to accommodate new market requirements, to accommodate customer service growth and to effect the merger of six former utilities into a single company in 2000. At the time of the merger, all six former utilities (Sarnia Hydro-Electric Commission, Petrolia Public Utilities Commission, Point Edward Public Utilities Commission, Watford Public Utilities Commission, Alvinston Public Utilities Commission, and Oil Springs Hydro-Electric Commission) centrally located in the current office building (formerly Sarnia Hydro-Electric Commission) at 855 Confederation Street. All five other administrative offices were closed.

Since 1990 staff has increased significantly and, as a result, staff are doubled up in offices, sitting in hallways or utilizing spaces not designated to safely and effectively accommodate personnel. Not only were a number of roles accommodated in the building due to the merger but entire departments have been created in the last 18 years to meet new industry requirements. These new functions include retail/wholesale settlement, Ontario Energy Board compliance, strategic planning, regulatory financial reporting, and more sophisticated billing and information technology requirements.

(ii) Equipment Bay Space

The equipment needs of Bluewater Power have also grown over the years as the company has evolved. In addition, similar to the personnel impact of the merger, Bluewater Power assumed responsibility for all equipment bay storage requirements for the trucks and other equipment absorbed as part of the merger. In addition, in 2004 Bluewater Power also made a strategic decision to move its meter reading services in-house and this decision resulted in an additional four vehicles. In total, the vehicle base of Bluewater Power has increased by 18 units over the last 10 years.

(iii) Parking Spaces

The growth in staff has resulted in a shortage of parking spaces. Although Bluewater Power promotes carpooling and bicycle riding, the utility often experiences the situation where it has approximately 40 more staff than parking spaces. Employees are often forced to park at public locations outside Bluewater Power's property which is not only inefficient and inconvenient but results in a potential safety hazard with employees crossing busy streets to retrieve their vehicles.

The Multi-Year Program:

The total project will be broken into five phases as follows:

Phase I

Phase I involves the renovation of Bluewater Power's customer reception area to make better use of current available space. The foyer will be decreased in size to allow for additional office space in the Customer Service area. This will assist in alleviating some of the more pressing issues of office doubling up. It is estimated that this phase will cost approximately $185,000.

Phase II

Phase II will involve the creation of six additional vehicle bays and equipment storage space. It is critical that equipment not be kept outdoors due to both security issues and to ensure protection of the asset from environmental factors which helps to maximize life expectancy. Phase II will involve the creation of five truck bays with an additional covered space to store equipment. This project is due to be completed in 2009 at a projected cost of approximately $863,315. This project will be publicly tendered in the market in order to achieve the best possible pricing.

Phase III

Phase III will involve the creation of additional parking spaces on site. These spaces will be converted from "green space" owned by Bluewater Power on its current property. The approximate cost will be $150,000. This project will be completed in 2010. Due to the fact that these costs fall beyond the test year, they will not affect the application.

Phase IV

Phase IV will involve the transformation of current unfinished basement space. Bluewater Power has an under-utilized area of unfinished space in the office building's basement. Although unsuitable for permanent offices, a meeting room and storage area will be created in this area. Bluewater Power estimates the cost of this renovation at approximately $250,000 and plans to finish this phase in 2010. Due to the fact that these costs fall beyond the test year, they will not affect the application.

Phase V

The fifth phase of the project will involve an actual building addition. This will be the most comprehensive and intensive phase of the project. This is scheduled to commence in the year 2011. This project, at this time, is expected to cost $2,500,000 - $4,000,000. This addition will provide sufficient space to fully accommodate the utility's current needs and allow for limited growth opportunities to take Bluewater Power into the next decade of the electricity industry. Due to the fact that these costs fall beyond the test year, they will not affect the application.

2008 Expenditures: $185,000 (budgeted)

As explained above, this expenditure relates to Phase I of the multi-year building renovation project.

2009 Expenditures: $863,315 (budgeted)

As explained above, this expenditure relates to Phase II of the multi-year building renovation project.

Bluewater Power SAP ERP 6.0 Upgrade Plan – Independent Assessment

Introduction

The following is an independent technology assessment completed by Sarah Horsley, President and Sole Proprietor of SJH Consulting: a Management Consulting Company based out of Aurora, Ontario focusing on the energy and utility industry. The intent of this report is to provide an assessment of the current enterprise resource planning ("ERP") solution in place at Bluewater Power Distribution Corporation ("Bluewater Power") and make recommendation as to its future direction.

Having 12 years experience as a senior management consultant in the global utilities market , I have assisted and provided consulting expertise to numerous global SAP clients. I am an SAP Certified, qualified, and experienced consultant with deep expertise assisting energy and utility clients in developing, implementing and enhancing their ERP, meter to cash "(CIS"), and advanced metering infrastructure ("AMI") systems and processes.

For 11 years, I worked for IBM Canada within the Energy & Utility Practice before leaving in 2007 to form SJH Consulting. As an Associate Partner within the practice, I was recognized as IBM's Global Subject Matter Expert (SME) on SAP for Utilities. During my last year at IBM, I represented IBM North America on a global joint SAP / IBM Team to design and develop an integrated solution for AMI between the SAP for Utilities application and third party MDM providers.

In regard to SAP, I have over ten years "hands-on" experience leading, designing, configuring, implementing and optimizing utility CIS environments around the globe. My experience is primarily focusing in customer service, field

service, sales and marketing, as well as the credit and collections area. In addition, I bring strong integration expertise with various modules of SAP, including Sales and Distribution, Financials, Materials Management, Service Management, Plant Maintenance, IS-U/CCS and CRM as well as interfaces to legacy systems in the customer service, sales & marketing areas.

During my 12 years of consulting experience, I have led multiple facets of projects including functional team lead, conversion, testing, change management, overall integration, and project management. In addition to the management experience I excel in understanding the processes and requirements, along with the ability to easily engage with all levels of an organization to ensure objectives of a project are fully understood and achieved. Within the past year as part of SJH Consulting, I have been providing strategic direction and management consulting to various utilities within North America; specifically in Texas and Ontario.

The Bluewater Power Mandate

I have been retained to provide a critical analysis of Bluewater Power's proposal to upgrade its SAP ERP to 6.0 version.

During my last eight months at IBM Canada and over the past nine months at SJH Consulting, I have been regularly meeting and communicating with Bluewater Power. The focus of these communications has been on Bluewater Power's current SAP environment, discovering some of the pain points of the current SAP installed version, investigating potential fixes of those pain points and identifying the advantages, risk and cost associated with upgrading to the new SAP ERP 6.0 version. During the months at IBM, I spent time at the Bluewater Power offices in Sarnia as well as multiple conference calls and face

to face meetings with Bluewater Power's IT personnel to understand the components, functions, reports and customizations, including code and interfaces to internal and third party systems.

I have also reviewed the Bluewater Power SAP ERP 6.0 Upgrade Plan document. Based on my review and the communications described above, it is my recommendation that they engage in an upgrade to SAP as proposed by Bluewater Power.

Independent Assessment and Recommendations

My overall recommendation is for Bluewater Power to upgrade to SAP ECC 6.0 as soon as possible; Bluewater Power is on an old version of SAP and is not able to currently achieve the business benefits and level of service to its customers that it could with the new technology and functionality available in version SAP ECC 6.0. Based on experience with other SAP Global clients, it is not a wise business or IT approach to continue with the same version of SAP Enterprise 4.7 and try to custom develop work around solutions (code) to fix some of the pain points currently experienced by Bluewater Power. By doing so, the total cost of ownership will be higher over time than investing in an upgrade within the next year; this is primarily due to upgrading to the next available solution while within the regular maintenance window, minimizing the number of customizations involved in the upgrade and being able to deploy the "best practice" processes and tools to the business as soon as possible to be able to begin taking advantage for the business benefits.

SAP Maintenance

Bluewater Power's current ERP system is an older version than the current SAP version (ECC 6.0) which became available for general release in March 2006. It

is my understanding that the current SAP 4.7 Enterprise system implemented at Bluewater Power enters extended maintenance in March 2009. The extended maintenance option means a customer will pay time and material for any additional support. SAP typically recommends their clients remain on a fully supported version that is covered under mainstream maintenance guaranteeing the delivery of necessary fixes and legal patches as well as enhancements to delivered functionality. Once a product leaves mainstream maintenance for extended maintenance SAP will continue to deliver fixes and patches but no functional (business) enhancements. As I will note in more detail within this document, there is new functionality being deployed at the end of this year and will continue on a annual basis**, plus in order to take advantage of functionality required for IFRS the upgrade needs to be complete by 2010.** Having worked directly with a dozen utilities globally, I can confirm that it is an industry best practice to keep current with upgrades for package ERP or CIS solutions. Companies which find themselves many versions behind end up having a higher total cost of ownership over a five year period in part due to the need for a larger IT organization required to maintain the current older solution, break/fix support and enhancements required to support new business or regulatory requirements which are not standard or missing functions within their implemented outdated version. Also, when a client does decide to upgrade typically it ends up being a complete re-install of the software as there the version is too old to follow a software vendor upgrade path or solution. Due to this, the project cost and effort ends up being greater than if the company had completed the recommended upgrade path and kept current with the software versions.

Limitations of Existing System

As stated in the Bluewater Power ERP 6.0 Upgrade Plan document prepared by Bluewater Power, there are many limitations with their existing SAP version. After a review of the Bluewater Power system and discussion with its IT organization (Keith Broad, Tom Janes and Martine Vanderheide) I do agree with the limitations identified within this report.

These limitations will be resolved with an upgrade to SAP ECC 6.0; not only is the functionality available within the solution, but almost of all of it will be accomplished using the standard delivered functions provided by SAP. Clients have seen business and financial benefits by using this standard functionality within ECC 6.0. Some of the benefits seen by other utility clients are as follows:

- Reduced Customer Service Costs due to reduced errors (15% – 25%)
    - SAP provides functionality for the call center which allows for data fields to be pre-populated; this will prevent agents from having to manually re-enter data multiple times which currently leads to errors
- Increase customer service/call center capacity (20% – 30%)
    - The performance of the Customer Interaction Center which will be the front end screen and tool used by the Call Center agents is a lot more efficient and faster than the current, old technology EC20 used by the Bluewater Power agents.
- Improved 1st Call Resolution Rates (4%-5%); Reduction in Repeat Calls (20% – 30%)
    - The Customer Interaction Center provides the information the agents require on the initial screen; therefore allowing agents to respond to customers inquiries in an accurately and efficient manner.

- Improved technical utilization (up to 10%)
    - Clients have seen a decrease in the technical support required from using the SAP ECC 6.0 version of SAP versus other version due to the improved technology
- Reduced Bad Debt (20% – 30%)
    - By implementing the enhanced dunning functionality clients have found they are able to identify and automate actions on non-paying customers; many of these processes are manual today causing a large amount of collections effort and cost as well as missing opportunities to contact customer who are not paying due to the manual processes in place today.
- Improve Days outstanding (14% – 42%)
    - By implementing the new automated dunning functionality clients have seen an improvement in customer's payment habits resulting in a corporate improvement in days outstanding.

Bluewater Power has noted the improvement in the SAP User Interface; the new interface which will be used mainly by the Call Center, but would also be leveraged by other departments, will provide great time savings for the corporation as a whole. This tool has a very strong and flexible search engine which allows users to quickly search for accounts based on almost unlimited amounts of data stored within the SAP tables; for the call center there is also the added function to integrate the SAP Interaction Center to a Computer Telephony Integration (CTI) /Interactive Voice Response (IVR) environment which would allow the SAP system to auto-populated the inbound calling customers account details on the agents screen for them to validate with the caller – this is based on information the agent has initially entered in the IVR or by doing a system look up of the phone number the customer is calling from. A Customer Overview or summary screen would automatically be populated which has the current

information/status as well as some historical data related to the customers billing, payment, service order, collection activities and internal credit worthiness (rating) just to name a few. This typically provides 80%-90% of the data required for customer inquiries.

The following are some additional benefits, in addition, to those identified within the Bluewater Power ERP 6.0 Upgrade Plan:
Smart Metering – one of the key development areas by SAP for their utilities solution is AMI; SAP has been working on the development of web services for key AMI business processes. Their objective is for the SAP web services to be used to communicate to a third party MDMR system in order to automate these processes for smart meters. SAP has a release strategy in place for the deployment of these web services. The first of the web services will be delivered as an enhancement pack to ECC 6.0 in December 2008. By upgrading the solution this will reduce the amount of development and technical support required due to the delivered SAP web services.

Alternatives

As mentioned by Bluewater Power its SAP ERP 6.0 Upgrade Plan, an alternative approach to upgrading to SAP ECC 6.0 would be to stay with the current 4.7 version and develop the functionality required to fix the current system limitations. As mentioned earlier within this document, having worked with many other utilities and SAP clients over the past 12 years, I have seen clients who do not upgrade or keep current with the current SAP version. This may appear to save money, however this cost saving is just short term as the total cost of ownership per year tends to increase the more custom development within a system; this is primarily due to the increased technical support required to support and manage

the break/fixes within the solution. Once the client decides that their current solution does need to be upgrade, the project effort and cost tends to be more substantial than a upgrade from a current version to the new version as vendors have “upgrade procedures” or tools which accelerate the upgrade; if the current version is too old many clients face having to do a re-install, which essentially is a system replacement to get to the current version. Also, the more developments the current version has the higher the risk of an upgrade as many of these developments may not be required due to the new functionality, therefore once the technical upgrade is initially performed within a development environment the custom development would have to be manually removed from the system, plus in a lot of cases due to changes within the new version many hours of extra effort is required to confirm the development has been upgrade successfully and the testing is successful. This extra effort or having to re-implement the new version of the software versus performing an upgrade, results in a greater amount of cost long term to the client.

I have also completed a review of the pricing exercise provided to Bluewater Power; a duration of six months is very reasonable for such an upgrade. If Bluewater Power only required a technical upgrade with no additional functionality the duration could be decreased to three to four months, however due to the additional effort to design and implement the new functions and processes a six month project is a recommended duration. Anything shorter would mean having to add more resources and would add to the cost as the right duration and amount of effort required to test the upgraded solution would be at risk. An upgrade of any kind, specifically one with new functionality needs to endure rigorous testing in order to ensure a smooth cut-over with minimal impact to the business and customer. Given the duration, the consulting cost appears to be competitive especially since the cost of this type of skilled SAP consultants

is increase as resource become scarce with the current number of Global SAP for Utilities projects on-going.

It is my professional and independent recommendation for Bluewater Power to upgrade from their current version of SAP 4.7 Enterprise to ECC 6.0 in 2009 in order to resolve the limitations described in Bluewater Power's SAP ERP 6.0 Upgrade Plan, and to take advantage of the new functionality within this current version of the ERP solution which is the primary corporate software application.

System Expansions

The *Distribution System Code* ("DSC"), under the Definition section 1.2 defines expansion as follows:

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

Bluewater Power continually expands its distribution system to accommodate customer-driven requests for service or additional power requirements. Each request for power is assessed individually and an economic evaluation is performed to determine whether the future incremental distribution revenue from a system expansion will pay for the capital costs and ongoing maintenance costs of the system expansion. A shortfall in revenue will result in a capital contribution being required from the customer.

On July 27, 2006 the OEB posted amendments to the DSC specific to Chapter 3 related to expansions, alternative bids, enhancements and provided greater clarity regarding the rights and obligations of LDC's and customers with respect to distribution system expansion.

Bluewater Power filed an updated 'Conditions of Service' with the OEB to reflect the above noted amendments to the DSC. The Conditions of Service document is filed under Exhibit 1, Tab 2, Schedule 7.

Table 2.3.7.1 below indicates the breakdown of the three historical years of system expansion.

System Expansion

Table 2.3.7.1

	2005	2006	2007
Residential	$103,074	$102,011	$210,232
Commercial/Industrial	$404,043	$536,286	$301,918
Subdivision	$508,643	$239,323	$654,729
TOTAL	$1,015,760	$877,620	$1,166,879

The projections for 2008 and 2009 are $800,000 and $978,799 respectively and are based on the trends from 2005 to 2007, along with any known information from builders or land developers

Capitalization Policy

Bluewater Power records capital assets at cost in accordance with Canadian Generally Accepted Accounting Principles and with Article 410 of the Accounting Procedures Handbook ("APH"). All expenditures by the Corporation are classified as either capital or operating expenditures. The intention of these classifications is to allocate costs across accounting periods in a manner that appropriately matches those costs with the related current and future economic benefits.

Accordingly, all expenditures are capitalized that are material in amount and which meet the definition of a capital asset. Those terms are defined as follows:

Materiality: Bluewater Power's materiality threshold is $1,000.

Definition of a capital asset: The determination of whether an expenditure is capital or operating is made objectively through a disciplined process of budgeting as well as close monitoring and analysis by the Finance Department. Expenditures incurred to enhance the service potential of an existing capital asset meet the definition of "betterment", i.e., service potential is enhanced when there is an increase in the physical output or service capacity of the capital asset, associated operating costs are lowered, the useful life of the capital asset is extended, or the quality of output is improved. Accordingly, betterment-related expenditures are capitalized while repairs and maintenance related expenditures are classified as operating expenses.

Bluewater Power's capital budgeting process includes consideration of capitalized labour because resource planning is a critical component of capital budgeting. The appropriate level of capitalized labour is determined during the budgeting process and calculated in accordance with the methodology set out below. Unplanned capital expenditures throughout the year are not typical but, if required, are reviewed and approved by the CEO in consultation with senior management.

Nature of Capital Expenditures

Non-utility assets are accounted for separately from utility assets for the purposes of rate regulation to ensure there is no cross-subsidization between regulated and non-regulated utility lines of business. Specifically, the following APH accounts are used when applicable: 2075, 2180, 4375, and 4380.

Capital Contributions

Capital assets funded in whole or in part by external parties are capitalized at full cost. Contributions relating to capital projects received from external parties are recorded in APH account 1995 which credits (offsets) the capitalized costs in whole or in part. For rate making purposes, this ensures that only the net capital amount is included in rate base. Contributed capital is amortized (offsetting amortization expense) at the same rate as the related capital assets. For rate making purposes, this ensures that net amortization expense is included in rates.

Determination of Quantum of Cost

The cost of a capitalized item is the consideration given up and includes:

i) Direct acquisition, construction or development costs such as materials, external contracting, professional fees, commissioning and testing;
ii) Direct internal costs such as internal labour and equipment charges;
iii) Indirect internal costs such as management and overhead;
iv) Financing costs such as an Allowance for Funds Used During Construction (AFUDC) as approved by the OEB.

Direct costs are based on invoiced amounts from suppliers of goods and services. Direct internal costs are assigned on the basis of timesheets submitted and include labour and equipment charges. Internal labour is based on average hourly rates for each operational area, plus a burden rate of 24% representing statutory and extended benefits. Equipment charges for rolling stock used in capital operations are charged to capital at the same rates charged to third parties.

Indirect internal costs are applied to any project that is managed internally representing the costs of management labour and overhead necessary to facilitate capital investments. The methodology is based on a common simplified approach whereby each capital project that is managed internally has an additional amount of 10% included in the total capital cost for management labour and overhead. The capitalization rate of 10% has been determined to include levels of management labour and overhead consistent with past practice at Bluewater Power wherein such costs were included in the former hourly burden rate. The revised methodology which has been applied to 2009 seeks to achieve a consistent result for Bluewater Power and utilizing a more acceptable methodology as observed broadly in the utility sector and previously approved by the OEB for other utilities. A capitalization rate of 10% is conservative compared to other utilities in the electricity industry, however, absent a detailed study to support a higher rate Bluewater Power believes the result achieved is fair and reasonable to both current and future ratepayers.

Bluewater Power Asset Management Plan

This report represents a description of the capital asset management plan of Bluewater Power Distribution. The asset management plan has evolved through years of refinement of daily planning and budget processes. The plan finds its foundation in an asset condition report completed in 1999 by Elecsar Engineering Ltd. ("1999 Report") as updated on an ongoing basis through a disciplined approach to Asset Maintenance Programs discussed herein.

In order to respond to distribution system priorities the level of spending in the areas of Operations has been increasing in recent years and lies in the range of $3 million to $4 million per annum between 2006 and 2009 (this does not include other corporate spending on metering, IT and other). A high-level preliminary analysis would suggest that annual spending of $5 million will be required in coming years to maintain the distribution infrastructure adequately. This projected $5 million expenditure includes $4 million in sustaining capital investments projected as a target for those programs at Exhibit 2, Tab 1, Schedule 3 – Variance Analysis on Rate Base Table plus $1 million in non-routine capital investments typically pursued annually.

Bluewater Power owns capital assets in the communities of Sarnia, Petrolia, Point Edward, Watford, Alvinston and Oil Springs. Those assets have a net book value at year-end 2007 of approximately $38 million. Bluewater Power manages the assets in each municipality individually through planning review processes to ensure no assets are overlooked in the short or long term.

Asset Management Processes

In 1999, Bluewater Power commissioned a capital asset condition report from Elecsar Engineering Ltd. to review the condition of substations and feeders. The 1999 Report made several detailed recommendations related to specific feeders and substations that have been largely implemented. In addition to specific recommendations, the 1999 Report made comments of a more general nature that have been actively pursued by the utility and form part of what has become the Asset Management Plan described in this report.

The Bluewater Power Planning and Design Department ("Design Services" or "Engineering") holds bi-weekly meetings to review on-going capital projects, O&M projects and regular system reports. The meetings include representatives from the Lines Group, Purchasing Department ("Purchasing" or "Materials Management"), Meter Department and Field Technicians. The system discussions and minutes from the meetings help form the direction for the management of assets in future years. The continuing dialogue helps to educate field and management staff regarding future system improvements and forms the basis of our budget preparation on an ongoing basis.

Operations Departments (Lines, Planning and Design, Meter, Fleet) budget planning commences in August of each year. Operations budget items are proposed based on comprehensive outage data, consideration of future load growth, field inspection reports with regard to the condition and age of plant and a review of multi-year capital projects and information gathered through the Asset Management Programs.

In September, the Planning and Design departments facilitate budget meetings to review proposals, to prioritize and refine a draft capital and Operating and Maintenance report by October.

In early November, the Operations Senior Manager presents the proposed budgets to the Senior Management Team one line item at a time. Capital spending requests are scrutinized by the Senior Management Team and must be supported with credible back up. The President and CEO ultimately determines the final capital budget that will be presented to the Board of Directors for review.

Senior Management Team presents the proposed budgets to the Bluewater Power Board of Directors where individual projects are once again scrutinized and reviewed.

The Bluewater Power Asset Management Plan is supported by utilizing a combination of data systems described as follows.

The Bluewater Power Geographic Information System ("GIS") is a spatially-based data system that is used to track individual pieces of equipment in the field, as well as customer and loading data geographically. All physical changes to the distribution system are captured in the GIS, so that the system is accurately described in the GIS at all times. The GIS is also utilized in conjunction with the planning process to responsively and accurately plan system maintenance requirements. Supervisory Control and Data Acquisition (SCADA) plays an important role in the Bluewater Power Asset Management Plan by providing both real time and historic distribution system data. SCADA is used to study feeder loading and to project future feeder loading, as well as to study system peaks. The data collected through SCADA is routinely used during the planning and implementation of capital and maintenance programs.

The Bluewater Power Outage Management System has been built in-house in a Microsoft Access database. The system is made accurate through diligent tracking and is utilized to trend power outage by cause, by time of year, and by geographic location. This information is vital to the Asset Management Plan when prioritizing and supporting recommended capital and maintenance programs.

The Bluewater Power Fleet Management System has been built in-house in a Microsoft Access database. The system houses all vehicle maintenance records, testing, and results. The Fleet Management system facilitates fleet maintenance and provides supporting evidence for new vehicle purchase proposals.

Bluewater Power assets are managed by utilizing technical support combined with the expert knowledge of Operations staff through a disciplined yearly routine. Due to the advanced age of Bluewater Power's distribution system, the sensitivities of large industrial customers and the complication associated with operating three distribution voltage levels (4 kV, 8 kV and 27.6 kV) it is imperative that Bluewater Power uses all available tools to improve upon the excellent level of service its customers have come to expect.

The distribution system capital and maintenance programs outline the processes used by Bluewater Power to determine the investments that are necessary to ensure the distribution system's ability to deliver safe, reliable electricity to Bluewater Power customers. The programs are comprised of the following major elements:

1. Capital Asset Planning

Capital asset planning is required to maintain adequate capacity and a secure source of supply to meet customer needs. Areas within the network requiring significant improvement or a capacity upgrade of existing assets are identified and considered for capital investment. Identified opportunities for capital investment are prioritized based on secure sources of supply and any asset renewal benefits.

The overall condition of the capital assets of Bluewater Power has been reviewed and is generally in good condition. Bluewater Power has well designed maintenance programs for all of its assets that ensures capital assets will be maintained in top condition and allows potential sources of power failures to be identified before failure occurs. Bluewater Power's work order system is evidence that maintenance is being performed and is documented through the GIS; any identified problems are corrected as required.

2. Capacity and Secure Source of Supply Planning

Capacity planning and secure source of supply planning play important roles in the way the distribution system and capital asset components are managed. The primary function of capacity planning is to ensure the reliability of service for all existing customers as well as planning for future load growth. Secure source of supply planning focuses on the development of contingency plans to be used if a major asset should fail and allows affected customers to be supplied from redundant power sources. Ultimately, the final objective is to have adequate capacity for the entire electrical distribution system in order to deliver a safe and reliable supply of electricity.

3. Capital Asset Maintenance Program

Effective asset maintenance improves the reliability of service and maximizes equipment life span. It reduces unplanned outages by identifying and correcting deteriorating plant before a failure occurs.

The asset maintenance plan includes corrective and preventative asset maintenance cycles and quantifies asset maintenance requirements for each asset type. Examples of maintenance cycle activities include:

- pole inspections and testing
- thermography scanning
- tree trimming
- insulator washing
- substation and vault inspection
- substation maintenance
- maintenance of subdivision transformer and switches

It is the policy of Bluewater Power that all inspections on distribution transformers, distribution stations, all lines and associated equipment are conducted on a regular cyclical basis and the inspection results recorded in accordance with OEB requirements. Bluewater Power exceeds the recommended minimum inspections as set out by the OEB to the extent that it performs inspections every three years of the entire rural service area instead of six years as indicated. Once inspections are completed all of the inspection records including required infrastructure repairs are entered into the GIS.

Bluewater Power's three year inspection cycle of all urban and rural infrastructures reduces the number of unplanned outages by identifying and correcting potential deficiencies before a failure occurs. While age is certainly a major factor contributing to capital asset deterioration, there are many other factors contributing to deterioration such as the asset's material or its location within the system. For example, it has been noted through inspections that the heavy industrial area in the south of Sarnia has created air quality issues in the past impacting system performance. Deterioration of assets may arise at random through events such as animal contacts, tree

contacts or lightning strikes. These factors cannot be predicted or identified without first performing regular maintenance inspections and testing on the assets.

Individual Capital Asset Maintenance Programs

The following sections provide an overview of the Bluewater Power capital asset maintenance programs. These programs and their respective service areas and work procedures are based upon historical maintenance activities and procedures.

Pole Inspections and Testing

Each year, approximately 5,289 or one-third of Bluewater Power's wooden poles are inspected. A visual inspection of the pole is first carried out in order to identify defects such as cracks, split tops, lightning strikes, shrinkage, discoloration and pole feathering toward the top of the pole. Any defects found are recorded in a pole inspection report. A non-destructive resistance test is then performed to check the structural integrity of the pole. The procedure is accomplished by boring a 1.5 to 3.0 mm diameter drill at a 45 degree angle to a boring depth of approximately 38 mm, which identifies rotting that occurs at or just below ground level. Specialized equipment records the data, which can be read immediately or printed at a later date, thus ensuring a permanent record of pole inspections. This type of testing not only improves the predictability of pole failures, but also exceeds legislated safety and reliability requirements for pole inspection and prevents the expense of unnecessary pole replacements.

Thermography Scanning

Each year, all Bluewater Power overhead distribution plant, equipment, transformers and substations are inspected using thermo graphic technology. The inspections reveal temperature variances that can indicate an overloading issue, a bad connection or overheated equipment. If not corrected, heat stress will eventually lead to equipment failure. The system inspector records a thermo graphic picture of the area as well as a standard real life image; both images are date and time stamped. The system inspector proceeds to identify any areas of concern on the image using a specialized software package. These images are included in a Thermography Report, which also contains the following:

- inspection site information
- exact location of temperature variances
- description of the components and an assessment of the severity of any areas of concern
- work recommendation
- degrees above ambient temperature
- load conditions
- date and time

Tree Trimming

Tree trimming is an integral part of the Bluewater Power preventative line maintenance program as it minimizes the chances of power interruptions due to interference between overhead distribution equipment and any surrounding trees. To ensure public safety, it is important to maintain clearances between energized conductors and tree branches. Tree trimming involves the removal of any overhanging branches or large limbs, trimming around conductors to maintain a clear path, and the clearing of any distribution right-of-ways. Bluewater Power's tree trimming maintenance program has a four year cycle with Bluewater Power's service territory divided into four quadrants. Each quadrant is trimmed on a yearly rotating basis:

- Year 1 – Section 1 of Sarnia and Point Edward
- Year 2 – Section 2 of Sarnia and Oil Springs

- Year 3 – Section 3 of Sarnia and Watford and Alvinston
- Year 4 – Section 4 of Sarnia and Petrolia

Insulator Washing

Each year, Bluewater Power conducts insulator washing on all insulators that are associated with the 27.6 KV feeders with added attention to insulators in heavy industrial areas. Insulator washing eliminates contaminates that could reduce the insulating properties of the insulator. Contaminants can cause insulators to flashover and/or create the potential for a pole fire thus creating the possibility of a large scale power outage.

Substation and Vault Inspections

Substation and vault inspections play an integral role in the detection of potential equipment failures. Assessing the condition of substations and vaults through inspection and documentation is an effective proactive maintenance measure which enables Bluewater Power to prevent any possible equipment failures. Methods that are employed to monitor critical substation equipment, manholes and vaults are as follows:

- bi-weekly visual inspections of all substations – documented visual inspections for any defects
- monthly vault inspections – documented visual inspections for any defects
- Annual substation transformer oil analysis - Oil analysis is conducted annually on all Bluewater Power substation transformers. This analysis can detect a potential transformer failure that could be caused by the release of gases, state of the paper insulation, the insulating oil's ability to withstand electrical stress and other bi-products that occur during arcing within the transformer windings itself.
- Annual substation thermography testing – Substations are inspected using a thermo graphic camera which records and reveals any temperature variances caused by excessive heat.

- Annual substation battery testing - Storage battery testing is conducted yearly at all Bluewater Power substations. This testing detects potential equipment failure by measuring the chemical and electrical effects that indicate deterioration of the battery blocks. Failure of the battery blocks can result in a loss of control of the substation equipment.

By employing these preventative maintenance techniques any hidden deterioration of the condition or performance of substations and vaults may be identified. In most cases the early detection of a potential cause of equipment failure allows adequate time to rectify problems and thereby avoid equipment failure.

Substation Maintenance

Substation maintenance is an annual program based on a four year cycle. Each substation is completely shut down and inspected, cleaned and tested to avoid the possibility of unforeseen power outages as a result of equipment failure. This type of maintenance preserves system reliability and ensures public safety and customer satisfaction.
When deficiencies or component defects are identified all repairs are completed during the substation outage. During this maintenance program the following work is completed:

- inspection of primary and secondary connections for signs of overheating
- inspection and cleaning of all bushings and insulators
- an insulation resistance test is performed on the high voltage and low voltage windings to ground and correct the values to a base of 20 degrees C.
- a power factor dissipation test is performed to measure the quality of the major insulation
- a turns ration test is performed on all tap positions
- inspection for liquid leaks and excessive rusting
- liquid temperature, winding temperature, liquid level, bushing and tap-changer liquid levels, and tank pressure are recorded
- Verification that cell mechanical interlocks preclude the breaker being removed or restored to the operating position with the breaker contacts closed
- remove the breaker from the cell, dust cubicle and check the tightness of all control wiring

- vacuum and dust circuit breakers
- check power and control stabs
- check porcelain and insulation for any cracks and holes
- check wear mark indicators to ensure contact integrity
- open and close the breaker a minimum of three times to check for friction and binding
- manually close breakers and check contacts for alignment and mating
- lubricate in accordance with manufacturers' recommendations

Electrical Tests:

- If external cabinet is available operate the breaker
- put the breaker in the test position in the cell and operate the breaker using the control switch
- open the breaker by closing the tripping contacts of each relay
- check phase to phase and phase to ground insulation resistance using a "Meggar"
- test all relays
- *Air and Load Break Switches:*
- Check switch for correct operation and alignment
- inspect and clean all insulators
- check interlocks for correct operation
- visually inspect contacts
- visually inspect bus

Maintenance of Subdivision Transformers and Switches

Maintenance of transformers and switches is an annual program that includes servicing and repair of components that are located in subdivisions that are supplied by pad-mount transformers and switches. This maintenance is scheduled on a seven year cycle, and is conducted to prevent pad-mount transformer components from failing and causing a loss of supply to a large area. Maintenance activities consist of the following:

- General vault clean-up (removal of weeds, excess dirt etc.)
- clean and tighten connections to prevent tracking
- inspect elbows; clean or replace as necessary
- Meggar and test cables
- replace pins
- identify and repair any other deteriorating conditions

Allowance for Working Capital

Summary of 2009 Working Capital Allowance

The proposed working capital allowance for the 2009 test year is $13,613,408, calculated as 15% of OM&A and cost of power. It is apparent from Table 2.4.1.1 that Bluewater Power's working capital allowance is forecast to increase significantly from 2007 to 2008, primarily caused by an increase in cost of power expenses.

Table 2.4.1.1

Summary of Working Capital Allowance

	2007 Actual	2008 Bridge Year	2009 Test Year
Total Applicable Expenses	$81,203,578	$88,723,212	$90,756,053
Working Capital Allowance (15%)	$12,180,537	$13,308,482	$13,613,408

For a brief summary of the breakdown of the contribution to Working Capital Allowance for Controllable Expenses and Working Capital Allowance, please refer back to Table 2.1.3.1.

Attachment 1 to Exhibit 2, Tab 4, Schedule 2 provides a detailed breakdown for the calculation of working capital allowance on an account basis from 2007 to 2009.

Working Capital Allowance Calculations by Accounts

The working capital allowances for 2007, 2008 and 2009 are detailed in Exhibit 2, Tab 4, Schedule 2, Attachment 1.

Working Capital Allowance by Account

		Working Capital Allowance Factor:	**15.0%**
Account Grouping	**Account Description**	**2009 Projected Acct Balance**	**Working Capital Allowance**
3350-Power Supply Expenses	4705-Power Purchased	62,444,763	9,366,714
	4708-Charges-WMS	5,958,032	893,705
	4710-Cost of Power Adjustments		
	4712-Charges-One-Time		
	4714-Charges-NW	4,655,750	698,363
	4715-System Control and Load Dispatching		
	4716-Charges-CN	4,705,961	705,894
	4720-Other Expenses		
	4725-Competition Transition Expense		
	4730-Rural Rate Assistance Expense	1,145,775	171,866
	4750-Charges-LV	189,602	28,440
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	944,384	141,658
	5010-Load Dispatching	208,989	31,348
	5012-Station Buildings and Fixtures Expense	100	15
	5014-Transformer Station Equipment - Operation Labour	26,000	3,900
	5015-Transformer Station Equipment - Operation Supplies and Expenses		
	5016-Distribution Station Equipment - Operation Labour		
	5017-Distribution Station Equipment - Operation Supplies and Expenses	420	63
	5020-Overhead Distribution Lines and Feeders - Operation Labour		
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	231,369	34,705
	5030-Overhead Subtransmission Feeders - Operation		

Working Capital Allowance by Account

		Working Capital Allowance Factor:	**15.0%**
Account Grouping	**Account Description**	**2009 Projected Acct Balance**	**Working Capital Allowance**
	5035-Overhead Distribution Transformers- Operation	1,965	295
	5040-Underground Distribution Lines and Feeders - Operation Labour	899,617	134,943
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	306,371	45,956
	5050-Underground Subtransmission Feeders - Operation		
	5055-Underground Distribution Transformers - Operation		
	5060-Street Lighting and Signal System Expense		
	5065-Meter Expense	437,516	65,627
	5070-Customer Premises - Operation Labour		
	5075-Customer Premises - Materials and Expenses	43,220	6,483
	5085-Miscellaneous Distribution Expense	404,711	60,707
	5090-Underground Distribution Lines and Feeders - Rental Paid		
	5095-Overhead Distribution Lines and Feeders - Rental Paid	30,690	4,604
	5096-Other Rent		
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering		
	5110-Maintenance of Buildings and Fixtures - Distribution Stations		
	5112-Maintenance of Transformer Station Equipment		

Working Capital Allowance by Account

		Working Capital Allowance Factor:	**15.0%**
Account Grouping	**Account Description**	**2009 Projected Acct Balance**	**Working Capital Allowance**
	5114-Maintenance of Distribution Station Equipment	7,275	1,091
	5120-Maintenance of Poles, Towers and Fixtures	14,300	2,145
	5125-Maintenance of Overhead Conductors and Devices	83,520	12,528
	5130-Maintenance of Overhead Services		
	5135-Overhead Distribution Lines and Feeders - Right of Way		
	5145-Maintenance of Underground Conduit		
	5150-Maintenance of Underground Conductors and Devices	16,900	2,535
	5155-Maintenance of Underground Services	5,145	772
	5160-Maintenance of Line Transformers	26,000	3,900
	5165-Maintenance of Street Lighting and Signal Systems		
	5170-Sentinel Lights - Labour		
	5172-Sentinel Lights - Materials and Expenses		
	5175-Maintenance of Meters	4,500	675
	5178-Customer Installations Expenses- Leased Property		

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Working Capital Allowance by Account

		Working Capital Allowance Factor:	**15.0%**
Account Grouping	**Account Description**	**2009 Projected Acct Balance**	**Working Capital Allowance**
	5185-Water Heater Rentals - Labour		
	5186-Water Heater Rentals - Materials and Expenses		
	5190-Water Heater Controls - Labour		
	5192-Water Heater Controls - Materials and Expenses		
	5195-Maintenance of Other Installations on Customer Premises		
3650-Billing and Collecting	5305-Supervision	124,802	18,720
	5310-Meter Reading Expense	148,146	22,222
	5315-Customer Billing	887,684	133,153
	5320-Collecting	233,138	34,971
	5325-Collecting- Cash Over and Short		
	5330-Collection Charges	788	118
	5335-Bad Debt Expense	102,885	15,433
	5340-Miscellaneous Customer Accounts Expenses		
3700-Community Relations	5405-Supervision		
	5410-Community Relations - Sundry	52,000	7,800
	5415-Energy Conservation	45,540	6,831
	5420-Community Safety Program	119,331	17,900
	5425-Miscellaneous Customer Service and Informational Expenses		
	5505-Supervision		
	5510-Demonstrating and Selling Expense		
	5515-Advertising Expense		

Working Capital Allowance by Account

		Working Capital Allowance Factor:	**15.0%**
Account Grouping	**Account Description**	**2009 Projected Acct Balance**	**Working Capital Allowance**
	5520-Miscellaneous Sales Expense		
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	962,527	144,379
	5610-Management Salaries and Expenses	209,019	31,353
	5615-General Administrative Salaries and Expenses	1,713,680	257,052
	5620-Office Supplies and Expenses	2,860	429
	5625-Administrative Expense Transferred Credit	(543,487)	(81,523)
	5630-Outside Services Employed	178,675	26,801
	5635-Property Insurance	166,076	24,911
	5640-Injuries and Damages		
	5645-Employee Pensions and Benefits	1,986,471	297,971
	5650-Franchise Requirements		
	5655-Regulatory Expenses	437,711	65,657
	5660-General Advertising Expenses	21,000	3,150
	5665-Miscellaneous General Expenses	724,793	108,719

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Working Capital Allowance by Account

		Working Capital Allowance Factor:	**15.0%**
Account Grouping	**Account Description**	**2009 Projected Acct Balance**	**Working Capital Allowance**
	5670-Rent		
	5675-Maintenance of General Plant	91,788	13,768
	5680-Electrical Safety Authority Fees		
	5685-Independent Market Operator Fees and Penalties		
	5695-Smart Meters OM&A Contra		
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	297,750	44,663
TOTAL		**90,756,053**	**13,613,408**

Working Capital Allowance by Account

		Working Capital Allowance Factor:	**15.0%**
Account Grouping	**Account Description**	**2008 Projected Acct Balance**	**Working Capital Allowance**
3350-Power Supply Expenses	4705-Power Purchased	62,352,337	9,352,850
	4708-Charges-WMS	5,949,214	892,382
	4710-Cost of Power Adjustments		
	4712-Charges-One-Time		
	4714-Charges-NW	4,638,339	695,751
	4715-System Control and Load Dispatching		
	4716-Charges-CN	4,688,440	703,266
	4720-Other Expenses		
	4725-Competition Transition Expense		
	4730-Rural Rate Assistance Expense	1,144,080	171,612
	4750-Charges-LV	164,987	24,748
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	648,444	97,267
	5010-Load Dispatching	197,415	29,612
	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	400	60
	5020-Overhead Distribution Lines and Feeders - Operation Labour		
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	229,370	34,406
	5030-Overhead Subtransmission Feeders - Operation		

Working Capital Allowance by Account

		Working Capital Allowance Factor:	**15.0%**
Account Grouping	**Account Description**	**2008 Projected Acct Balance**	**Working Capital Allowance**
	5035-Overhead Distribution Transformers- Operation	1,300	195
	5040-Underground Distribution Lines and Feeders - Operation Labour	260,994	39,149
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	231,928	34,789
	5050-Underground Subtransmission Feeders - Operation		
	5055-Underground Distribution Transformers - Operation		
	5060-Street Lighting and Signal System Expense		
	5065-Meter Expense	273,300	40,995
	5070-Customer Premises - Operation Labour	56,379	8,457
	5075-Customer Premises - Materials and Expenses	30,171	4,526
	5085-Miscellaneous Distribution Expense	299,785	44,968
	5090-Underground Distribution Lines and Feeders - Rental Paid		
	5095-Overhead Distribution Lines and Feeders - Rental Paid	29,376	4,406
	5096-Other Rent		
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering		
	5110-Maintenance of Buildings and Fixtures - Distribution Stations		
	5112-Maintenance of Transformer Station Equipment		

Working Capital Allowance by Account

		Working Capital Allowance Factor:	**15.0%**
Account Grouping	**Account Description**	**2008 Projected Acct Balance**	**Working Capital Allowance**
	5114-Maintenance of Distribution Station Equipment	4,500	675
	5120-Maintenance of Poles, Towers and Fixtures	12,000	1,800
	5125-Maintenance of Overhead Conductors and Devices	75,470	11,321
	5130-Maintenance of Overhead Services		
	5135-Overhead Distribution Lines and Feeders - Right of Way		
	5145-Maintenance of Underground Conduit		
	5150-Maintenance of Underground Conductors and Devices	16,000	2,400
	5155-Maintenance of Underground Services	4,900	735
	5160-Maintenance of Line Transformers	24,000	3,600
	5165-Maintenance of Street Lighting and Signal Systems		
	5170-Sentinel Lights - Labour		
	5172-Sentinel Lights - Materials and Expenses		
	5175-Maintenance of Meters	3,540	531
	5178-Customer Installations Expenses- Leased Property		

Working Capital Allowance by Account

		Working Capital Allowance Factor:	**15.0%**
Account Grouping	**Account Description**	**2008 Projected Acct Balance**	**Working Capital Allowance**
	5185-Water Heater Rentals - Labour		
	5186-Water Heater Rentals - Materials and Expenses		
	5190-Water Heater Controls - Labour		
	5192-Water Heater Controls - Materials and Expenses		
	5195-Maintenance of Other Installations on Customer Premises		
3650-Billing and Collecting	5305-Supervision	109,523	16,428
	5310-Meter Reading Expense	129,818	19,473
	5315-Customer Billing	813,915	122,087
	5320-Collecting	232,243	34,836
	5325-Collecting- Cash Over and Short		
	5330-Collection Charges	750	113
	5335-Bad Debt Expense	84,500	12,675
	5340-Miscellaneous Customer Accounts Expenses		
3700-Community Relations	5405-Supervision		
	5410-Community Relations - Sundry	36,400	5,460
	5415-Energy Conservation	35,376	5,306
	5420-Community Safety Program	103,633	15,545
	5425-Miscellaneous Customer Service and Informational Expenses		
	5505-Supervision		
	5510-Demonstrating and Selling Expense		
	5515-Advertising Expense		

Working Capital Allowance by Account

		Working Capital Allowance Factor:	**15.0%**
Account Grouping	**Account Description**	**2008 Projected Acct Balance**	**Working Capital Allowance**
	5520-Miscellaneous Sales Expense		
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	738,263	110,739
	5610-Management Salaries and Expenses	180,016	27,002
	5615-General Administrative Salaries and Expenses	1,176,415	176,462
	5620-Office Supplies and Expenses	2,000	300
	5625-Administrative Expense Transferred Credit		
	5630-Outside Services Employed	212,442	31,866
	5635-Property Insurance	161,843	24,276
	5640-Injuries and Damages		
	5645-Employee Pensions and Benefits	2,053,952	308,093
	5650-Franchise Requirements		
	5655-Regulatory Expenses	281,665	42,250
	5660-General Advertising Expenses	10,000	1,500
	5665-Miscellaneous General Expenses	652,365	97,855

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Working Capital Allowance by Account

		Working Capital Allowance Factor:	**15.0%**
Account Grouping	**Account Description**	**2008 Projected Acct Balance**	**Working Capital Allowance**
	5670-Rent		
	5675-Maintenance of General Plant	81,424	12,214
	5680-Electrical Safety Authority Fees		
	5685-Independent Market Operator Fees and Penalties		
	5695-Smart Meters OM&A Contra		
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	290,000	43,500
TOTAL		**88,723,212**	**13,308,482**

Working Capital Allowance by Account

		Working Capital Allowance Factor:	**15.0%**
Account Grouping	**Account Description**	**2007 Actual Acct Balance**	**Working Capital Allowance**
3350-Power Supply Expenses	4705-Power Purchased	53,860,178	8,079,027
	4708-Charges-WMS	4,256,575	638,486
	4710-Cost of Power Adjustments	2,036,164	305,425
	4712-Charges-One-Time		
	4714-Charges-NW	5,824,186	873,628
	4715-System Control and Load Dispatching		
	4716-Charges-CN	5,088,770	763,316
	4720-Other Expenses		
	4725-Competition Transition Expense		
	4730-Rural Rate Assistance Expense	943,624	141,544
	4750-Charges-LV		
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	498,120	74,718
	5010-Load Dispatching	197,013	29,552
	5012-Station Buildings and Fixtures Expense	1,222	183
	5014-Transformer Station Equipment - Operation Labour		
	5015-Transformer Station Equipment - Operation Supplies and Expenses	592	89
	5016-Distribution Station Equipment - Operation Labour		
	5017-Distribution Station Equipment - Operation Supplies and Expenses	6,835	1,025
	5020-Overhead Distribution Lines and Feeders - Operation Labour		
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	266,362	39,954
	5030-Overhead Subtransmission Feeders - Operation		

Working Capital Allowance by Account

		Working Capital Allowance Factor:	**15.0%**
Account Grouping	**Account Description**	**2007 Actual Acct Balance**	**Working Capital Allowance**
	5035-Overhead Distribution Transformers- Operation	1,859	279
	5040-Underground Distribution Lines and Feeders - Operation Labour	284,583	42,687
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	260,449	39,067
	5050-Underground Subtransmission Feeders - Operation		
	5055-Underground Distribution Transformers - Operation	1,824	274
	5060-Street Lighting and Signal System Expense		
	5065-Meter Expense	221,594	33,239
	5070-Customer Premises - Operation Labour	60,288	9,043
	5075-Customer Premises - Materials and Expenses	20,655	3,098
	5085-Miscellaneous Distribution Expense	356,260	53,439
	5090-Underground Distribution Lines and Feeders - Rental Paid		
	5095-Overhead Distribution Lines and Feeders - Rental Paid	29,335	4,400
	5096-Other Rent		
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering		
	5110-Maintenance of Buildings and Fixtures - Distribution Stations		
	5112-Maintenance of Transformer Station Equipment		

Working Capital Allowance by Account

		Working Capital Allowance Factor:	**15.0%**
Account Grouping	**Account Description**	**2007 Actual Acct Balance**	**Working Capital Allowance**
	5114-Maintenance of Distribution Station Equipment	8,536	1,280
	5120-Maintenance of Poles, Towers and Fixtures	11,354	1,703
	5125-Maintenance of Overhead Conductors and Devices	67,908	10,186
	5130-Maintenance of Overhead Services		
	5135-Overhead Distribution Lines and Feeders - Right of Way		
	5145-Maintenance of Underground Conduit	69	10
	5150-Maintenance of Underground Conductors and Devices	18,988	2,848
	5155-Maintenance of Underground Services	4,582	687
	5160-Maintenance of Line Transformers	8,796	1,319
	5165-Maintenance of Street Lighting and Signal Systems		
	5170-Sentinel Lights - Labour		
	5172-Sentinel Lights - Materials and Expenses		
	5175-Maintenance of Meters	2,320	348
	5178-Customer Installations Expenses- Leased Property		

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Working Capital Allowance by Account

		Working Capital Allowance Factor:	**15.0%**
Account Grouping	**Account Description**	**2007 Actual Acct Balance**	**Working Capital Allowance**
	5185-Water Heater Rentals - Labour		
	5186-Water Heater Rentals - Materials and Expenses		
	5190-Water Heater Controls - Labour		
	5192-Water Heater Controls - Materials and Expenses		
	5195-Maintenance of Other Installations on Customer Premises		
3650-Billing and Collecting	5305-Supervision	107,335	16,100
	5310-Meter Reading Expense	112,856	16,928
	5315-Customer Billing	746,719	112,008
	5320-Collecting	216,441	32,466
	5325-Collecting- Cash Over and Short		
	5330-Collection Charges	975	146
	5335-Bad Debt Expense	93,010	13,952
	5340-Miscellaneous Customer Accounts Expenses		
3700-Community Relations	5405-Supervision		
	5410-Community Relations - Sundry	57,142	8,571
	5415-Energy Conservation	12,028	1,804
	5420-Community Safety Program	25,470	3,821
	5425-Miscellaneous Customer Service and Informational Expenses		
	5505-Supervision		
	5510-Demonstrating and Selling Expense		
	5515-Advertising Expense		

Working Capital Allowance by Account

		Working Capital Allowance Factor:	**15.0%**
Account Grouping	**Account Description**	**2007 Actual Acct Balance**	**Working Capital Allowance**
	5520-Miscellaneous Sales Expense		
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	734,123	110,118
	5610-Management Salaries and Expenses	310,953	46,643
	5615-General Administrative Salaries and Expenses	1,121,756	168,263
	5620-Office Supplies and Expenses	6,177	927
	5625-Administrative Expense Transferred Credit		
	5630-Outside Services Employed	327,672	49,151
	5635-Property Insurance	146,548	21,982
	5640-Injuries and Damages		
	5645-Employee Pensions and Benefits	1,590,751	238,613
	5650-Franchise Requirements		
	5655-Regulatory Expenses	221,246	33,187
	5660-General Advertising Expenses	12,363	1,854
	5665-Miscellaneous General Expenses	657,148	98,572

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Working Capital Allowance by Account

		Working Capital Allowance Factor:	**15.0%**
Account Grouping	**Account Description**	**2007 Actual Acct Balance**	**Working Capital Allowance**
	5670-Rent		
	5675-Maintenance of General Plant	84,913	12,737
	5680-Electrical Safety Authority Fees		
	5685-Independent Market Operator Fees and Penalties		
	5695-Smart Meters OM&A Contra		
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	278,911	41,837
TOTAL		**81,203,578**	**12,180,537**

REVENUE

Distribution Revenue

Overview of Distribution Revenue

This exhibit provides the details of Bluewater Power's distribution revenue for the OEB-approved historical year (2006 EDR), historical actual year (2007), bridge year (2008) and test year (2009). A detailed variance analysis of the distribution revenue components by rate class is also provided.

Throughput Revenue

Information related to Bluewater Power's throughput revenue includes details such as weather normalized forecasting methodology, normalized volumes, and customer count forecast tables. The details are found in Exhibit 3, Tab 2, Schedule 1.

Other Revenue

Other revenue includes items such as late payment charges, miscellaneous service revenues and retail service revenue. A summary of these revenues is presented in Exhibit 3, Tab 3, Schedule 1.

Summary of Distribution Revenue

Bluewater Power's distribution revenue is projected to be $21,436,077 as detailed in Table 3.1.2.1 below.

Table 3.1.2.1
2009 Test Year Distribution Revenue

Distribution Revenue	**2009 Projection**
Residential	10,717,712
General Service <50 kW	3,417,654
General Service 50 to 999 kW	3,324,043
General Service 1,000 to 4,999 kW	1,365,143
Large	2,042,545
Unmetered Scattered Load	121,232
Sentinel Lighting	33,169
Street Lighting	434,948
Gross Revenue (before Transformer Allowances)	**21,456,445**
Transformer Allowances	(559,364)
Total Revenue	**20,897,081**
Less: Low voltage charges embedded in distribution rates	(189,602)
BASE REVENUE REQUIREMENT	**20,707,479**
TOTAL OTHER OPERATING REVENUE	**728,598**
TOTAL DISTRIBUTION REVENUES	**21,436,077**

Exhibit 3, Tab 1, Schedule 2, Attachment 1 provides a schedule of the distribution revenue and the other distribution revenue for the test year, bridge year and historic year.

Operating Revenue Summary

Distribution Revenue * Pro-forma, as if EDR rates became effective January 1st	2009 Projection *	2008 Projection *	Var $	2008 Projection *	2007 Actual *	Var $
Residential	10,717,712	8,287,144	2,430,568	8,287,144	8,264,880	22,264
General Service <50 kW	3,417,654	2,703,400	714,254	2,703,400	2,689,848	13,552
General Service 50 to 999 kW	3,324,043	2,461,815	862,227	2,461,815	2,412,399	49,416
General Service 1,000 to 4,999 kW	1,365,143	1,198,956	166,187	1,198,956	1,237,467	(38,511)
Large	2,042,545	1,428,598	613,946	1,428,598	1,428,049	549
Unmetered Scattered Load	121,232	78,411	42,821	78,411	78,281	130
Sentinel Lighting	33,169	19,310	13,859	19,310	19,306	5
Street Lighting	434,948	250,142	184,806	250,142	247,702	2,440
Gross Revenue (before Transformer Allowances)	**21,456,445**	**16,427,776**	**5,028,669**	**16,427,776**	**16,377,931**	**49,845**
Transformer Allowances	(559,364)	(557,136)	(2,228)	(557,136)	(587,498)	30,362
Total Revenue	20,897,081	15,870,640	5,026,441	15,870,640	15,790,433	80,207
Less: Low voltage charges embedded in distribution rates	(189,602)	(164,987)	(24,615)	(164,987)	(179,624)	14,637
BASE REVENUE REQUIREMENT	**20,707,479**	**15,705,653**	**5,001,826**	**15,705,653**	**15,610,809**	**94,844**

Operating Revenue Summary

Distribution Revenue ** Pro-forma, as if EDR rates became effective January 1st*	**2007 Actual ***	**2006 EDR**	**Var $**
Residential	8,264,880	8,173,144	91,736
General Service <50 kW	2,689,848	2,741,280	(51,433)
General Service 50 to 999 kW	2,412,399	2,189,615	222,784
General Service 1,000 to 4,999 kW	1,237,467	893,438	344,029
Large	1,428,049	1,727,454	(299,405)
Unmetered Scattered Load	78,281	76,253	2,028
Sentinel Lighting	19,306	14,473	4,833
Street Lighting	247,702	240,714	6,988
Gross Revenue (before Transformer Allowances)	**16,377,931**	**16,056,371**	**321,561**
Transformer Allowances	(587,498)	(594,268)	6,770
Total Revenue	15,790,433	15,462,103	328,330
Less: Low voltage charges embedded in distribution rates	(179,624)	(179,624)	
BASE REVENUE REQUIREMENT	**15,610,809**	**15,282,479**	**328,330**

Operating Revenue Summary

Other Operating Revenue [1]	2009 Projection	2008 Projection	Var $	2008 Projection	2007 Actual	Var $
4080-Distribution Services Revenue	84,603	84,000	603	84,000	84,311	(311)
4082-Retail Services Revenues	68,097	68,097		68,097	68,543	(446)
4084-Service Transaction Requests (STR) Revenues	5,091	5,091		5,091	5,091	0
4090-Electric Services Incidental to Energy Sales						
4210-Rent from Electric Property	136,320	132,498	3,822	132,498	134,346	(1,848)
4225-Late Payment Charges	225,433	212,950	12,483	212,950	213,563	(613)
4230-Sales of Water and Water Power						
4235-Miscellaneous Service Revenues	135,840	129,300	6,540	129,300	147,538	(18,238)
4325-Revenues from Merchandise, Jobbing, Etc.	361,084	289,755	71,329	289,755	636,625	(346,870)
4330-Costs and Expenses of Merchandising, Jobbing, Etc.	(92,578)	(94,058)	1,480	(94,058)	(155,017)	60,959
4355-Gain on Disposition of Utility and Other Property	15,026	22,131	(7,105)	22,131	4,152	17,979
4390-Miscellaneous Non-Operating Income	33,318	25,000	8,318	25,000	58,976	(33,976)
4405-Interest and Dividend Income	(243,636)	(123,604)	(120,032)	(123,604)	193,485	(317,089)
TOTAL OTHER OPERATING REVENUE [1]	**728,598**	**751,160**	**(22,562)**	**751,160**	**1,391,613**	**(640,453)**
Total Distribution Revenue (see above)	20,707,479	15,705,653	5,001,826	15,705,653	15,610,809	94,844
TOTAL DISTRIBUTION REVENUES	**21,436,077**	**16,456,813**	**4,979,264**	**16,456,813**	**17,002,422**	**(545,609)**

[1] Excludes pass-through charges and non-utility amounts

Operating Revenue Summary

Other Operating Revenue [1]	**2007 Actual**	**2006 EDR**	**Var $**
4080-Distribution Services Revenue	84,311	85,390	(1,079)
4082-Retail Services Revenues	68,543	62,619	5,924
4084-Service Transaction Requests (STR) Revenues	5,091	506	4,586
4090-Electric Services Incidental to Energy Sales		85,392	(85,392)
4210-Rent from Electric Property	134,346	1	134,345
4225-Late Payment Charges	213,563	129,052	84,511
4230-Sales of Water and Water Power		107,184	(107,184)
4235-Miscellaneous Service Revenues	147,538	114,786	32,752
4325-Revenues from Merchandise, Jobbing, Etc.	636,625	804,527	(167,902)
4330-Costs and Expenses of Merchandising, Jobbing, Etc.	(155,017)	(102,184)	(52,833)
4355-Gain on Disposition of Utility and Other Property	4,152	653	3,499
4390-Miscellaneous Non-Operating Income	58,976		58,976
4405-Interest and Dividend Income	193,485	730,901	(537,416)
TOTAL OTHER OPERATING REVENUE [1]	**1,391,613**	**2,018,826**	**(627,213)**
Total Distribution Revenue (see above)	15,610,809	15,282,479	328,330
TOTAL DISTRIBUTION REVENUES	**17,002,422**	**17,301,305**	**(298,883)**

[1] Excludes pass-through charges and non-utility amounts

Calculations of Distribution Revenue Table

A table of calculations of distribution revenue for 2006 EDR, 2006 Actual Pro-Forma, 2007 Actual Pro-Forma, 2008 Bridge Year, and 2009 Test Year is provided as Exhibit 3, Tab 1, Schedule 3, Attachment 1.

Distribution Revenue Calculations

2006 EDR Approved	Customers (Connections)	kWh's per Customer (Connection)	kW's per Customer (Connection)	Dist. Rate per kWh	Dist. Rate per kW	Monthly Service Charge [1]	Distribution Revenue
Residential	30,648	8,783		$0.0117		$13.66	8,173,144
General Service <50 kW	3,705	34,188		$0.0128		$25.19	2,741,280
General Service 50 to 999 kW	360	609,422	1,298.833		$1.6252	$330.95	2,189,615
General Service 1,000 to 4,999 kW	12	14,245,359	24,506		$1.5261	$3,087.90	893,438
Large	5	70,335,893	112,788		$1.1436	$18,042.23	1,727,454
Unmetered Scattered Load	254	11,641		$0.0128		$12.60	76,253
Sentinel Lighting	320	2,030	4.869		$4.8281	$1.81	14,473
Street Lighting	9,345	938	2.491		$3.7416	$1.37	240,714
Gross Revenue (before Transformer Allowances)							**16,056,371**
Transformer Allowances (enter total credits as negative amount)							(594,268)
Total Revenue							**15,462,103**
Less: Low voltage charges embedded in distribution rates							(179,624)
DISTRIBUTION REVENUE							**15,282,479**

[1] *Excluding Smart Meter Rate Adder*

*2006 Actual Pro-forma ** ** As if EDR rates became effective January 1st*	Customers (Connections)	kWh's per Customer (Connection)	kW's per Customer (Connection)	Dist. Rate per kWh	Dist. Rate per kW	Monthly Service Charge [1]	Distribution Revenue
Residential	30,997	8,348		$0.0117		$13.66	8,108,556
General Service <50 kW	3,779	31,203		$0.0128		$25.19	2,651,633
General Service 50 to 999 kW	352	618,297	1,679.830		$1.6252	$330.95	2,358,914
General Service 1,000 to 4,999 kW	15	13,956,149	27,671		$1.5261	$3,087.90	1,189,257
Large	4	76,073,224	123,602		$1.1436	$18,042.23	1,431,431
Unmetered Scattered Load	264	11,336		$0.0128		$12.60	78,224
Sentinel Lighting	526	1,330	3.057		$4.8281	$1.81	19,188
Street Lighting	9,568	897	2.515		$3.7416	$1.37	247,317
Gross Revenue (before Transformer Allowances)							**16,084,520**
Transformer Allowances (enter total credits as negative amount)							(588,353)
Total Revenue							**15,496,166**
Less: Low voltage charges embedded in distribution rates							(179,624)
DISTRIBUTION REVENUE							**15,316,542**

[1] *Excluding Smart Meter Rate Adder*

Distribution Revenue Calculations

*2007 Actual Pro-forma ** ** As if EDR rates became effective January 1st*	Customers (Connections)	kWh's per Customer (Connection)	kW's per Customer (Connection)	Dist. Rate per kWh	Dist. Rate per kW	Monthly Service Charge [1]	Distribution Revenue
Residential	31,436	8,481		$0.0117		$13.64	8,264,880
General Service <50 kW	3,826	31,338		$0.0128		$25.16	2,689,848
General Service 50 to 999 kW	362	605,200	1,661		$1.6241	$330.56	2,412,399
General Service 1,000 to 4,999 kW	16	12,661,459	26,443		$1.5252	$3,084.29	1,237,467
Large	4	79,550,379	123,137		$1.1431	$18,021.16	1,428,049
Unmetered Scattered Load	266	11,198		$0.0128		$12.58	78,281
Sentinel Lighting	526	1,304	3		$4.8230	$1.81	19,306
Street Lighting	9,667	883	2		$3.7378	$1.37	247,702
Gross Revenue (before Transformer Allowances)							**16,377,931**
Transformer Allowances (enter total credits as negative amount)							(587,498)
Total Revenue							**15,790,433**
Less: Low voltage charges embedded in distribution rates							(179,624)
DISTRIBUTION REVENUE							**15,610,809**

[1] Excluding Smart Meter Rate Adder

*2008 Projection ** ** As if EDR rates became effective January 1st*	Customers (Connections)	kWh's per Customer (Connection)	kW's per Customer (Connection)	Dist. Rate per kWh	Dist. Rate per kW	Monthly Service Charge [1]	Distribution Revenue
Residential	31,720	8,340		$0.0117		$13.64	8,287,144
General Service <50 kW	3,875	30,917		$0.0128		$25.16	2,703,400
General Service 50 to 999 kW	379	569,029	1,557		$1.6241	$330.56	2,461,815
General Service 1,000 to 4,999 kW	16	11,488,172	24,864		$1.5252	$3,084.29	1,198,956
Large	4	80,016,612	123,258		$1.1431	$18,021.16	1,428,598
Unmetered Scattered Load	266	11,236		$0.0128		$12.58	78,411
Sentinel Lighting	526	1,302	3		$4.8230	$1.81	19,310
Street Lighting	9,837	877	2		$3.7378	$1.37	250,142
Gross Revenue (before Transformer Allowances)							16,427,776
Transformer Allowances							(557,136)
Total Revenue							15,870,640
Less: Low voltage charges embedded in distribution rates							(164,987)
DISTRIBUTION REVENUE							**15,705,653**

[1] Excluding Smart Meter Rate Adder

Distribution Revenue Calculations

2009 Projection ** As if EDR rates became effective January 1st*	**Customers (Connections)**	**kWh's per Customer (Connection)**	**kW's per Customer (Connection)**	**Dist. Rate per kWh**	**Dist. Rate per kW**	**Monthly Service Charge [1]**	**Distribution Revenue**
Residential	32,006	8,325		$0.0150		$17.50	10,717,712
General Service <50 kW	3,924	30,720		$0.0160		$31.52	3,417,654
General Service 50 to 999 kW	396	546,047	1,499		$2.1298	$433.49	3,324,043
General Service 1,000 to 4,999 kW	16	11,319,320	24,923		$1.7345	$3,507.63	1,365,143
Large	4	80,485,576	123,378		$1.6337	$25,755.94	2,042,545
Unmetered Scattered Load	266	8,229		$0.0228		$22.37	121,232
Sentinel Lighting	526	1,301	3		$8.2803	$3.11	33,169
Street Lighting	10,009	871	2		$6.4356	$2.36	434,948
Gross Revenue (before Transformer Allowances)							21,456,445
Transformer Allowances							(559,364)
Total Revenue							20,897,081
Less: Low voltage charges embedded in distribution rates							(189,602)
DISTRIBUTION REVENUE							**20,707,479**

[1] Excluding Smart Meter Rate Adder

Variance Analysis on Distribution Revenue

Bluewater Power's total distribution revenue including other distribution revenue is forecast to be $21,436,077 for 2009 as shown in Exhibit 3, Tab 1, Schedule 2. The distribution revenue excluding other revenue totals $20,707,479 or 97% of total revenue. The remaining revenue of $728,598 is earned from other distribution revenue, which is explained in the next section.

The variance in distribution revenue is related to either volumetric changes (changes in customer count or consumption/demand) or price changes. The tables that are provided below for each rate class break down the changes between customer count, consumption/demand, and price changes.

In the variance analysis that follows, Bluewater Power has explained any distribution revenue variances greater than 1% of net distribution revenue per 2006 EDR or $153,000. Those items exceeding the materiality threshold are highlighted in Table 3.1.4.1 below.

2009 Test Year to 2008 Bridge Year Variances

The overall variance for 2008 to 2009 is presented in Table 3.1.4.1 below. The 2009 projection is calculated using the 2009 proposed rates. Those rate classes that exceed the materiality threshold are highlighted. Any rate class experiencing a material variance is addressed in the tables that follow, wherein the variance for each rate class is broken down in terms of the impact of customer count, consumption/demand, and price changes.

Table 3.1.4.1
2009 to 2008 Distribution Revenue Variances

Distribution Revenue	2009 Projection *	2008 Projection	$ Variance
Residential	10,717,712	8,287,144	2,430,568
General Service <50 kW	3,417,654	2,703,400	714,254
General Service 50 to 999 kW	3,324,043	2,461,815	862,227
General Service 1,000 to 4,999 kW	1,365,143	1,198,956	166,187
Large	2,042,545	1,428,598	613,946
Unmetered Scattered Load	121,232	78,411	42,821
Sentinel Lighting	33,169	19,310	13,859
Street Lighting	434,948	250,142	184,806
Gross Revenue (before Transformer Allowances)	21,456,445	**16,427,776**	5,028,669
Transformer Allowances	(559,364)	(557,136)	(2,228)
Total Revenue	20,897,081	**15,870,640**	5,026,441
Less: Low voltage charges embedded in distribution rates	(189,602)	(164,987)	(24,615)
DISTRIBUTION REVENUE	**20,707,479**	**15,705,653**	5,001,826

* At proposed rates

Table 3.1.4.2
Residential Variance

Rate Class	Variance	2008 Projected	2009 Projected	Variance	$ Variance
Residential					
Volume Variance	kWh	264,548,206	266,434,436	1,886,230	$ 22,068.89
	# customers	31,720	32,006	286	$ 46,812.48
	Total Volume Variance				$ 68,881.37
Price Variance	Variable Price	$0.0117	$0.0150	$0.0033	$ 881,046.46
	Fixed Price	$13.64	$17.50	$3.86	$ 1,480,640.45
	Total Price Variance				$ 2,361,686.91
Total Residential Variance					$ 2,430,568.28

Table 3.1.4.3
General Service <50 kW Variance

Rate Class	Variance	2008 Projected	2009 Projected	Variance	$ Variance
General Service <50 kW					
Volume Variance	kWh	119,801,538	120,544,382	742,844	$ 9,508.40
	# customers	3,875	3,924	49	$ 14,794.08
	Total Volume Variance				$ 24,302.48
Price Variance	Variable Price	$0.0128	$0.0160	$0.0032	$ 390,282.11
	Fixed Price	$25.16	$31.52	$6.36	$ 299,669.53
	Total Price Variance				$ 689,951.65
Total GS < 50 kW Variance					$ 714,254.13

Table 3.1.4.4
General Service 50 to 999 kW Variance

Rate Class	Variance	2008 Projected	2009 Projected	Variance	$ Variance
General Service 50 to 999 kW					
Volume Variance	kW	590,129	593,516	3,387	$ 5,500.83
	# customers	379	396	17	$ 67,434.24
	Total Volume Variance				$ 72,935.07
Price Variance	Variable Price	$1.6241	$2.1298	$0.5057	$ 300,156.56
	Fixed Price	$330.56	$433.49	$102.93	$ 489,135.71
	Total Price Variance				$ 789,292.26
Total GS 50 to 999 kW Variance					$ 862,227.33

Table 3.1.4.5
General Service 1,000 to 4,999 kW

Rate Class	Variance	2008 Projected	2009 Projected	Variance	$ Variance
General Service 1,000 to 4,999 kW					
Volume Variance	kW	397,831	398,767	936	$ 1,427.59
	# customers	16	16	0	$ -
	Total Volume Variance				$ 1,427.59
Price Variance	Variable Price	$1.5252	$1.7345	$0.2093	$ 83,478.86
	Fixed Price	$3,084.29	$3,507.63	$423.34	$ 81,280.61
	Total Price Variance				$ 164,759.46
Total GS 50 to 999 kW Variance					$ 166,187.05

Table 3.1.4.6
Large Variance

Rate Class	Variance	2008 Projected	2009 Projected	Variance	$ Variance
Large					
Volume Variance	kW	493,030	493,510	480	$ 548.69
	# customers	4	4	0	$ -
	Total Volume Variance				$ 548.69
Price Variance	Variable Price	$1.1431	$1.6337	$0.4906	$ 242,128.24
	Fixed Price	$18,021.16	$25,755.94	$7,734.78	$ 371,269.48
	Total Price Variance				$ 613,397.72
Total Large Variance					$ 613,946.41

Table 3.1.4.7
Street Lighting Variance

Rate Class	Variance	2008 Projected	2009 Projected	Variance	$Variance
Street Lighting					
Volume Variance	kW	23,656	23,562	(94)	$ (351.35)
	# customers	9,837	10,009	172	$ 2,827.68
	Total Volume Variance				$ 2,476.33
Price Variance	Variable Price	$3.7378	$6.4356	$2.6978	$ 63,565.63
	Fixed Price	$1.37	$2.36	$0.99	$ 118,764.51
	Total Price Variance				$ 182,330.14
Total Street Lighting Variance					$ 184,806.47

2008 to 2007 Variances

There are no material distribution revenue variances between 2008 and 2007.

2007 to 2006 EDR Variances

The overall variance for 2006 EDR to 2007 is presented in Table 3.1.4.8 below. Those rate classes that exceed the materiality threshold are highlighted. Any rate class experiencing a material variance is addressed in the tables that follow, wherein the variance for each rate class is broken down in terms of the impact of customer count, consumption/demand, and price changes.

Table 3.1.4.8
Overall Variances

Distribution Revenue	**2007 Actual**	**2006 EDR Approved**	**Variance**
Residential	8,264,880	8,173,144	91,736
General Service <50 kW	2,689,848	2,741,280	(51,433)
General Service 50 to 999 kW	2,412,399	2,189,615	222,784
General Service 1,000 to 4,999 kW	1,237,467	893,438	344,029
Large	1,428,049	1,727,454	(299,405)
Unmetered Scattered Load	78,281	76,253	2,028
Sentinel Lighting	19,306	14,473	4,833
Street Lighting	247,702	240,714	6,988
Gross Revenue (before Transformer Allowances)	**16,377,931**	**16,056,371**	**321,561**
Transformer Allowances	(587,498)	(594,268)	6,770
Total Revenue	15,790,433	15,462,103	328,330
Less: Low voltage charges embedded in distribution rates	(179,624)	(179,624)	0
DISTRIBUTION REVENUE	**15,610,809**	**15,282,479**	**328,330**

Table 3.1.4.9
General Service 50 to 999 kW Variance

Rate Class	Variance	2006 EDR	2007 Actual	Variance	$ Variance
General Service 50 to 999 kW					
Volume Variance	kW	467,580	601,223	133,643	$ 217,196.60
	# customers	360	362	2	$ 7,942.80
	Total Volume Variance				$ 225,139.40
Price Variance	Variable Price	$1.6252	$1.6241	-$0.0011	$ (661.35)
	Fixed Price	$330.95	$330.56	($0.39)	$ (1,694.16)
	Total Price Variance				$ (2,355.51)
Total GS 50 to 999 kW Variance					$ 222,783.90

Table 3.1.4.10
General Service 1,000 to 4,999 kW Variance

Rate Class	Variance	2006 EDR	2007 Actual	Variance	$ Variance
General Service 1,000 to 4,999 kW					
Volume Variance	kW	294,070	423,081	129,011	$ 196,883.69
	# customers	12	16	4	$ 148,219.20
	Total Volume Variance				$ 345,102.89
Price Variance	Variable Price	$1.5261	$1.5252	-$0.0009	$ (380.77)
	Fixed Price	$3,087.90	$3,084.29	($3.61)	$ (693.12)
	Total Price Variance				$ (1,073.89)
Total GS 1,000 to 4,000 kW Variance					$ 344,028.99

Table 3.1.4.11
Large Variance

Rate Class	Variance	2006 EDR	2007 Actual	Variance	$ Variance
Large					
Volume Variance	kW	563,939	492,550	(71,389)	$ (81,640.80)
	# customers	5	4	(1)	$ (216,506.76)
	Total Volume Variance				$ (298,147.56)
Price Variance	Variable Price	$1.1436	$1.1431	-$0.0005	$ (246.27)
	Fixed Price	$18,042.23	$18,021.16	($21.07)	$ (1,011.36)
	Total Price Variance				$ (1,257.63)
Total Large Variance					$ (299,405.20)

Throughput Revenue

Weather Normalization Forecasting Methodology

Bluewater Power has used weather normalized forecasts in its determination of load for those rate classes that are weather sensitive. The weather sensitive rate classes are: Residential, General Service <50 kW and General Service 50 to 999 kW. The remaining rate classes, being General Service 1,000 to 4,999 kW ("Intermediate"), Large Use, Street Lighting, Sentinel Lighting and Unmetered Scattered Load are not considered weather sensitive and the forecasts for those rate classes are based on consumption trends over the last four years.

The weather normalization is based on a report prepared by Elenchus Research Associates ("ERA"). The ERA report titled 'Medium Term Weather Normalized Distribution System Load Forecast 2008 to 2009' dated April 24, 2008, is labeled as Exhibit 3, Tab 2, Schedule 1, Attachment 1 and referenced as "The Elenchus forecast report".

The methodology uses actual unadjusted data for 2004 to 2007 which is then modeled to determine a weather normalized forecast for 2008 and 2009 for the weather sensitive classes. A ten year average from 1998 to 2007 has been adopted as the appropriate definition of normal weather which is more consistent with weather experienced in recent years, and has been used in other electricity distribution applications (Toronto Hydro Electric System Limited in EB-2005-0421 and EB-2007-0680).

Given the importance of accurate load forecasts, a survey was sent out to the industrial Intermediate and Large Use customers in May, 2008 requesting information on their projected volumes for the next three years. Of the ten surveys sent out, four customers replied with their projected load. Of the four that returned responses, all had projected a flat load projection for the next three years, consistent with their 2007 data.

There are four variances from what is presented as the load forecast for Bluewater Power, and the forecast presented in the Elenchus forecast report:

1. Table 6 on page 10 of the Elenchus forecast report contains the 2007 kW actual demand for the Intermediate rate class as 428,081kW. The corrected value of 423,081 has been reflected in the load forecast for Bluewater Power as detailed in Exhibit 3, Tab 2, Schedule 3, Table 3.2.3.2 -Normalized Volume Forecast Table.

2. Table 6 on page 10 of the Elenchus forecast report includes 100% of the 2007 actual load for a customer that was formerly a Large Use customer and is currently an Intermediate customer. The customer is a manufacturing plant that as of the filing date of this application is sitting idle. The forecast Bluewater Power has used assumes a 50% decrease in the volume from the 2007 levels. Further discussion on this customer is provided in Exhibit 3, Tab 2, Schedule 2, page 2. The 2007 annual demand of 52,367 kW embedded in the Elenchus forecast report has been reduced to 26,245 kW annual demand for the 2008 forecast, and 26,306 kW annual demand projected for 2009.

3. Table 6 on page 10 of the Elenchus forecast report includes a projected increase in the Unmetered Scattered Load ("USL") of 0.3% over the 2007 levels. The usage for traffic lights is a part of the USL data. Throughout the 2007 calendar year Bluewater Power completed a project to convert the traffic lights to LED, which has resulted in decreased annual consumption over historical levels. Bluewater Power had projected that the conversion would decrease traffic light usage by approximately 700,000 kWh annually. Therefore the projected load for 2009 is forecast at 2,188,838 annual kWh which is 810,139 kWh lower than the value in the Elenchus forecast report. The 2009 forecast is based on the year to date June 2008 actual results with the remaining forecast for July to December 2008 increased by 0.3% as indicated in the Elenchus forecast report for the USL rate category.

4. Table 8 on page 12 of the Elenchus forecast report indicates the 2008 and 2009 number of customers for the Intermediate rate class of 15, and for the Large Use rate class of 5. In fact, the statistics detailed in the remaining Elenchus forecast report reflect the movement of one Large Use customer to the Intermediate rate class, therefore the number of connections reported in the Bluewater forecast is 16 Intermediate customers, and 4 Large Use customers.

Medium Term Weather Normalized Distribution System Load Forecast 2008 to 2009

Prepared for

Bluewater Power Corporation

April 24, 2008

1 INTRODUCTION

This document outlines the results and methodology used to derive the weather normal load forecast prepared for use in Bluewater Power Corporation's rebasing rate application for 2009 rates. A weather normal load forecast is developed for the bridge year (2008) and test year (2009) and weather normalized historical consumption is also derived.

The forecast for Bluewater Power is generally based on monthly class specific retail data. The Company was able to provide data from January 2003 to December 2007. The retail metered data has been prorated to represent calendar month consumption. That is, the billing data has been adjusted to account for unbilled amounts, the effect of meter reading dates, etc. The retail consumption amounts do not include losses; therefore, distribution system losses are not part of the class retail volumes. These volumes will need to be adjusted for distribution system losses to reconcile with wholesale purchases by the LDC. For analysis of residential consumption, the entire data series was used. Weather correction and forecasting for general service class kWh volumes is based on data from January 2004 to January 2007, due to anomalous monthly consumption in 2003. Forecasting efficiency is increased significantly when monthly observations from 2003 are excluded.

Short-term variation in electricity consumption is heavily influenced by three main factors – weather (e.g. heating and cooling), which is by far the dominant effect for most systems; economic factors (increases or decreases in economic activity leads to changes in employment, industrial and commercial activity, building and population change); and timing factors (non-holiday weekdays when businesses are typically operating). We have tried to incorporate variables to account for all of these factors in considering Bluewater Power's load and correcting for weather anomalies.

In order to isolate demand determinants at the class specific level, we have estimated equations to weather normalize and forecast kWh consumption for the residential, GS<50 and GS>50 classes. For GS>50 class kW demand, historical monthly load

factors are calculated and applied to normalized kWh. Forecast kW is calculated in the same way except that the 2007 monthly load factors are applied. Consumption for intermediate and large user classes, street lighting and sentinel lighting, and unmetered scattered load (USL) is not considered weather sensitive, and these forecasts are based on trend consumption. Monthly data for intermediate and large user class consumption was regressed against monthly weather data for Sarnia and found to have very little correlation with weather.

The estimated equations for weather sensitive class specific monthly consumption and their statistics are presented in the Appendix (Section 3) of this report. Results for both the residential and GS<50 classes are well within the acceptable range of explanatory power. The result for the GS>50 class is at the lower end of what would be considered acceptable, with an adjusted R-Squared of 0.68, it explains approximately 68 per cent of monthly load variance. As can be seen from the equation statistics reproduced in the Appendix, the overall regression is statistically significant. As is explained in more detail in the next section, on an annual basis, within-sample prediction error is no greater than 1.5 per cent in any given year. On an annual prediction basis, the mean absolute percentage error for the four years 2004 to 2007 is 1.06 per cent, well within acceptable limits.

Another issue that should be pointed out is that timing variables (i.e., peak days) do not appear to affect GS< 50 class kWh usage[1]. In general, energy consumption excluding the effects of weather has exhibited very little trend for the residential and general service classes over the past several years. This result is consistent with the 2006 Census for Sarnia which reported the City's population increased by only 543 persons from 2001 to 2006, or a little less than 0.2% per year. A summary of the population census for the City of Sarnia is reproduced in the Appendix.

[1] Other variations of timing were also tried (peak hours and non-linear relationships in the variables). All resulted in poorer overall performance for in-sample annual prediction.

2 CLASS SPECIFIC NORMALIZED AND FORECAST RESULTS

2.1 RESIDENTIAL AND GENERAL SERVICE CLASSES

In order to determine the relationship between observed weather and energy consumption, monthly weather observations describing the extent of heating or cooling required within the month are necessary. Environment Canada publishes monthly observations on heating degree days (HDD) and cooling degree days (CDD) for selected weather stations across Canada. Heating degree days for a given day are the number of Celsius degrees that the mean temperature is below 18°C. Cooling degree days for a given day are the number of Celsius degrees that the mean temperature is above 18°C. For Bluewater Power, we have used monthly HDD and CDD as reported at Sarnia Airport.

In order to measure the change in economic activity, a data series must be chosen which represents, as much as possible, regional economic activity. We have used the monthly full-time employment levels for the Windsor-Sarnia area, as reported in Statistics Canada's Monthly Labour Force Survey (CANSIM series v2054779).

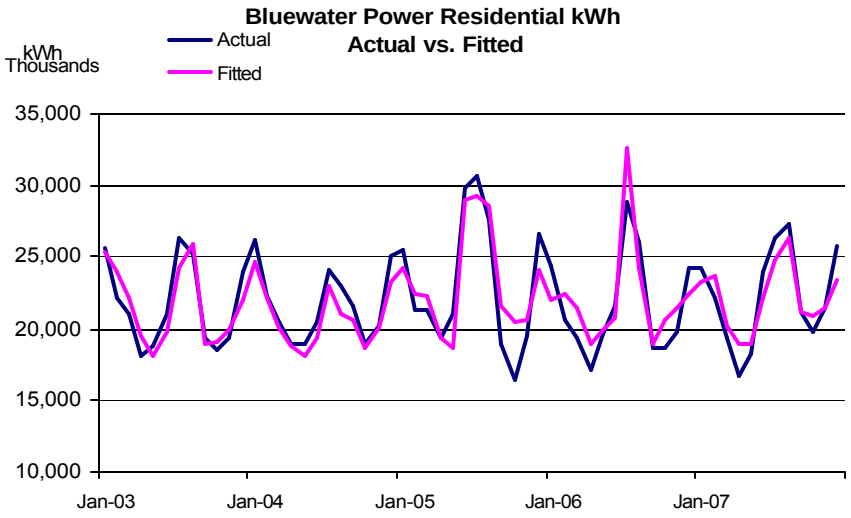
Finally, we have used the number of non-holiday weekdays in the month to account for peak day consumption. We have included New Year's Day, Good Friday, Easter Monday, Victoria Day, Canada Day, August Civic Holiday (Simcoe Day), Labour Day, Thanksgiving Day, Christmas and Boxing Day. From 2008, we have included the Ontario Family Day holiday in February, but we have not included Remembrance Day in November. The historical data for monthly employment and peak days are displayed in *Table 1* below.

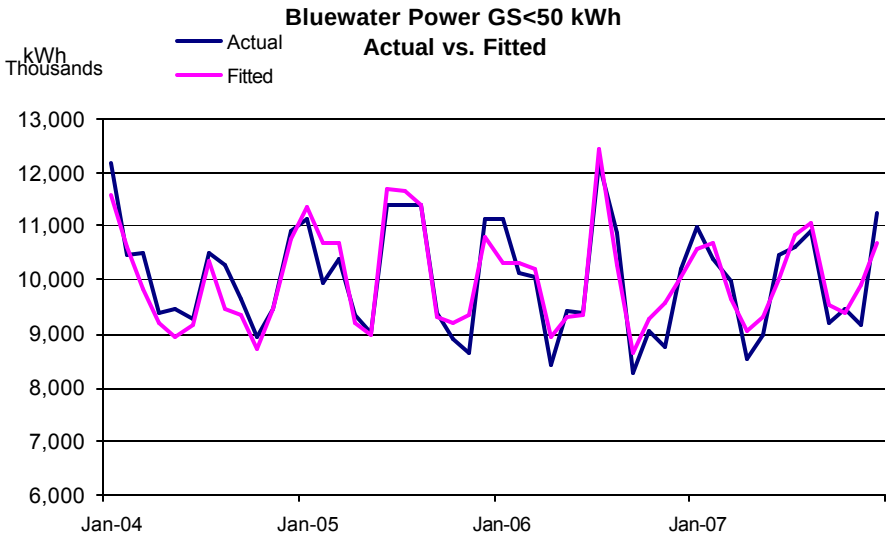
Table 1
Monthly Peak Days

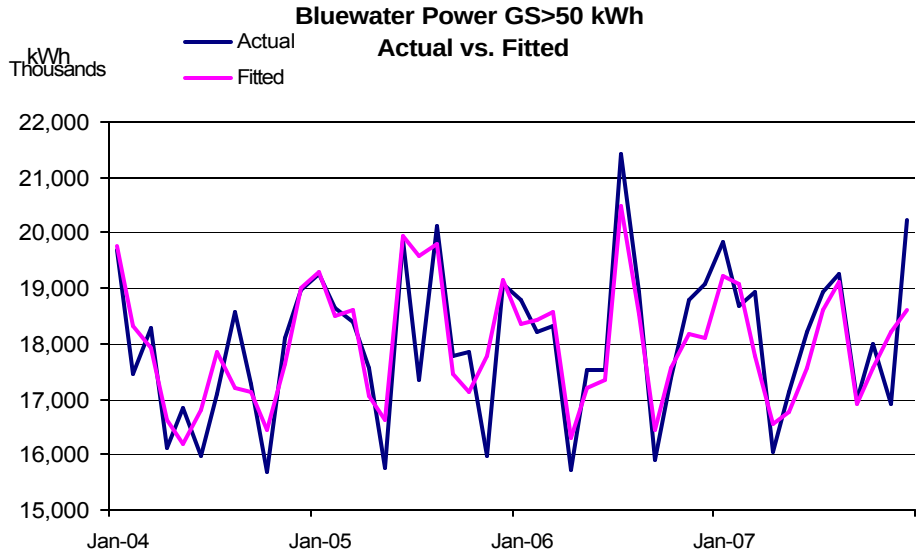
	2003	2004	2005	2006	2007
January	21	21	20	21	22
February	20	20	20	20	20
March	21	23	21	23	22
April	20	20	21	18	19
May	21	20	21	22	22
June	21	22	22	22	21
July	22	21	20	20	22
August	20	21	22	22	22
September	21	21	21	20	19
October	22	20	20	21	22
November	20	22	22	22	22
December	21	21	20	19	19
	Full-time employment ('000s) Windsor-Sarnia [3570], Ontario				
January	249.4	239.3	243.4	247.3	247.1
February	246.2	235.8	242.3	246.5	239
March	242.3	233.3	240.5	243.6	232.7
April	240.2	235.2	244.6	245.3	235.7
May	242.1	239.8	249.3	247.1	238.2
June	245.4	246.4	254.2	251.5	243.9
July	247.4	249.2	257.8	256.4	247.9
August	251.5	251.3	257.6	261.1	252
September	250.5	250.2	257.8	263.1	254.1
October	248.9	248	255.3	263.5	254.9
November	244.8	245.3	252.3	262.1	253
December	242.8	244.7	251.8	257.6	250
Ann % chg	***1.3%***	***-1.1%***	***3.0%***	***1.3%***	***-3.2%***

Using this data, regression equations describing the relationship between monthly actual energy and the explanatory variables were estimated for residential, GS<50 and GS>50 classes. All the data showed strong correlation with weather, as expected. The residential and GS < 50 class kWh consumption also showed some correlation with economic activity[2]. GS>50 class kWh consumption correlated with weather, peak days, and economic activity. The charts below illustrate historic class kWh consumption and prediction using our regression equation estimates.

[2] For the residential class, employment level has explanatory power. For GS<50, the change in monthly employment lagged one period has explanatory power.


Bluewater Power Residential kWh
Actual vs. Fitted
Actual
Fitted
kWh
Thousands
35,000
30,000
25,000
20,000
15,000
10,000
Jan-03
Jan-04
Jan-05
Jan-06
Jan-07


Bluewater Power GS<50 kWh
Actual vs. Fitted
Actual
Fitted
kWh
Thousands
13,000
12,000
11,000
10,000
9,000
8,000
7,000
6,000
Jan-04
Jan-05
Jan-06
Jan-07


Bluewater Power GS>50 kWh
Actual vs. Fitted
Actual
Fitted
kWh
Thousands
22,000
21,000
20,000
19,000
18,000
17,000
16,000
15,000
Jan-04
Jan-05
Jan-06
Jan-07

Annual estimates are compared to actual values in the table below. Mean absolute percentage error (MAPE) of the estimates for the period are all less than 2% with the largest absolute error on an annual estimate at 4%.

Table 2

Year	*Actual Residential kWh*	*Predicted kWh*	*Error*
2003	259,763,319	259,250,361	-0.20%
2004	260,280,308	249,878,342	-4.00%
2005	278,165,933	280,533,519	0.85%
2006	258,763,018	266,047,814	2.82%
2007	266,618,398	265,099,907	-0.57%
	Mean Absolute Percent Error		*1.69%*

	Actual GS<50 kWh	*Predicted kWh*	*Error*	*Actual GS>50 kWh*	*Predicted kWh*	*Error*
2004	121,030,693	117,424,340	-2.98%	210,062,947	210,846,024	0.37%
2005	122,041,096	124,288,790	1.84%	217,698,595	220,935,239	1.49%
2006	117,915,371	118,526,038	0.52%	217,640,501	215,533,001	-0.97%
2007	119,898,584	120,646,495	0.62%	219,082,316	215,991,152	-1.41%
	Mean Absolute Percent Error		*1.49%*			*1.06%*

2.2 WEATHER NORMALIZATION AND FORECASTED CONSUMPTION

It is not possible to accurately forecast weather for months or years in advance. Therefore, one can only base future weather expectations on what has happened in the past. Individual years may experience unusual spells of weather (unusually cold winter, unusually warm summer, etc.). However, over time, these unusual spells "average" out. While there may be trends over several years (e.g., warmer winters for example), using several years of data rather than one particular year filters out the extremes of any particular year. For Bluewater Power, the 10 year average from 1998 to 2007 has been adopted as the appropriate definition of weather normal. Other definitions also exist. Environment Canada publishes 30 year "Climate Normal" data based on observations from 1971 to 2000. The OEB has considered yet others (for example, a five-year rolling average used to predict heating degree days for bridge year and test year in the case of Natural Resource Gas Limited (RP-2004-0167)). Our view is that a ten-year average based on the most recent ten calendar years available is a reasonable compromise that likely reflects the "average" weather experienced in recent years. Others have also adopted this definition (for example, Toronto Hydro Electric System Limited in EB-2005-0421 and EB-2007-0680).

Presented below is a table outlining the 10-year and 30-year average monthly HDD and CDD for Sarnia Airport.

Table 3 – 30-yr and 10-yr HDD and CDD, Sarnia Airport

	1971-2000 30-yr normal		1998-2007 10-yr normal	
	HDD	CDD	HDD	CDD
Jan	718.4	0	681.0	0.0
Feb	633.7	0	597.8	0.0
Mar	537.8	0.1	525.8	0.2
Apr	347.3	2	328.2	1.3
May	179.8	14.4	163.7	14.6
Jun	50.8	51.5	44.1	68.3
Jul	10.1	99.6	7.0	108.3
Aug	15.6	78.8	10.3	85.2
Sep	85.5	27	59.5	38.8
Oct	252.3	2	231.4	6.0
Nov	423.1	0	382.7	0.0
Dec	627.8	0	605.1	0.0
Annual	**3,882.3**	**275.4**	**3,636.5**	**322.6**

Forecasts for Ontario's employment outlook for 2008 and 2009 are available from four Canadian Chartered Banks at time of writing. Their forecasts are summarized below.

Table 4 - Employment Forecast – Ontario
(figures in annual percentage change)

	BMO *(Winter 2008)*	RBC *(April 2008)*	Scotia *(March 31, 2008)*	TD *(April 16,2008)*	avg
2008	0.7	0.9	1.1	1.0	0.9
2009	0.7	1.0	0.7	0.4	0.7

No specific forecast from a third-party independent source for the employment in Sarnia is available. Therefore, a provincial average outlook is used. In using the Ontario provincial average outlook for employment growth, the load forecast for Bluewater Power may be subject to potential downside risk. In 2007, Ontario employment grew on

average by about 1.5 per cent[3] whereas in the Windsor-Sarnia CMA, employment decreased by 3.2 per cent (as can be seen in Table 1 on page 5 of this report).

Incorporating the forecast economic variables, monthly peak days, and 10-yr weather normal heating and cooling degree days, the following weather corrected consumption and forecast values are calculated:

Table 5 - Weather Corrected Consumption for Bluewater Power

			10-yr (1998-2007)	
Year	Actual residential kWh	%chg	Weather Normal	%chg
2003	259,763,319		262,564,911	
2004	260,280,308	0.2%	259,693,274	-1.1%
2005	278,165,933	6.9%	267,615,085	3.1%
2006	258,763,018	-7.0%	271,029,182	1.3%
2007	266,618,398	3.0%	262,311,194	-3.2%
2008F			264,548,206	0.9%
2009F			266,434,436	0.7%
Year	Actual GS<50 kWh	%chg	Weather Normal	%chg
2004	121,030,693		120,229,106	
2005	122,041,096	0.83%	120,625,273	0.3%
2006	117,915,371	-3.38%	120,795,929	0.1%
2007	119,898,584	1.68%	119,643,998	-1.0%
2008F			119,801,538	0.1%
2009F			120,544,382	0.6%
Year	Actual GS>50 kWh	%chg	Weather Normal	%chg
2004	210,062,947		213,784,437	
2005	217,698,595	3.63%	216,568,970	1.3%
2006	217,640,501	-0.03%	218,032,800	0.7%
2007	219,082,316	0.66%	214,903,890	-1.4%
2008F			215,661,960	0.4%
2009F			216,234,424	0.3%
Year	Actual GS>50 kW	%chg	Weather Normal	%chg
2004	566,672		579,111	
2005	592,406	4.5%	590,317	1.9%
2006	591,300	-0.2%	593,533	0.5%
2007	601,223	1.7%	589,074	-0.8%
2008F			590,129	0.2%
2009F			593,516	0.6%

[3] Source: Statistics Canada v2063945.

2.3 NON-WEATHER SENSITIVE CLASSES

For classes that do not have weather sensitivity (intermediate and large users, street and sentinel lighting, unmetered scattered load), class consumption is forecast based on the annual consumption trend over the past 4 years. Table 6 (below) outlines historical customer consumption for these classes from 2003 to 2007 and forecast bridge year (2008) and test year (2009) consumption:

Table 6

Intermediate and Large Users Historic and Trend Forecast Consumption

	Intermediate				*Large User*			
Year	kWh	%	kW	%	kWh	%	kW	%
2003	215,734,696		424,741		312,370,603		491,030	
2004	223,698,552	3.7%	435,039	2.4%	319,916,639	2.4%	491,745	0.1%
2005	225,996,193	1.0%	430,146	-1.1%	295,104,220	-7.8%	479,410	-2.5%
2006	209,342,236	-7.4%	415,068	-3.5%	304,292,895	3.1%	494,407	3.1%
2007	202,583,345	-3.2%	428,081	3.1%	318,201,517	4.6%	492,550	-0.4%
avg 2003-07		**-1.5%**		**0.2%**		**0.6%**		**0.1%**
2008F	199,605,803		429,076		320,066,446		493,030	
2009F	196,672,025		430,073		321,942,304		493,510	

Lighting Customers Historic and Trend Forecast Consumption

	Street lighting				*Sentinel Lighting*			
Year	kWh	%	kW	%	kWh	%	kW	%
2003	8,219,864		24,138		691,348		1,655	
2004	8,969,846	9.1%	24,180	0.2%	721,397	4.3%	1,655	0.0%
2005	8,585,892	-4.3%	24,423	1.0%	699,473	-3.0%	1,850	11.8%
2006	8,581,095	-0.1%	24,059	-1.5%	669,378	-4.3%	1,608	-13.1%
2007	8,536,684	-0.5%	23,751	-1.3%	685,929	2.5%	1,634	1.6%
avg 2003-07		**1.1%**		**-0.4%**		**-0.1%**		**0.1%**
2008F	8,627,815		23,656		685,033		1,635	
2009F	8,719,920		23,562		684,138		1,637	

Unmetered Scattered Load (USL)

Year	kWh	%
2003	2,938,924	
2004	3,006,781	2.3%
2005	2,997,759	-0.3%
2006	2,992,773	-0.2%
2007	2,978,570	-0.5%
avg 2003-07		**0.3%**
2008F	2,988,756	
2009F	2,998,977	

2.4 HISTORIC, BRIDGE, AND TEST YEARS

Table 7 below presents the results for class specific historic actual and historic normalized (2007) kWh and kW (where applicable), and normalized forecast values for bridge year (2008) and test year (2009).

Table 7 – Load Forecast (Historical, Bridge and Test Years).

	2007 Actual	2007 Normalized	2008f Normalized	2009f Normalized
Residential (kWh)	266,618,398	262,311,194	264,548,206	266,434,436
GS<50 (kWh)	119,898,584	119,643,998	119,801,538	120,544,382
GS>50 (kWh)	219,082,316	214,903,890	215,661,960	216,234,424
(kW)	601,223	589,074	590,129	593,516
Intermediate (kWh)	202,583,345	202,583,345	199,605,803	196,672,025
(kW)	428,081	428,081	429,076	430,073
Large User (kWh)	318,201,517	318,201,517	320,066,446	321,942,304
(kW)	492,550	492,550	493,030	493,510
Street Lights (kWh)	8,536,684	8,536,684	8,627,815	8,719,920
(kW)	23,751	23,751	23,656	23,562
Sentinel Lights (kWh)	685,929	685,929	685,033	684,138
(kW)	1,634	1,634	1,635	1,637
USL (kWh)	2,978,570	2,978,570	2,988,756	2,998,977
Total Retail kWh	1,138,585,343	1,129,845,127	1,131,985,557	1,134,230,606

2.5 CUSTOMER CONNECTIONS

Table 8 below outlines the average annual number of active customer connections in each class and a trend forecast for annual customers based on the average customer additions over the 2003 to 2007 period.

Table 8 – Average Annual Customer Connections

	Residential	%chg	GS<50	%chg	GS>50	%chg	Street Light	%chg	Sent Light	%chg
2003	30,327		3,637		303		9,020		526	
2004	30,560	*0.8%*	3,687	*1.4%*	333	*9.9%*	9,345	*3.6%*	526	*0.0%*
2005	30,734	*0.6%*	3,685	*-0.1%*	347	*4.2%*	9,548	*2.2%*	526	*0.0%*
2006	30,997	*0.9%*	3,779	*2.6%*	352	*1.4%*	9,568	*0.2%*	526	*0.0%*
2007	31,436	*1.4%*	3,826	*1.2%*	362	*2.8%*	9,667	*1.0%*	526	*0.0%*
2003-2007		**0.9%**		**1.3%**		**4.6%**		**1.8%**		**0.0%**
2008f	31,720		3,875		379		9,837		526	
2009f	32,006		3,924		396		10,009		526	
	Intermediate		LU		USL					
2003	12		5		254					
2004	12		5		254					
2005	17		5		255					
2006	14		5		264					
2007	15		5		266					
2008f	15		5		266					
2009f	15		5		266					

3 APPENDIX

Results from the regression equation estimation are presented below:

RESIDENTIAL kWH

Prais-Winsten estimates using the 60 observations 2003:01-2007:12
Dependent variable: l_Res__kWh

Variable	*Coefficient*	*Std. Error*	*t-statistic*	*p-value*	
const	15.5976	0.480783	32.4420	<0.00001	***
HDD	0.000548272	6.17829e-05	8.8742	<0.00001	***
CDD	0.00454282	0.000368478	12.3286	<0.00001	***
FT_EmpWin_Sarn	0.00410371	0.00192124	2.1360	0.03707	**

Statistics based on the rho-differenced data:

Unadjusted R^2 = 0.800796
Adjusted R^2 = 0.790124
F-statistic (3, 56) = 1759.63 (p-value < 0.00001)
Durbin-Watson statistic = 1.73972

GS <50 kWH

OLS estimates using the 48 observations 2004:01-2007:12
Dependent variable: GsIt50_kWh

Variable	*Coefficient*	*Std. Error*	*t-statistic*	*p-value*	
const	7.65048e+06	183211	41.7579	<0.00001	***
HDD	5031.05	437.335	11.5039	<0.00001	***
CDD	31297.8	2379.4	13.1536	<0.00001	***
d_FT_EmpWin_1	60948.7	27517.4	2.2149	0.03199	**

Unadjusted R2 = 0.829049
Adjusted R2 = 0.817393
F-statistic (3, 44) = 71.1279 (p-value < 0.00001)
Durbin-Watson statistic = 1.93351

GS >50 kWH

Prais-Winsten estimates using the 48 observations 2004:01-2007:12
Dependent variable: l_Gsgt50_kWh

Variable	*Coefficient*	*Std. Error*	*t-statistic*	*p-value*	
const	15.801	0.234909	67.2643	<0.00001	***
HDD	0.000328613	3.25533e-05	10.0946	<0.00001	***
CDD	0.00193335	0.00020816	9.2878	<0.00001	***
Peakdays	0.0114183	0.00641558	1.7798	0.08218	*
FT_EmpWin_Sarn	0.00206353	0.000720573	2.8637	0.00645	***

Statistics based on the rho-differenced data:

Unadjusted R^2 = 0.708297
Adjusted R^2 = 0.681162
F-statistic (4, 43) = 3450.54 (p-value < 0.00001)
Durbin-Watson statistic = 1.99455

GS>50 LOAD FACTOR

Month	Hours	Load factor
Jan-04	744	81.94%
Feb-04	696	62.73%
Mar-04	744	49.99%
Apr-04	720	46.81%
May-04	744	43.75%
Jun-04	720	43.47%
Jul-04	744	45.29%
Aug-04	744	57.17%
Sep-04	720	41.80%
Oct-04	744	43.79%
Nov-04	720	59.47%
Dec-04	744	48.69%
Jan-05	744	58.87%
Feb-05	672	49.10%
Mar-05	744	58.33%
Apr-05	720	55.48%
May-05	744	41.74%
Jun-05	720	47.73%
Jul-05	744	44.50%
Aug-05	744	48.50%
Sep-05	720	50.12%
Oct-05	744	48.87%

Month	Hours	Load factor
Nov-05	720	51.56%
Dec-05	744	54.23%
Jan-06	744	48.75%
Feb-06	672	50.78%
Mar-06	744	56.22%
Apr-06	720	43.56%
May-06	744	46.67%
Jun-06	720	45.68%
Jul-06	744	54.34%
Aug-06	744	47.80%
Sep-06	720	54.89%
Oct-06	744	47.37%
Nov-06	720	68.66%
Dec-06	744	47.00%
Jan-07	744	60.90%
Feb-07	672	50.08%
Mar-07	744	56.63%
Apr-07	720	47.64%
May-07	744	52.13%
Jun-07	720	43.70%
Jul-07	744	44.78%
Aug-07	744	60.96%
Sep-07	720	38.23%
Oct-07	744	40.24%
Nov-07	720	75.10%
Dec-07	744	48.54%

Select a view

All data | Aboriginal peoples | Education | Families and households | Immigration and citizenship | Labour | Language | Language of work | Mobility and migration | Place of work | Population | Visible minority | Or | Build your own

All data

Sarnia
Ontario
(City)
Select another region

Ontario
(Province)
Select another region

Population and dwelling counts	Sarnia, City Total	Sarnia, City Male	Sarnia, City Female	Ontario Total	Ontario Male	Ontario Female
Population in 2006[1]	71,419			12,160,282†		
Population in 2001[1]	70,876			11,410,046†		
2001 to 2006 population change (%)	0.8			6.6		
Total private dwellings[2]	31,610			4,972,869		
Private dwellings occupied by usual residents[3]	30,114			4,554,251		
Population density per square kilometre	433.8			13.4		
Land area (square km)	164.63			907,573.82		

Figure

Age characteristics	Sarnia, City Total	Sarnia, City Male	Sarnia, City Female	Ontario Total	Ontario Male	Ontario Female
Total population[4]	71,420	34,195	37,230	12,160,285	5,930,700	6,229,580
0 to 4 years	3,330	1,680	1,650	670,770	343,475	327,290
5 to 9 years	3,600	1,800	1,800	721,590	369,670	351,920
10 to 14 years	4,500	2,250	2,250	818,445	420,705	397,740
15 to 19 years	5,115	2,530	2,585	833,115	427,185	405,925
20 to 24 years	4,740	2,350	2,385	797,255	400,445	396,815
25 to 29 years	3,695	1,780	1,915	743,695	360,525	383,170
30 to 34 years	3,590	1,755	1,840	791,955	382,030	409,925
35 to 39 years	4,000	1,975	2,030	883,990	430,220	453,770
40 to 44 years	5,160	2,425	2,735	1,032,415	507,130	525,280
45 to 49 years	5,945	2,880	3,070	991,970	486,390	505,585
50 to 54 years	5,795	2,840	2,960	869,400	423,345	446,060
55 to 59 years	5,160	2,590	2,570	774,530	378,530	395,995
60 to 64 years	4,035	1,965	2,070	581,985	283,545	298,440
65 to 69 years	3,235	1,505	1,725	466,240	222,640	243,600
70 to 74 years	3,065	1,375	1,690	401,950	187,510	214,445
75 to 79 years	2,835	1,265	1,570	338,910	149,585	189,325
80 to 84 years	2,075	790	1,285	250,270	97,240	153,035
85 years and over	1,545	450	1,100	191,810	60,555	131,260
Median age of the population[5]	43.2	42.2	44.0	39.0	38.1	39.9
% of the population aged 15 and over	84.0	83.2	84.7	81.8	80.9	82.7

Figure

Common-law status characteristics	Sarnia, City Total	Sarnia, City Male	Sarnia, City Female	Ontario Total	Ontario Male	Ontario Female
Total population 15 years and over[6]	59,990	28,460	31,530	9,949,485	4,796,850	5,152,630
Not in a common-law relationship	55,445	26,180	29,260	9,257,730	4,448,935	4,808,790
In a common-law relationship	4,545	2,275	2,265	691,755	347,915	343,840

Search for another place

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Sarnia (CY)

Map

Geographic hierarchy

Ontario

Map

Geographic hierarchy

Data quality note(s)

Explanation of Causes and Assumptions for the Volume Forecast

Bluewater Power is presenting a reasonable forecast of consumption and demand given the known market factors available at the time of filing.

Residential Rate Class

The annual percentage of population change in Sarnia from 2001 to 2006 was an increase of 0.8% (Statistics Canada report, detailed on page 16 of the Elenchus forecast report). The study prepared by Elenchus indicates the 2003-2007 average growth rate for the number of customers is 0.9%, which is consistent with the Statistics Canada results. The annual growth in the forecast kWh for the residential customers is 0.9% and 0.7% for the years 2008 and 2009 respectively. The year 2007 saw a decrease of 3.2% in the normalized kWh over 2006 which is attributed to the 'culture of conservation' among customers. Given the ongoing push for conservation from the Ontario Power Authority ("OPA") and the media, Bluewater Power feels the average usage per customer may decline, however, for the purposes of this forecast Bluewater Power has not incorporated any further load reductions per customer. Therefore, using the 2007 weather normalized forecast is an appropriate starting point to forecast 2008 and 2009 usage.

General Service <50 Rate Class

The GS<50 rate class has also been fairly flat in growth. The number of customers has increased an average of 1.3% over the 2003-2007 time periods and that increase is projected to continue for 2008 and 2009. The total projected usage for this rate class is an increase of 0.1% and 0.6% for 2008 and 2009 respectively, which reflects an increase in the number of customers offset by general conservation in the class.

General Service >50 Rate Class

A higher level of growth in the GS>50 rate category is mainly due to the increase in the number of larger retail businesses that have opened in the last five years. The 2003-2007 average growth is 4.6% which is the forecast growth projected for 2008 and 2009. The total usage for this rate class is forecast to increase by 0.2% and 0.6% 2008 and 2009, respectively.

Intermediate and Large Use Rate Classes

Bluewater Power currently has 16 customers in the Intermediate rate category, and 4 in the Large Use rate category. One hundred percent of the Large Use customers are within the manufacturing sector, and 50% of the Intermediate customers are in the manufacturing sector.

Of Bluewater Power's General Service >50 category, approximately 12% are in manufacturing.

Bluewater Power is mindful of the general downward trend of manufacturing and, in particular chemical manufacturing in Ontario. Any downward trend within Bluewater Power's service territory has the impact of eroding distribution revenue. If the markets do decline, Bluewater Power may not be able to generate enough revenue to meet its service requirement through an Incentive Rate Mechanism ("IRM") period.

Within Bluewater Power's territory, one of the five customers in the Large Use rate category was reclassified into the Intermediate rate category in early 2008, given its substantial reduction in load. The plant has been idle since April 15, 2008, and local media reports have indicated that the plant may not resume production. Bluewater Power has already been impacted by a loss of revenue with the customer being moved from Large Use to the Intermediate rate category. If the customer were to be lost completely there would be a distribution margin impact of approximately $70,000 per year. Bluewater Power has attempted to contact this customer directly as part of Bluewater Power's forecasting efforts, but we have been unable to seek confirmation for any potential future scenarios.

Bluewater Power has maintained this customer in the load forecast as an Intermediate customer, and has projected its demand at 50% of the 2007 level. However, Bluewater Power has serious concerns with the viability of this customer and we hereby provide notice that it may be necessary to update this forecast prior to approval of rates if circumstances change such that the customer has given notice that they will cease production completely in the Test Year.

The Intermediate and Large rate classes are not considered weather sensitive, therefore the forecast is based on consumption trends over the past four years. Bluewater Power has not forecast any customer growth in these rate classes other than the movement of customers between classes as discussed above.

The load forecast assumes a 0.2% increase in kW demand for the Intermediate rate class for 2008 and 2009, and a 0.1% increase in kW demand for the Large Use rate class for 2008 and 2009.

Street Lighting, Sentinel Lighting and Unmetered Scattered Load ("USL")

There is projected to be a slight growth of 1.8% in the number of street light connections mainly due to the construction of new subdivisions, which require new streetlights on the newly constructed roads.

Bluewater Power does not add any new sentinel connections therefore there is no projected growth for the rate class.

Finally, there projected to be no growth in the unmetered scattered load rate class as Bluewater Power discourages new connections without meters.

Normalized Volume Forecast Table

Table 3.2.3.1 and 3.2.3.2 depict three years of actual data in the form of 2006 EDR plus 2006 and 2007 actual. The last three columns show weather normalized data for 2007, as well as 2008 and 2009 forecast prepared on a weather normalized basis. Table 5, page 9 of The Elenchus forecast report details the changes forecast for 2008 and 2009 as well as discusses the three or four year historical trend.

Table 3.2.3.1
kWh by Rate Class

Customer Class Name	2006 EDR Approved	2006 Actual	2007 Actual	2007 Normalized	2008 Normalized	2009 Normalized
Residential	269,172,954	258,763,018	266,618,398	262,311,194	264,548,206	266,434,436
General Service <50 kW	126,666,633	117,915,371	119,898,584	119,643,998	119,801,538	120,544,382
General Service 50 to 999 kW	219,392,039	217,640,501	219,082,316	214,903,890	215,661,960	216,234,424
General Service 1,000 to 4,999 kW	170,944,308	209,342,236	202,583,345	202,583,345	183,810,752	181,109,127
Large	351,679,464	304,292,894	318,201,517	318,201,517	320,066,446	321,942,304
Unmetered Scattered Load	2,956,878	2,992,774	2,978,570	2,978,570	2,988,756	2,188,838
Sentinel Lighting	649,471	699,378	685,929	685,929	685,033	684,138
Street Lighting	8,769,187	8,581,095	8,536,684	8,536,684	8,627,815	8,719,920
TOTAL	1,150,230,934	1,120,227,267	1,138,585,343	1,129,845,127	1,116,190,506	1,117,857,569

Table 3.2.3.2
kW by Rate Class

Customer Class Name	2006 EDR Approved	2006 Actual	2007 Actual	2007 Normalized	2008 Normalized	2009 Normalized
Residential						
General Service <50 kW						
General Service 50 to 999 kW	467,580	591,300	601,223	589,074	590,129	593,516
General Service 1,000 to 4,999 kW	294,070	415,068	423,081	423,081	397,831	398,767
Large	563,939	494,407	492,550	492,550	493,030	493,510
Unmetered Scattered Load						
Sentinel Lighting	1,558	1,608	1,634	1,634	1,635	1,637
Street Lighting	23,274	24,059	23,751	23,751	23,656	23,562
TOTAL	1,350,421	1,526,442	1,542,239	1,530,090	1,506,281	1,510,992

Customer Count Forecast Table

Table 3.2.4.1 below depicts the average number of customers for 2006, 2007 and the number of customers forecast for 2008 and 2009. Table 3.2.4.2 depicts the annual variances on customer counts.

Table 3.2.4.1 - Customer Count

Customer Class Name	2006 EDR Approved	2006 Actual	2007 Actual	2007 Normalized	2008 Normalized	2009 Normalized
Residential	30,648	30,997	31,436	31,436	31,720	32,006
General Service <50 kW	3,705	3,779	3,826	3,826	3,875	3,924
General Service 50 to 999 kW	360	352	362	362	379	396
General Service 1,000 to 4,999 kW	12	15	16	16	16	16
Large	5	4	4	4	4	4
Unmetered Scattered Load	254	264	266	266	266	266
Sentinel Lighting	320	526	526	526	526	526
Street Lighting	9,345	9,568	9,667	9,667	9,837	10,009
TOTAL	44,649	45,505	46,103	46,103	46,623	47,147

Table 3.2.4.2 - Variance on Customer Count

Customer Class Name	2006 EDR Approved	2007 Normalized	2008 Normalized	2009 Normalized
Residential	30,648	31,436	31,720	32,006
% change		*2.6%*	*0.9%*	*0.9%*
General Service <50 kW	3,705	3,826	3,875	3,924
% change		*3.3%*	*1.3%*	*1.3%*
General Service 50 to 999 kW	360	362	379	396
% change		*0.6%*	*4.7%*	*4.5%*
General Service 1,000 to 4,999 kW	12	16	16	16
% change		*33.3%*		
Large	5	4	4	4
% change		*-20.0%*		
Unmetered Scattered Load	254	266	266	266
% change		*4.7%*		
Sentinel Lighting	320	526	526	526
% change		*64.4%*		
Street Lighting	9,345	9,667	9,837	10,009
% change		*3.4%*	*1.8%*	*1.7%*
TOTAL	**44,649**	**46,103**	**46,623**	**47,147**
% change		*3.3%*	*1.1%*	*1.1%*

2007 vs. 2006 EDR

The customer numbers for 2006 EDR were based on a three year average from 2002 to 2004. Therefore, the increase from 2006 EDR to 2007 covers a period that is, effectively, greater than three years.

The residential class in Table 3.2.4.2 has experienced an increase of 2.6% from 2006 EDR to 2007. On an annual basis, that would equate to an increase of approximately 0.7%. This application has assumed a current growth rate of approximately 0.9% for the Residential rate class for 2009, which would seem to be consistent with the increase experienced during the period from 2006 EDR to 2007.

The same is true for GS<50, the 2007 to 2006 EDR variance is 3.3%, which equates to an annual growth of less than 1%.

The GS 1000 to 4999 kW – Intermediate category had an increase of four customers or 33% between 2006 EDR and 2007. This reflects three customers that were moved from the GS>50 category given their usage increase, and an addition of one customer that was moved from Large Use to Intermediate in 2008. For consistency of statistical modeling the forecast was restated to include this one customer back to 2006 actual data.

The decrease of one customer in the Large Use category reflects that same one customer that was moved to the Intermediate rate category in 2008.

The change in the Sentinel Lighting category of an additional 206 connections (an increase of 64%) relates to more refined data as a result of the extensive effort expended as part of the cost allocation study.

The increase in the Street Light connections of 322 units (an increase of 3.4%) relates to an increase over the three year period. New street lights are primarily related to construction of new subdivisions.

Other Annual Variances

The GS>50 rate category includes a projected increase of 17 customers in both 2008 and 2009. This is mainly due to the number of retail establishments that have been added in the Bluewater Power service territory.

The Residential, GS<50 and Street Lighting rate classes are projecting variances of 0.9%, 1.3% and 1.8%, respectively, which relates to the trend of historical customer connections.

The Intermediate, Large Use, Unmetered Scattered Load and Sentinel Light categories are not projecting any increases.

Historical Average Consumption

The table below indicates the historical actual average annual consumption, the 2007 normalized average annual consumption and the 2008 and 2009 forecast annual average consumption.

Table 3.2.5.1
Historical Average Annual Consumption

Customer Class Name		2006 EDR Approved	2006 Actual	2007 Actual	2007 Normalized	2008 Normalized	2009 Normalized
Residential	Average kWh/customer	8,783	8,348	8,481	8,344	8,340	8,325
General Service <50 kW	Average kWh/customer	34,188	31,203	31,338	31,271	30,917	30,720
General Service 50 to 999 kW	Average kWh/customer	609,422	618,297	605,200	593,657	569,029	546,047
	Average kW/customer	1,299	1,680	1,661	1,627	1,557	1,499
General Service 1,000 to 4,999 kW	Average kWh/customer	14,245,359	13,956,149	12,661,459	12,661,459	11,488,172	11,319,320
	Average kW/customer	24,506	27,671	26,443	26,443	24,864	24,923
Large	Average kWh/customer	70,335,893	76,073,224	79,550,379	79,550,379	80,016,612	80,485,576
	Average kW/customer	112,788	123,602	123,137	123,138	123,258	123,378
Unmetered Scattered Load	Average kWh/customer	11,641	11,336	11,198	11,198	11,236	8,229
Sentinel Lighting	Average kWh/customer	2,030	1,330	1,304	1,304	1,302	1,301
	Average kW/customer	5	3	3	3	3	3
Street Lighting	Average kWh/customer	938	897	883	883	877	871
	Average kW/customer	2	3	2	2	2	2

Other Revenue

Other Distribution Revenue

Other Distribution Revenue is any revenue that is distribution in nature but that is sourced from means other than distribution rates. It includes items such as OEB approved specific service charges, late payment revenue, retail service charges, sale of scrap metal, distribution related billable revenue, and interest income. Table 3.3.1.1 provides a summary of the other revenue items. Variances on the revenue items will be explained in Exhibit 3, Tab 3, Schedule 2.

Table 3.3.1.1
Summary of Other Revenue

USA #	Service	2007 Actual	2008 Bridge	2009 Test
4080	Distribution Service Revenue	$84,311	$84,000	$84,603
4082	Retail Service Charges	$68,543	$68,097	$68,097
4084	Service Transaction Request Revenue	$5,091	$5,091	$5,091
4210	Rent from Electric Property	$134,346	$132,498	$136,320
4225	Late Payment Charges	$213,563	$212,950	$225,433
4235	Specific Service Charges	$147,538	$129,300	$135,840
4325	Other Jobbing Revenue	$636,625	$289,755	$361,084
4330	Costs and Expenses of Merchandising, Jobbing Etc.	$ (155,017)	$ (94,058)	$(92,578)
4355	Gain on Disposition of Utility Property	$4,152	$22,131	$15,026
4390	Sale of Scrap Metal	$58,976	$25,000	$33,318
4405	Interest and Dividend Income	$193,485	$ (123,604)	$ (243,636)
	Total Revenue Offsets	$1,391,613	$751,160	$728,598

Materiality Analysis on Other Distribution Revenue

Specific Service Charges

The forecast of revenue to be received from the specific service charges for 2008 and 2009 is determined by a detailed review of 2006 and 2007 actual data. The projections provide for existing trends to continue, but incorporating any known factors that would affect the revenue projections. Bluewater Power proposes to continue to charge all of the previously authorized specific service charges at the same rates, and does not propose to add any new charges at this time.

Table 3.3.2.1
Specific Service Charges

USA #	Service	2007 Actual	2008 Bridge	2009 Test	2009 vs. 2008	2008 vs. 2007
4235	Collection of account charge – no disconnection	69,071	60,000	60,900	900	(9,071)
4235	Income tax letter	2,550	1,800	1,935	135	(750)
4235	Returned Cheque charge (plus bank charges)	8,496	9,000	9,120	120	504
4235	Legal letter charge	5,520	4,000	5,145	1,145	(1,520)
4235	Account set up charge / change of occupancy charge	50,022	50,000	50,350	350	(22)
4235	Disconnect/Reconnect at meter – during regular hours	11,138	4,000	7,280	3,280	(7,138)
4235	Disconnect/Reconnect at meter – after regular hours	740	500	1,110	610	(240)
	Total Account 4235	147,537	129,300	135,840	6,540	(18,237)

The variances that represent increases or decreases of greater than $5,000 for any specific service charge are highlighted in the table above. The explanations for those variances are as follows:

a) The collection of account charges varies each year. The 2007 actual results are higher than the previous two years. The 2008 and 2009 projections anticipate a return to results more consistent with 2006 actual results.

b) The number of disconnects fluctuate each year. The three year average from 2005 to 2007 was 135 transactions resulting in average revenue of $8,775. The 2008 budget was adjusted in 2009 to be more reflective of the three-year average.

Late Payment Charges

Table 3.3.2.2
Late Payment Charges

USA #	Service	2007 Actual	2008 Bridge	2009 Test	2009 vs. 2008	2008 vs. 2007
4225	Late Payment - per month	213,563	212,950	225,433	12,483	(613)

The variance of $12,483 between 2009 and 2008 relates to continuous enhancements to the billing system and collection practices which allow more late payment charges to be assessed and successfully collected than in previous years.

SSS Administration and Retail Service Charges

The revenue forecast for SSS Administration and Retail Service Charges are all based on historical trends, and there is no material variance reported.

Table 3.3.2.3
SSS Administration and Retail Service Charges

USoA #	Service	2007 Actual	2008 Bridge	2009 Test	2009 vs. 2008	2008 vs. 2007
4080	Standard Supply Service -- Administrative Charge	84,311	84,000	84,603	603	(311)
4080 Total	**Total**	**84,311**	**84,000**	**84,603**	**603**	**(311)**
4082	Retailer Service Agreement -- standard charge	500	0	0	0	(500)
4082	Retailer Service Agreement -- monthly fixed charge (per retailer)	2,660	2,660	2,660	0	0
4082	Retailer Service Agreement -- monthly variable charge (per customer)	40,923	40,923	40,923	0	0
4082	Distributor-Consolidated Billing -- monthly charge (per customer)	24,538	24,538	24,538	0	0
4082	Retailer-Consolidated Billing -- monthly credit (per customer)	(16)	(24)	(24)	0	(8)
4082 Total		**68,605**	**68,097**	**68,097**	**0**	**(508)**
4084	Service Transaction Request -- request fee (per request)	2,239	2,239	2,239	0	0
4084	Service Transaction Request -- processing fee (per processed request)	2,853	2,853	2,853	0	0

Pole Rental

Based on the OEB Decision of March 7, 2005, the province-wide rate of $22.35 per pole was established for telecommunication and cable companies for the use of utility poles for the purpose of supporting transmission lines. Bluewater Power adheres to that rate for the CCTA members and related parties.

The 2009 test year forecast revenue was based on the updated and known number of connections at this time multiplied by the applicable rate.

Table 3.3.2.4
Pole Rental

USoA #	Service	2007 Actual	2008 Bridge	2009 Test	2009 vs. 2008	2008 vs. 2007
4210	Specific Charge for Access to the Power Poles – per pole/year	134,346	132,498	136,320	3,822	(1,848)

Sale of Scrap Metal

The sale of scrap metal was unusually high in 2007 reflecting significant equipment that was brought out of service in respect of a single property where the use was downgraded from heavy industrial to storage. That level of scrap was a one-time event that cannot be expected to repeat itself.

Table 3.3.2.5
Sale of Scrap Metal

USoA #	Service	2007 Actual	2008 Bridge	2009 Test	2009 vs. 2008	2008 vs. 2007
4390	Sale of Scrap Metal	58,976	25,000	33,318	8,318	(33,976)

Other Revenue Offsets

The 2007 amount relates to distribution billable work (not including Non-Core Distribution Activities reallocated to Account 4375). The 2007 fiscal year was not only busy for Non-Core Distribution Activities as discussed in Exhibit 4, Tab 2, Schedule 7, but it was also unusually busy for Bluewater Power with respect to distribution billable work. The 2007 year included a large job where Bluewater Power's utility assets were relocated at the expense of a customer ($208K), and also included abnormally high amount of damages to utility property due to car accidents ($150K). The 2008 bridge year and 2009 test year are budgeted to more closely reflect normal billable activity in prior years.

The 2007 and 2008 amounts for 'Revenue from Affiliate' relate mainly to management fees and the use of utility assets for Non-Core Distribution Activities. These fees are charged on a fully allocated cost basis and are discussed in detail at Exhibit 4, Tab 2, Schedule 4 – Shared Services. The basis from 2008 to 2009 represents management fees from three affiliates (identified in this application as GenCo, Blackwell, and Electek). In addition, a new management fee will be earned by Bluewater Power in 2009 from a newly activated affiliate (identified in this application as SHESC). SHESC will undertake Non-Core Distribution Activities that were undertaken within the utility in 2007 and 2008.

Table 3.3.2.6
Other Revenue Offsets

USoA #	Service	2007 Actual	2008 Bridge	2009 Test
4325	Distribution Related Billable work	$ 524,560	$ 167,500	$ 165,318
4330	Distribution Related Expenses	$ (155,017)	$ (94,058)	$ (92,578)
4325	Revenue from Affiliates/Non-core distribution activities	$ 88,952	$ 118,155	$ 191,766
4325	Miscellaneous one time revenue	$ 23,113	$ 4,100	$ 4,000
4355	(Gain)/Loss on disposal	$ 4,152	$ 22,131	$ 15,026
	Total	**$ 485,760**	**$ 217,828**	**$ 283,532**

Interest and Dividend Income

The 2008 bridge year is comprised of anticipated interest income of $100,320 related to positive cash balances and an additional credit of ($223,924) related to carrying charges on the regulatory accounts expected in 2008. These carrying charges have been booked as an offset to this revenue account in order to avoid an unintentional discrimination from technical compliance with the USoA, as discussed in detail at Exhibit 1, Tab 3, Schedule 7 – Compliance with Uniform System of Accounts.

In 2009 there is not expected to be a positive cash balance mainly due to the outlay of funds required for smart meters, building renovations, SAP upgrade and other capital projects. The projected ($243,636) is related to carrying charges on the deferral accounts for 2009.

Table 3.3.2.7
Interest and Dividend Income

USoA #	Service	2007 Actual	2008 Bridge	2009 Test
4405	Interest and Dividend Income	$ 193,485	$ (123,604)	$ (243,636)

Rate of Return on Other Distribution Revenue

In this application Bluewater Power has applied for the same Specific Service Charges previously approved in the 2008 Tariffs of Rates and Charges (EB-2007-0862). The Specific Service Charges schedule follows the OEB recommended charges for all but one item, and as such Bluewater has no further information related to the rate of return on non-core delivery activities.

The one charge not based on the OEB recommended charges is the account set-up fee. As part of the 2006 EDR process, Bluewater did not request the standard amount of $30 for Account Set Up charges, but rather remained at the then current level of $10 per transaction. It was determined that the $10 charge covered the cost of account set-up and the $30 charge was too high for customers. Bluewater proposes to maintain the Account Set-up charge at $10 per transaction.

Revenue from Affiliates

Bluewater Power is a fully integrated utility that directly employs the staff who provide service to its distribution customers. The utility employs staff in the area of corporate services that also provide services to affiliates. Those services are provided under service agreements requiring the payment of costs on a fully allocated cost basis as addressed in Exhibit 4, Tab 2, Schedule 4 – Shared Services.

Bluewater Power has three affiliates that became active for the first time in the fourth quarter of 2007 (defined hereafter as GenCo, Blackwell and Electek). In addition to these three existing affiliates, a fourth affiliate (defined hereafter as SHESC) is proposed to become active on January 1, 2009 to carry-out Non-Core Distribution Activities as discussed in Exhibit 1, Tab 2, Schedule 6 – Planned Changes in Corporate or Operational Structure.

Accordingly, Bluewater Power earned no revenue from affiliates in 2007. Management fees commenced in 2008 and, as demonstrated in Table 3.3.4.1 are projected to grow significantly in 2009 for two reasons:

(i) Management Fees in 2008 and 2009 are budgeted amounts representing the estimated need for corporate services that is anticipated in the year for each affiliate. Over the course of 2008, a better understanding has been gained of the demands for corporate services and that has allowed for improved budgeting.

(ii) The addition of SHESC as an active affiliate in 2009 brings a new source of Management Fees for Bluewater Power.

Table 3.3.4.1

	2007 Actual	2008 Bridge Year	2009 Test Year
Management Fees	$0	$42,500	$94,310
Use of Asset Fees	$0	$0	$40,000
Total	$0	$42,500	$134,310

The increase in the level of revenue earned by Bluewater Power from its affiliates serves as a revenue offset. Therefore, the affiliation of Bluewater Power to affiliates in a broad range of activities helps the utility to earn revenue that serves as an offset to revenue requirement, which ultimately benefits ratepayers.

For the 2009 Test year, the following table summarizes the revenues budgeted to be received from affiliates under service agreements.

Table 3.3.4.2

	GenCo	Blackwell	Electek	SHESC	TOTAL
Management Fee	$8,000	$6,000	$33,750	$46,560	$94,310
Office Space	$7,200	$0	$0	$12,000	$19,200
Vehicle Costs	$0	$0	$0	$20,800	$20,800
TOTAL	$15,200	$6,000	$33,750	$79,360	$134,310

1. Bluewater Power Generation Corporation ("GenCo")

GenCo is a holding company incorporated on June 6, 2007 that became active on January 1, 2008 with the transfer of two former Bluewater Power employees, the former Vice President of Client Services and his Executive Assistant who now serve at GenCo as the Chief Operating Officer and Executive Assistant, respectively. Together these employees are responsible for managing GenCo, providing management services to Blackwell Renewable Energy Inc. and for finding other generation investment opportunities for GenCo. As a holding company, GenCo receives no payments from Bluewater Power.

GenCo relies on Bluewater Power for certain corporate services and those services are provided on a fully-allocated cost basis under a service agreement. Although GenCo is primarily self-sufficient, a management fee of $8,000 has been budgeted for 2009 based on an estimate of time required for Bluewater Power to provide services in the area of finance, Human Resources and other time spent by Senior Management.

The two employees of GenCo also occupy office space at Bluewater Power. Use of this asset is charged to the affiliate at the rate of $7200 per annum, which rate is based on an estimate of market value.

2. Blackwell Renewable Energy Inc. ("Blackwell")

Blackwell operates a 1.6 MW generator operating on landfill gas and producing electricity being sold to the OPA under a 20 year power purchase agreement. The company was incorporated on June 6, 2007 and became active on November 26, 2007 with the hiring of an operator at the start of the commissioning phase of the generator. Blackwell receives payment from Bluewater Power as a generator operating within Bluewater Power's licensed distribution territory.

Blackwell relies on Bluewater Power for certain corporate services and those services are provided on a fully-allocated cost basis under a service agreement.

Blackwell primarily relies upon GenCo, which provides hands-on management and administrative assistance under a management agreement between those two affiliates. The corporate services that Blackwell does receive from Bluewater Power are limited, but a management fee of $6,000 has been budgeted for 2009 based on an estimate of time required for Bluewater Power to provide services in the area of finance, Human Resources and time spent by Senior Management.

3. Electek Power Services Inc. ("Electek")

Electek is a company specializing in high-voltage protection and control work for electrical distributors (both private companies operating their own distribution system and OEB licensed distributors) primarily located in Southwestern Ontario. Electek has been in business since 2002, but was acquired by Bluewater Power Corporation ("BPC") on November 1, 2007. Electek receives payment from Bluewater Power as Electek provides testing and maintenance services to the utility with an estimated annual value of less than $25,000. Electek has been a service provider to Bluewater Power since at least 2002 and, therefore, the financial relationship pre-exists BPC's acquisition of Electek.

Electek has operated as a going concern for five years prior to Bluewater Power's acquisition of the company, and during that time did not receive management services (other than annual tax

filings) from third parties. Nevertheless, Bluewater Power has budgeted to charge Electek for management fees for 2009 estimated at $33,750. Those management fees include corporate services ($9,000 for finance, Human Resources and time spent by Senior Management), as well as direct administrative assistance ($8,750 for shared administrator). In addition, the VP Operations holds the formal position of Chief Operating Officer for which $15,000 is charged to Electek

4. Sarnia Hydro Energy Services Corporation ("SHESC")

SHESC is a company incorporated in October of 2000 and, although the company obtained an electricity retailer license on December 22, 2004 the company has been inactive from incorporation to present. As discussed in Exhibit 1, Tab 2, Schedule 6 – Planned Changes in Corporate or Operational Structure it is proposed that Non-Core Distribution Activities currently undertaken within Bluewater Power will be transferred to SHESC, along with six employees and related equipment.

The Affiliate Activities that are proposed to take place through SHESC commencing on January 1, 2009 will be undertaken by six employees transferred from Bluewater Power to the affiliate. These employees are primarily self-sufficient, but management fees totaling $46,560 have been budgeted in relation to:

1. Supervision: Bluewater Power anticipates providing a supervisor to SHESC for 1 hour per working day at an estimated fully-allocated cost of $14,560.
2. Corporate services: The six employees of SHESC, under supervision, will be responsible for work orders, time sheets and general administration. However, corporate services of $17,000 have been budgeted in 2009 for finance, Human Resources and time spent by Senior Management. The majority of these fees are anticipated in relation to invoicing and finance related services.

3. Materials Management: The municipal clients for whom SHESC will be providing streetlight and traffic light services manage their own inventory. However, certain parts and equipment will be managed by Bluewater Power and $15,000 has been budgeted for those services.

SHESC will be based out of a portion of a Bluewater Power owned building. That portion of the building was vacant until it was occupied by the Civil Crew and its equipment in 2005. The rent of $12,000 per annum to be charged by Bluewater Power to SHESC is based on an estimate of market value.

SHESC will take ownership of the civil equipment currently owned by Bluewater Power on, or about, January 1, 2009. SHESC will utilize Bluewater Power owned bucket-trucks and will pay based on the number of hours the equipment is used multiplied by a market based hourly rate representing the fully allocated cost reduced to an hourly equivalent.
The amount budgeted in 2009 is $20,800.

Revenue Sharing

Description of Revenue Sharing

Bluewater Power has no OEB approved revenue sharing program for its customers.

OPERATING COSTS

Overview

Overview of Operating Costs

Bluewater Power's operating costs are comprised of: operations, maintenance and administration ("OM&A") expenses; Ontario capital taxes ("OCT") and municipal taxes; as well as depreciation and amortization costs. The costs represent the annual expenditures required to sustain Bluewater Power's distribution operations. This includes costs associated with maintaining a high level of safety for the public and Bluewater Power employees; complying with provisions of the Distribution System Code regarding system operation and maintenance; complying with the provisions of the Standard Supply Service Code and the Retail Settlement Code concerning the quality of customer care required; meeting environmental requirements, maintaining compliance with OEB and Ministry of Energy direction; and maintaining targeted service quality and reliability performance levels.

This exhibit is divided into two further Tabs. Tab 2 provides a very detailed description of OM&A, while Tab 3 provides the calculations and summary of both Income Taxes and Capital Taxes.

Tab 2 - OM&A Costs

The second Tab of this Exhibit on operating costs discusses in detail that the majority of OM&A is comprised of Payroll Related Costs (as that term is defined in this Exhibit). Since Payroll Related Costs generally comprise 70% of the utilities OM&A, one would expect any variance in OM&A to relate primarily to Payroll Related Costs and that is, indeed, what is found with this application

Shared Services and Non-Core Distribution Activities

Another focus under this Tab 2 is shared services. Bluewater Power engages in Non-Core Distribution Activities such as streetlight and traffic light capital and maintenance, Water Billing, OPA conservation programs, as well as on-demand linework for third parties. The costs associated with these activities are booked to Account 4380 as defined in the USofA. In the 2009 Test Year, the only Non-core Distribution Activities proposed to be continued within the utility are Water Billing and OPA conservation programs.

Bluewater Power has three affiliates currently active, as well as a fourth affiliate proposed to be active during the 2009 Test Year. These affiliates contribute revenue to the utility in the form of Management Fees and Use of Asset fees that help to reduce revenue requirement.

All costs reallocated to Account 4380 in relation to Non-Core Distribution Activities and all fees charged to affiliates are charged on the Fully-allocated cost basis, including a return on invested capital.

Miscellaneous Matters

The remainder of items addressed in Tab 2 relate to matters such as purchasing policies summarized at Exhibit 4, Tab 2, Schedule 8 and Bluewater Power has provided a list of top vendors at Schedule 9. Distribution Losses are shown herein to have been reduced from 2007 to 2009 as discussed in Exhibit 4, Tab 2, Schedule 11.

Tab 3 – Income and Capital Tax

Exhibit 4, Tab 3, Schedule 1 provides a summary of Income Tax and Capital Taxes proposed to be recovered through rates.

Summary of Operating Costs

Since the introduction of the Energy Competition Act, 1998 Ontario's electricity industry has undergone significant industry, market and regulatory change. These changes have resulted in increased operational and regulatory complexity as well as growing demand for investment in capital infrastructure. Bluewater Power has responded to these changes by committing the necessary resources to maintain a safe and reliable distribution system while also meeting customer and regulatory expectations. The resulting cost pressures have been mitigated through efficiency measures such as those discussed below, but the utility has, nevertheless not been able to achieve its regulated rate of return in the most recent four calendar years.

The net impact on OM&A of these efficiency measures combined with new operational/ regulatory requirements has been a consistent increase in gross OM&A over the period from 2006 EDR to 2009 Test Year. In part, this increase in costs reflects the transition and initial investment cost associated with operational and regulatory changes that are expected to produce performance improvements that customers will enjoy on an on-going basis.

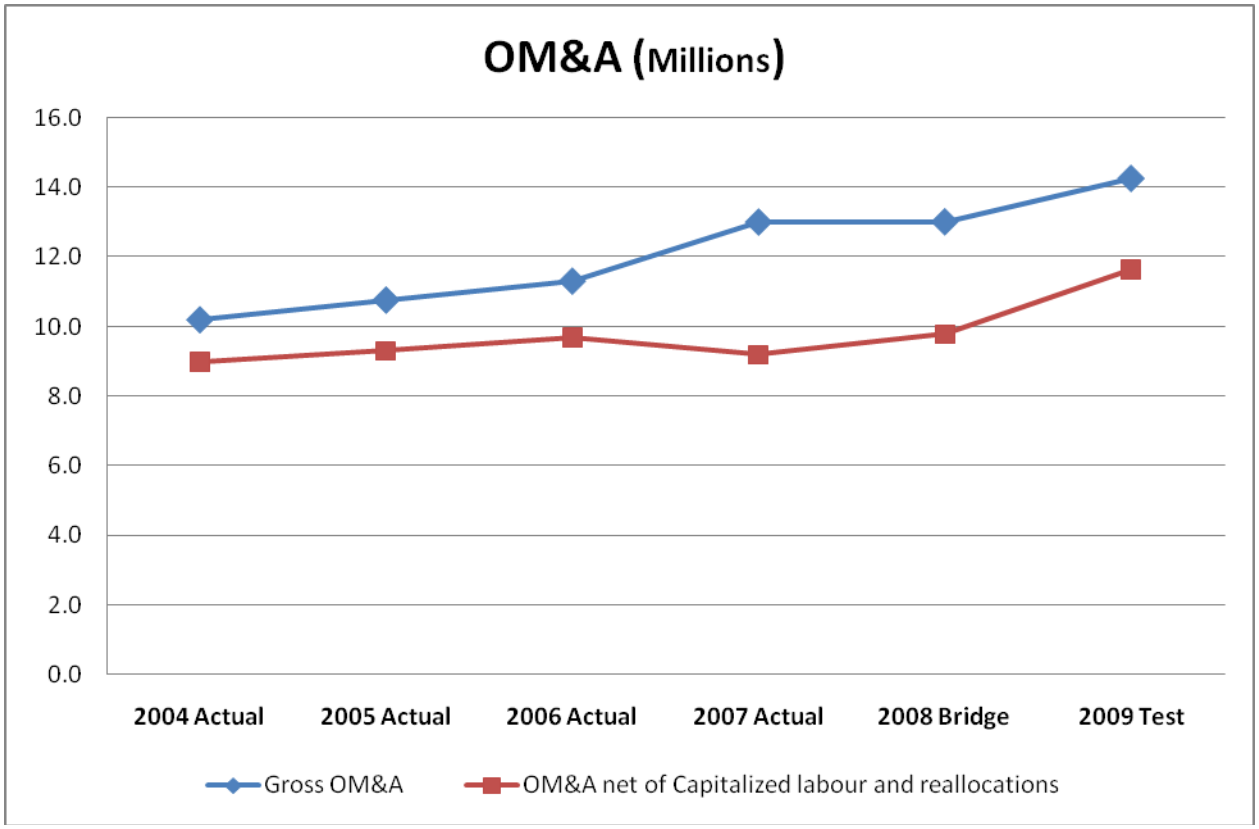
Looking to OM&A, the impact of Non-Core Distribution Activities is demonstrated in the table below with a decrease in distribution OM&A for 2007. The year 2007 reflects a peak in Non-Core Distribution Activities which has the effect of reducing distribution OM&A since costs that would ordinarily be reflected in distribution OM&A are reallocated to Account 4380 such that they are no longer included in distribution OM&A. The 2008 Bridge Year has been budgeted to reflect more "normal" levels of Non-Core Distribution Activities and the 2009 Test Year only includes Water Billing and OPA conservation programs, as all other activities have been moved to an affiliate.

Table 4.1.2.1

	2006 EDR	2007 Actual	2008 Bridge Year	2009 Test Year
Operations, Maintenance & Administration	9,182,512	8,915,170	9,495,815	11,358,419
Depreciation & Amortization	3,130,369	3,847,902	4,045,269	4,358,109
Capital and Property Tax	139,687	278,911	290,000	297,750
Income Taxes	1,151,955	1,309,920	762,084	1,322,854
Total Operating Costs	13,604,523	14,351,903	14,593,168	17,337,132

Table 4.1.2.1 looks at distribution OM&A, while Table 4.1.2.2 below shows distribution OM&A side-by-side with Gross OM&A. What the table below demonstrates is that Bluewater Power has experienced a steady upward trend in its total Gross OM&A over the period from 2004 to 2009. Distribution OM&A shows a more rapid increase from 2007 to 2009, but what Table 4.1.2.2 below demonstrates is that 2009 is more consistent with historical increases and 2007 appears as an atypical year in this trend analysis.

Table 4.1.2.2



The atypical result for 2007 reflects three factors working in a complementary manner to drive down distribution OM&A while gross OM&A continues to increase. The first two factors are changes in process intentionally implemented by Bluewater Power:

(1) First, Bluewater Power improved its diligence in capturing capitalized labour. Bluewater Power's Capitalization Policy did not changed between 2002 and 2008, but we have exercised increasing diligence in capturing capitalized labour such that the cost of capital improvements can be shared more fairly across generations of customers.

(2) Second, Bluewater Power improved its diligence in reallocating costs to Account 4380 in order to remove the costs associated with Non-Core Distribution Activities from distribution OM&A.

(3) The third, and most significant, factor to consider is the sudden and significant increase in Non-Core Distribution Activities in 2007. The year 2007 stands out in Table 4.1.2.2 as the year where Gross OM&A and distribution OM&A move in opposite directions. In fact, 2007 Gross OM&A increases by 15% over 2006 levels while distribution OM&A decreases by 5% over 2006. That apparent anomaly is driven primarily by the increase in Non-Core Distribution Activities which increases Gross OM&A (related primarily to direct costs such as materials) but decreases distribution OM&A as base Payroll Related Costs and overhead are reallocated to Account 4380.

Therefore, what appears in the following analyses as a somewhat rapid increase in distribution OM&A from 2007 to 2009 is more accurately described as a steady increase that is distorted by an atypical 2007 result. Whereas 2007 to 2009 appears to represent a 27% increase in distribution OM&A over 2 years, the same comparison for 2006 to 2009 represents in a 20% increase in OM&A over 3 years. Although Schedule 3 that follows presents a variance analysis on 2007 to 2009 OM&A with a 13% annual increase, we suggest the reader be mindful that the same analysis over 2006 to 2009 would produce a 6.6% annual increase over the period.

The 2009 Test Year budget represents a return to more “pure” distribution activities, where costs pressures are significant and driven by increased regulatory pressure, an aging workforce and and increased need for capital spending. The improved processes implemented in 2007 continue to benefit ratepayers, but those efficiencies have been maximized and the opportunities to shelter the increase in Gross OM&A are diminished.

Electrical utilities in Ontario have been subject to continuous change since privatization in the year 2000. Over the past eight years, electrical utilities have faced increasing levels of regulation by the OEB, Electrical Safety Authority, and the IESO. More recently, electrical utilities have been charged with increasing responsibilities in the area of conservation, customer education and distributed generation.

Bluewater Power has faced all of these challenges with diligence, but the consequence of facing these increasing pressures is an increase in the cost of managing the business. Looking to the details of the increase in distribution OM&A from 2007 to 2009, we see that the primary driver of the increase is with Payroll Related Costs which alone explains 71% of the variance. The top 5 variances beyond Payroll Related Costs are:

- Future Benefits (7% of variance)
- Rebasing Costs (5% of variance)
- External Costs (5% of variance)
- Advertising Costs (2% of variance)
- Employee Costs (2% of variance)

As would be expected, the primary driver of the variance is Payroll Related Costs. The next two schedules of this application provide the explanation and justification for those increases. We believe it is demonstrated that those costs cannot be avoided if this utility is to maintain system reliability, system planning, customer satisfaction, meet its regulatory obligations, and prepare for retirements through effective succession planning. The justification for the increases in Payroll Related Costs can be summarized as falling within one of four categories:

(1) Routine Increases (32%): Routine cost increases such as Cost of Living and Progression Increases, including Incentive Pay, account for approximately one-third of the increase in Payroll Related Costs from 2007 to 2009.

(2) New Staff prior to Test Year (21%): Bluewater Power has seen corporate restructurings in 2008 and a proposed restructuring for 2009. We have already hired, or taken steps to hire, new staff as replacements or to fill new roles created to respond to increased demands or as part of succession planning.

(3) New Staff for the Test Year (37%): Bluewater Power has proposed to hire six new staff for the 2009 Test Year. Two of the positions are replacements, and the remaining four positions are in response to increased workload and/or succession planning.

(4) Miscellaneous Changes (10%): The remaining variances are explained by a series of partially offsetting variances primarily in the area of: students, contracted services, overtime, Benefits, Payroll Accrual, Capitalized Labour and the impact of the Corporate Reorganization.

Bluewater Power recognizes that this application appears to represent a significant increase in OM&A for the 2009 Test Year, but we believe each component of this increase is explained and justified in this application. Moreover, these increases are necessary for this utility to maintain its systems and operations while reaching its regulated rate of return.

Bluewater Power staff have worked hard to maintain operations in a safe and reliable manner, and to control distribution OM&A through increased Non-Core Distribution Activities. We have also gone without certain positions being replaced. However, this situation cannot be sustained indefinitely.

Bluewater Power comes before the OEB having managed distribution OM&A, but without reaching its regulated rate of return. Table 4.1.2.3 demonstrates the ROE for Bluewater Power, calculated using actual after-tax net income for the year (not including an unusual adjustment in 2005) divided by the level of equity.

Table 4.1.2.3

	2004	2005	2006	2007
Actual Return on Rate Base	4.6%	8.5%	5.2%	7.0%
The level of equity in 2004 and 2005 was 50% of the Rate Base from the 2001 RUD Rate Application. The level of equity in 2006 and 2007 was 50% of the Rate Base from the 2006 EDR application.				

Bluewater Power has been under-recovering for the past 4 calendar years. The increase in OM&A proposed by Bluewater Power is to improve the financial position of this utility so that it can maintain its infrastructure, comply with the regulatory regimes, service its customers, and achieve its regulated ROE.

OM&A Costs

OM&A Costs Table

The OM&A Cost Table is attached as Exhibit 4, Tab 2, Schedule 1, Attachment 1.

OM&A Expenses*

Account Grouping	2009 Projection	2008 Projection	Var $	2008 Projection	2007 Actual	Var $	2007 Actual	2006 EDR Approved	Var $
3500-Distribution Expenses - Operation	3,535,352	2,258,862	**1,276,490**	2,258,862	2,206,991	51,871	2,206,991	280,776	**1,926,215**
3550-Distribution Expenses - Maintenance	157,640	140,410	17,230	140,410	122,553	17,857	122,553	256,425	**(133,872)**
3650-Billing and Collecting	1,497,443	1,370,749	126,694	1,370,749	1,277,336	93,413	1,277,336	267,288	**1,010,048**
3700-Community Relations	216,871	175,409	41,462	175,409	94,640	80,769	94,640	189,005	(94,365)
3800-Administrative and General Expenses	5,951,113	5,550,385	**400,728**	5,550,385	5,213,650	**336,735**	5,213,650	8,187,189	**(2,973,539)**
3950-Taxes Other Than Income Taxes	297,750	290,000	7,750	290,000	278,911	11,089	278,911	139,687	**139,224**
TOTAL	**11,656,169**	**9,785,815**	**1,870,354**	**9,785,815**	**9,194,081**	**591,734**	**9,194,081**	**9,320,370**	**(126,289)**

** Operations, Maintenance & Administration*
Note: Variances in excess of the below-noted materiality threshold appear in ***bold***

Total Distribution Expenses		*13,831,084*			*13,041,983*			*13,245,730*	
Materiality Threshold			*138,311*			*130,420*			*132,457*

Variance Analysis on 2007 to 2009 OM&A Costs

The OEB Filing Guidelines require explanation of variances in OM&A by account group on a year-over-year basis. That annual analysis is provided at Exhibit 4, Tab 2, Schedule 3. Prior to presenting that information, Bluewater Power believes that it is helpful to examine the major drivers of the variance in their totality. In preparing this additional variance analysis, Bluewater Power was mindful of the OEB expressed preference in previous decisions for comparisons of the Test Year with the latest year of actual financials. Accordingly, Bluewater Power has prepared this variance analysis as a comparison of 2007 actual and 2009 projected.

1.0 Primary Drivers of Variance

The total OM&A increase from 2007 Actual to 2009 Projected is $2,462,088 and is primarily driven by the variance in Payroll Related Costs. Table 4.2.2.1 below clearly demonstrates that Payroll Related Costs are, by far, the most significant driver of the variance, explaining 71% of the increase in OM&A from 2007 to 2009. That result should be expected considering that Payroll Related Costs generally represent 70% of the utility's OM&A in any given year. Given its significance, Payroll Related Costs are discussed in detail in the following pages.

The next three highest individual variances exceed $100,000 each, but all of the remaining variances are found in the form of numerous variances in the range of $20,000 to $40,000 each. Table 4.2.2.1 displays the Payroll Related Costs, as well as the next top 5 individual variances.

Table 4.2.2.1
2007 to 2009 Primary Variances

	2007 Actual	2009 Test Year	Variance	% variance
Gross O&M	$13,005,765	$14,264,694	$1,258,929	
Capitalized labour	$ (1,646,078)	$ (1,781,198)	$ (135,120)	
Reallocations to 4380	$ (2,010,589)	$ (734,749)	$1,275,840	
Reallocations to 4330	$ (155,017)	$ (92,578)	$62,439	
Net O&M	**$9,194,081**	**$11,656,169**	**$2,462,088**	
Payroll Related costs (net of capitalized labour)	$5,850,612	$7,598,516	$1,747,904	71%
Future Benefits	$523,092	$694,415	$171,323	7%
Rebasing Costs	$	$113,007	$113,007	5%
External Costs	$595,308	$716,206	$120,898	5%
Advertising	$16,352	$ 59,400	$43,048	2%
Employee Costs	$495,333	$536,627	$41,294	2%
All other	$1,713,384	$1,937,998	$224,614	9%
Net O&M	**$9,194,081**	**$11,656,169**	**$2,462,088**	**100%**

Before addressing the Payroll Related Costs in detail, the following sections address the next top five variances that help to provide context to the variance analyses that are found in the next schedule.

Future Benefits ($171,323 or 7% of the variance)

Future Benefits is an actuarial calculation required to determine costs related to employee future benefits that must be recognized in the current year for employees employed in the year. The increase in Future Benefits is driven by the increase in employee count as well as an updated actuarial forecast. This variance is explained in detail in Exhibit 4, Tab 2, Schedule 3 for account group Administration and General Expense in each of 2007 to 2008 and 2008 to 2009.

Rebasing Costs ($113,007 or 4.5% of the variance)

Regulatory costs have remained generally consistent from 2007 to 2009, with the exception of the additional costs required to undertake this rebasing application. This application is projected to cost $339,021, resulting in one-third of that cost ($113,007) being included for recovery in this rate application. Those costs are discussed in detail in Exhibit 4, Tab 2, Schedule 3 under the 2008 to 2009 variance for account group Administration and General Expense (Section 'Non-material Variances').

External Costs ($120,898 or 4.5% of the variance)

This increase is comprised of a series of minor increases in spending in areas such as legal fees, banking fees, collection costs, and general consulting fees. The increase is primarily explained by the following:

- An increase of $15,000 in consulting and testing fees in anticipation of increased activity in monitoring of soil conditions at MS#1, located at Front St. and Maxwell St. This property has been subject to continuous monitoring since the early 1990's and the level of spending can be impacted by external forces such as road and sewer servicing in the vicinity.
- An increase of $19,606 in insurance costs (approximately 13% increase) is anticipated from 2007 to 2009. The majority of this increase has impacted the utility in 2008 as the increase from 2008 to 2009 is only $4226 due to Bluewater Power's prudent management of these costs.
- Audit fees have been forecast to increase in 2009, thereby creating a variance from 2007 to 2009 of $16,125. Bluewater Power paid $21,275 in audit fees in 2007 and, based on our review of audit fees paid by similar utilities, we believe those fees are likely to increase significantly in 2009.
- Bluewater Power has budgeted an increase of approximately $20,000 in legal fees in recognition of the fact that the in-house legal counsel will be primarily involved in the 2009 Rebasing application in the first quarter of 2009.

- Bluewater Power lost one employee in its control room and determined that the position did not require replacement. That will be accomplished by increasing overtime in 2009 by $14,000 (as discussed below) and through spending consulting fees of $26,000. Those consulting fees are one-time costs intended to assist in the streamlining of the control room processes and operations.
- The design services department has budgeted for a $26,000 increase in engineering consulting fees in 2009 to assist the utility to manage day-to-day work as the department focuses its effort on an asset condition assessment and other long-term planning. We are working to develop a relationship with a local engineering consulting firm and we believe this approach will allow the required degree of consistency at the lowest possible cost.

Advertising Costs ($43,048 or 2% of the variance)

The $43,038 increase is primarily the result of two key efforts to educate customers. First, Bluewater Power has budgeted approximately $6,000 for general advertising and promotion of conservation activities that are not included in an OPA program. Bluewater Power is a proud and willing participant in the conservation movement and these funds will be spent on initiatives such as the Blackout Challenge, municipal energy conservation, and local initiatives that seek to promote overall energy conservation or generation of renewable energy. Second, Bluewater Power has budgeted approximately $20,000 in anticipation of customer education regarding distribution and commodity rates, as well as ensuring Bluewater Power's customers are aware of their rights with respect to retailers of electricity. Bluewater Power believes both of these programs are essential and directly benefit customers as they attempt to understand and respond to the complexities of the electricity market in Ontario.

Employee Costs ($41,294 or 2.5% of the variance)

The $40,992 increase is primarily represented by increases in training costs (both course fees and the associated travel) and is, therefore, a direct result of Bluewater Power's effort to attract and retain employees into its workforce. Increases in these costs also result from increased staff turnover caused by the increased mobility of today's modern workforce. Turnover leads to increased training costs in order to train replacements.

2.0 Payroll Related Costs

For the purposes of this variance analysis, Payroll Related Costs are defined to include salary, wages, incentive, students, contract employees, overtime, statutory and extended benefits. These costs do not include employee costs (training, FR clothing, boot allowance, cell phones, etc.) nor do they include the future benefit costs, both of which are addressed above separately as primary drivers of the variance in OM&A.

As demonstrated in Table 4.2.2.2 below, the increase in Payroll Related Costs (net of Capitalized Labour) from 2007 to 2009 is $1,747,904. This increase is driven by a series of drivers identified in Table 4.2.2.2 below.

Table 4.2.2.2

Drivers of Variance in Payroll Related Costs 2007 to 2009			
Changes/Additions to Payroll Related Costs from 2007 to 2009:		**Percent of total variance**	**Reference**
Cost of living increase over two years	$324,204	18.5%	See section 2.1
Progression increase over two years	$203,859	11.7%	See section 2.2
Incentive Pay increase over two years	$34,562	2.0%	See section 2.3
Reorganization of staff	$ (55,362)	-3.2%	See Section 2.4(a)
Replacement Staff	$160,307	9.2%	See Section 2.4(b)
New Positions 2008	$200,100	11.4%	See Section 2.4(c)
New Positions 2009	$410,384	23.5%	See Section 2.4(d)
Miscellaneous Variances	$16,977	1.0%	See Section 2.5
Growth in Benefits	$269,620	15.4%	See Section 2.6
Change in Payroll Accrual	$225,503	12.9%	See Section 2.7
Corporate Reorganization to create affiliate	$92,870	5.3%	See Section 2.8
Increase in Capitalized Labour	$ (135,120)	-7.7%	See Section 2.9
Variance Explained	**$1,747,904**	**100.0%**	

2.1 Cost of Living Increases ($324,204 variance or 18.5% of variance in Payroll Related Costs)

Bluewater Power's contract with its unionized employees covers the period from April 1, 2006 to March 31, 2009. The increase under that contract was 3% annually in each of the three years of the contract. Annual cost of living increases for non-union and management employees are generally the same as the union-negotiated rate, although that is not a specifically endorsed policy of Bluewater Power or its Board of Directors. Nevertheless, for the sake of this analysis Bluewater Power has assumed across all employee categories that any increase in pay greater than 3% annually was a progression increase, and that all increases up to 3% relate to a cost of living increase.

The increase for the 2009 Test Year has been set at a 3% increase over 2008 wage rates commencing April 1, 2009. This is consistent with negotiated settlements in the utility sector over the past 12 months which have ranged between 3% and 5% per annum. It is worth noting that settlements in the "public sector" in Ontario have tended to exceed 3.0% annually and, more locally, the trades involved in construction and maintenance in the Sarnia-Lambton region trend closer to 3.2% due to increased demand on skilled trades.

2.2 Progression Increases ($203,859 variance or 11.7% of variance in Payroll Related Costs)

Increases in total compensation paid to employees in existing positions that are not otherwise attributable to cost of living increases have been classified as a progression increase. The total progression increase of $203,859 represents two years of progression and is spread across employee groups as follows:

- Management $ 30,834
- Non-Union $ 51,947
- Union $121,078

There are two types of progressions affecting these numbers. First, there are regular progressions, which are mandated by union contract or pay grids. The majority of the increases would fall into this category.

The second type of progression is an increase required in order to retain key employees or employee groups. The loss of key staff in non-union positions, as well as the increased pressure imposed on all existing staff, has necessitated a focus on employee retention. Staff at Bluewater Power has been extended beyond the requirements under which they operated when the utility was a public utility commission. Staff is responding well to increased regulatory requirements from the OEB, and the Electrical Safety Authority.

Compensation levels for senior management are set by the Compensation Committee of the Board of Directors annually in consultation with the Chief Executive Officer. Compensation for other non-union positions is implemented by the CEO within a range approved by the Board of Directors.

The process of compensation review commences with a comprehensive study undertaken by the Vice-president of Human Resources. All compensation levels are considered in the context of a position description questionnaire undertaken and evaluated by the Hay Group, an independent consultant well known for its work on employee compensation. This questionnaire includes consideration of (a) knowledge level required (technical/practical knowledge, managerial skills, and human relations), (b) need to problem solve, (c) accountability for results, and (d) working conditions. The process of review is extensive and the result is a comparative analysis that rates each position relative to all others in the organization. These internal comparisons are tied to external comparators by the Hay Group utilizing comparators that are not only sector specific but are also of the same relative size.

Compensation is reviewed annually by the Compensation Committee in consultation with the CEO and the Vice-president of Human Resources. The review takes place over the period from November to February, with the final decision expected by March. The final compensation is approved in total by the Board of Directors as a whole.

The increase due to progression in 2009 has been budgeted at $59,713. Given that the total progression over two years totals $203,859, the majority of progression increase is found in the transition from 2008 to 2009. Therefore, the majority of the total increase in employee cost due to progression has been approved and implemented by Bluewater Power's Board of Directors following the process outlined above.

2.3 Incentive Pay ($34,562 variance or 2.0% of variance in Payroll Related Costs)

Bluewater Power has an incentive pay program that applies to all management, non-union and union employees. The program was implemented to incent both individual and overall corporate performance. The program was implemented specifically to drive key performance at the utility in the following areas:

1. *Spending Performance* – Operating and maintenance spending must be within the company's annual budget, as approved by the Board of Directors.
2. *Reliability and Service* - Bluewater Power must meet all Ontario Energy Board requirements for performance service quality indicators. This includes acceptable levels of reliability, outages, and customer service. This is to ensure that employees do not sacrifice service levels for financial targets.
3. *Financial Performance* - Bluewater Power must exceed the budgeted net income before taxes for the fiscal year, as approved by the Board of Directors.
4. *Safety Performance* – Bluewater Power must maintain a safe environment for its employees and the public.

Each year, the Board of Directors considers these four criteria and determines whether incentive compensation will be payable with respect to the prior year. In preparation for that consideration, and as part of annual employee performance reviews, individual performance evaluations have been undertaken by managers and supervisors. If corporate performance meets the above objectives, individual incentive pay is calculated as a percentage of base wage/salary depending upon the individual's performance.

The program has been successful in helping the utility meets its goals identified above. More specifically, Bluewater Power notes the following important points:

1. *Spending Performance* – Operating and maintenance spending has not been controlled by the utility and the budgeted amounts have not been exceeded since the program was implemented.
2. *Reliability & Service* – Bluewater Power has met or exceeded all OEB reliability and service criteria.
3. *Financial Performance* – Bluewater Power has exceeded the budgeted net income after tax, as set by the Board of Directors, since the program was implemented. Although Bluewater Power has not achieved it regulated ROE, its Board of Directors has typically budgeted a net income that is mindful of the need to make safety, reliability, regulatory compliance and customer service a priority.
4. *Safety Performance* – Bluewater Power has recently earned its Bronze Award from EUSA for 250,000 hours without a lost time injury.

The incentive pay program is continually under review, and in February of 2008 the Board of Directors asked that the program be reviewed to ensure that the corporate performance criteria remain relevant to the utility. The analysis was considered by the Board in June and approval was given to continue the program indefinitely.

The increase in total incentive pay of $34,562 is explained in part by increases in staff levels, as well as an increase in the compensation levels on which the incentive pay is based. The increase is also partially explained by improved performance of staff, resulting in higher payouts. In all cases, the increase in incentive pay is justified by the improved performance at Bluewater Power which ultimately benefits ratepayers.

In that regard, Bluewater Power notes that the amount included to be recovered in rates through this application represents 90% of the incentive compensation otherwise budgeted for 2009. The remaining 10% of incentive compensation is considered to be attributable to shareholder benefit, as was proposed by Bluewater Power and approved by the OEB in Bluewater Power's 2006 EDR application. The gross increase in incentive pay from 2007 to 2009 is $60,349, but the increase described above is net of $25,787 which has been reallocated to Account 4380 to ensure it is not recovered through rates.

2.4 Changes to Employee Counts

A detailed description of employee costs is also found at "Exhibit 4, Tab 2, Schedule 9 – Employee Description", but the following table helps to demonstrate the change in positions at Bluewater Power as at January 1 over the period from 2007 to 2009.

From 2007 to 2008, Table 4.2.2.3 demonstrates that no employees were added on a net basis. However, that is the result of three employees leaving Bluewater Power and three employees joining the company. Three employees left the employment of Bluewater Power prior to January 1, 2008 and the positions were left open but not filled (one position is shown as filled mid-year 2008 and the other two positions are shown as pending). At the same time, three new staff members were added to Bluewater Power prior to January 1, 2008. Two of those employees are described below as replacements and the third is a new position created in late 2007.

From 2008 to 2009, the FTE count rises to 99 employees, but that increase of six FTEs is comprised of the following changes:

- During the third-quarter of 2008, Bluewater' Power's FTE count has risen to 95 as two apprentice linepersons have been hired.
- During the fourth-quarter of 2008, the four positions shown below as "pending" are to be filled. These positions include the VP Strategic Development, Professional Engineer, Administrative Assistant and IT Programmer
- Six new positions are being filled for 2009. Those positions include an accountant, HR administrator, Line Technician, Line Supervisor and 2 Linepersons.
- All of these additions are offset by the six positions leaving the utility to join the affiliate (as discussed at Exhibit 1, Tab 2, Schedule 6 – Planned Changes in Corporate or Operational Structure), as well as one retirement from 2008 where the position is not being replaced (described below as an Operator).

Table 4.2.2.3

Employee Count as of January 1st of each year			
	2007	**2008**	**2009**
Base of Employees	83	83	83
Re-organizations:			
Vice-President	1	Pending	1
Executive Assistant	1	Pending	1
Engineer	1	Pending	1
Operator	1	1	
Civil Crew	4	4	
Affiliate Lineperson	2	2	
Replacements:			
H&S Officer		1	1
IT Programmer		Pending	1
A/R Analyst	mid-year	1	1
2008 Positions:			
Apprentice Lineperson		mid-year	2
Project Administrator		mid-year	1
Design Technician	end-of-year	1	1
2009 Positions:			
Accountant			1
HR Administrator			1
Line Technician			1
Line Supervisor			1
Lineperson			2
TOTAL	93	93	99

Overall, there is a net increase in employee count of six FTEs from 2007 to 2009. That net result is comprised of a series of changes in corporate structure, positions leaving and being replaced, as well as the creation of new positions to meet the challenges of the electrical industry in Ontario. All of those discussions are set out in detail below.

2.4(a) Re-organizations of Staff ($-55,362 variance or -3.2% of variance in Payroll Related Costs)

Re-organization #1 – Vice-President: The Vice-President of Client Services left Bluewater Power to take on new responsibilities at Bluewater Power Generation Corporation as of January 1, 2008. This left vacant an established role at the utility. The responsibilities of this position have been satisfied temporarily by other senior managers assuming additional responsibilities, but the position will be replaced with a new position to be called Vice-President of Strategic Development. It is believed that this newly defined position is necessary in order to drive efficiencies and effectiveness in the utility (examples would include identifying strategic partnerships to reduce costs, or overseeing process improvements that affect multiple departments). The remaining members of the senior management team have been able to assume certain responsibilities on a temporary basis, but there have been no resources to pursue strategic development initiatives that were typically the responsibility of the VP Client Services. Bluewater Power believes it is necessary to not only re-establish but expand this position which will, over time, benefit ratepayers.

Re-organization #2 – Executive/Administrative Assistant: The Executive Assistant to the VP Client Services likewise was transferred to Bluewater Power Generation Corporation. The former Executive Assistant also provided administrative assistance to the Design Services Department, particularly as that group responded to the increased demands in the area of distributed generation. It is proposed to replace this position with an Administrative Assistant who will assist both the VP Strategic Development and the Design Services Department.

Re-organization #3 – Professional Engineer: In late 2007, Bluewater Power's Professional Engineer resigned. Efforts were commenced immediately to identify an interim solution to Bluewater Power's engineering needs, which has led to increased consulting costs in 2008. Bluewater Power does not have a Professional Engineer on staff at this time, but it is intended to be filed prior to the commencement of 2009 on a full-time basis.

Re-organization #4 – Control Room Operator: Bluewater Power experienced a resignation in its Control Room group in 2008 and it has been determined that the position will not be replaced. The decision to not replace this position has been projected to cause an increase in overtime for the remaining members of the group and will also necessitate increased responsibilities being assumed by other members of the Control Room. Overall, Bluewater Power believes this decision is justified and reasonable.

2.4(b) Replacement Staff ($160,307 variance of 9.2% of variance in Payroll Related Costs)

Replacement #1 - Health & Safety Officer: This position was vacant in 2006 and most of 2007 due to a retirement. Health & safety ("H&S") has always been a paramount concern at Bluewater Power. Without attempting to diminish the importance of H&S, during that period of time responsibility for H&S was distributed amongst all of Bluewater's employees, while coordination and monitoring fell on supervisors and managers, primarily within the Lines and Operations Department. Despite these reorganizational efforts, following 500,000 hours without a lost-time injury, Bluewater experienced four lost time injuries during the period from mid-2006 to early 2007 and the senior management team determined to reinstate the Health & Safety Officer position in order to bring further specific focus to H&S issues. Accordingly, the position was reinstated in late 2007 and there have been no lost-time injuries since that time.

Replacement #2 – IT Programmer: In early 2007, Bluewater's in-house SAP programmer resigned. Market conditions have been such that Bluewater Power has been unable to fill the position. SAP programming has been covered by outside consultants at a greater cost in the interim but the increased cost has made it necessary for some work to be held in abeyance. For example, system improvements to SAP base codes have been postponed and process improvements such as standardization of address forms and improvements to the estimation process have all been held in abeyance. These improvements would have increased efficiencies and/or customer satisfaction but could not be justified if carried out by external consultants. Given the proposed upgrade to the SAP system in 2009, it is critical that this position be replaced prior to commencement of the SAP capital upgrade. Following

the upgrade, the replacement of the in-house programmer will permit the utility to cost effectively take full advantage of its billing system which will lead to improved operational efficiencies and customer satisfaction.

Replacement #3 – Accounts Receivable Analyst: This position was filled under contract for the first six months in 2007 as a replacement of an employee on Long-Term Disability. The position, therefore, is a long-standing position critical to the functioning of the organization. The position was converted in 2007 to a full-time position and that has continued in 2008 and beyond.

2.4(c) New Positions 2008 ($200,100 or 11.4% of the variance in Payroll Related Costs)

Positions #1 and #2 – Apprentice Linesperson: Bluewater Power hired two apprentice linepersons in the third quarter of 2008. Beginning in 2007, Bluewater Power has participated in the training of two co-op students from the Cambrian College lines technician program and these students have successfully moved into the position of Apprentice Linesperson mid-2008. The effort to train and retain young staff is critical to Bluewater Power's attempt to manage and sustain its workforce. (It is worth noting that Bluewater Power has budgeted to employ two co-op students in each of 2007, 2008 and 2009). In addition to assisting with succession planning, these two new positions have been determined to be the most cost effective means to meet the requirements of increasing capital programs at Bluewater Power as discussed elsewhere in this application.

Position #3 - Project Administrator: This position was added in mid-2008 to assist with administration in both the Customer Service Department and the Operations Department. The addition of this administrator has permitted management and supervisors to assume additional responsibilities caused by loss of key staff as well as increased regulatory and operational burdens. The use of a lower cost Project Administrator to free up time for managers and supervisors has allowed Bluewater Power to mitigate the additional cost pressures brought on by these external forces. This position carries with it greater

responsibility than an administrative assistant, but Bluewater Power has become generally aware that it has traditionally been underserviced in the area of administrative assistance. This position, as well as the restructured executive assistant discussed above under the heading of Adjustments, has allowed managers and supervisors in Operations and Customer Service to improve output at a reduced cost compared to adding new management.

Position #4 – Design Technician: This new position was added in late 2007 in response to increasing demands on the Design Services Department caused by (i) ESA Regulation 22/04, (ii) distributed generation, and (iii) increased levels of subdivision development. First, Bluewater Power's Design Services Department has dealt with ESA requirements through internal staff and without the need to spend money on external consultants. This has placed increased demands on staff caused by the need to document system standards, improve inspection and documentation procedures, as well as the need to carry out annual reviews and audits. These new regulations have impacted efficiencies in the areas of maintenance, capital and the joint use of poles. Second, the Design Services Department has also faced increased pressure caused by distributed generation; Bluewater Power is currently performing engineering and design for its distribution system to accommodate ten significant distributed generation projects under the OPA Standard Offer program. Thirdly, all of these new challenges have been compounded by an increased workload as the years 2007 and 2008 have seen increased development in Sarnia-Lambton for both the residential and commercial sectors. It is anticipated that similar levels of development will continue in 2009.

2.4(d) New Positions 2009 ($410,384 or 23.5% of the Variance in Payroll Related Costs)

Position #1 - Accountant: A new accountant position is critical to the Finance Department in 2009 and 2010 to assist Bluewater Power in its ability to face the challenges associated with the changes to the International Financial Reporting Standards. In general, there is also growing demand on the Finance Department caused by enhanced OEB reporting, capital reporting and tracking, and services to affiliates (these services are provided to affiliates through a Service Agreement under which costs are recovered on a fully-allocated basis).

This position is not entirely a new role, as the Manager of Regulatory Affairs was a shared position in 2006 with 0.3 FTE assigned to finance and 0.7 FTE assigned to regulatory. Finally, this position is critical to succession planning as Bluewater Power faces a likely retirement from the Finance Department at some point beyond 2010.

Position #2 – Human Resources Administrator: Staff levels have increased since privatization in 2000 by approximately one-third. In addition, in 1999 Bluewater Power (Sarnia Hydro at the time) assumed certain administrative responsibilities over its benefit program in order to realize cost savings. These factors have increased demands on the Human Resources Department but no new staff has been added. In addition to increased demand, the nature of the employment market has changed in recent years and that is evidenced by the increased effort required in the area of recruitment. Firstly, because skilled trades are in a short supply, this increases the demands on time to perform an effective recruitment. Secondly, because modern employees are more mobile the workforce is routinely in flux resulting in more positions requiring recruitment more often. Therefore, this full-time position has been included in 2009 in order to respond to the increased demands on the Human Resources Department. It should be noted, however, that this increase is partially reflected in 2007 Actuals since a contract position was in place at a cost of approximately $20,000.

Position #3 - Line Technician: In addition to assisting with the increased workload in the Design Services Department, as discussed above with respect to the Design Technician position, an additional Line Technician will be hired to address the increasingly complex needs of Bluewater Power's large customers. As discussed in the Asset Management Plan at Exhibit 2, Tab 3, Schedule 9, Bluewater Power has identified the need to address power quality issues above and beyond normal reliability concerns. This need relates to the increasing sensitivity of large customers located in Chemical Valley. Bluewater Power intends to assign this new position as the main point of contact for industry. This position will also have primary responsibility for the continuous improvement process so that Bluewater Power can focus more closely on asset assessment and long-term planning as a critical juncture in the lifespan of the system approaches. This position is, therefore, not only critical

to Bluewater Power's large customers, but will also benefit all customers through improved quality of service.

Position #4 - Supervisor: The Operations Department has a need to plan for the replacement of critical supervisors who are eligible to retire over the next ten years. For example, the Manager of Lines is eligible to retire in late 2009 and is likely to retire shortly thereafter. The sudden departure of key personnel due to retirements in organizations so dependent upon skilled trades can create a significant and detrimental loss of knowledge. Therefore, the need to allow knowledge transfer opportunities through the training of replacements is critical. An overlap of one to two years is ideal, if not necessary, in order to ensure adequate knowledge transfer. In addition, that overlap will also assist Bluewater Power as it prepares to manage its proposed increased capital program. The increased capital program (as addressed in the Asset Assessment Report) will require greater planning. In addition, the increase in staff necessary to perform increased capital work will place new demands on supervisors. For the purposes of both succession planning and increased workload, a new supervisor will be added for 2009.

Positions #5 & #6 - Lineperson: As discussed above, two linepersons will be moved from Bluewater Power to its affiliate to perform street light and traffic light capital and maintenance. These positions will be replaced in 2009. Taken together, these changes do not create a net add in employee numbers, however, they do create an increase in the costs sought to be recovered through rates since the 2007 costs were reallocated to Account 4380 (see discussion at Section 2.8). These two new positions are necessary in order to keep pace with increasing capital demands being faced by Bluewater Power. The utility has plans to increase capital spending in coming years in order to respond to its aging infrastructure. Since capitalized labour represents a large portion of capital spending, it can become a reality that the availability of staff can become a limit to the level of capital spending. Therefore, increasing staff in the Operations Department is critical for Bluewater Power to respond to the capital needs of the system. It is worth noting that, although the cost associated with these two linepersons has been included in 2009 OM&A, it is entirely

offset by the fact that capitalized labour has increased in 2009 Projection versus 2007 Actual by $135,120.

2.5 Miscellaneous Variances ($16,977 or 1.0% of the variance in Payroll Related Costs)

The variances comprising the miscellaneous variances are minor in nature, with justifications not related to other variances in this analysis. They have been grouped together for convenience and are discussed individually below the table that follows.

Table 4.2.2.4

Decrease in contracts	$ (70,686)
Increase in overtime	$47,908
Students	$14,059
Variance in Reallocation for Water Billing and OPA	$25,696
TOTAL miscellaneous variances	**$16,977**

- Decrease in contracts: The increase in FTEs is partly offset by the decrease in costs related to contract employees identified here as totaling $70,686. As discussed within the justification for various new positions above, contract positions from 2007 have been filled with full-time positions in 2009.
- Increase in overtime: The increases in overtime relate primarily to the elimination of the Control Room position, and general increases in overtime which are addressed in materiality analyses that follow in the next schedule.
- Students: Student costs have increased from 2007 to 2009 driven by an increase in pay for students, as well as two new positions on a net basis.
- Variance in reallocation of water billing and OPA: As discussed elsewhere, Bluewater Power plans to continue water billing and OPA programs in 2009 and costs for these programs are reallocated to Account 4380. The variance between 2008 and 2009 of $25,696 reflects a decrease in the costs reallocated in 2009 which has the effect of leaving greater costs in OM&A. This decrease is the net result of an increase in the reallocation of water billing related costs of $27,973 and a decrease in the reallocation of OPA related costs of $53,669. The reason for fewer costs being reallocated in respect of OPA programs is that 2007 was the year in which the OPA programs were established and, therefore, greater effort was expended by staff than is anticipated in 2009 as these programs become more self-sufficient.

2.6 Statutory and Extended Benefits ($269,620 or 15.4% of the variance in Payroll Related Costs)

Statutory benefits include Employment Insurance, Canada Pension Plan, Workplace Safety and Insurance Board, and the Employer Health Tax. These costs follow directly from employment figures and are non-discretionary. During the period from 2007 to 2009, the increase in these costs accounts for an increase of $29,862. Of this increase, the majority relates to employees not on staff at the beginning of 2007 reflecting the fact that rates for statutory benefits have changed only marginally over the period from 2007 to 2009.

Of the $269,620 increase, the remaining $239,758 relate to growth in extended benefits at Bluewater Power, which are comprised of 11 different individual items. The five main components of extended benefits (responsible for 96% of the cost in the 2007 Actuals) are as follows:

- OMERS at $450,031
- Extended health benefits at $246,164
- Retiree benefits (health and life insurance) at $237,581
- Long-term disability at $111,079
- Dental at $94,630

Variances in extended and statutory benefit costs directly follow either:

(i) *Changes in Compensation Paid*: Benefits are determined either by headcount or compensation paid, and an increase in either can drive an increase in benefits costs. Of the $269,620 increase in costs, the vast majority relates to increases in headcount or compensation.

(ii) *Changes in benefit rates*. Bluewater has made extensive efforts to control costs by controlling benefits (for example, commencing in 2006, new employees are no longer entitled to retiree benefits at retirement). Bluewater has also actively pursued negotiations with its suppliers to control costs and is pleased to note that, other than increases due to new employees, the benefit costs for the utility have remained almost unchanged.

2.7 Change in Payroll Accrual ($225,503 or 12.9% of the variance in Payroll Related Costs)

Annual payroll budgets are prepared on the basis of the actual 26 bi-weekly pay periods that will end in the budget year. Those budgeted pay periods typically do not match the calendar year, so a payroll accrual reversal is made at the beginning of the year and an accrual is made at the end of the year to shift the pay periods into the calendar year. The net payroll accrual in 2009 exceeded the net payroll accrual in 2007 by $225,503, reflecting the fact that more net payroll was accrued for in 2009 than was accrued for in 2007, and the fact that payroll costs increased between 2008 and 2009.

2.8 Corporate Restructuring ($92,870 or 5.3% of the variance in Payroll Related Costs)

As discussed at Exhibit 1, Tab 2, Schedule 6 – Planned Changes in Corporate or Operational Structure, Bluewater Power will be transferring six employees to an affiliate. Those employees are represented by the four person civil crew and two linepersons. The removal of these employees results in a savings of $471,929 in 2009 versus 2007. However, a similar reduction in distribution OM&A was already realized in 2007 to the extent that costs related to civil work, traffic lights, streetlights and on-demand linework were reallocated to Account 4380.

The conclusion reached in Exhibit 1, Tab 2, Schedule 6 of this application is that the proposed corporate restructuring has no financial consequence on rate payers. That conclusion relates to a theoretical discussion of whether ratepayers would be better off in 2009 with Non-Core Distribution Activities taking place within the utility or taking place in an affiliate. As long as the costs that are likely to be reallocated in 2009 equal the costs removed from OM&A through the corporate restructuring, then ratepayers are no better or worse off. In the analysis undertaken in Exhibit 1, Tab 2, Schedule 6, we had to assume an average year of Non-Core Distribution Activities for 2009.

However, we know that 2007 was an exceptionally busy year for Non-Core Distribution Activities (due to both Affiliate Activities (as defined in Exhibit 1, Tab 2, Schedule 6) as well as one-time activities). Moreover, the discussion relevant to this OM&A variance analysis is not a theoretical discussion but a factual comparison of reallocations in 2007 versus costs removed to the affiliate in 2009. Table 4.2.2.5 demonstrates that the reallocations in 2007 exceed the labour and benefit costs moved to the affiliate in 2009.

Table 4.2.2.5

Reallocation in 2007 (Affiliate Activities)	$435,265.00
Reallocation in 2007 (One-time Activities)	$129,534.00
Labour and Benefits moved to Affiliate	$ (471,929.00)
Net Impact on OM&A due to Corporate Restructuring	**$92,870.00**

Therefore, although there is no theoretical impact of the proposed corporate restructuring on rate payers, this variance analysis is not a theoretical investigation. It is a variance analysis that seeks to compare actual reallocations in 2007 with the costs proposed to be removed from distribution OM&A through the corporate restructuring. That analysis reveals there is a detrimental impact on ratepayers of $92,870.

2.9 Capitalized Labour (-$135,120 or -7.7% of the variance in Payroll Related Costs)

The increase in Payroll Related Costs from 2007 to 2009 is partially offset by the fact that capitalized labour has also increased from 2007 to 2009 by $135,120. It is worth analyzing capitalized labour over the relevant years of comparison because that analysis demonstrates a trend toward increased levels of capitalized labour.

Table 4.2.2.6
Capitalized Labour vs Capital Spending

	2006 EDR	2007 Actual	2008 Bridge	2009 Projected
Capitalized Labour	1,203,578	1,646,078	1,951,750	1,781,198
Capital Spending	4,391,836	4,858,828	5,139,900	8,286,810
Capitalized Labour as Percentage of Capital	27.4%	33.9%	38.0%	21.5%

The increase in Capitalized Labour from 2006 EDR to 2007 reflects the fact that capital spending increased from year to year. Another important factor over that period was increased diligence in tracking and recording capital work. Bluewater Power's capitalization policy has been in place since 2002, therefore the increase in Capitalized Labour as a percentage of Capital must be explained by improved diligence and careful consideration of capitalization practices. The decrease in the percentage for 2009 reflects the fact that the 2009 Capital Budget includes two major projects that will be managed externally and do not have significant

Capitalized Labour components. Without those two projects Capital Spending would be $5,978,350 and the Capitalized Labour would represent 29.8% of Capital Spending.

Commencing in January 1, 2009, Bluewater Power has proposed a change to its capitalization policy. As explained in Exhibit 2, Tab 3, Schedule 8 – Capitalization Policy, the intention of the policy change is to achieve a consistent result for Bluewater Power compared to previous years while utilizing a more standard methodology. That new methodology is more similar to capitalization policies observed throughout the utility sector and is a methodology that has been approved previously by the OEB for other utilities.

The change in capitalization policy is designed to lead to similar results to what would have been expected under our previous policy. However, the distribution of Capitalized Labour among Account Groups will vary under the new policy. For example, the reduction in the burdened labour rate for direct labour will reduce account groups that are actively involved in performing capital work (such as “Distribution Expenses – Operations”). Whereas the account group known as “Administration and General Expenses” will see increases in capitalized labour as the 10% capitalization rate is applied directly to that account group. Discussions on these impacts are found in the Variance Analysis by Account Group that follows.

Annual Variance Analysis on OM&A Costs

The previous schedule provides the essential context to the analysis that follows. The OEB Filing Guidelines require variances by Account Group on an annual basis for the Test Year, Bridge Year, Historic Year and last Board approved. The results of that analysis are the three variance analyses that follow – 2009 vs. 2008, 2008 vs. 2007, and 2007 vs. 2006 EDR. Where necessary, the reader will be referred back to Exhibit 4, Tab 2, Schedule 2 for further information

2009 vs. 2008 Variances

Table 4.2.3.1

Account Grouping	2009 Projection	2008 Projection	Var $
3500-Distribution Expenses - Operation	3,535,352	2,258,862	**1,276,490**
3550-Distribution Expenses - Maintenance	157,640	140,410	**17,230**
3650-Billing and Collecting	1,497,443	1,370,749	**126,694**
3700-Community Relations	216,871	175,409	**41,462**
3800-Administrative and General Expenses	5,951,113	5,550,385	**400,728**
3950-Taxes Other Than Income Taxes	297,750	290,000	**7,750**
TOTAL	**11,656,169**	**9,785,815**	**1,870,354**

The overall variance from 2008 to 2009 is $1,870,354, representing a 19.1% increase. That increase in OM&A includes consideration of capitalized labour as the level of capitalized labour is accounted for below in the appropriate account group. The primary driver of the variance is the increase in Payroll Related Costs caused by the need to replace positions and to create new positions necessary to respond to increased demands on staff and succession planning.

The materiality threshold based on 2008 expenses is $138,311.

Table 4.2.3.2
Distribution Expenses - Operations

Account Grouping	2009 Projection	2008 Projection	Variance $
Capitalized Labour	(914,975)	(1,528,089)	613,114
Salary	844,719	635,979	208,740
Labour	2,095,752	1,911,234	184,518
Overtime	367,648	302,450	65,198
Employee Costs	179,256	128,515	50,741
Fleet	222,806	173,554	49,252
Third Party Costs	223,350	177,676	52,724
All Others	516,797	457,543	52,204
Total	3,535,352	2,258,862	1,276,490

Capitalized labour across the utility has decreased from 2008 to 2009 by $170,552, but that only explains a portion of the decrease in capitalized labour for this account group of $613,114. The primary explanation is the fact that, although the change in the capitalization policy discussed at Exhibit 2, Tab 3, Schedule 8 has not reduced overall capitalization, it has disproportionately impacted this account group. That is because under the revised capitalization policy, the burdened labour rate applied to direct labour has decreased by approximately 30% from 2008 to 2009. That reduction in the burden rate has been replaced by a capitalization rate of 10% that is added to each project. That capitalization rate is allocated to the account group “Administration and General Expenses” which increases capitalized labour in that account group and lowers capitalized labour in this account group. Overall, the level of capitalized labour is consistent as discussed at Exhibit 4, Tab 2, Schedule 2, Section 2.9.

The increase in salary and labour for this account group from 2008 to 2009 is explained, in part, by a cost of living increase of approximately $80,000, progression increase of approximately $24,500 all addressed above in the general discussion of Payroll Related Costs in Exhibit 4, Tab 2, Schedule 2, Section 2.0.

New positions at Bluewater Power also contribute to the variance in this account group from 2008 to 2009. The justification for these new positions is found Exhibit 4, Tab 2, Schedule 2, Section 2.4. The details of how these new positions impact the variance from 2008 to 2009 is explained below for salary and labour separately.

The increase in salary is largely the result of the addition of the following positions from 2008 to 2009:

- New Supervisor in 2009;
- Full year of Engineer in 2009 vs. part year in 2008
- New Administrative Assistant in 2009
- Full year of Project Administrator in 2009 vs. part year in 2008

The increase in labour is largely the result of the net increase in staff described as follows:

- Two Apprentice Linepersons were added mid-year 2008, therefore the 2009 budget represents a full-year of costs vs. a part year in 2008
- Two new Linepersons are added in 2009
- New Line Technician in 2009
- Control Room operator resigns is 2008 and position not replaced
- Two Linepersons and four members of the civil crew have been removed from 2009 and transferred to an affiliate but, again, it is important to note that the majority of costs associated with these positions were already removed from 2008 since those costs were largely reallocated to Account 4380 (as discussed at Exhibit 4, Tab 2, Schedule 2, Section 2.8.)

The remaining increases from 2008 to 2009 related to a series of non-material changes that are explained and justified as follows:

1. The increase in third party costs of $52,724 is driven by an increase in consulting costs budgeted for 2009 in the areas of Design Services and Control Room. The increase in Design Services is necessary to assist Bluewater Power in accommodating day-to-day work as it undertakes a fulsome asset assessment study. The increase in consulting costs with respect to the Control Room is to assist with the development of process improvements that will allow the utility to cope with the decrease in staff in the Control Room.

2. The increase in Fleet of $49,252 is primarily driven by the increase in the price of fuel. The budget for 2008 is likely to be exceeded; therefore the budget for 2009 is realistically more reflective of actual prices in today's market. Although Bluewater Power has undertaken extensive efforts to reduce its use of fuel through the use of fuel efficient vehicles in its fleet, this increase in cost of fuel is beyond our control.

3. The increase of 5% in overtime from 2008 to 2009 reflects, in part, an increase in base salaries on which the overtime rate is paid. A further increase of $33,000 is a result of the budget for 2009 being adjusted to better reflect the historical average of overtime, whereas the 2008 budget did not reflect the historic average. Finally, the overtime budget was increased by $14,000 in order to allow the Control Room to continue to function without the replacement of a retirement that took place in 2008.

4. The increase in employee cost of $50,741primarily relates to increases in training. That increase is driven by the new positions created during 2008 and 2009, including the two Apprentice Linepersons hired mid-2008. In addition, new training has been proposed in order to improve knowledge across the workforce as key employees approach retirement or move into supervisory positions. For example, $12,000 has been budgeted as a new cost in 2009 relating to substation maintenance and $16,000 for EUSA update.

Table 4.2.3.3
Distribution Expenses - Maintenance

Account Grouping	2009 Projection	2008 Projection	Variance $
3550-Distribution Expenses - Maintenance	157,640	140,410	17,230

The items affecting the Maintenance account group include those items described in the Asset Management Plan as the Asset Maintenance Programs. To be specific, these costs relate to: testing of substation batteries, transformer oil analysis, insulator washing, and manhole and vault maintenance. This variance is well under the materiality threshold.

Table 4.2.3.4
Billing & Collecting

Account Grouping	2009 Projection	2008 Projection	Variance $
Labour	877,960	828,560	49,400
Overtime	63,500	17,880	45,620
Benefits	108,130	87,248	20,881
Miscellaneous	231,060	211,337	19,724
Incentive	28,942	18,449	10,493
Salary	97,441	88,430	9,011
Capitalized Labour	(47,301)	-	(47,301)
All Other	137,712	118,845	18,866
Total	1,497,443	1,370,749	126,694

The Billing and Collecting account group has no single variance that amounts to a material variance requiring explanation. Nevertheless, we offer the following comments to aid the Board in its understanding of this variance.

The increase in labour is generally consistent with what would be expected for cost of living and progression increases.

The SAP Upgrade project is driving the increase in capitalized labour, as well as contributing to the increase in overtime. That capital project is addressed at "Exhibit 2, Tab 3, Schedule 6 – Materiality Analysis on Capital Additions" and this level of capitalization is necessary to complete that project.

Table 4.2.3.5
Community Relations

Account Grouping	2009 Projection	2008 Projection	Variance $
3700-Community Relations	216,871	175,409	41,462

The Community Relations variance is well under the materiality threshold, but we offer the following comments to aid the OEB in its understanding of this account group.

The majority of the increase in community relations is driven by an increase in advertising in two areas. First, Bluewater Power has budgeted approximately $6,000 for general advertising and promotion of conservation activities that are not included in an OPA program. Bluewater Power is a proud and willing participant in the conservation movement and these funds will be spent on initiatives such as the Blackout Challenge, municipal energy conservation, and local initiatives that seek to promote overall energy conservation or generation of renewable energy. Second, Bluewater Power has budgeted approximately $20,000 in anticipation of customer education regarding distribution and commodity rates, as well as ensuring Bluewater Power's customers are aware of their rights with respect to retailers of electricity.

Table 4.2.3.6
Administration and General Expenses

Account Grouping	2009 Projection	2008 Projection	Variance $
Salary	2,345,392	2,009,672	335,720
Payroll Accrual	268,252	60,331	207,921
Regulatory	240,148	118,000	122,148
Benefits	1,449,703	1,374,246	75,456
Employee costs	303,482	240,109	63,373
Consulting	131,050	94,050	37,000
Future Benefit	694,415	847,994	(153,579)
Capitalized Labour	(818,922)	(423,661)	(395,261)
All Other Costs	1,285,093	1,202,644	82,450
Total	5,951,113	5,550,385	400,728

The Administration and General Expenses variance in this account group is made-up of four material variances. Two are positive variances and two are negative variances. Each variance is addressed separately below.

Salary

The increase in salary from 2008 to 2009 is explained, in part, by a cost of living increase of approximately $60,000 and progression increases approximately $20,000.

New positions from 2008 to 2009 also contribute to the material variances, but the details of how these positions impact the variance from 2008 to 2009 is explained below.

The remaining increase in salary of $255,720 ($335,720 less $80,000) is primarily due to the increase in staffing levels impacting this account group. The justification for these new positions is found at Exhibit 4, Tab 2, Schedule 2, Section 2.4, but the positions added in 2009 versus 2008 are as follows:

- Vice-President Strategic Development (a new position in 2009 over 2008, although a similar position existed in 2007)
- HR Administrator (a new position in 2009)
- Accountant (a new position in 2009)

Payroll Accrual

The payroll accrual is the only other material increase from 2008 to 2009. As addressed earlier, this is an accounting treatment required in order to move the payroll budget to a calendar year basis. The variance of $207,921 is a direct result of the fact that there were more net days accrued at the end of 2009 than were accrued in 2008 and the payroll for 2009 exceeds 2008.

Future Benefits

Future benefits are determined by a third party actuary and is an accounting adjustment that is required in order to properly reflect the future cost of benefits to be included in OM&A in relation to employees employed in the current year. These follow directly from payroll costs and negotiation of benefits.

A full "Actuarial Valuation Report for Post-Retirement Non-Pension Benefits" ("AVR") is typically carried out every three years, or whenever there is a significant change to the information on which the report is based. The report is usually prepared during the audit process and is retrospective in nature such that it is definitive for the prior year only.

In preparation for this rate application, Bluewater Power commissioned an AVR with respect to the 2008 calendar year. This report was commissioned earlier than typical in order to facilitate the best possible information for this application. During that review it was discovered that the previous AVR contained a mistaken assumption with respect to post-retirement benefits and, as a consequence, prior years were underestimated. An adjustment of $326,806 was required, and the result is that the 2008 future benefit appears as a significant increase over the prior year as is clearly demonstrated in the table below.

Table 4.2.3.7
Future Benefits

2006 EDR	2007	2008	2009
$168,804	$523,092	$847,994	$625,599 [1]
			$68,816 [2]
			Total = $694,415

1. Based on a three year average of 2006, 2007 and 2008
2. The 2008 Actuarial Valuation Report reflects 91 employees, so an estimate has been included representing the additional costs to reflect 99 employees in 2009

The amount budgeted for 2009 is based on a three year average of 2006 to 2008. To the extent that the three year average accounts for the adjustment in 2008, Bluewater Power believes that leads to a fair and reasonable result. By including the one-time adjustment as part of a three year average, Bluewater Power has effectively recovered those costs over three years. Bluewater Power believes that this is the most efficient manner for this utility to address the issue. Moreover, this is the earliest opportunity to address the error as it was only detected in preparation for this rebasing application.

Capitalized Labour

Capitalized labour in this account group has increased by $395,261 leading to a reduction in the amount sought to be recovered through rates. This increase in capitalization impacting this account group is a direct result of the change in the capitalization policy. The change in policy does not increase the total amount sought to be capitalized but distributes the capitalized labour differently than in the past.

Capitalized labour in 2009 includes the $543,487 capitalized due to the 10% capital rate applied to capital projects in 2009. Capitalized labour in 2008 reflects the $194,000 in management labour capitalized in 2008 (See Exhibit 4, Tab 2, Schedule 2, Section 2.9 for a further discussion). The increase in this account group of $395,261 is offset by a decrease in the Operations account group.

Non-Material Variances

The increase in regulatory costs of $122,148 is not a material change, but does warrant further discussion. The vast majority of the increase represents the cost of this rebasing exercise, which has been included at one-third of the total, which is $113,000. These costs were budgeted as follows:

Legal	$125,000
Consulting	$125,000
Intervener	$ 60,000
Misc. Expenses	$ 29,000
TOTAL	$339,000 allocated over three years = $113,000 per year

These costs are unavoidable as they are a direct result of the regulatory process involved in preparing Bluewater Power's first costs of service application based on a forward test year. Bluewater Power has undertaken the majority of the work on this rate application in-house and notes that it has taken this exercise very seriously, thus the cost of legal and consulting included for recovery has directly contributed to the clarity and diligence demonstrated by this application.

Finally, Bluewater Power notes that the increase in benefits of $75,456 and the increase in employee costs of $63,373 are primarily related to new positions addressed earlier. These costs are unavoidable and are a direct result of employment levels that are justified earlier in this schedule.

Table 4.2.3.8
Taxes Other than Income Tax

Account Grouping	2009 Projection	2008 Projection	Variance $
3950-Taxes Other Than Income Taxes	297,750	290,000	7,750

This account group includes costs related to property tax and capital tax. The variance in this account group is well below the materiality threshold.

2008 vs. 2007 Variances

Table 4.2.3.9
2008 vs. 2007 Variances

Account Grouping	2008 Projection	2007 Actual	Var $
3500-Distribution Expenses - Operation	2,258,862	2,206,991	51,871
3550-Distribution Expenses - Maintenance	140,410	122,553	17,857
3650-Billing and Collecting	1,370,749	1,277,336	**93,413**
3700-Community Relations	175,409	94,640	**80,769**
3800-Administrative and General Expenses	5,550,385	5,213,650	**336,735**
3950-Taxes Other Than Income Taxes	290,000	278,911	11,089
TOTAL	**9,785,815**	**9,194,081**	**591,734**

The overall variance from 2007 to 2008 is $591,734, representing a 6.4% increase. The primary driver is Payroll Related Costs caused by the need to replace positions, new positions necessary to respond to increased demand on staff and succession planning.

The materiality threshold for 2008 based on 2007 expenses is $130,420.

Table 4.2.3.10
Distribution Expenses - Operations

Account Grouping	2008 Projection	2007 Actual	Variance $
Labour	1,911,234	1,572,147	339,088
Salary	635,979	580,436	55,543
Benefits	216,573	177,713	38,860
Fleet	173,554	157,332	16,221
Third Party Costs	177,676	213,170	(35,494)
Overtime	302,450	362,788	(60,338)
Capitalized Labour	-1,528,089	-1,248,254	(279,835)
All other costs	369,485	391,659	(22,174)
Total	2,258,862	2,206,991	51,871

The increase in salary and labour for this account group from 2007 to 2008 is explained, in part, by a cost of living increase of approximately $47,000, a progression increase of approximately $73,500 all addressed above in the general discussion of Payroll Related Costs.

New positions at Bluewater Power also contribute to the variance in this account group from 2007 to 2008. The justification for these new positions is found at Exhibit 4, Tab 2, Schedule 2, Section 2.4. The details of how these new positions impact the variance from 2008 to 2009 is explained below for salary and labour separately.

The increase in salary of $55,543 is due to changes in the following positions from 2008 to 2009:

- Design Technician (a new position in 2008)
- Project Administrator (a new position added mid-year in 2008)
- Partially offset by the fact that Bluewater Power had nearly full year of the Engineer position in 2007 versus only a partial year in the 2008 budget

The increase in labour of $339,088 represents a net increase in staff described as follows:

- Two Apprentice Linepersons were added mid-year 2008
- The reallocation of costs related to Non-Core Distribution Activities to Account 4380 in 2007 was $564,904, whereas in 2008 the reallocation was $275,216. This creates a variance of $289,688 which drives the 2008 labour figures higher than 2007 figures. The level of Non-Core Distribution Activities in 2007 was extraordinarily high, and included two one-time projects (LED Traffic Light Exchange and Blackwell Civil Work) which could not be anticipated to be repeated when preparing the 2008 budget.

The only other material variance relates to capitalized labour. The increase in capitalized labour from 2007 to 2008 of $279,835 is explained by the overall increase in capitalized labour across the utility. Overall, there is an increase from 2007 to 2008 driven by the increase in capital spending of $306,672. Given the involvement of Operations in providing direct labour to capital projects it would be anticipated that a large portion of that increase in capitalized labour would impact this account group.

The remaining variances from 2007 to 2008 are not material but we offer the following comments to aid the OEB in its understanding of this account group:

- The decrease in third party costs from 2007 to 2008 of $35,494 is mainly due to the fact that 2007 was a higher than normal year for tree trimming.
- The increase in Fleet of $16,221 is primarily driven by the increase in the price of fuel. As noted earlier, the 2008 budget is likely to be exceeded given the sudden increase in fuel costs experienced in 2008.
- The decrease in overtime from 2007 to 2008 of $60,338 is explained by the fact that 2007 was an exceptionally busy year. Increased levels of Non-Core Distribution Activities combined with relatively consistent levels of capital spending, necessitated that some work be undertaken after hours. The budget for 2008 was set at a lower rate in anticipation of lesser demand on time.

- The increase in benefits reflects the increase in the number of employees as discussed at Exhibit 4, Tab 2, Schedule 2, Section 2.6.

Table 4.2.3.11
Distribution Expenses - Maintenance

Account Grouping	2008 Projection	2007 Actual	Variance $
3550-Distribution Expenses - Maintenance	140,410	122,553	17,857

The items affecting this account group include those items described in the Asset Management Plan (at Exhibit 2, Tab 3, Schedule 9) as the Asset Maintenance Programs. To be specific, these costs relate to: testing of substation batteries, transformer oil analysis, insulator washing, and manhole and vault maintenance. This variance is well under the materiality threshold.

Table 4.2.3.12
Billing & Collecting

Account Grouping	2008 Projection	2007 Actual	Variance $
Labour	828,560	757,562	70,998
Third Party Costs	66,870	54,716	12,154
Capitalized Labour		(9,674)	9,674
Salary	88,430	85,766	2,664
Benefits	87,248	84,636	2,612
All Other	299,639	304,328	(4,689)
Total	1,370,747	1,277,334	93,413

The increase in salary and labour is explained, in part, by a cost of living increase of approximately $25,000 and progression increases of approximately $20,000. The remaining variance between years is immaterial and is a result of increases in turnover due to maternity leaves or replacements for employees on Long Term Disability, which results in higher costs due to the need to overlap employees. These cost increases cannot be avoided.

Table 4.2.3.13
Community Relations

Account Grouping	2008 Projection	2007 Actual	Variance $
3700-Community Relations	175,409	94,640	80,769

This variance is primarily comprised of the new position created in 2008 described earlier as the Health and Safety Officer. These costs are booked to this account group on the basis that the position relates not only to employee safety, but also to community safety. The APH identifies community safety costs as belonging to this account group. This position is believed to be necessary for the reasons outlined earlier in this Schedule.

Table 4.2.3.14
Administration and General Expenses

Account Grouping	2008 Projection	2007 Actual	Variance $
Future Benefit	847,994	523,092	324,902
Benefits	1,374,246	1,225,037	149,209
Salary	2,070,003	1,967,615	102,388
Third Party Costs	244,583	220,064	24,519
Regulatory	118,000	107,104	10,896
Capitalized Labour	(423,661)	(347,734)	(75,927)
Employee Costs	240,109	328,630	(88,521)
Contract Employees	49,064	162,383	(113,319)
All Other Costs	1,030,046	1,027,457	2,589
Total	5,550,384	5,213,649	336,735

The variance in this account group is made-up of two material variances, and four variances that are not material but warrant further explanation. Each variance is addressed separately below.

Future Benefits

The first material variance relates to future benefits as discussed earlier in this Schedule. It was noted earlier that the 2008 employee future benefit includes a one-time adjustment that will impact the 2008 financial statements. This cost is a required accounting treatment to properly reflect the cost of future benefits for current employees and, as such, is unavoidable.

Benefits

The Benefit increase of $149,209 is primarily explained by a decrease in the reallocation of benefit costs to Account 4380 from 2007 to 2008. As discussed previously, 2007 was an extraordinarily busy year from the perspective of Non-Core Distribution Activities. One consequence is that this drives $115,938 of this variance as the difference between benefits reallocated to non-utility accounts in 2007 ($174,143) versus 2008 ($58,205).

Salary

The increase in salary from 2007 to 2008 at $102,388 is not material and, on a net basis, is explained in its entirety by a cost of living increase of $60,000 and a progression increase of $45,000. This account group had fluctuations in employee numbers during this that essentially offset eachother. The explanation and justification for these changes in positions is provided earlier in this Schedule but the details of how that impacted the variance from 2007 to 2008 is described as follows:

- The Vice-President Client Services moved to Bluewater Power Generation Corporation as of January 1, 2008 and has not been replaced in 2008;
- The Executive Assistant to the Vice-President Client Services also moved as of January 1, 2008;
- IT Programmer only included for a few months in 2007 actual financials, but budgeted to be replaced in 2008.
- The Accounts Receivable Representative converted from contract to full-time in July 2007, resulting in an increase in salary and explaining part of the decrease in contract.
- As discussed above, more 2007 Payroll Related Costs were reallocated to Account 4380 in 2007 versus 2008. That primarily impacts the Operations account group, but also impacts Administration and explains approximately ($45,341) of this variance.

Contract Services

The $113,319 decrease in contract services from 2007 to 2008 is a result of one employee moving from contract to full time (the Accounts Receivable Analyst paid approximately $21,000 in 2007 on contract). In addition, Bluewater Power employed a Human Resources Administrator in 2007 on contract at a cost of $20,000 and that cost was not repeated in 2008. Finally, in response to the tremendous amount of non-utility work in 2007, the civil crew was supplemented utilizing contract staff at a cost of approximately $31,500. None of these costs were budgeted to continue in 2008.

Employee Costs

The variance in employee costs represents a decrease of $88,521 and has two primary drivers. Firstly, Bluewater Power introduced fire resistant clothing for its outside workforce in 2007 and there were significant start-up costs associated with that program that will not be repeated. Secondly, the variance is driven by the fact that training in 2007 was higher than 2008 due to efforts by the utility to cross-train its employees in 2007. Training remained a priority for the utility in 2008, but the focus in 2008 has been to employ co-op students whose training costs will be incurred in years beyond 2008.

Capitalized Labour

The increase in capitalized labour of $75,927 represents an allocation issue only. The Capitalization Policy in 2007 and 2008 were identical, and capitalization of management and overhead were similar. However, the 2008 capitalized labour was entirely allocated to Administration and General Expense, whereas the capitalized labour in 2007 was allocated with $57,550 going to Administration and General Expense, and the remaining $119,920 being allocated to Operations.

Table 4.2.3.15
Taxes Other than Income Tax

Account Grouping	2008 Projection	2007 Actual	Variance $
3950-Taxes Other Than Income Taxes	290,000	278,911	11,089

This account group includes costs related to property tax and capital tax. The variance in this account group is well below the materiality threshold.

2006 EDR vs. 2007 Variances

Table 4.2.3.16
2006 EDR vs. 2007 Variances

Account Grouping	2007 Actual	2006 EDR Approved	Var $
3500-Distribution Expenses – Operation	2,206,991	280,776	**1,926,215**
3550-Distribution Expenses – Maintenance	122,553	256,425	**(133,872)**
3650-Billing and Collecting	1,277,336	267,288	**1,010,048**
3700-Community Relations	94,640	189,005	**(94,365)**
3800-Administrative and General Expenses	5,213,650	8,187,189	**(2,973,539)**
3950-Taxes Other Than Income Taxes	278,911	139,687	**139,224**
TOTAL	**9,194,081**	**9,320,370**	**(126,289)**

Overall, the variance from 2006 EDR to 2007 Actual is a decrease in OM&A of $126,289. It is difficult to carry out a variance analysis on an Account Group basis for these years for a number of reasons:

(a) First and foremost, the accounting treatment from year-to-year was not consistent. As is clearly demonstrated in Table 4.2.3.16 above, all Payroll Related Costs in 2006 EDR went to the Administration and General Expenses account group thereby creating a negative variance with 2007 for that account group and positive variances for most other account groups.

(b) A further issue making comparison difficult is the fact that accounting for Non-Core Distribution Activities improved in 2007 so that comparisons with prior years are difficult. The result is that 2006 EDR is overstated in comparison to 2007 because costs are included in OM&A for 2006 EDR that are not included in 2007.

Given these challenges, Bluewater Power has presented the variance analysis at the Account Group only and we have provided comments below on the variance on a total basis.

One could point to the fact that OM&A decreased from 2006 EDR to 2007 Actual by $126,289 as a tremendous accomplishment for this utility in its effort to control costs. Given that 2006 EDR is based on 2004 Actual, the reduction in OM&A occurred despite the fact that employees received a 3% annual cost of living increase. Moreover, employee count increased by 8 FTEs over that period as shown in Exhibit 4, Tab 2, Schedule 9.

What is important to understand is that the increases in OM&A that Bluewater Power obviously experienced in that timeframe were offset .While gross OM&A was increasing steadily, distribution OM&A went down due to:

(1) Improved diligence in capturing capitalized labour.
(2) Improvements in reallocation: Prior to 2007 reallocation of costs to Account 4380 was inconsistent. Detailed methodology and improved diligence procedures were put in place in 2007, but 2006 was not corrected (and certainly not 2006 EDR which is based on 2004) as it has no real impact on ratepayers in this rate application.
(3) Increased Non-Core Distribution Activities: The 2006 EDR application included $777,324 in revenue offsets in the form of billable revenue, and it is likely that a significant portion of those revenues and associated costs related to Non-Core Distribution Activities. Nevertheless, 2007 was a significantly busier year.

The result of these three factors is that, while gross OM&A at Bluewater Power has steadily increased, the utility was able to control increases in distribution OM&A. The result of these factors (as discussed in greater detail in Exhibit 4, Tab 2, Schedule 1) is that 2007 is an atypical year.

Shared Services

Shared services can refer to either the sharing of employees or the sharing of assets owned by the utility to perform Non-Core Distribution Activities. Those Non-Core Distribution Activities have roughly the same benefit to ratepayers no matter how they are structured, but their structure falls within two distinct areas:

(1) Shared Services with Affiliates

Corporate services are provided by Bluewater Power to affiliates on a fully-allocated cost basis under service agreements in accordance with section 2.2.5.1 of the *Affiliates Relationship Code for Electricity Distributors and Transmitters (Amended, Effective May 16, 2008)*, (the "ARC"). In addition, certain affiliates rely upon assets owned by Bluewater Power and the utility charges for the use of those assets in accordance with the service agreements.

Section 2.3.4.2 of the ARC requires costs to be charged to an affiliate on a fully-allocated cost basis, and it is further directed that such charges shall include a return on the utility's invested capital.

The service agreements under which these shared services are provided to affiliates are found in Exhibit 4, Tab 2, Schedule 5 – Service Agreement(s). The revenues earned by Bluewater Power that are associated with these service agreements are discussed in Exhibit 3, Tab 3, Schedule 5 – Revenue from Affiliates.

(2) Shared Services used for Non-Core Distribution Activities

Shared costs related to salary and labour (including corporate services), as well as assets that are utilized in the provision of Non-Core Distribution Activities are allocated to Account 4380. The APH requires that the costs associated with the provision of Non-Core Distribution Activities shall be booked to Account 4380 – Expenses of Non-Utility Operations and "shall include all elements of costs incurred in such operations".

The shared services utilized in the provision of Non-Core Distribution Activities are discussed in detail in Exhibit 4, Tab 2, Schedule 7 – Non-Core Distribution Activities.

Bluewater Power applies the same methodology to determine appropriate charges for shared services whether those shared services are provided to an affiliate or are provided to perform Non-Core Distribution Activities. Section 2.3.4.2 of the ARC requires costs to be charged to an affiliate on a fully-allocated basis, and it is further directed that such charges shall include a return on the utility's invested capital. The direction for Non-Core Distribution Activities in Account 4380 does not include a detailed methodology to determine costs incurred in such operations, so Bluewater Power has chosen to follow the same methodology used for the calculation of shared services to affiliates. In other words, on a fully-allocated cost basis, including a return on the utility's invested capital.

The main costs elements are as follows:

(1) Shared Labour and Salary: Costs related to shared employees are charged/allocated on the basis of estimated labour multiplied by the hourly rate plus the direct costs of benefits (in the case of salaried employees, an hourly equivalent is utilized);

(2) Direct Labour: Where an employee is dedicated to Non-Core Distribution Activities for all, or a significant portion of the year, costs are charged/allocated on the basis of a percentage of full annual cost (salary or labour) plus the direct costs of benefits.

(3) Building overhead: is charged/allocated on the basis of square footage in order to recover the return on invested capital and operating costs with respect to the asset.

(4) Use of Capital: is charged/allocated on the basis of a return on the original invested capital.

(5) Vehicles: are charged/allocated on the basis of hours used multiplied by an hourly rate representing the fully allocated cost reduced to an hourly equivalent.

(6) Other Direct Costs: Include the actual cost of service, and include items such as material and equipment, which is charged/allocated on an actual cost basis.

Service Agreement(s)

Exhibit 4, Tab 2, Schedule 5, Attachment 1 is the Services Agreement between Bluewater Power Distribution Corporation and Bluewater Power Generation Corporation and Blackwell Renewable Energy Inc.

Exhibit 4, Tab 2, Schedule 5, Attachment 2 is the Services Agreement between Bluewater Power Distribution Corporation and Electek Power Services Inc.

SERVICES AGREEMENT

THIS SERVICES AGREEMENT is made as of the 1st day of JANUARY, 2008

BETWEEN:

BLUEWATER POWER GENERATION CORPORATION, a corporation incorporated pursuant to the laws of the Province of Ontario

(referred to as "BW Generation" after this)

- and -

BLACKWELL RENEWABLE ENERGY INC., a corporation incorporated pursuant to the laws of the Province of Ontario

(referred to as "Blackwell" after this
and/or
(referred to collectively as "**Affiliates**")

- and –

BLUEWATER POWER DISTRIBUTION CORPORATION, a corporation incorporated pursuant to the laws of the Province of Ontario

(referred to as "BWP Distribution" after this)

WHEREAS:

1. Each of the Parties to this Agreement are corporations incorporated under the *Business Corporations Act* (Ontario);

2. BWP Distribution carries on the business of distributing electricity within the City of Sarnia, the Town of Petrolia, the Village of Point Edward, the Village of Oil Springs, the Township of Brooke-Alvinston, and the Township of Warwick; and

3. BWP Distribution agrees to provide certain services to the Affiliates on the terms as set forth in this Agreement.

NOW THEREFORE in consideration of the mutual covenants contained in this Agreement and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

ARTICLE 1 – INTERPRETATION

1.1 Definitions

Unless the context otherwise specifies or requires, for the purposes of this Agreement all capitalized terms herein shall have the meanings set forth below

(a) **"Agreement"** means this Services Agreement together with all Schedules attached to it, as they may be amended from time to time;

(b) **"Business Day"** means any day other than a Saturday, Sunday, statutory or bank holiday in the Province of Ontario;

(c) **"Claim"** has the meaning ascribed to it in **Section 4.4**;

(d) **"Confidential Information"** means information BWP Distribution has obtained relating to a specific consumer, retailer or generator in the process of providing current or prospective distribution service;

(e) **"Defaulting Party"** has the meaning ascribed to it in **Section 8.1**;

(f) **"Effective Date"** means JANUARY 1, 2008;

(g) **"Event of Default"** has the meaning described to it in **Section 8.1**;

(h) **"Force Majeure Event"** has the meaning ascribed to it in **Section 11.1;**

(i) **"IESO"** means the Independent Electricity System Operator;

(j) **"Law"** means any law, rule, regulation, code, order, writ, judgement, decree or other legal or regulatory determination by a court, regulatory agency, including the IESO, or governmental authority of competent jurisdiction;

(k) **"Party"** means a party to this Agreement and "Parties" means every party;

(l) **"Person"** means an individual, corporation, partnership, joint venture, association, trust, pension fund, union, governmental agency, official, board, tribunal, ministry, commission or department;

(m) **"Personnel"** means employees, agents, professional advisors, contractors and subcontractors;

(n) **"Prime Rate"** means, for any day, an annual rate of interest equal to the rate of interest which BWP Distribution's principal bank establishes at its principal office in Toronto as the reference rate of interest to determine interest rates that it will charge on such day for commercial loans in Canadian dollars made to its customers in Canada and which it refers to as its "prime rate of interest";

(o) **"Services"** are Services that are provided under **Section 3.1** of this Agreement;

(p) **"Term"** has the meaning ascribed to it in **Section 2.1** of this Agreement; and

(q) **"Third Party Expenses"** means all fees, costs and charges paid to third parties by BWP Distribution on behalf of an Affiliate in connection with providing the Services or incurred by BWP Distribution's employees while providing Services under this agreement.

1.2 **Construction of Agreement**

In this Agreement:

(a) words denoting the singular include the plural and vice versa and words denoting any gender include all genders;

(b) all usage of the word "including" or the phrase "e.g.," in this Agreement shall mean "including, without limitation," throughout this Agreement;

(c) any reference to a statute shall mean the statute in force as at the date hereof, together with all regulations promulgated under it, as the same may be amended, re-enacted, consolidated or replaced, from time to time, and any successor statute, unless otherwise expressly provided;

(d) any reference to a specific executive position or an internal division or department of a Party shall include any successor positions, divisions or departments having substantially the same responsibilities or performing substantially the same functions;

(e) when calculating the period of time within which or following which any act is to be done or step taken, the date which is the reference day in calculating such period shall be excluded, and if the last day of such period is not a Business Day, the period shall end on the next Business Day;

(f) all dollar amounts are expressed in Canadian dollars;

(g) the division of this Agreement into separate Articles, Sections, subsections and Schedules and the insertion of headings is for convenience of reference only and shall not affect the construction or interpretation of this Agreement;

(h) words or abbreviations which have well known or trade meanings are used in accordance with their recognized meanings;

(i) the terms and conditions are the result of negotiations between the Parties and the Parties therefore agree that this Agreement shall not be construed in favour of or against any Party by reason of the extent to which any Party or its professional advisors participated in the preparation of this Agreement.

ARTICLE 2 – TERM

2.1 Term

Unless terminated in accordance with **Section 10.1** of this Agreement, this Agreement shall come into force on the Effective Date and shall continue in full force and effect for a period of five (5) years and the term shall be automatically extended for a further period of one (1) year unless a Party gives notice in writing that the Agreement is not to be extended, as it relates to that Party, on a date which is at least ninety (90) days prior to the end of the term, or the end of renewal as the case may be.

ARTICLE 3 – BWP DISTRIBUTION SERVICES AND COVENANTS

3.1 Services

Subject to the terms, covenants and conditions contained in this Agreement, BWP Distribution will provide, or cause to be provided, to the Affiliates the services set out in **Schedule "A"** (collectively the **"Services"**), as may be required by the Affiliates.

3.2 Service Standards

Subject to the terms, covenants and conditions contained in this Agreement, BWP Distribution will provide the Services to the Affiliates, or cause them to be provided, to the standards set out in **Schedule "B"** (collectively the **"Service Standards").**

3.3 Changes

The Affiliates, collectively or individually and BWP Distribution may, from time to time, agree to modifications to a Service or a Service Standard by negotiating appropriate changes to the descriptions of the Service on the Service Standard and the consideration in connection with such changes and shall initial and attach amended schedules in this Agreement.

3.4 General BWP Distribution Covenants

(a) BWP Distribution shall be responsible for obtaining all necessary licences and permits and for complying with all applicable federal, provincial and municipal laws, codes and regulations in connection with the provision of the Services and BWP Distribution shall,

when requested, provide an Affiliate with adequate evidence of its compliance with this **Section 3.4**;

(b) BWP Distribution shall, while on the premises used by an Affiliate, comply with all the rules and regulations of the Affiliate from time to time in force, which are brought to its notice or of which it could reasonably be aware;

(c) BWP Distribution shall pay for and maintain for the benefit of BWP Distribution appropriate insurance concerning the operations and liabilities of BWP Distribution relevant to this Agreement including, without limiting the generality of the foregoing, workers' compensation and employment insurance in conformity with applicable statutory requirements in respect of any remuneration payable by BWP Distribution to any employees of BWP Distribution and public liability and property damage insurance;

3.5 Regulatory Change

If any change of Law after the date of this Agreement renders this Agreement illegal or unenforceable, then the Parties shall be required to renegotiate in good faith for thirty (30) days with a goal of developing a substitute agreement with such amendments as are necessary to comply with such change of Law.

ARTICLE 4 – MUTUAL COVENANTS

4.1 Confidentiality of Confidential Information

No Personnel of a Party shall have access to any Confidential Information in the possession of another Party, except for purposes related to the Services and in compliance with the Affiliate Relationship Code for Electricity Distributors and Transmitters prescribed by the Ontario Energy Board.

4.2 Maintain Records

The Parties will maintain such records as may be necessary in connection with this Agreement and as are agreed upon by the Parties acting reasonably.

4.3 Notification of Changes of Circumstances

BWP Distribution shall promptly give written notice to an Affiliate of any changes or prospective changes in circumstances that would materially affect the resources required for the Services provided to the Affiliate, including any anticipated material change in the nature or level of business of BWP Distribution, the number of employees of BWP Distribution, or any efforts relating to the organization of or collective bargaining by employees of BWP Distribution, or any lease or service arrangements contemplated with any third parties.

4.4 Notice of Claims, Etc.

BWP Distribution shall promptly give written notice to the Affiliates, and an Affiliate shall promptly give written notice to BWP Distribution, of all material claims, proceedings, notice of regulatory non-compliance from any regulatory authority, disputes (including labour disputes) or litigation (collectively, **"Claims"**) which it reasonably believes could have a material adverse effect on the fulfillment of any of the material terms hereof by BWP Distribution or the Affiliate (whether or not any such Claim is covered

by insurance) in respect of its own operations of which any of them is aware. Each Party shall provide the other Party with all information reasonably requested from time to time concerning the status of such Claims and any developments relating thereto.

ARTICLE 5 – FEES AND COSTS

5.1 Fees

(a) The Affiliates shall pay to BWP Distribution the fees and charges set out in **Schedule "C"** for services received from BWP Distribution.

5.2 Taxes

In addition to the fees, the Affiliates shall pay to BWP Distribution an amount equal to any and all goods and services taxes, sales taxes, value-added taxes or any other taxes (excluding income taxes) properly eligible on the supply of services provided by a third party under this Agreement.

ARTICLE 6 – REPRESENTATIONS AND WARRANTIES

6.1 Representations and Warranties of BWP Distribution

BWP Distribution represents and warrants to the Affiliates as follows and acknowledges that the Affiliates are relying on such representations and warranties:

(a) BWP Distribution is a corporation, duly incorporated, validly existing and in good standing under the laws of the Province of Ontario and it has the rights, powers and privileges to execute and deliver this Agreement and to perform its obligations hereunder;

(b) the execution, delivery and performance of this Agreement has been duly authorized by all necessary corporate action;

(c) this Agreement constitutes a legal, valid and binding obligation of BWP Distribution, enforceable against BWP Distribution by the Affiliates in accordance with its terms; and

(d) BWP Distribution has the necessary resources and expertise to acquire or perform the Services.

6.2 Representations and Warranties of the Affiliates

Each Affiliate represents and warrants to BWP Distribution as follows and acknowledges that BWP Distribution is relying on such representations and warranties:

(a) the Affiliate is a company, duly organized, validly existing and in good standing under the laws of the Province of Ontario and it has the rights, powers and privileges to execute and deliver this Agreement and to perform its obligations hereunder;

(b) the execution, delivery and performance of this Agreement has been duly authorized by all necessary corporate actions; and

(c) this Agreement constitutes a legal, valid and binding obligation of the Affiliate, enforceable against the Affiliate by BWP Distribution in accordance with its terms.

6.3 **Warranty**

(a) BWP Distribution warrants that the work and services it provides will be performed in a professional and workman like manner subject to Section 6.3(b) below. BWP Distribution warrants that any fault or defect due solely or indirectly to workmanship of BWP Distribution shall be corrected as soon as is reasonably possible upon notification by the affected Affiliate at no cost to the Affiliate;

(b) in respect of BWP Distribution workmanship, this warranty period shall extend to a defect or failure occurring within 90 days of the date that the original Work was completed.

ARTICLE 7 – INDEMNIFCATION

7.1 **Indemnification**

(a) Each Affiliate shall indemnify, defend and hold harmless BWP Distribution, its officers, directors, and employees (each a **"BWP Distribution Indemnitee")** from and against any and all claims, demands, suits, losses, liabilities, damages, obligations, payments, costs and expenses and accrued interest thereon (including the costs and expenses of, and accrued interest in respect of, any and all actions, suits, proceedings, assessments, judgements, awards, settlements and compromises relating thereto and reasonable lawyers' fees and reasonable disbursements in connection therewith) (each an **"Indemnifiable Loss"),** asserted against or suffered by any BWP Distribution Indemnitee relating to, or in connection with, or resulting from or arising out of the provision of the Services to that Affiliate.

(b) BWP Distribution shall be deemed to hold the provisions of **Section 7.1(a)** that are for the benefit of the BWP Distribution Indemnitees that are not party to this Agreement in trust for such persons as third party beneficiaries under this Agreement.

7.2 **Limit of Liability**

(a) Each Affiliate agrees that BWP Distribution liability, if any, to that Affiliate or any third party in connection with or arising under this Agreement, including without limitation, any liability arising from any act or omission of BWP Distribution in the provision of the Services, whether arising in contract, tort, equity or otherwise, shall be limited to actions or liabilities resulting solely from the fraud or wilful misconduct of BWP Distribution in the provision of the Services and shall not exceed an amount equal to the total amount paid by that Affiliate to BWP Distribution under this Agreement for Services over the twelve month period preceding the date that the cause of action or claim giving rise to the liability first arose.

(b) BWP Distribution shall not be liable for any damages caused by delay in delivering or furnishing any Services referred to in this Agreement.

7.3 Notwithstanding anything else to the contrary in this Agreement, the Parties agree that BWP Distribution shall not be responsible for any sanctions, fines, penalties, or similar obligations imposed on an Affiliate, and each Affiliate agrees to indemnify and hold harmless BWP Distribution from any such sanctions fines, penalties or similar obligations.

ARTICLE 8 – DEFAULT

8.1 Events of Default

The occurrence of any one or more of the following events shall constitute a Default by a Party (the **"Defaulting Party"**) under this Agreement and shall constitute an Event of Default if such Default is not remedied prior to the expiry of any notice period and any cure period applicable to such Default:

(a) if the Defaulting Party defaults in the payment of any amount due to the other Party under this Agreement and such default shall continue unremedied for sixty (60) days following notice in writing thereof to the Defaulting Party by the other Party; and

(b) if the Defaulting Party fails in any material respect to perform or observe any of its other material obligations under this Agreement and such failure shall continue unremedied for a period of sixty (60) days following notice in writing thereof (giving particulars of the failure in reasonable detail) from the other Party to the Defaulting Party or such longer period as may be reasonably necessary to cure such failure (if such failure is capable of being cured), provided that the Defaulting Party:

(i) proceeds with all due diligence to cure or cause to be cured such failure; and

(ii) in proceeding so, can be reasonably expected to cure or cause to be cured such failure within a reasonable time frame acceptable to the other Party acting reasonably.

ARTICLE 9 – REMEDIES

9.1 Default Remedies

(a) Unless otherwise agreed to in writing, in the event of an Event of Default the non-defaulting Party may terminate this Agreement as it relates to the non-defaulting Party upon notice in writing and all amounts payable by the defaulting Party hereunder shall become due and payable forthwith;

(b) The remedies in this section are expressly in lieu of any or all of the remedies which may be available to each of BWP Distribution and an Affiliate in respect of or under this Agreement resulting from the furnishing, the failure to furnish or the quality of any Services.

ARTICLE 10 – TERMINATION

10.1 Termination

This Agreement shall terminate:

(a) In accordance with the provisions of **Section 9.1**; or

(b) upon issuance of a notice of non-renewal in accordance with **Section 2.1**.

10.2 Notice of Termination

Any termination hereof pursuant to Section 10.1 shall be by written notice of the terminating Party.

ARTICLE 11 – GENERAL

11.1 Force Majeure

No Party shall be liable for a failure or delay in the performance of its obligations pursuant to this Agreement:

(a) provided that such failure or delay could not have been prevented by reasonable precautions;

(b) provided that such failure or delay cannot reasonably be circumvented by the non-performing Party through the use of alternate sources, work around plans or other means; and

(c) if and to the extent such failure or delay is caused, directly or indirectly, by fire, flood, earthquake, elements of nature or acts of God, acts of war, terrorism, riots, civil disorders, rebellions, strikes, lock outs or labour disruptions or revolutions in Canada, or any other similar causes beyond the reasonable control of such Party, (each a "**Force Majeure Event**").

Upon the occurrence of a Force Majeure Event, the non-performing Party shall be excused from any further performance of those of its obligations pursuant to this Agreement affected by the Force Majeure Event only for so long as:

(a) such Force Majeure Event continues; and

(b) such Party continues to use commercially reasonable efforts to recommence performance whenever and to whatever extent possible without delay.

The Party delayed by a Force Majeure Event shall:

(a) immediately notify the other Parties by telephone (to be confirmed in writing within five (5) days of the inception of such delay) of the occurrence of a Force Majeure Event; and

(b) describe in reasonable detail the circumstances causing the Force Majeure Event.

11.2 **Dispute Resolution**

If any dispute arising in relation to an event of default under **Section 8.1(b)** or its implementation of **Section 8.1(b)** cannot be resolved by negotiation between the two disputing Parties, then the dispute shall be referred to one arbitrator agreeable to and appointed by both Parties to the dispute. If the Parties cannot agree on one arbitrator, the matter in dispute shall be referred to a panel of three arbitrators, one of which shall be appointed by BWP Distribution, one appointed by the Affiliate in the dispute and the third appointed by the two arbitrators selected by the disputing Parties. The arbitrator or arbitrators shall receive such oral and written evidence as may be required to investigate the matter in dispute and to render a decision and shall be guided by this Agreement and the intent of this Agreement. The decision of the arbitrator or arbitrators shall be provided in writing to the disputing Parties no later than thirty (30) days after the sole arbitrator or the third arbitrator has been appointed. The decision of the arbitrator or arbitrators shall be final and binding on the disputing Parties.

11.3 **Assignment**

No Party shall, without the written consent of the other Parties, which may be arbitrarily withheld in the sole discretion of a Party, assign or transfer its interest in this Agreement. This Agreement shall be binding on the Parties and their respective successors and permitted assigns. Any purported assignment in contravention of this Agreement shall be void.

11.4 **Notices**

All notices, request, approvals, consents and other communications required or permitted under this Agreement shall be in writing and addressed as follows:

(a) If to the Affiliates,

5100 Blackwell Side Road
Sarnia, ON N7T 7H3
Attn: Tim Vanderheide, Chief Operating Officer
Fax: 519-344-6094

(b) if to BWP Distribution,

P.O. Box 2140
855 Confederation St.
Sarnia, ON N7T 7L6
Attn: Alex Palimaka, Vice President Corporate Services & General Counsel
Fax: 519-344-6094

and shall be sent by fax and the Party sending such notice shall telephone to confirm receipt. A copy of any such notice shall also be sent on the date such notice is transmitted by fax by registered express mail or courier with the capacity to verify receipt of delivery. Any Party may change its address or fax number for notification purposes by giving the other Party notice of the new

address or fax number and the date upon which it will become effective in accordance with the terms of this Agreement. A notice shall be deemed to have been received as of the next Business Day following its transmission by fax.

11.5 Severability

If any provision of this Agreement is held by a court of competent jurisdiction to be unenforceable or contrary to law, then the remaining provisions of this Agreement, or the application of such provisions to persons or circumstances other than those as to which it is invalid or unenforceable shall not be affected thereby, and each such provision of this Agreement shall be valid and enforceable to the extent granted by law. If any clause is deemed unenforceable or contrary to law, the parties shall alter the said clause and this agreement to produce enforceability or compliance with law such that the intent of the original clause is maintained and such change or alteration may be established through the dispute resolution clause in this agreement.

11.6 Waiver

No delay or omission by a Party to exercise any right or power it has under this Agreement or to object to the failure of any covenant of any other Party to be performed in a timely and complete manner, shall impair any such right or power or be construed as a waiver of any succeeding breach or any other covenant. All waivers must be in writing and signed by the Party waiving its rights

11.7 Entire Agreement

This Agreement supercedes any prior agreement between BWP Distribution and any of the Affiliates in relation to the Services provided for in this Agreement, and constitutes the entire Agreement between the Parties with respect to the Services, and there are no other representations, understandings or agreements, either oral or written, between the Parties other than as set out in this Agreement.

11.8 Amendments

No amendment to, or change, waiver or discharge of, any provision of this Agreement shall be valid unless in writing and signed by authorized representatives of each Party.

11.9 Governing Law

This Agreement shall be governed by the laws of the Province of Ontario and the laws of Canada applicable therein. The Parties hereby agree that the courts of the Province of Ontario shall have exclusive jurisdiction over disputes under this Agreement, and the Parties agree that jurisdiction and venue in such courts is appropriate and irrevocably attorn to the jurisdiction of such courts.

11.10 Survival

The terms of **Article** 7, **Article 9** and **Article 11** shall survive the expiration of this Agreement or termination of this Agreement for any reason.

11.11 **Third Party Beneficiaries**

Each Party intends that this Agreement shall not benefit or create any right or cause of action in or on behalf of any person or entity other than the Parties.

11.12 **Covenant of Further Assurances**

The Parties agree that, subsequent to the execution and delivery of this Agreement and without any additional consideration, the Parties shall execute and deliver or cause to be executed and delivered any further legal instruments and perform any acts which are or may become necessary to effectuate the purposes of this Agreement and to complete the transactions contemplated under it.

IN WITNESS WHEREOF this Agreement has been executed by the duly authorized signatories of the parties hereto as of the date first written above.

BLUEWATER POWER GENERATION CORPORATION

Per: _____

Name: Tim Vanderheide
Title: Chief Operating Officer

Per: _____

Name:
Title:

BLACKWELL RENEWABLE ENERGY INC.

Per: _____

Name: Tim Vanderheide
Title: Chief Operating Officer

Per: _____

Name:
Title:

BLUEWATER POWER DISTRIBUTION CORPORATION

Per: _____

Name: Alex Palimaka
Title: Vice President Corporate Services & General Counsel

Per: _____

Name:
Title:

SCHEDULE A

Description of Services

1. **"Finance Services"**, if any, will include treasury services, controllership services and audit services.

   (a) Treasury services will include financing, i.e., cash flow management and investment of funds, banking, financial guarantees, ie: letters of credit, bonds, prudentials, payroll services, accounts payable services, account receivables, office services, obtaining and maintaining credit ratings, Securities Commission reporting, management of customer deposits, interest and T5 reporting, taxation (PILs), GST and PST remittances and corporate VISA card.

   (b) Controllership services will include financial systems, financial processes, policies and procedures, financial controls and compliance, financial reporting and analysis, annual budgets, financial operations, billing, collecting, capitalization and depreciation, WIP and inventory, labour charging, allocations and burdens, managing external audit, risk and contract management, insurance programs, liability, D&O, fleet, facilities, OEB reporting, incentive plan reporting, billing system quality control.

   (c) Audit services will include risk management audit reports to Audit Committee and Board of Directors.

2. **"Corporate Support Services"**, if any, will include human resources services, IT services, safety services and new services.

   (a) Human resources services will include programming and consulting including recruitment, compensation and benefits, employee relations, labour relations.

   (b) IT services will include personal computer systems support and communications support.

   (c) Safety services will include safety program development, monitoring, reporting, implementation and support.

   (d) New support services will include such new services as may be agreed upon by the parties from time to time with a price to be negotiated at that time.

SCHEDULE B

Description of Service Standards

Service Standards

(a) BWP DISTRIBUTION will adhere to industry standards, based on standards set by the WSIB, Electric Utility Safety Association, and Occupational Health & Safety Standards as applicable and in any case shall perform the Services in a good and workmanlike manner and to a standard of performance that a competent professional and diligent independent provider of the services in the same circumstances would reasonably be expected to provide.

(b) BWP DISTRIBUTION will make all reasonable efforts to meet or exceed performance measures established by the Ontario Energy Board, Measurement Canada and by the IESO.

SCHEDULE C

Fees & Charges

	SERVICES	FEES	PERIOD OF FEE
1.	**Finance Services**	Cost	Monthly
2.	**Corporate Support Services**	Cost	Monthly

Terms & Conditions		
1	Prices	Subject to Applicable Taxes
2	Payment	Monthly invoice, Net 30 days
3	Cost	Shall mean BWP Distribution's fully allocated cost to provide the Services.

SERVICES AGREEMENT

THIS SERVICES AGREEMENT is made as of the 1st day of JANUARY, 2008

BETWEEN:

ELECTEK POWER SERVICES INC., a corporation incorporated pursuant to the laws of the Province of Ontario

(referred to as "Electek" after this)

- and –

BLUEWATER POWER DISTRIBUTION CORPORATION, a corporation incorporated pursuant to the laws of the Province of Ontario

(referred to as "BWP Distribution" after this)

WHEREAS:

1. Each of the Parties to this Agreement are corporations incorporated under the *Business Corporations Act* (Ontario);

2. BWP Distribution carries on the business of distributing electricity within the City of Sarnia, the Town of Petrolia, the Village of Point Edward, the Village of Oil Springs, the Township of Brooke-Alvinston, and the Township of Warwick; and

3. BWP Distribution agrees to provide certain services to Electek on the terms as set forth in this Agreement.

NOW THEREFORE in consideration of the mutual covenants contained in this Agreement and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

ARTICLE 1 – INTERPRETATION

1.1 Definitions

Unless the context otherwise specifies or requires, for the purposes of this Agreement all capitalized terms herein shall have the meanings set forth below

(a) **"Agreement"** means this Services Agreement together with all Schedules attached to it, as they may be amended from time to time;

(b) **"Business Day"** means any day other than a Saturday, Sunday, statutory or bank holiday in the Province of Ontario;

(c) **"Claim"** has the meaning ascribed to it in **Section 4.4**;

(d) **"Confidential Information"** means information BWP Distribution has obtained relating to a specific consumer, retailer or generator in the process of providing current or prospective distribution service;

(e) **"Defaulting Party"** has the meaning ascribed to it in **Section 8.1**;

(f) **"Effective Date"** means JANUARY 1, 2008;

(g) **"Event of Default"** has the meaning described to it in **Section 8.1**;

(h) **"Force Majeure Event"** has the meaning ascribed to it in **Section 11.1;**

(i) **"IESO"** means the Independent Electricity System Operator;

(j) **"Law"** means any law, rule, regulation, code, order, writ, judgement, decree or other legal or regulatory determination by a court, regulatory agency, including the IESO, or governmental authority of competent jurisdiction;

(k) **"Party"** means a party to this Agreement and "Parties" means every party;

(l) **"Person"** means an individual, corporation, partnership, joint venture, association, trust, pension fund, union, governmental agency, official, board, tribunal, ministry, commission or department;

(m) **"Personnel"** means employees, agents, professional advisors, contractors and subcontractors;

(n) **"Prime Rate"** means, for any day, an annual rate of interest equal to the rate of interest which BWP Distribution's principal bank establishes at its principal office in Toronto as the reference rate of interest to determine interest rates that it will charge on such day for commercial loans in Canadian dollars made to its customers in Canada and which it refers to as its "prime rate of interest";

(o) **"Services"** are Services that are provided under **Section 3.1** of this Agreement;

(p) **"Term"** has the meaning ascribed to it in **Section 2.1** of this Agreement; and

(q) **"Third Party Expenses"** means all fees, costs and charges paid to third parties by BWP Distribution on behalf of an Affiliate in connection with providing the Services or incurred by BWP Distribution's employees while providing Services under this agreement.

1.2 Construction of Agreement

In this Agreement:

(a) words denoting the singular include the plural and vice versa and words denoting any gender include all genders;

(b) all usage of the word "including" or the phrase "e.g.," in this Agreement shall mean "including, without limitation," throughout this Agreement;

(c) any reference to a statute shall mean the statute in force as at the date hereof, together with all regulations promulgated under it, as the same may be amended, re-enacted, consolidated or replaced, from time to time, and any successor statute, unless otherwise expressly provided;

(d) any reference to a specific executive position or an internal division or department of a Party shall include any successor positions, divisions or departments having substantially the same responsibilities or performing substantially the same functions;

(e) when calculating the period of time within which or following which any act is to be done or step taken, the date which is the reference day in calculating such period shall be excluded, and if the last day of such period is not a Business Day, the period shall end on the next Business Day;

(f) all dollar amounts are expressed in Canadian dollars;

(g) the division of this Agreement into separate Articles, Sections, subsections and Schedules and the insertion of headings is for convenience of reference only and shall not affect the construction or interpretation of this Agreement;

(h) words or abbreviations which have well known or trade meanings are used in accordance with their recognized meanings;

(i) the terms and conditions are the result of negotiations between the Parties and the Parties therefore agree that this Agreement shall not be construed in favour of or against any Party by reason of the extent to which any Party or its professional advisors participated in the preparation of this Agreement.

ARTICLE 2 – TERM

2.1 Term

Unless terminated in accordance with **Section 10.1** of this Agreement, this Agreement shall come into force on the Effective Date and shall continue in full force and effect for a period of five (5) years and the term shall be automatically extended for a further period of one (1) year unless a Party gives notice in writing that the Agreement is not to be extended, as it relates to that Party, on a date which is at least ninety (90) days prior to the end of the term, or the end of renewal as the case may be.

ARTICLE 3 – BWP DISTRIBUTION SERVICES AND COVENANTS

3.1 Services

Subject to the terms, covenants and conditions contained in this Agreement, BWP Distribution will provide, or cause to be provided, to Electek the services set out in **Schedule "A"** (collectively the **"Services"**), as may be required by Electek.

3.2 Service Standards

Subject to the terms, covenants and conditions contained in this Agreement, BWP Distribution will provide the Services to Electek, or cause them to be provided, to the standards set out in **Schedule "B"** (collectively the **"Service Standards").**

3.3 Changes

Electek and BWP Distribution may, from time to time, agree to modifications to a Service or a Service Standard by negotiating appropriate changes to the descriptions of the Service on the Service Standard and the consideration in connection with such changes and shall initial and attach amended schedules in this Agreement.

3.4 General BWP Distribution Covenants

(a) BWP Distribution shall be responsible for obtaining all necessary licences and permits and for complying with all applicable federal, provincial and municipal laws, codes and regulations in connection with the provision of the Services and BWP Distribution shall,

when requested, provide an Affiliate with adequate evidence of its compliance with this **Section 3.4**;

(b) BWP Distribution shall, while on the premises used by an Affiliate, comply with all the rules and regulations of the Affiliate from time to time in force, which are brought to its notice or of which it could reasonably be aware;

(c) BWP Distribution shall pay for and maintain for the benefit of BWP Distribution appropriate insurance concerning the operations and liabilities of BWP Distribution relevant to this Agreement including, without limiting the generality of the foregoing, workers' compensation and employment insurance in conformity with applicable statutory requirements in respect of any remuneration payable by BWP Distribution to any employees of BWP Distribution and public liability and property damage insurance;

3.5 Regulatory Change

If any change of Law after the date of this Agreement renders this Agreement illegal or unenforceable, then the Parties shall be required to renegotiate in good faith for thirty (30) days with a goal of developing a substitute agreement with such amendments as are necessary to comply with such change of Law.

ARTICLE 4 – MUTUAL COVENANTS

4.1 Confidentiality of Confidential Information

No Personnel of a Party shall have access to any Confidential Information in the possession of another Party, except for purposes related to the Services and in compliance with the Affiliate Relationship Code for Electricity Distributors and Transmitters prescribed by the Ontario Energy Board.

4.2 Maintain Records

The Parties will maintain such records as may be necessary in connection with this Agreement and as are agreed upon by the Parties acting reasonably.

4.3 Notification of Changes of Circumstances

BWP Distribution shall promptly give written notice to an Affiliate of any changes or prospective changes in circumstances that would materially affect the resources required for the Services provided to the Affiliate, including any anticipated material change in the nature or level of business of BWP Distribution, the number of employees of BWP Distribution, or any efforts relating to the organization of or collective bargaining by employees of BWP Distribution, or any lease or service arrangements contemplated with any third parties.

4.4 Notice of Claims, Etc.

BWP Distribution shall promptly give written notice to Electek, and Electek shall promptly give written notice to BWP Distribution, of all material claims, proceedings, notice of regulatory non-compliance from any regulatory authority, disputes (including labour disputes) or litigation (collectively, **"Claims"**) which it reasonably believes could have a material adverse effect on the fulfillment of any of the material terms hereof by BWP Distribution or Electek (whether or not any such Claim is covered by insurance) in

respect of its own operations of which any of them is aware. Each Party shall provide the other Party with all information reasonably requested from time to time concerning the status of such Claims and any developments relating thereto.

ARTICLE 5 – FEES AND COSTS

5.1 Fees

(a) Electek shall pay to BWP Distribution the fees and charges set out in **Schedule "C"** for services received from BWP Distribution.

5.2 Taxes

In addition to the fees, Electek shall pay to BWP Distribution an amount equal to any and all goods and services taxes, sales taxes, value-added taxes or any other taxes (excluding income taxes) properly eligible on the supply of services provided by a third party under this Agreement.

ARTICLE 6 – REPRESENTATIONS AND WARRANTIES

6.1 Representations and Warranties of BWP Distribution

BWP Distribution represents and warrants to Electek as follows and acknowledges that Electek are relying on such representations and warranties:

(a) BWP Distribution is a corporation, duly incorporated, validly existing and in good standing under the laws of the Province of Ontario and it has the rights, powers and privileges to execute and deliver this Agreement and to perform its obligations hereunder;

(b) the execution, delivery and performance of this Agreement has been duly authorized by all necessary corporate action;

(c) this Agreement constitutes a legal, valid and binding obligation of BWP Distribution, enforceable against BWP Distribution by Electek in accordance with its terms; and

(d) BWP Distribution has the necessary resources and expertise to acquire or perform the Services.

6.2 Representations and Warranties of Electek

Elecek warrants to BWP Distribution as follows and acknowledges that BWP Distribution is relying on such representations and warranties:

(a) Electek is a company, duly organized, validly existing and in good standing under the laws of the Province of Ontario and it has the rights, powers and privileges to execute and deliver this Agreement and to perform its obligations hereunder;

(b) the execution, delivery and performance of this Agreement has been duly authorized by all necessary corporate actions; and

(c) this Agreement constitutes a legal, valid and binding obligation of Electek, enforceable against the Affiliate by BWP Distribution in accordance with its terms.

6.3 Warranty

(a) BWP Distribution warrants that the work and services it provides will be performed in a professional and workman like manner subject to Section 6.3(b) below. BWP Distribution warrants that any fault or defect due solely or indirectly to workmanship of BWP Distribution shall be corrected as soon as is reasonably possible upon notification by the affected Affiliate at no cost to the Affiliate;

(b) in respect of BWP Distribution workmanship, this warranty period shall extend to a defect or failure occurring within 90 days of the date that the original Work was completed.

ARTICLE 7 – INDEMNIFCATION

7.1 Indemnification

(a) Eelctek shall indemnify, defend and hold harmless BWP Distribution, its officers, directors, and employees (each a **"BWP Distribution Indemnitee")** from and against any and all claims, demands, suits, losses, liabilities, damages, obligations, payments, costs and expenses and accrued interest thereon (including the costs and expenses of, and accrued interest in respect of, any and all actions, suits, proceedings, assessments, judgements, awards, settlements and compromises relating thereto and reasonable lawyers' fees and reasonable disbursements in connection therewith) (each an **"Indemnifiable Loss"),** asserted against or suffered by any BWP Distribution Indemnitee relating to, or in connection with, or resulting from or arising out of the provision of the Services to Electek.

(b) BWP Distribution shall be deemed to hold the provisions of **Section 7.1(a)** that are for the benefit of the BWP Distribution Indemnitees that are not party to this Agreement in trust for such persons as third party beneficiaries under this Agreement.

7.2 Limit of Liability

(a) Electek agrees that BWP Distribution liability, if any, to Electek or any third party in connection with or arising under this Agreement, including without limitation, any liability arising from any act or omission of BWP Distribution in the provision of the Services, whether arising in contract, tort, equity or otherwise, shall be limited to actions or liabilities resulting solely from the fraud or wilful misconduct of BWP Distribution in the provision of the Services and shall not exceed an amount equal to the total amount paid by Eelctek to BWP Distribution under this Agreement for Services over the twelve month period preceding the date that the cause of action or claim giving rise to the liability first arose.

(b) BWP Distribution shall not be liable for any damages caused by delay in delivering or furnishing any Services referred to in this Agreement.

7.3 Notwithstanding anything else to the contrary in this Agreement, the Parties agree that BWP Distribution shall not be responsible for any sanctions, fines, penalties, or similar obligations imposed on Electek, and Eelctek agrees to indemnify and hold harmless BWP Distribution from any such sanctions fines, penalties or similar obligations.

ARTICLE 8 – DEFAULT

8.1 Events of Default

The occurrence of any one or more of the following events shall constitute a Default by a Party (the **"Defaulting Party"**) under this Agreement and shall constitute an Event of Default if such Default is not remedied prior to the expiry of any notice period and any cure period applicable to such Default:

(a) if the Defaulting Party defaults in the payment of any amount due to the other Party under this Agreement and such default shall continue unremedied for sixty (60) days following notice in writing thereof to the Defaulting Party by the other Party; and

(b) if the Defaulting Party fails in any material respect to perform or observe any of its other material obligations under this Agreement and such failure shall continue unremedied for a period of sixty (60) days following notice in writing thereof (giving particulars of the failure in reasonable detail) from the other Party to the Defaulting Party or such longer period as may be reasonably necessary to cure such failure (if such failure is capable of being cured), provided that the Defaulting Party:

(i) proceeds with all due diligence to cure or cause to be cured such failure; and

(ii) in proceeding so, can be reasonably expected to cure or cause to be cured such failure within a reasonable time frame acceptable to the other Party acting reasonably.

ARTICLE 9 – REMEDIES

9.1 Default Remedies

(a) Unless otherwise agreed to in writing, in the event of an Event of Default the non-defaulting Party may terminate this Agreement as it relates to the non-defaulting Party upon notice in writing and all amounts payable by the defaulting Party hereunder shall become due and payable forthwith;

(b) The remedies in this section are expressly in lieu of any or all of the remedies which may be available to each of BWP Distribution and Eelctek in respect of or under this Agreement resulting from the furnishing, the failure to furnish or the quality of any Services.

ARTICLE 10 – TERMINATION

10.1 Termination

This Agreement shall terminate:

(a) In accordance with the provisions of **Section 9.1**; or

(b) upon issuance of a notice of non-renewal in accordance with **Section 2.1**.

10.2 Notice of Termination

Any termination hereof pursuant to Section 10.1 shall be by written notice of the terminating Party.

ARTICLE 11 – GENERAL

11.1 Force Majeure

No Party shall be liable for a failure or delay in the performance of its obligations pursuant to this Agreement:

(a) provided that such failure or delay could not have been prevented by reasonable precautions;

(b) provided that such failure or delay cannot reasonably be circumvented by the non-performing Party through the use of alternate sources, work around plans or other means; and

(c) if and to the extent such failure or delay is caused, directly or indirectly, by fire, flood, earthquake, elements of nature or acts of God, acts of war, terrorism, riots, civil disorders, rebellions, strikes, lock outs or labour disruptions or revolutions in Canada, or any other similar causes beyond the reasonable control of such Party, (each a "**Force Majeure Event**").

Upon the occurrence of a Force Majeure Event, the non-performing Party shall be excused from any further performance of those of its obligations pursuant to this Agreement affected by the Force Majeure Event only for so long as:

(a) such Force Majeure Event continues; and

(b) such Party continues to use commercially reasonable efforts to recommence performance whenever and to whatever extent possible without delay.

The Party delayed by a Force Majeure Event shall:

(a) immediately notify the other Parties by telephone (to be confirmed in writing within five (5) days of the inception of such delay) of the occurrence of a Force Majeure Event; and

(b) describe in reasonable detail the circumstances causing the Force Majeure Event.

11.2 Dispute Resolution

If any dispute arising in relation to an event of default under **Section 8.1(b)** or its implementation of **Section 8.1(b)** cannot be resolved by negotiation between the two disputing Parties, then the dispute shall be referred to one arbitrator agreeable to and appointed by both Parties to the dispute. If the Parties cannot agree on one arbitrator, the matter in dispute shall be referred to a panel of three arbitrators, one of which shall be appointed by BWP Distribution, one appointed by the Affiliate in the dispute and the third appointed by the two arbitrators selected by the disputing Parties. The arbitrator or arbitrators shall receive such oral and written evidence as may be required to investigate the matter in dispute and to render a decision and shall be guided by this Agreement and the intent of this Agreement. The decision of the arbitrator or arbitrators shall be provided in writing to the disputing Parties no later than thirty (30) days after the sole arbitrator or the third arbitrator has been appointed. The decision of the arbitrator or arbitrators shall be final and binding on the disputing Parties.

11.3 Assignment

No Party shall, without the written consent of the other Parties, which may be arbitrarily withheld in the sole discretion of a Party, assign or transfer its interest in this Agreement. This Agreement shall be binding on the Parties and their respective successors and permitted assigns. Any purported assignment in contravention of this Agreement shall be void.

11.4 Notices

All notices, request, approvals, consents and other communications required or permitted under this Agreement shall be in writing and addressed as follows:

(a) If to Electek,

1376 Lougar Ave., Unit C
Sarnia, ON N7S 5N7
Attn: Brad Gray, Chief Operating Officer
Fax: 519-344-6094

(b) if to BWP Distribution,

P.O. Box 2140
855 Confederation St.
Sarnia, ON N7T 7L6
Attn: Alex Palimaka, Vice President Corporate Services & General Counsel
Fax: 519-344-6094

and shall be sent by fax and the Party sending such notice shall telephone to confirm receipt. A copy of any such notice shall also be sent on the date such notice is transmitted by fax by registered

express mail or courier with the capacity to verify receipt of delivery. Any Party may change its address or fax number for notification purposes by giving the other Party notice of the new address or fax number and the date upon which it will become effective in accordance with the terms of this Agreement. A notice shall be deemed to have been received as of the next Business Day following its transmission by fax.

11.5 **Severability**

If any provision of this Agreement is held by a court of competent jurisdiction to be unenforceable or contrary to law, then the remaining provisions of this Agreement, or the application of such provisions to persons or circumstances other than those as to which it is invalid or unenforceable shall not be affected thereby, and each such provision of this Agreement shall be valid and enforceable to the extent granted by law. If any clause is deemed unenforceable or contrary to law, the parties shall alter the said clause and this agreement to produce enforceability or compliance with law such that the intent of the original clause is maintained and such change or alteration may be established through the dispute resolution clause in this agreement.

11.6 **Waiver**

No delay or omission by a Party to exercise any right or power it has under this Agreement or to object to the failure of any covenant of any other Party to be performed in a timely and complete manner, shall impair any such right or power or be construed as a waiver of any succeeding breach or any other covenant. All waivers must be in writing and signed by the Party waiving its rights

11.7 **Entire Agreement**

This Agreement supercedes any prior agreement between BWP Distribution and any of Electek in relation to the Services provided for in this Agreement, and constitutes the entire Agreement between the Parties with respect to the Services, and there are no other representations, understandings or agreements, either oral or written, between the Parties other than as set out in this Agreement.

11.8 **Amendments**

No amendment to, or change, waiver or discharge of, any provision of this Agreement shall be valid unless in writing and signed by authorized representatives of each Party.

11.9 **Governing Law**

This Agreement shall be governed by the laws of the Province of Ontario and the laws of Canada applicable therein. The Parties hereby agree that the courts of the Province of Ontario shall have exclusive jurisdiction over disputes under this Agreement, and the Parties agree that jurisdiction and venue in such courts is appropriate and irrevocably attorn to the jurisdiction of such courts.

11.10 **Survival**

The terms of **Article** 7, **Article 9** and **Article 11** shall survive the expiration of this Agreement or termination of this Agreement for any reason.

11.11 Third Party Beneficiaries

Each Party intends that this Agreement shall not benefit or create any right or cause of action in or on behalf of any person or entity other than the Parties.

11.12 Covenant of Further Assurances

The Parties agree that, subsequent to the execution and delivery of this Agreement and without any additional consideration, the Parties shall execute and deliver or cause to be executed and delivered any further legal instruments and perform any acts which are or may become necessary to effectuate the purposes of this Agreement and to complete the transactions contemplated under it.

IN WITNESS WHEREOF this Agreement has been executed by the duly authorized signatories of the parties hereto as of the date first written above.

ELECTEK POWER SERVICES INC.

Per: _____

Name: Brad Gray
Title: Chief Operating Officer & Secretary

Per: _____

Name:
Title:

BLUEWATER POWER DISTRIBUTION CORPORATION

Per: _____

Name: Alex Palimaka
Title: Vice President Corporate Services & General Counsel

Per: _____

Name:
Title:

SCHEDULE A

Description of Services

1. **"Finance Services"**, if any, will include treasury services, controllership services and audit services.

   (a) Treasury services will include financing, i.e., cash flow management and investment of funds, banking, financial guarantees, ie: letters of credit, bonds, prudentials, payroll services, accounts payable services, account receivables, office services, obtaining and maintaining credit ratings, Securities Commission reporting, management of customer deposits, interest and T5 reporting, taxation (PILs), GST and PST remittances and corporate VISA card.

   (b) Controllership services will include financial systems, financial processes, policies and procedures, financial controls and compliance, financial reporting and analysis, annual budgets, financial operations, billing, collecting, capitalization and depreciation, WIP and inventory, labour charging, allocations and burdens, managing external audit, risk and contract management, insurance programs, liability, D&O, fleet, facilities, OEB reporting, incentive plan reporting, billing system quality control.

   (c) Audit services will include risk management audit reports to Audit Committee and Board of Directors.

2. **"Corporate Support Services"**, if any, will include human resources services, IT services, safety services and new services.

   (a) Human resources services will include programming and consulting including recruitment, compensation and benefits, employee relations, labour relations.

   (b) IT services will include personal computer systems support and communications support.

   (c) Safety services will include safety program development, monitoring, reporting, implementation and support.

   (d) New support services will include such new services as may be agreed upon by the parties from time to time with a price to be negotiated at that time.

SCHEDULE B

Description of Service Standards

Service Standards

(a) BWP DISTRIBUTION will adhere to industry standards, based on standards set by the WSIB, Electric Utility Safety Association, and Occupational Health & Safety Standards as applicable and in any case shall perform the Services in a good and workmanlike manner and to a standard of performance that a competent professional and diligent independent provider of the services in the same circumstances would reasonably be expected to provide.

(b) BWP DISTRIBUTION will make all reasonable efforts to meet or exceed performance measures established by the Ontario Energy Board, Measurement Canada and by the IESO.

SCHEDULE C

Fees & Charges

	SERVICES	FEES	PERIOD OF FEE
1.	**Finance Services**	Cost	Monthly
2.	**Corporate Support Services**	Cost	Monthly

Terms & Conditions		
1	Prices	Subject to Applicable Taxes
2	Payment	Monthly invoice, Net 30 days
3	Cost	Shall me BWP Distribution's fully allocated cost to provide the Services

Corporate Cost Allocation

The corporate structure of Bluewater Power and its affiliates does not require any form of corporate cost allocation as defined in the OEB Filing Guidelines.

Issues related to the allocation of corporate costs are addressed with respect to allocation to affiliates in Exhibit 3, Tab 3, Schedule 4 – Revenue from Affiliates and with respect to allocation to Non-Core Distribution Activities in Exhibit 4, Tab 2, Schedule 7 – Non-Core Distribution Activities.

Non-Core Distribution Activities

Bluewater Power has proposed a corporate restructuring for January 1, 2009 to move Affiliate Activities (as defined in Exhibit 1, Tab 2, Schedule 6 – Planned Changes in Corporate or Operational Structure) out of the regulated utility and into an affiliate in order to comply with certain directions from the OEB Compliance Office. With that restructuring, the only remaining Non-Core Distribution Activities that are proposed to continue in Bluewater Power during the 2009 test year are water billing for municipal shareholders (as permitted by section 5(2) of *O.Reg.161/99*) and C&DM (as permitted by section 71(2) of the *Ontario Energy Board Act*).

The costs associated with those activities will be reallocated to Account 4380 for the 2009 test year. The methodology set out below has been applied to the reallocation of costs for all Non-Core Distribution Activities during the period from 2007 to 2009.

Commencing with the 2007 calendar year, a disciplined and detailed approach led to accurate reallocation of costs as set-out below. As discussed in Exhibit 4, Tab 2, Schedule 4 – Shared Services, the methodology applied to determine shared services is based on the fully-allocated cost, including a return on invested capital. This methodology was developed in response to the lack of clear direction found in Account 4380 which merely states:

> *"4380 Expenses of Non-Utility Operations*
>
> *A. This account shall include expenses applicable to operations that are non-utility in character but nevertheless constitute a distinct operating activity of the enterprise as a whole, such as the operation of a department where such operation not defined as a utility, or the operation of a service organization for furnishing supervision, management, engineering, and similar services to others.*
>
> *B. The expenses shall include all elements of costs incurred in such operations, and the accounts shall be subdivided so as to permit ready summarization of expenses by activity as follows: Operation, Maintenance, Rents, and Amortization.*
>
> *Example Items*
>
> *1. Street Lighting services*
> *2. Managing or operating of water or sewage services (effective to December 31, 2004)*
> *3. Erecting and removing temporary electricity service (non-utility related) such as community decorative lighting*
> *4. Electricity generation*
> *5. Electricity transmission*
> *6. Expenses associated with non-distribution conservation and demand Management (CDM) activities (e.g., Ontario Power Authority funded CDM programs)*
> *7. Other services not defined as distribution related and not provided for elsewhere in the USoA."*

Based on the fully-allocated methodology employed by Bluewater Power, the reallocation of costs for the two Non-Core Distribution Activities that will continue in 2009 are summarized in the table that follows.

Table 4.2.7.1

	Water Billing			OPA		
	2007	**2008**	**2009**	**2007**	**2008**	**2009**
Employee Costs	$243,250	$252,973	$270,852	$105,632	$48,869	$51,962
Overhead & Use of Capital	$75,041	$76,509	$75,164	$4,285	$2,250	$2,195
Vehicles	$5,922	$6,136	$6,307	$0	$0	$0
Other Direct Costs	$42,654	$108,225	$107,656	$513,304	$0	$0
TOTAL	**$366,867**	**$443,844**	**$459,979**	**$623,221**	**$51,119**	**$54,156**

Water Billing

Costs are allocated to Account 4380 utilizing the methodology discussed in Exhibit 4, Tab 2, Schedule 4 – Shared Services, but more particularly identified as follows:

1. Direct Cost: One full-time Water Billing Representative whose time is dedicated to water billing and elevated customer service issues is allocated in its entirety.

2. Meter Reading Costs: These costs include employee costs associated with meter readers, reading equipment costs and vehicle costs. These costs are allocated based on the ratio of water meters read to electricity meters read.

3. Billing Costs: Refers to paper stock which is allocated (for shared bills only) on the basis of surface area as determined by the percentage of area occupied by water, where common area is shared 50:50.

4. Mailing Costs: These costs include mailroom labour, envelopes and postage and are allocated as a ratio of the number of mailings including water bills divided by the total number of mailings (a mailing is defined as a piece of information in an envelope for delivery, such that an envelope containing a bill with both electricity and water, as well as an OEB information bulletin would be considered three mailings).

5. Customer Service Costs: These costs include employee costs from the Customer Service Department. These costs are allocated based on an estimate of time requirements which have been determined to be related to the water billing function.
6. Overhead and Use of Capital: These costs represent overhead and have been allocated on the basis of FTE equivalents for employee costs allocated to water billing. These costs also include a return on investments directly related to modifications to Bluewater Power's billing system in order to carry out water billing.

Ontario Power Authority Conservation & Demand Management Programs

Bluewater Power participated in the 2007 OPA programs entitled The Great Refrigerator Round-up, peaksaver, 10/10 Summer Savings and the Electricity Retrofit Incentive Program. The costs associated with carrying out these programs are allocated to Account 4380 utilizing the methodology discussed in Exhibit 4, Tab 2, Schedule 4 – Shared Services, but more particularly identified as follows:

1. Employee Costs: The allocation for the OPA's C&DM programs is almost entirely represented by employee costs. Those costs are based on actual hours spent in 2007 and estimates for 2008 and 2009. The decrease from 2007 to 2008/2009 represents the fact that 2007 was the first year of the programs and significantly more effort was required implementing and, then, carrying out the programs.

2. Overhead and Use of Capital: These costs represent overhead and have been allocated on the basis of FTE equivalent for employees working on OPA programs.

3. Other Direct Costs: These costs are only included for 2007 based on actual costs incurred. No amount has been budgeted for 2008 and 2009 because they are not known costs at this time and any costs that are incurred are merely a flow-through to be paid by OPA.

Finally, it should be noted that in the 2009 test year, a further amount of $25,787 will be reallocated to Account 4380 representing 10% of Bluewater Power's incentive pay program. This amount has been determined not to relate to distribution activities for the benefit of ratepayers as discussed in Exhibit 4, Tab 2, Schedule 2 – Variance Analysis on OM&A Costs Table. This amount has been assigned to Account 4380, and brings the total OM&A costs reallocated to Account 4380 in the 2009 test year to $539,922. In other words, these are costs being incurred by Bluewater Power but which are not sought to be recovered through rates as they relate to non-core distribution activities.

Purchase of Services

Bluewater Power's policy is to purchase equipment, materials, and services in a cost effective manner with full consideration given to price as well as product quality, the ability to deliver on time, reliability, compliance with engineering specifications and quality of service. Vendors are screened to ensure knowledge, reputation, and financial ability to meet the needs of Bluewater Power. The purpose of this policy is to specify the purchasing guidelines and procedures that are followed by the staff of Bluewater Power with respect to the procurement of goods and services for the operation of the Corporation.

All purchases of goods and services for the corporation are to be processed through the Materials Management Department through the use of properly authorized purchase requisitions.

The procedures for administering Bluewater Power's Purchasing Policy are in accordance with generally accepted best purchasing and accounting principles, as well as regulatory requirements as applicable. The procurement of goods and/or services for Bluewater Power is carried out with highest of ethical standards and in partial deference to the public nature of the expenditures.

Purchase Authorization

The appropriate Supervisor, Manager, Officer or designate must approve all purchases via a signed purchase requisition, prior to a purchase order being issued by the Buyer. Purchase authorization for each purchasing group is required from the corresponding approval authority below.

Purchasing Group	Approval Authority
CEO	Controller or Any Vice-President
Vice-Presidents and Directors	CEO
Administrative Assistants	Department Head / CEO
Executive Assistant	CEO
Stores	Materials Manager / VP Corporate Services
Information Technology	Director of Information Technology / CEO
Health & Safety Officer	VP Human Resources / CEO
Human Resources	VP Human Resources / CEO
Design Services	Manager of Design Services / VP Operations
Operations	Operations Supervisor / VP Operations
Meter Services	Manager of Meter Services / VP Operations
Client Services	Director of Client Services / CEO
Finance	Controller / CEO
Regulatory	Manager of Regulatory Affairs / VP Corporate Services
Lines Supervisor	Lines Manager / VP Operations
Vehicles	Lines Manager / VP Operations
Building Maintenance	Operations Supervisor / VP Operations

Emergency Purchases

If the need to purchase is driven by an emergency that is so great as to outweigh the objectives set out in this policy, then a full statement of the reasons justifying the purchase shall be included as part of the purchase order file. Approval shall be required after the fact from the Controller, Director, Vice-President or CEO.

Tendering

When goods or services are tendered, a Tender/Request for Proposal/Request for Quote will be issued to a minimum of three vendors, where three qualified vendors can be identified. The Materials Manager shall be the sole authority in accepting proposals.

Payment Authorization

No invoice shall be paid unless accompanied by a Purchase Requisition that is signed at the appropriate level of authorization. Where an item is not included in the corporate budget, then any purchase greater than $1,000 requires the authorization of the Controller and CEO. Authorization for any item, whether budgeted or not, shall also be required as follows:

▪ Level One	$0 - $9,999	Manager or Supervisor with Budget Responsibility
▪ Level Two	$10,000 - $24,999	Vice-President
▪ Level Three	$25,000 - $29,999	President
▪ Level Four	$30,000 and over	Board of Directors

Maintaining coded stock at pre-set quantities by using maximum and minimum inventory levels are not be subject to authorized dollar limits. Materials Management staff has authority to sign requisitions and order items as required to maintain appropriate stock levels.

Following the processing of the purchase order, a copy of the approved purchase requisition and purchase order will be forwarded to the Originator and the original to Materials Management for filing.

Table 4.2.8.1
2007 Top Vendors

Vendor	$ Amount		Product / Service
Moloney Electric	687,802		Transformers
HD Supply Utiilities	501,902		Cable, Wire, Transformer, Lines
Pachecos Contractors	274,328		Civil Construction
Ruddy	248,949		Electrical Supplies
Posi Plus	234,855		Freightliner Truck
Softchoice Corp	177,084		Software
Guardian Tree Systems Inc.	176,343		Tree Trimming Service
Deloitte Inc.	168,130		Support Services
Canon Technologies Inc.	165,802		Peaksaver Load Control
Erie Thames Services	148,287		Meter Re-Verification
SAP Canada	126,341		SAP System Annual Maintenance
Canada Post Corp	121,200		Bulk Letter Postage
Canada Power Products Corp	113,863		Transformer
CCSI Technology Solutions Corp	110,951		Support System
Guillevin International Co	89,281		Electrical Supplies
City of Sarnia	83,097		Fuel
Anixter Canada Inc	81,612		Electrical Wire
Imperial Roofing	72,393		Service Centre Roof Repairs
Electrozad Supply	60,613		Electrical Supplies
Guelph Utility Pole Co Ltd	59,300		Wood Poles
Bayview Chrysler Dodge Ltd	55,957		Dodge Ram, Caravan and Repairs
Dell Canada Ltd	46,725		Computers and Supplies
Itron Canada Ltd	43,338		Meters
IBM Canada Ltd	41,538		Tape Library, Storage and Maintenance
Lafarge Canada Ltd	40,372		Sand and Gravel Supply
Bell Canada	39,687		Telephone System
Badger Daylighting	36,098		Hydrovac Pole Installation
KPMG LLP	33,605		Financial Audit
TOTAL	4,039,453		

Employee Description

The Bluewater Power Employee Description is attached as Exhibit 4, Tab 2, Schedule 9, Attachment 1.

Bluewater Power Employee Description

	2006 EDR (2004 Actual)	2007 Actual	2008 Bridge Year	2009 Test Year
Number of employees (FTEs)				
Executive CEO, COO, VP/Directors, Management & Supervisors	15	14	13	15
Non Union - non supervisor	19	20	21	27
Union	51	59	59	57
Total	85	93	93	99
Number of part time employees				
Executive CEO, COO, VP/Directors, Management & Supervisors	-	-	-	-
Non Union - non supervisor	-	-	-	-
Union	-	-	-	-
Total	-	-		-
Total Compensation				
Executive CEO, COO, VP/Directors, Management & Supervisors	1,300,035	1,391,247	1,357,488	1,583,028
Non Union - non supervisor	1,096,167	1,268,541	1,450,167	1,750,594
Union	2,682,294	3,192,536	3,371,912	3,358,816
Total	5,078,496	5,852,324	6,179,567	6,692,438
Compensation - Average Yearly Base Wages				
Executive CEO, COO, VP/Directors, Management & Supervisors	86,669	99,375	104,422	105,535
Non Union - non supervisor	57,693	63,427	69,056	64,837
Union	52,594	54,111	57,151	58,927
Total	196,956	216,913	230,629	229,299
Compensation - Yearly Overtime				
Executive CEO, COO, VP/Directors, Management & Supervisors	35,250	13,486	11,500	13,220
Non Union - non supervisor	10,659	8,355	7,000	9,000
Union	348,228	370,895	310,830	421,228
Total	394,137	392,736	329,330	443,448
Compensation - Yearly Incentive				
Executive CEO, COO, VP/Directors, Management & Supervisors	-	110,917	100,830	151,127
Non Union - non supervisor	-	42,858	32,590	45,141
Union	-	46,052	50,548	50,597
Total	-	199,827	183,969	246,865
Compensation - Yearly Benefits				
Executive CEO, COO, VP/Directors, Management & Supervisors	235,125	306,608	286,299	346,177
Non Union - non supervisor	268,432	276,870	374,498	416,281
Union	646,935	775,706	833,511	801,488
Total	1,150,492	1,359,184	1,494,308	1,563,946

Loss Adjustment Factor Calculation

Bluewater Power has calculated the total loss factor to be applied to customers' consumption based on the average wholesale and retail kWh for the years 2003 to 2007. The calculations are summarized in Table 4.2.10.1 below.

Table 4.2.10.1
Total Loss Factor Calculation

	Description	2003	2004	2005	2006	2007	Total
A	Wholesale kWh	1,174,348,564	1,175,428,273	1,173,477,963	1,147,372,211	1,165,886,654	5,836,513,665
B	Wholesale kWh for Large Use Customers	356,054,749	364,633,983	342,203,316	342,789,427	353,502,003	1,759,183,478
C	Net Wholesale kWh (A-B)	818,293,815	810,794,290	831,274,647	804,582,784	812,384,651	4,077,330,187
D	Retail kWh (Distributor)	1,134,820,863	1,147,687,162	1,151,289,161	1,120,197,268	1,138,585,342	5,692,579,798
E	Retail kWh for Large Use Customers	352,494,201	360,987,643	338,781,282	339,361,533	349,966,983	1,741,591,642
F	Net Retail kWh (D-E)	782,326,662	786,699,519	812,507,879	780,835,735	788,618,360	3,950,988,155
G	Losses (C-F)	35,967,153	24,094,771	18,766,768	23,747,049	23,766,291	126,342,032
H	Distribution Loss Adjustment (G/C)	4.40%	2.97%	2.26%	2.95%	2.93%	3.10%
I	Supply Facility Loss Adjustment (Deemed)	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%
J	Total Loss Factor (5 year average)						3.560%

Details of Total Losses

Table 4.2.11.1 compares the current loss factors as approved in the 2006 EDR Decision, with the proposed loss factors for the 2009 Test Year.

Table 4.2.11.1
Current and Proposed Loss Factors by class

	Current	2009 Proposed
Supply Facilities Loss Factor (using default)	1.0045	1.0045
Distribution Loss Factor - Secondary Metered Customer < 5,000 kW	1.0399	1.0310
Distribution Loss Factor - Secondary Metered Customer > 5,000 kW	1.0100	1.0100
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	1.0295	1.0207
Distribution Loss Factor - Primary Metered Customer > 5,000 kW	1.0000	1.0000
Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0446	1.0356
Total Loss Factor - Secondary Metered Customer > 5,000 kW	1.0145	1.0145
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0342	1.0253
Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0045	1.0045

Variance and Materiality Analysis on Distribution Losses

Bluewater Power's loss factor is below 5%. Nevertheless, Bluewater Power expects this loss factor to continue to decrease as a result of a number of capital projects described at Exhibit 2, Tab 3, Schedule 6 – Materiality Analysis on Capital Additions, including:

- UT6 – Substation Conversion
- UT7 – 27.6 Feeder program
- UT9 – 4 kV Load Conversion
- UT21 – 27.6 kV lines upgrades
- UT22 – Perch DS Conversion
- UT24 – Load Balancing program
- UT34 – 8 kV Load Conversion

Retail Transmission Adjustment Calculations

Bluewater Power adjusted the retail transmission service rates ("RTS") as part of the 2008 IRM rate application (EB-2007-0862). As of May 1, 2008, the rate for RTS – Network Service decreased by 18%, and the rate for RTS – Line and Transformation Connection Service decreased by 5%.

Bluewater Power is not proposing to change the rates of any of the retail transmission charges at this time.

Bluewater Power is proposing to dispose of the balances in RSVA Accounts 1584 and 1586 as discussed in Exhibit 5, Tab 1, Schedule 2.

Income and Capital Taxes

Tax Calculations Overview

Exhibit 4, Tab 3, Schedule 1, Attachment 1 details the Taxable Income, which is proposed to be $2,511,480 for the 2009 Test year.

Exhibit 4, Tab 3, Schedule 1, Attachment 2 details the Capital Tax items. The Ontario Capital Tax (OCT) is proposed to be $85,857 for 2009, and the Large Corporations Tax (LCT) is forecast to be $0.

The PILs expense is proposed for 2009 to be $1,322,854, and is detailed at Exhibit 4, Tab 3, Schedule 2.

Exhibit 4, Tab 3, Schedule 3, Attachment 1 details the Capital Cost Allowance (CCA) of $4,642,980 for 2009 with the Undepreciated Capital Cost (UCC) at $43,718,383.

Exhibit 4, Tab 3, Schedule 3, Attachment 2 details the Cumulative Eligible Capital (CEC) which is projected to be $1,604,596 for 2009.

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Taxable Income

	T2 S1 line #	2006 EDR Approved			2008 Projection	2009 @ existing rates	2009 @ new dist. rates
		Tax Return	Less: Non-Distribution Portion	Utility Only			
Income/(Loss) before PILs/Taxes (Accounting) [1]		2,098,932		2,098,932	1,186,162	(868,584)	1,974,129
Additions:							
Interest and penalties on taxes	103	5,540		5,540	2,049	2,049	2,049
Amortization of tangible assets	104	3,130,369		3,130,369	4,045,269	4,358,109	4,358,109
Amortization of intangible assets	106						
Recapture of capital cost allowance from Schedule 8	107						
Gain on sale of eligible capital property from Schedule 10	108						
Income or loss for tax purposes- joint ventures or partnerships	109						
Loss in equity of subsidiaries and affiliates	110						
Loss on disposal of assets	111						
Charitable donations	112	9,852		9,852			
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	20,862		20,862	29,398	29,398	29,398
Non-deductible automobile expenses	122						
Non-deductible life insurance premiums	123						
Non-deductible company pension plans	124						
Tax reserves beginning of year	125						
Reserves from financial statements- balance at end of year	126						
Soft costs on construction and renovation of buildings	127						
Book loss on joint ventures or partnerships	205						

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Taxable Income

	T2 S1 line #	2006 EDR Approved			2008 Projection	2009 @ existing rates	2009 @ new dist. rates
		Tax Return	Less: Non-Distribution Portion	Utility Only			
Income/(Loss) before PILs/Taxes (Accounting) [1]		2,098,932		2,098,932	1,186,162	(868,584)	1,974,129
Capital items expensed	206	5,974		5,974			
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	2,088,064		2,088,064			
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237						
Net employee future benefits (accrual less amounts paid)	292	354,570		354,570	847,994	694,415	694,415
Interest on a/c 6035 (customer deposits)					56,820	56,820	
Interest on a/c 6005 (long term debt)					1,404,877	1,404,876	
Capital taxes expensed (included in IBT)					135,000	135,000	
Carrying charges accrued (expensed not paid)					223,924	243,636	243,636
Total Additions		**5,615,231**		**5,615,231**	**6,745,331**	**6,924,303**	**5,327,607**

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Taxable Income

	T2 S1 line #	2006 EDR Approved			2008 Projection	2009 @ existing rates	2009 @ new dist. rates
		Tax Return	Less: Non-Distribution Portion	Utility Only			
Income/(Loss) before PILs/Taxes (Accounting) [1]		2,098,932		2,098,932	1,186,162	(868,584)	1,974,129
Deductions:							
Gain on disposal of assets per financial statements	401				57,300	26,500	26,500
Dividends not taxable under section 83	402						
Capital cost allowance from Schedule 8	403	2,903,731		2,903,731	3,667,133	4,642,980	4,642,980
Terminal loss from Schedule 8	404						
Cumulative eligible capital deduction from Schedule 10 CEC	405	174,508		174,508	129,867	120,776	120,776
Allowable business investment loss	406						
Deferred and prepaid expenses	409						
Scientific research expenses claimed in year	411						
Tax reserves end of year	413						
Reserves from financial statements - balance at beginning of year	414						
Contributions to deferred income plans	416						
Book income of joint venture or partnership	305						
Equity in income from subsidiary or affiliates	306						
Deemed interest expense (per rate model)					1,803,527	2,124,815	
Carrying charges accrued (revenue not received)	393	2,794,381		2,794,381			
Capital taxes calculated by PILS model					81,212	85,857	
Total Deductions		**5,872,620**		**5,872,620**	**5,739,039**	**7,000,928**	**4,790,256**

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Taxable Income

	T2 S1 line #	2006 EDR Approved			2008 Projection	2009 @ existing rates	2009 @ new dist. rates
		Tax Return	Less: Non-Distribution Portion	Utility Only			
Income/(Loss) before PILs/Taxes (Accounting) [1]		2,098,932		2,098,932	1,186,162	(868,584)	1,974,129
NET INCOME (LOSS) FOR TAX PURPOSES		**1,841,543**		**1,841,543**	**2,192,454**	**(945,209)**	**2,511,480**
Charitable donations from Schedule 2		9,852		9,852			
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)							
Non-capital losses of preceding taxation years from Schedule 4							
Net-capital losses of preceding taxation years from Schedule 4							
Limited partnership losses of preceding taxation years from Schedule 4							
TAXABLE INCOME (LOSS)		**1,831,691**		**1,831,691**	**2,192,454**	**(945,209)**	**2,511,480**

[1] 2049 = "Earnings before Tax' (sheet E1); 2049 = "Earnings before Tax' (sheet E2); 2049 = "Deemed Return On Equity' (sheet E3)

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Capital Taxes

	2008	2009
OCT (Ontario Capital Tax):		
Rate Base	51,094,378	53,158,483
Less: Exemption	15,000,000	15,000,000
Deemed Taxable Capital	36,094,378	38,158,483
Tax Rate	0.225%	0.225%
OCT payable	**81,212**	**85,857**
Federal LCT (Large Corporations Tax):		
Rate Base	51,094,378	53,158,483
Less: Exemption	50,000,000	50,000,000
Deemed Taxable Capital	1,094,378	3,158,483
Tax Rate		
LCT payable		

PILs

Exhibit 4, Tab 3, Schedule 2, Attachment 1 details the PILs amount.

RateMaker PILs v1.02 © Elenchus Research Associates

Total PILs Expense

	2008 Projection	2009 Projection [1]	2009 Test [1]
Regulatory Taxable Income/(Loss)	2,192,454	(945,209)	2,511,480
Combined Income Tax Rate	33.50%		33.00%
Total Income Taxes	734,472		828,788
Investment & Miscellaneous Tax Credits			
Income Tax Payable	**734,472**		828,788
Large Corporations Tax (LCT)			
Ontario Capital Tax (OCT)	81,212	85,857	85,857
Grossed-up Income Tax			1,236,997
Grossed-up LCT			
Total PILs Expense	**815,684**	**85,857**	**1,322,854**

[1] 'Projection' per existing rates; 'Test' based on proposed revenue requirement

Capital Cost Allowance (CCA) and Cumulative Eligible Capital (CEC)

Exhibit 4, Tab 3, Schedule 3, Attachments 1 and 2 detail the Capital Cost Allowance ("CCA") and the Cumulative Eligible Capital ("CEC").

RateMaker PILs v1.02 © Elenchus Research Associates

Undepreciated Capital Costs (UCC)

Class	Description	UCC Balance 31 Dec/07 [1]	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC 2008 Opening Balance
1	Distribution System - post 1987	17,774,795			**17,774,795**
2	Distribution System - pre 1988	12,648,854			**12,648,854**
8	General Office/Stores Equip	1,563,219			**1,563,219**
10	Computer Hardware/ Vehicles	1,196,950			**1,196,950**
10.1	Certain Automobiles				
12	Computer Software	238,150			**238,150**
13.1	Leasehold Improvement # 1				
13.2	Leasehold Improvement # 2				
13.3	Leasehold Improvement # 3				
13.4	Leasehold Improvement # 4				
14	Franchise				
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs				
43.1	Certain Energy-Efficient Electrical Generating Equipment				
45	Computers & Systems Software acq'd post Mar 22/04	158,600			**158,600**
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				
47	Distribution System post Feb 22/05	5,145,146			**5,145,146**
50	Computers & Systems Software acq'd post Mar 19/07	256,117			**256,117**
98	Transformers in inventory at YE - no CCA taken until used	1,208,729			**1,208,729**
	TOTAL	**40,190,560**			**40,190,560**

[1] per Schedule 8 of 2007 corporate tax return

RateMaker PILs v1.02 © Elenchus Research Associates

Undepreciated Capital Costs (UCC)

Class	Description	2008 Projected Additions	2008 Projected Retirements	UCC Before 1/2 Yr Adjustment	1/2 Year Reduction	Reduced UCC	Rate %	2008 CCA
1	Distribution System - post 1987	398,023		18,172,818	199,012	17,973,807	4.0%	718,952
2	Distribution System - pre 1988			12,648,854		12,648,854	6.0%	758,931
8	General Office/Stores Equip	97,791		1,661,010	48,896	1,612,115	20.0%	322,423
10	Computer Hardware/ Vehicles	504,440	252,339	1,449,051	126,051	1,323,001	30.0%	396,900
10.1	Certain Automobiles						30.0%	
12	Computer Software	938,835		1,176,985	469,418	707,568	100.0%	707,568
13.1	Leasehold Improvement # 1						25 years	
13.2	Leasehold Improvement # 2						4 years	
13.3	Leasehold Improvement # 3							
13.4	Leasehold Improvement # 4							
14	Franchise						6 years	
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs						8.0%	
43.1	Certain Energy-Efficient Electrical Generating Equipment						30.0%	
45	Computers & Systems Software acq'd post Mar 22/04			158,600		158,600	45.0%	71,370
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)						30.0%	
47	Distribution System post Feb 22/05	2,475,438		7,620,584	1,237,719	6,382,865	8.0%	510,629
50	Computers & Systems Software acq'd post Mar 19/07	143,621		399,738	71,811	327,928	55.0%	180,360
98	Transformers in inventory at YE - no CCA taken until used			1,208,729		1,208,729		
	TOTAL	**4,558,148**	**252,339**	**44,496,369**	**2,152,905**	**42,343,465**		**3,667,133**

[1] per Schedule 8 of 2007 corporate tax return

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Undepreciated Capital Costs (UCC)

Class	Description	UCC 31 Dec/08
1	Distribution System - post 1987	17,453,866
2	Distribution System - pre 1988	11,889,923
8	General Office/Stores Equip	1,338,587
10	Computer Hardware/ Vehicles	1,052,151
10.1	Certain Automobiles	
12	Computer Software	469,418
13.1	Leasehold Improvement # 1	
13.2	Leasehold Improvement # 2	
13.3	Leasehold Improvement # 3	
13.4	Leasehold Improvement # 4	
14	Franchise	
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	
43.1	Certain Energy-Efficient Electrical Generating Equipment	
45	Computers & Systems Software acq'd post Mar 22/04	87,230
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	
47	Distribution System post Feb 22/05	7,109,955
50	Computers & Systems Software acq'd post Mar 19/07	219,378
98	Transformers in inventory at YE - no CCA taken until used	1,208,729
	TOTAL	**40,829,236**

[1] per Schedule 8 of 2007 corporate tax return

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Undepreciated Capital Costs (UCC)

Class	Description	2009 Projected Additions	2009 Projected Retirements	UCC Before 1/2 Yr Adjustment	1/2 Year Reduction	Reduced UCC	Rate %	2009 CCA
1	Distribution System - post 1987	1,067,317		18,521,183	533,659	17,987,524	4.0%	719,501
2	Distribution System - pre 1988			11,889,923		11,889,923	6.0%	713,395
8	General Office/Stores Equip	72,509		1,411,096	36,255	1,374,842	20.0%	274,968
10	Computer Hardware/ Vehicles	565,599	26,500	1,591,250	269,550	1,321,700	30.0%	396,510
10.1	Certain Automobiles						30.0%	
12	Computer Software	2,167,170		2,636,588	1,083,585	1,553,003	100.0%	1,553,003
13.1	Leasehold Improvement # 1							
13.2	Leasehold Improvement # 2							
13.3	Leasehold Improvement # 3							
13.4	Leasehold Improvement # 4							
14	Franchise							
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs						8.0%	
43.1	Certain Energy-Efficient Electrical Generating Equipment						30.0%	
45	Computers & Systems Software acq'd post Mar 22/04			87,230		87,230	45.0%	39,254
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)						30.0%	
47	Distribution System post Feb 22/05	3,220,271		10,330,226	1,610,136	8,720,090	8.0%	697,607
50	Computers & Systems Software acq'd post Mar 19/07	465,762		685,140	232,881	452,259	55.0%	248,742
98	Transformers in inventory at YE - no CCA taken until used			1,208,729		1,208,729		
	TOTAL	**7,558,628**	**26,500**	**48,361,364**	**3,766,064**	**44,595,300**		**4,642,980**

[1] per Schedule 8 of 2007 corporate tax return

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Undepreciated Capital Costs (UCC)

Class	Description	UCC 31 Dec/09
1	Distribution System - post 1987	17,801,682
2	Distribution System - pre 1988	11,176,527
8	General Office/Stores Equip	1,136,128
10	Computer Hardware/ Vehicles	1,194,740
10.1	Certain Automobiles	
12	Computer Software	1,083,585
13.1	Leasehold Improvement # 1	
13.2	Leasehold Improvement # 2	
13.3	Leasehold Improvement # 3	
13.4	Leasehold Improvement # 4	
14	Franchise	
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	
43.1	Certain Energy-Efficient Electrical Generating Equipment	
45	Computers & Systems Software acq'd post Mar 22/04	47,977
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	
47	Distribution System post Feb 22/05	9,632,619
50	Computers & Systems Software acq'd post Mar 19/07	436,397
98	Transformers in inventory at YE - no CCA taken until used	1,208,729
	TOTAL	**43,718,383**

[1] per Schedule 8 of 2007 corporate tax return

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Cumulative Eligible Capital (CEC)

	2008				2009			
CEC Opening Balance [1]				**2,005,239**				**1,725,372**
Eligible Capital Property (ECP) Acquisitions								
Other Adjustments								
Subtotal		**x 3/4 =**				**x 3/4 =**		
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after December 20, 2002		**x 1/2 =**				**x 1/2 =**		
Amount transferred on amalgamation or wind-up of subsidiary								
Subtotal before deductions				**2,005,239**				**1,725,372**
ECP Dispositions (net)	200,000							
Other Adjustments								
Subtotal	200,000	**x 3/4 =**	150,000	**(150,000)**		**x 3/4 =**		
Balance before tax deduction				**1,855,239**				**1,725,372**
Tax Deduction		*Rate:*	***7.0%***	**129,867**		*Rate:*	***7.0%***	**120,776**
CEC Ending Balance				**1,725,372**				**1,604,596**

[1] 2008 amount per ending balance on Schedule 10 of 2007 corporate rax return

Federal T2 tax return

Exhibit 4, Tab 3, Schedule 4, Attachments 1 and 2 present the Federal T2 tax returns.

Canada Revenue Agency | Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

200

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec, Ontario, or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, and paragraphs 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 services office or tax centre. 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 the *T2 Corporation – Income Tax Guide* (T4012).

055 **Do not use this area**

Exhibit 4
Tab 3
Schedule 4
Attachment 1

Identification

Business Number (BN) 001 86572 7390 RC0001

Corporation's name

002 Bluewater Power Distribution Corporation

Has the corporation changed its name since the last time you filed your T2 return? 003 1 Yes ☐ 2 No ☒

If **yes**, do you have a copy of the articles of amendment? ***(Do not submit)*** . . . . 004 1 Yes ☐ 2 No ☐

Address of head office

Has this address changed since the last time you filed your T2 return? . . . . . 010 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 011 to 018)

011 855 Confederation Street

012 PO Box 2140

City: 015 Sarnia | Province, territory, or state: 016 ON

Country (other than Canada): 017 | Postal code/Zip code: 018 N7T 7L6

Mailing address (if different from head office address)

Has this address changed since the last time you filed your T2 return? . . . . . 020 1 Yes ☐ 2 No ☒

(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 you filed your T2 return? . . . . . 030 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 031 to 038)

031 855 Confederation Street

032 PO Box 2140

City: 035 Sarnia | Province,territory, or state: 036 ON

Country (other than Canada): 037 | Postal code/Zip code: 038 N7T 7L6

To which tax year does this return apply?

Tax year start: 060 2007-01-01 (YYYY MM DD) | Tax year-end: 061 2007-12-31 (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 ☒

If **yes**, provide the date control was acquired . . . . . 065 (YYYY MM DD)

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1)? . . . . . 066 1 Yes ☐ 2 No ☒

Is the corporation a professional corporation that is a member of a partnership? . . . . . 067 1 Yes ☐ 2 No ☒

Is this the first year of filing after:

Incorporation? . . . . . 070 1 Yes ☐ 2 No ☒

Amalgamation? . . . . . 071 1 Yes ☐ 2 No ☒

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 ☒

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . . 076 1 Yes ☐ 2 No ☒

Is this the final return up to dissolution? . . . . . 078 1 Yes ☐ 2 No ☒

Is the corporation a resident of Canada?

080 1 Yes ☒ 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 ☒

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

040 **Type of corporation at the end of the tax year**

1 ☒ 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)

Do not use this area

091	092	093	094	095	096
100					

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each *Yes* response, **attach** to the T2 return the schedule that applies.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation 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) is the corporation claiming the refundable portion of Part I tax?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming reserves of any kind?	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
Was the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	X	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation a member of a related group with one or more members subject to gross Part I.3 tax?	236		36
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

Attachments – continued from page 2

		Yes	Schedule
Is the corporation subject to Part XIII.1 tax?	255		92 *
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	X	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

*** We do not print this schedule.**

Additional information

Is the corporation inactive?	280	1 Yes		2 No	X
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281	1 Yes		2 No	X

What is the corporation's major business activity? 282
(Only complete if **yes** was entered at line 281)

If the major business activity involves the resale of goods, show whether it is wholesale or retail 283 1 Wholesale ☐ 2 Retail ☐

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Energy infastructure provider	285	100.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes		2 No	X
Did the corporation emigrate from Canada during the tax year?	292	1 Yes		2 No	X

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300		4,317,981	A
Deduct: Charitable donations from Schedule 2	311	23,061		
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		23,061 ▶	23,061	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			4,294,920	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		4,294,920	
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)			4,294,920	Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . . 400 4,317,981 A

Taxable income from line 360, **minus** 10/3 of the amount on line 632*, **minus** 3 times the amount on line 636**, and **minus** any amount that, because of federal law, is exempt form Part I tax . . . . . 405 4,294,920 B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

300,000 x (Number of days in the tax year in 2005 and in 2006 / Number of days in the tax year 365) = ... 1

400,000 x (Number of days in the tax year after 2006 / Number of days in the tax year 365 / 365) = ... 400,000 2

Add amounts at lines 1 and 2 400,000 4

Business limit (see notes 1 and 2 below) . . . . . 410 400,000 C

Notes:
1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 400,000 x 415 *** 81,226 / 11,250 D = ... 2,888,036 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 (Number of days in the tax year before January 1, 2008 / Number of days in the tax year 365 / 365) x 16 % = 5

Amount A, B, C, or F whichever is the least x (Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year / 365) x 17 % = 6

Amount A, B, C, or F whichever is the least x (Number of days in the tax year after December 31, 2008 / Number of days in the tax year / 365) x 17 % = 7

Total of amounts 5, 6, and 7 – enter on line 9 430 G

* 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.

** 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 the previous tax years, the amount to be entered at 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 at 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.

Resource deduction

Taxable resource income [as defined in subsection 125.11(1)] . . . . . 435 H

Amount H x (Number of days in the tax year in 2005 / Number of days in the tax year 365) x 3 % = I

Amount H x (Number of days in the tax year in 2006 / Number of days in the tax year 365) x 5 % = J

Amount H x (Number of days in the tax year in 2007 / Number of days in the tax year 365) x 7 % = K

Resource deduction – total of amounts I, J and K . . . . . 438 L
Enter amount L on line 10.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360							4,294,920	A
Amount Z1 from Part 9 of Schedule 27								B
Amount QQ from Part 13 of Schedule 27								C
Taxable resource income from line 435								D
Amount used to calculate the credit union deduction (from Schedule 17)								E
Amount from line 400, 405, 410, or 425, whichever is the least								F
Aggregate investment income from line 440								G
Total of amounts B, C, D, E, F, and G						▶		H
Amount A **minus** amount H (if negative, enter "0")							4,294,920	I
Amount I	4,294,920	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	365 / 365	x	7 % =	300,644	J
Amount I	4,294,920	x	Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 % =		K
Amount I	4,294,920	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 % =		K1
Amount I	4,294,920	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 % =		K2
General tax reduction for Canadian-controlled private corporations – total of amounts J, K, K1, and K2							300,644	L

Enter amount L on line 638.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, or a mutual fund corporation, and for tax years starting after May 1, 2006, any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 (for tax years starting after May 1, 2006, amount Z)								M
Amount Z1 from Part 9 of Schedule 27								N
Amount QQ from Part 13 of Schedule 27								O
Taxable resource income from line 435								P
Amount used to calculate the credit union deduction (from Schedule 17)								Q
Total of amounts N, O, P, and Q						▶		R
Amount M **minus** amount R (if negative, enter "0")								S
Amount S		x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	365 / 365	x	7 % =		T
Amount S		x	Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 % =		U
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 % =		U1
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 % =		U2
General tax reduction – total of amounts T, U, U1, and U2								V

Enter amount V on line 639.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income (from Schedule 7) ..... 440 _____ x 26 2 / 3 % = ... _____ A

Foreign non-business income tax credit from line 632 ..... _____

Deduct:

Foreign investment income (from Schedule 7) ..... 445 _____ x 9 1 / 3 % = _____
(if negative, enter "0") _____ ▶ _____ B

Amount A **minus** amount B (if negative, enter "0") ..... _____ C

Taxable income from line 360 4,294,920

Deduct:

Amount from line 400, 405, 410, or 425, whichever is the least ..... _____

Foreign non-business income tax credit from line 632 ..... _____ x 25 / 9 = _____

Foreign business income tax credit from line 636 ..... _____ x 3 = _____

_____ ▶ _____

4,294,920

x 26 2 / 3 % = 1,145,312 D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780) 880,446

Deduct: Corporate surtax from line 600 48,103

Net amount ..... 832,343 ▶ 832,343 E

Refundable portion of Part I tax – Amount C, D, or E, whichever is the least ..... 450 _____ F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year ..... 460 _____

Deduct: Dividend refund for the previous tax year ..... 465 _____

_____ ▶ _____ G

Add the total of:

Refundable portion of Part I tax from line 450 above ..... _____

Total Part IV tax payable from Schedule 3 ..... _____

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation ..... 480 _____

_____ ▶ _____ H

Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H ..... 485 _____

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 of Schedule 3 ..... 6,921,200 x 1 / 3 = 2,307,067 I

Refundable dividend tax on hand at the end of the tax year from line 485 above ..... _____ J

Dividend refund – Amount I or J, whichever is less (enter this amount on line 784) ..... _____

Part I tax

Base amount of Part I tax – taxable income (line 360 or amount Z, whichever applies) **multiplied** by 38.00 % . . . . . 550 1,632,070 A

Corporate surtax calculation

Base amount from line A above		1,632,070	1
Deduct:			
10 % of taxable income (line 360 or amount Z, whichever applies)		429,492	2
Investment corporation deduction from line 620 below			3
Federal logging tax credit from line 640 below			4
Federal qualifying environmental trust tax credit from line 648 below			5
For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:			
28.00 % of taxable income from line 360	a		
28.00 % of taxed capital gains	b		6
Part I tax otherwise payable (line A **plus** lines C and D **minus** line F)	c		
Total of lines 2 to 6		429,492	7
Net amount (line 1 **minus** line 7)		1,202,578	8

Corporate surtax*

Line 8 1,202,578 x (Number of days in the tax year before January 1, 2008 / Number of days in the tax year) 365 / 365 x 4 % = 600 48,103 B

* The corporate surtax is zero effective January 1, 2008.

Recapture of investment tax credit from Schedule 31 . . . . . 602 C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income (if it was a CCPC throughout the tax year)

Aggregate investment income from line 440			i
Taxable income from line 360	4,294,920		
Deduct:			
Amount from line 400, 405, 410, or 425, whichever is the least			
Net amount	4,294,920 ▶	4,294,920	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii . . . . . 604 D

Subtotal (**add** lines A, B, C, and D) 1,680,173 E

Deduct:

Small business deduction from line 430			9
Federal tax abatement	608	429,492	
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		
Resource deduction from line 438			10
General tax reduction for CCPCs from amount L	638	300,644	
General tax reduction from amount V	639		
Federal logging tax credit from Schedule 21	640		
Federal political contribution tax credit	644		
Federal political contributions 646			
Federal qualifying environmental trust tax credit	648		
Investment tax credit from Schedule 31	652	69,591	
	Subtotal	799,727 ▶	799,727 F

Part I tax payable – Line E **minus** line F . . . . . 880,446 G

Enter amount G on line 700.

Summary of tax and credits

Federal tax

Part I tax payable	700	880,446
Part I.3 tax payable from Schedule 33, 34, or 35	704	
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		880,446

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 Ontario
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Québec, Ontario, and Alberta)	760	
Provincial tax on large corporations (New Brunswick and Nova Scotia)	765	
Total tax payable	770	880,446 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld	801		
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	880,446	
Total credits	890	880,446	880,446 B

Refund code 894 Overpayment

Balance (line A **minus** line B)

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒

Certification

I, 950 McMichael-Dennis (Last name in block letters) 951 Janice (First name in block letters) 954 President & CEO (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 Date (yyyy/mm/dd) Signature of the authorized signing officer of the corporation 956 (519) 337-8201 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 1 Yes ☒ 2 No ☐

958 Name in block letters 959 Telephone number

Language of correspondence – Langue de correspondance

990 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.

1 English / Anglais ☒ 2 Français / French ☐

Schedule of Instalment Remittances

Name of corporation contact _____
Telephone number _____

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
		880,446

Total amount of instalments claimed (carry the result to line 840 of the T2 Return) 880,446 **A**

Total instalments credited to the taxation year per T9 880,446 **B**

Transfer

Account number	Taxation year end	Amount	Effective interest date	Description
From:				
To:				
From:				
To:				
From:				
To:				
From:				
To:				
From:				
To:				

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GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2007-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
Assets					
	Total current assets	1599	+	24,836,660	25,070,186
	Total tangible capital assets	2008	+	37,770,012	37,396,966
	Total accumulated amortization of tangible capital assets	2009	–		
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	2,380,000	2,480,000
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	64,986,672	64,947,152
Liabilities					
	Total current liabilities	3139	+	12,346,520	11,977,823
	Total long-term liabilities	3450	+	30,647,213	25,630,103
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	42,993,733	37,607,926
Shareholder equity					
	Total shareholder equity (mandatory field)	3620	+	21,992,939	27,339,226
	Total liabilities and shareholder equity	3640	=	64,986,672	64,947,152
Retained earnings					
	Retained earnings/deficit – end (mandatory field)	3849	=	3,970,834	9,317,121

* Generic item

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GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2007-12-31

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	+	87,450,745	85,877,256
	Cost of sales	8518	–	72,009,498	71,104,272
	Gross profit/loss	8519	=	15,441,247	14,772,984
	Cost of sales	8518	+	72,009,498	71,104,272
	Total operating expenses	9367	+	18,576,647	17,328,135
	Total expenses (mandatory field)	9368	=	90,586,145	88,432,407
	Total revenue (mandatory field)	8299	+	93,827,815	90,868,537
	Total expenses (mandatory field)	9368	–	90,586,145	88,432,407
	Net non-farming income	9369	=	3,241,670	2,436,130
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	=	3,241,670	2,436,130
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	–	1,500,000	1,225,000
	Deferred income tax provision	9995	–	100,000	
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	1,641,670	1,211,130

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 141

NOTES CHECKLIST

Corporation's name	Business Number	Tax year end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2007-12-31

- This schedule should be completed from the perspective of the person who prepared or reported on the **financial statements**. This person is referred to as the "accounting practitioner", in this schedule.
- For more information, see RC4088, *Guide to the General Index of Financial Information (GIFI) for Corporations* and T4012, *T2 Corporation – Income Tax Guide*.
- Attach a copy of this schedule, along with any Notes to the financial statements, to the GIFI.

Part 1 – Accounting practitioner information

Does the accounting practitioner have a professional designation?	095	1 Yes	X	2 No	
Is the accounting practitioner 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 accounting practitioner does not have a professional designation **or** is connected with the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4.

Part 2 – Type of involvement

Choose the option that represents the highest level of involvement of the accounting practitioner: 198

Completed an auditor's report	1	X
Completed a review engagement report	2	
Conducted a compilation engagement	3	

Part 3 – Reservations

If you selected option "1" or "2" under **Type of involvement** above, answer the following question:

Has the accounting practitioner expressed a reservation?	099	1 Yes		2 No	X

Part 4 – Other information

Were notes to the financial statements prepared?	101	1 Yes	X	2 No	
If *Yes*, complete lines 102 to 107 below:					
Are any values presented at other than cost?	102	1 Yes		2 No	X
Has there been a change in accounting policies since the last return?	103	1 Yes		2 No	X
Are subsequent events mentioned in the notes?	104	1 Yes		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		2 No	X
Is information regarding commitments mentioned in the notes?	107	1 Yes		2 No	X
Does the corporation have investments in joint venture(s) or partnership(s)?	108	1 Yes		2 No	X
If *Yes*, complete line 109 below:					
Are you filing financial statements of the joint venture(s) or partnership(s)?	109	1 Yes		2 No	

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2007-12-31

- 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*.
- Please provide us with the applicable details in the identification area, and complete the applicable lines that contain a numbered black box. You should report amounts in accordance with the Generally Accepted Accounting Principles (GAAP).
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Net income (loss) after taxes and extraordinary items per financial statements				1,641,670 A
Add:				
Provision for income taxes – current		101	1,500,000	
Provision for income taxes – deferred		102	100,000	
Interest and penalties on taxes		103	2,245	
Amortization of tangible assets		104	3,847,903	
Charitable donations and gifts from Schedule 2		112	23,061	
Scientific research expenditures deducted per financial statements		118	217,770	
Non-deductible meals and entertainment expenses		121	28,967	
	Subtotal of additions		5,719,946 ▶	5,719,946
Other additions:				
Miscellaneous other additions:				
600 Employee future benefits (accrual)		290	722,060	
601 Capital taxes expensed		291	128,412	
602 Carrying Charge Revenue		292	156,210	
603.1 Amortization of Regulatory Assets	1,879,700			
603.2 Ontario Specified Tax Credits	13,000			
	Total 1,892,700	293	1,892,700	
	Subtotal of other additions	199	2,899,382 ▶	2,899,382
	Total additions	500	8,619,328 ▶	8,619,328
Deduct:				
Gain on disposal of assets per financial statements		401	4,152	
Capital cost allowance from Schedule 8		403	3,431,534	
Cumulative eligible capital deduction from Schedule 10		405	150,932	
Scientific research expenses claimed in year from Form T661		411	122,708	
	Subtotal of deductions		3,709,326 ▶	3,709,326
Other deductions:				
Miscellaneous other deductions:				
700 Employee future benefits (paid)		390	198,967	
701 Capital tax paid		391	123,911	
703 Regulatory Assets Recovered		393	1,879,700	
704.1 Capitalized for actg expensed for tax	31,113			
	Total 31,113	394	31,113	
	Subtotal of other deductions	499	2,233,691 ▶	2,233,691
	Total deductions	510	5,943,017 ▶	5,943,017
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				4,317,981

* For reference purposes only

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 2

CHARITABLE DONATIONS AND GIFTS

Name of corporation	Business Number	Tax year-end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2007-12-31

- For use by corporations to claim any of the following:
  - charitable donations;
  - gifts to Canada, a province, or a territory;
  - gifts of certified cultural property;
  - gifts of certified ecologically sensitive land; or
  - additional deduction for gifts of medicine.
- The donations and gifts are eligible for a five-year carryforward.
- Use this schedule to show a credit transfer following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1) of the *Income Tax Act*.
- For donations and gifts made after March 22, 2004, subsection 110.1(1.2) of the *Income Tax Act* provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- Under proposed changes, the eligible amount of a charitable gift is the amount by which the fair market value of the gift exceeds the amount of an advantage, if any, for the gift.
- Under proposed changes, a gift of medicine made after March 18, 2007, to qualifying organizations for activities outside of Canada, may be eligible for an additional deduction if the gift is an eligible medical gift. This additional deduction is calculated in Part 6.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation – Income Tax Guide*.

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
Various	23,061
Subtotal	23,061
Add: Total donations of less than $100 each	
Total donations in current tax year	23,061

		Federal	Quebec	Alberta
Charitable donations at the end of the previous tax year				
Deduct: Charitable donations expired after five tax years	239			
Charitable donations at the beginning of the tax year	240			
Add:				
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250			
Total current-year charitable donations made (enter this amount on line 112 of Schedule 1) 210 23,061				
Subtotal (line 250 **plus** line 210)		23,061	23,061	23,061
Deduct: Adjustment for an acquisition of control (for donations made after March 22, 2004)	255			
Total charitable donations available		23,061 A	23,061	23,061
Deduct: Amount applied against taxable income (cannot be more than amount K in Part 2) (enter this amount on line 311 of the T2 return)	260	23,061	23,061	23,061
Charitable donations closing balance	280			

Amounts carried forward – Charitable donations

Year of origin:		Federal	Quebec	Alberta
1st prior year	2006			
2nd prior year	2005			
3rd prior year	2004			
4th prior year	2003			
5th prior year	2002			
6th prior year *	2001			
Total (to line A)				

* These donations expired in the current year.

Part 2 – Calculation of the maximum allowable deduction for charitable donations

Net income for tax purposes* **multiplied** by 75 % ..... 3,238,486 B

Taxable capital gains arising in respect of gifts of capital property included in Part 1 ** 225 ____ C

Taxable capital gain in respect of deemed gifts of non-qualifying securities per subsection 40(1.01) ..... 227 ____ D

The amount of the recapture of capital cost allowance in respect of charitable gifts ..... 230 ____

Proceeds of disposition, less outlays and expenses ** ..... ____ E

Capital cost ** ..... ____ F

Amount E or F, whichever is less ..... 235 ____

Amount on line 230 or 235, whichever is less ..... ____ G

Subtotal (**add** amounts C, D, and G) ____ H

Amount H **multiplied** by 25 % ____ I

Subtotal (amount B **plus** amount I) 3,238,486 J

Maximum allowable deduction for charitable donations (enter amount A from Part 1, amount J, or net income for tax purposes, whichever is less) ..... 23,061 K

* For credit unions, this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

Part 3 – Gifts to Canada, a province, or a territory

Gifts to Canada, a province, or a territory at the end of the previous tax year .....

Deduct: Gifts to Canada, a province, or a territory expired after five tax years .... 339 ____

Gifts to Canada, a province, or a territory at the beginning of the tax year ..... 340 ____ ▶ ____

Add: Gifts to Canada, a province, or a territory transferred on an amalgamation or the windup of a subsidiary ..... 350 ____

Total current-year gifts made to Canada, a province, or a territory * ..... 310 ____

Subtotal (line 350 **plus** line 310) ____

Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004) ..... 355 ____

Total gifts to Canada, a province, or a territory available .....

Deduct: Amount applied against taxable income (enter this amount on line 312 of the T2 return). ..... 360 ____

Gifts to Canada, a province, or a territory closing balance ..... 380 ____

* Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date. If no written agreement exists, enter the amount on line 210 and complete Part 2.

Part 4 – Gifts of certified cultural property

		Federal	Quebec	Alberta
Gifts of certified cultural property at the end of the previous tax year				
Deduct: Gifts of certified cultural property expired after five tax years	439			
Gifts of certified cultural property at the beginning of the tax year	440			
Add: Gifts of certified cultural property transferred on an amalgamation or the windup of a subsidiary	450			
Total current-year gifts of certified cultural property	410			
Subtotal (line 450 **plus** line 410)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	455			
Total gifts of certified cultural property available				
Deduct: Amount applied against taxable income (enter this amount on line 313 of the T2 return)	460			
Gifts of certified cultural property closing balance	480			

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Quebec	Alberta
1st prior year	2006			
2nd prior year	2005			
3rd prior year	2004			
4th prior year	2003			
5th prior year	2002			
6th prior year *	2001			
Total				

* These donations expired in the current year.

Part 5 – Gifts of certified ecologically sensitive land

		Federal	Quebec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year				
Deduct: Gifts of certified ecologically sensitive land expired after five tax years	539			
Gifts of certified ecologically sensitive land at the beginning of the tax year	540			
Add: Gifts of certified ecologically sensitive land transferred on an amalgamation or the windup of a subsidiary	550			
Total current-year gifts of certified ecologically sensitive land	510			
Subtotal (line 550 **plus** line 510)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	555			
Total gifts of certified ecologically sensitive land available				
Deduct: Amount applied against taxable income (enter this amount on line 314 of the T2 return)	560			
Gifts of certified ecologically sensitive land closing balance	580			

Amounts carried forward – Gifts of certified ecologically sensitive land

Year of origin:		Federal	Quebec	Alberta
1st prior year	2006			
2nd prior year	2005			
3rd prior year	2004			
4th prior year	2003			
5th prior year	2002			
6th prior year *	2001			
Total				

* These donations expired in the current year.

Part 6 – Additional deduction for gifts of medicine

		Federal		Quebec		Alberta	
Additional deduction for gifts of medicine at the end of the previous tax year							
Deduct: Additional deduction for gifts of medicine expired after five tax years	639						
Additional deduction for gifts of medicine at the beginning of the tax year	640						
Add: Additional deduction for gifts of medicine transferred on an amalgamation or the wind-up of a subsidiary	650						
Additional deduction for gifts of medicine for the current year:							
Proceeds of disposition	602		1		1		1
Cost of gifts of medicine	601		2		2		2
Subtotal (line 1 **minus** line 2)			3		3		3
Line 3 **multiplied** by 50 %			4		4		4
Eligible amount of gifts	600		5		5		5

Federal
A _____ x (B _____ / C) = Additional deduction for gifts of medicine for the current year 610 _____

Quebec
A _____ x (B _____ / C) = Additional deduction for gifts of medicine for the current year _____

Alberta
A _____ x (B _____ / C) = Additional deduction for gifts of medicine for the current year _____

where:
A is the **lesser** of line 2 and line 4
B is the eligible amount of gifts (line 600)
C is the proceeds of disposition (line 602)

Subtotal (line 650 **plus** line 610)				
Deduct: Adjustment for an acquisition of control	655			
Total additional deduction for gifts of medicine available				
Deduct: Amount applied against taxable income (enter this amount on line 315 of the T2 return)	660			
Additional deduction for gifts of medicine closing balance	680			

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Quebec	Alberta
1st prior year	2006			
2nd prior year	2005			
3rd prior year	2004			
4th prior year	2003			
5th prior year	2002			
6th prior year *	2001			
Total				

* These donations expired in the current year.

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DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2007-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid for purposes of a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act*.
- A recipient corporation is connected with a payer corporation at any time in a taxation year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the sections about Schedule 3 in the *T2 Corporation Income Tax Guide*.
- "X" under column A if dividend received from a foreign source (connected corporation only).
- "X" under column B if the payer corporation is connected.
- Enter in column F1, the amount of dividends received reported in column 240 that are eligible to a 45% gross up for the purpose of the dividend tax credit for individuals.
- Under column F2, enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received during the taxation year

Do not include dividends received from foreign non-affiliates.

		Complete if payer corporation is connected				
Name of payer corporation (Use only one line per corporation, abreviating its name if necessary)	A	B	C Business Number	D Taxation year end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends were paid YYYY/MM/DD	E Non-taxable dividend under section 83
200		205	210	220	230
1					
				Total	

Note: If your corporation's taxation year end is different than that of the connected payer corporation, your corporation could have received dividends from more than one taxation year of the payer corporation. If so, use a separate line to provide the information for each taxation year of the payer corporation.

			If payer corporation is not connected, leave these columns blank.		
F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d)	F1	F2	G Total taxable dividends paid by connected payer corporation	H Dividend refund of the connected payer corporation	I Part IV tax before deductions F x 1 / 3 *
240			250	260	270
1					
Total (enter amount of column F on line 320 of the T2 return)					J

For dividends received from connected corporations: Part IV tax equals: $\frac{\text{Column F x Column H}}{\text{Column G}}$

* Life insurers are not subject to Part IV tax on subsection 138(6) dividends.
Public corporations (other than subject corporations) do not need to calculate Part IV tax.

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1) . . . . . _____

Deduct:

Part IV.I tax payable on dividends subject to Part IV tax . . . . . 320 _____

Subtotal _____

Deduct:

Current-year non-capital loss claimed to reduce Part IV tax . . . . . 330 _____

Non-capital losses from previous years claimed to reduce Part IV tax . . . . 335 _____

Current-year farm loss claimed to reduce Part IV tax . . . . . 340 _____

Farm losses from previous years claimed to reduce Part IV tax . . . . . 345 _____

Total losses applied against Part IV tax _____ x 1 / 3 = _____

Part IV tax payable (enter amount on line 712 of the T2 return) . . . . . 360 _____

Part 3 – Taxable dividends paid in the taxation year for purposes of a dividend refund

	A	B	C	D
	Name of connected recipient corporation 400	Business Number 410	Taxation year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD 420	Taxable dividends paid to connected corporations 430
1	Bluewater Power Corporation	89247 0410 RC0001	2007-12-31	6,921,200
2				

Note

If your corporation's taxation year end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one taxation year of the recipient corporation. If so, use a separate line to provide the information for each taxation year of the recipient corporation.

Total 6,921,200

Total taxable dividends paid in the taxation year to other than connected corporations . . . . . 450 _____

Total taxable dividends paid in the taxation year for the purposes of a dividend refund (total of column D above plus line 450) 460 6,921,200

Part 4 – Total dividends paid in the taxation year

Complete this part if the total taxable dividends paid in the taxation year for purposes of a dividend refund (line 460 above) is different from the total dividends paid in the taxation year.

Total taxable dividends paid in the taxation year for the purposes of a dividend refund (from above) 460 6,921,200

Other dividends paid in the taxation year (total of 510 to 540) . . . . . _____

Total dividends paid in the taxation year 500 6,921,200

Deduct:

Dividends paid out of capital dividend account . . . . . 510 _____

Capital gains dividends . . . . . 520 _____

Dividends paid on shares described in subsection 129(1.2) . . . . . 530 _____

Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year . . . . . 540 _____

Subtotal _____ ▶ _____

Total taxable dividends paid in the taxation year for purposes of a dividend refund 6,921,200

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2007-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? 101 1 Yes ☐ 2 No ☒

	1 Class number 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (column 7 **multiplied** by column 8; or a lower amount) (line 403 of Schedule 1)**** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1	1		18,321,745	189,714		0	94,857	18,416,602	4	0	0	736,664	17,774,795
2	2		13,456,228			0		13,456,228	6	0	0	807,374	12,648,854
3	8		1,736,557	193,304		0	96,652	1,833,209	20	0	0	366,642	1,563,219
4	10		1,354,864	292,958		552	146,203	1,501,067	30	0	0	450,320	1,196,950
5	12		265,477	476,300		0	238,150	503,627	100	0	0	503,627	238,150
6	45		288,363			0		288,363	45	0	0	129,763	158,600
7	50			353,265		0	176,633	176,632	55	0	0	97,148	256,117
8	47		3,014,757	2,473,985		3,600	1,235,193	4,249,949	8	0	0	339,996	5,145,146
9			998,420	1,208,729	-998,420	0	604,365	604,364	0	0	0		1,208,729
		Total	39,436,411	5,188,255	-998,420	4,152	2,592,053	41,030,041				3,431,534	40,190,560

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) plus or minus certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

T2 SCH 8 (06)

Canada

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2007-12-31

This schedule is to be completed by a corporation having one or more of the following:
– related corporation(s)
– associated corporations(s)

	Name 100	Country of residence (if other than Canada) 200	Business Number (Canadian corporation only) (see note 1) 300	Relationship code (see note 2) 400	Number of common shares owned 500	% of common shares owned 550	Number of preferred shares owned 600	% of preferred shares owned 650	Book value of capital stock 700
1.	Sarnia Power Corporation		89252 3812 RC0001	3					
2.	Bluewater Power Corporation		89247 0410 RC0001	1					
3.	Sarnia Hydro Energy Services Corpc		89255 8214 RC0001	3					
4.	Blackwell Renewable Energy Inc		85839 3556 RC0001	3					
5.	Electek Power Services Inc.		86220 1712 RC0002	3					
6.	Bluewater Power Generation Corpor		85884 6215 RC0001	3					

Note 1: Enter "NR" if a corporation is not registered.
Note 2: Enter the code number of the relationship that applies from the following order: 1 – Parent 2 – Subsidiary 3 – Associated 4 – Related, but not associated.

T2 SCH 9(99)

Canada

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2007-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0") 200 2,156,171 A

Add:

Cost of eligible capital property acquired during the taxation year . . . . . 222 _____

Other adjustments . . . . . 226 _____

Subtotal (line 222 plus line 226) _____ x 3 / 4 = _____ B

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 . . 228 _____ x 1 / 2 = _____ C

amount B minus amount C (if negative, enter "0") _____ ▶ _____ D

Amount transferred on amalgamation or wind-up of subsidiary . . . . . 224 _____ E

Subtotal (add amounts A, D, and E) 230 2,156,171 F

Deduct:

Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year . . . . . 242 _____ G

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) . . . . . 244 _____ H

Other adjustments . . . . . 246 _____ I

(add amounts G,H, and I) _____ x 3 / 4 = 248 _____ J

Cumulative eligible capital balance (amount F minus amount J) . . . . . 2,156,171 K

(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business . . . . . 249 _____

amount K 2,156,171

less amount from line 249 _____

Current year deduction . . . . . 2,156,171 x 7.00 % = 250 150,932 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 150,932 ▶ 150,932 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") . . . . . 300 2,005,239 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)				N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988	400		1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)	401		2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402		3	
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408		4	
Line 3 minus line 4 (if negative, enter "0")		▶	5	
Total of lines 1, 2 and 5			6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7	
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8	
Subtotal (line 7 plus line 8)	409	▶	9	
Line 6 minus line 9 (if negative, enter "0")		▶		O
Line N minus line O (if negative, enter "0")				P
Line 5 _____ x 1 / 2 =				Q
Line P minus line Q (if negative, enter "0")				R
Amount R _____ x 2 / 3 =				S
Amount N or amount O, whichever is less				T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)	410			

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SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 - Associated for purposes of allocating the business limit (unless code 5 applies)
2 - CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 - Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 - Associated non-CCPC
5 - Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2004	$225,001 to $250,000
2005	$250,001 to $300,000
2006	maximum $300,000
2007	$300,001 to $400,000

If the calendar year to which this agreement applies is after 2007, ensure that the total at line A does not exceed $400,000.

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 2007

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . 075 1 Yes ☐ 2 No ☒

	1 Names of associated corporations 100	2 Business Number of associated corporations 200	3 Asso-ciation code 300	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % 350	6 Business limit allocated* $ 400
1	Bluewater Power Distribution Corporation	86572 7390 RC0001	1	400,000	100.0000	400,000
2	Sarnia Power Corporation	89252 3812 RC0001	1	400,000		
3	Bluewater Power Corporation	89247 0410 RC0001	1	400,000		
4	Sarnia Hydro Energy Services Corporation	89255 8214 RC0001	1	400,000		
5	Blackwell Renewable Energy Inc	85839 3556 RC0001	1	400,000		
6	Electek Power Services Inc.	86220 1712 RC0002	1	400,000		

	1 Names of associated corporations 100	2 Business Number of associated corporations 200	3 Asso-ciation code 300	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % 350	6 Business limit allocated* $ 400	
7	Bluewater Power Generation Corporation	85884 6215 RC0001	1	400,000			
				Total	100.0000	400,000	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. In this case, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

T2 SCH 23 (06)

Canada

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SCHEDULE 31

INVESTMENT TAX CREDIT – CORPORATIONS

General information

1. For use by a corporation that during a tax year:
   - earned an investment tax credit (ITC);
   - is claiming a deduction against its Part I tax payable;
   - is claiming a refund of credit earned during the current tax year;
   - is claiming a carryforward of credit from previous tax years;
   - is transferring a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the federal *Income Tax Act;*
   - is requesting a credit carryback; or
   - is subject to a recapture of ITC.
2. References to parts, sections, and subsections on this schedule are from the federal *Income Tax Act* and the federal *Income Tax Regulations.* References to interpretation bulletins and information circulars are to the latest versions.
3. The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward for credits earned in tax years that end after 1997 and a ten-year carryforward for credits earned in tax years that end before 1998. The apprenticeship job creation tax credit can only be carried back to tax years that end after May 1, 2006.
4. Investments or expenditures, as defined in subsection 127(9) and Part XLVI of the federal *Income Tax Regulations*, that earn the ITC are:
   - qualified property (Parts 4 to 7);
   - qualified expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). Complete and file Form T661, *Claim for Scientific Research and Experimental Development (SR&ED) Carried out in Canada*;
   - pre-production mining expenditures (Parts 18 to 20);
   - apprenticeship job creation expenditures (Parts 21 to 23); and
   - child care spaces expenditures (Parts 24 to 28).
5. Attach a completed copy of this schedule with the *T2 Corporation Income Tax Return.*
6. For more information on ITCs, see the section called "Investment Tax Credit" in the *T2 Corporation – Income Tax Guide*, Information Circular IC 78-4, *Investment Tax Credit Rates,* and its related Special Release. Also, see Interpretation Bulletin IT-151, *Scientific Research and Experimental Development Expenditures.*
7. For information on SR&ED, see Interpretation Bulletin IT-151, *Scientific Research and Experimental Development Expenditures;* Information Circular 86-4, *Scientific Research and Experimental Development;* Pamphlet T4052, *An Introduction to the Scientific Research and Experimental Development Program;* and Guide T4088, *Claiming Scientific Research and Experimental Development – Guide to Form T661.*

Detailed information

1. For the purpose of this schedule, **"investment"** means:
   The capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
2. An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
3. Property acquired has to be "available for use" before a claim for an ITC can be made.
4. Qualified expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which the expenditures or capital costs were incurred.
5. Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 of the Act is not applicable for the agreement to share any income or loss. For more information, see Interpretation Bulletin IT-151. Special rules apply to specified and limited partners.
6. For SR&ED expenditures made after February 22, 2005, the expression "in Canada" includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone. For SR&ED expenditures made before February 23, 2005, the expression "in Canada" generally includes the 12 nautical mile territorial sea.

Name of corporation	Business Number	Tax year-end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2007-12-31

Part 1 – Investments, expenditures and percentages

	Specified percentage
Investments	
Qualified property acquired primarily for use in Newfoundland and Labrador, Prince Edward Island, Nova Scotia, New Brunswick, the Gaspé Peninsula, or a prescribed offshore region	10 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC) throughout the tax year, this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate.	
If you are a corporation that is not a CCPC throughout the current tax year that incurred qualified expenditures for SR&ED in any area in Canada after 1995	20 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures:	
• in 2004	7 %
• after 2004	10 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment after May 1, 2006	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? **101** 1 Yes ☐ 2 No ☒

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC throughout the current tax year and the taxable income (before any loss carrybacks) for its previous tax year cannot be more than its business limit for that previous year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than the total of their business limits for that last year.

Note: A CCPC calculating a refundable ITC for tax years ending before March 23, 2004, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1). For tax years ending after March 22, 2004, the association rule remains the same except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

Some CCPCs that are not qualifying corporations may also earn a 100% refund on their share of any ITCs earned at the 35% rate on qualified current expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified capital expenditures eligible for the 35% credit rate. They are only eligible for the 40% refund.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or

c) any combination of persons referred to in a) or b) above.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? **102** 1 Yes ☐ 2 No ☒

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see the *Guide to the General Index of Financial Information (GIFI) for Corporations.* Enter contributions on line 350 of Part 8.

QUALIFIED PROPERTY

Part 4 – Eligible investments for qualified property from the current tax year

CCA* class number 105	Description of investment 110	Date available for use 115	Location used (province) 120	Amount of investment 125

*CCA: capital cost allowance

Total investment – enter in formula on line 240 in Part 5

Part 5 – Calculation of current-year credit and account balances – ITC from investments in qualified property

ITC at the end of the previous tax year

Deduct:

Credit deemed as a remittance of co-op corporations 210

Credit expired* 215

Subtotal ▶

ITC at the beginning of the tax year 220

Add:

Credit transferred on amalgamation or wind-up of subsidiary 230

ITC from repayment of assistance 235

Total current-year credit: total of column 125 _____ x 10 % = 240

Credit allocated from a partnership 250

Subtotal ▶

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line B1 in Part 30) 260

Credit carried back to the previous year(s) (from Part 6) A

Credit transferred to offset Part VII tax liability 280

Subtotal ▶

Credit balance before refund B

Deduct:

Refund of credit claimed on investments from qualified property (from Part 7) 310

ITC closing balance of investments from qualified property 320

* The credit expires after 20 tax years if it was earned in a tax year ending after 1997 and 10 tax years if it was earned in a tax year ending before 1998.

Part 6 – Request for carryback of credit from investments in qualified property

	Year	Month	Day		
1st previous tax year				Credit to be applied	901
2nd previous tax year				Credit to be applied	902
3rd previous tax year				Credit to be applied	903

Total (enter on line A in Part 5)

Part 7 – Calculation of refund for qualifying corporations on investments from qualified property

Current-year ITCs (total of lines 240 and 250 in Part 5) C

Credit balance before refund (amount B from Part 5) D

Refund (40 % of amount C or D, whichever is less) E

Enter amount E or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

Name of corporation	Business Number	Tax year-end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2007-12-31

SR&ED

Part 8 – Qualified expenditures for SR&ED

Current expenditures (including contributions to agricultural organizations for SR&ED)*	350	347,954
Capital expenditures	360	
Repayments made in the year (from line 560 on Form T661)	370	
Total (this must equal the amount from line 570 on Form T661)*	380	347,954

* Do not file form T661 if you are only claiming contributions made to agricultural organizations for SR&ED.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if the corporation is a CCPC throughout the current tax year.

Note: A CCPC that calculates SR&ED expenditure limit for tax years ending before March 23, 2004, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1). This also applies for tax years ending after March 22, 2004, except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? 385 1 Yes [X] 2 No [ ]

Complete lines 390 and 395 if you answered **no** to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

a) Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied) 390

b) Enter your reduced business limit** for the current tax year* (this amount cannot be more than the amount at line 4 on page 4 of the T2 return) 395

* If either of the tax years referred to at line 390 or 395 is less than 51 weeks, multiply the taxable income or the business limit by the following result: 365 divided by the number of days in these tax years. For details on the expression "Reduced business limit," see line 652 of the *T2 Corporation – Income Tax Guide*.

** If the corporation is claiming only a portion of the business limit from line 4 on page 4 of the T2 return because of its association with other corporations, calculate your reduced business limit as if the corporation was not associated in the current tax year. Enter the result at line 395.

Part 10 – Calculation of SR&ED expenditure limit for a CCPC throughout the current tax year

For stand-alone corporations:

Calculation of the $2,000,000 SR&ED expenditure limit $ *

Subtract: line 390 from Part 9 or $400,000*, whichever is more x 10 =

Excess (if negative, enter "0") F

Line F x (Line 395 / Line 4 on page 4 of the T2 return) = G1

Line G1 x (Number of days before February 26, 2008 / Number of days in the tax year 365) = G2

Calculation of the $3,000,000 SR&ED expenditure limit $

Subtract: line 390 from Part 9 or $400,000, whichever is more* x 10 =

Excess (if negative, enter "0") G3

Line G3 x (– (Taxable capital used in Canada for previous tax year –)) = G4

Line G4 x (Number of days after February 25, 2008 / Number of days in the tax year 365) = G5

SR&ED expenditure limit – Add lines G2 and G5) **G

For associated corporations:

If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49 400 **H

Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Line G or H x (Number of days in the tax year 365 / 365) = I

Your SR&ED expenditure limit for the year (enter the amount from line G, H, or I, whichever applies) 410

* If your tax year immediately follows a tax year that ended before 2007, the references to $6,000,000 and $400,000 should be $5,000,000 and $300,000 respectively.

** Amount G or H cannot be more than $3,000,000 ($2,000,000 for a tax year that ended before February 26, 2008).

Part 11 – Calculation of investment tax credits on SR&ED expenditures

Enter whichever is less: current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10)*	420		x	35 %	=	J
Line 350 minus line 410 (if negative, enter "0")	430	347,954	x	20 %	= 69,591	K
Line 410 minus line 350 (if negative, enter "0")			L			
Enter whichever is less: capital expenditures (line 360 from Part 8) or line L above*	440		x	35 %	=	M
Line 360 minus line L (if negative, enter "0")	450		x	20 %	=	N

Repayments (amount from line 370 in Part 8)

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount. Enter the amount of the repayment on the line that corresponds to the appropriate rate.

460		x	35 %	=
470		x	30 %	=
480		x	20 %	=
			Total	▶ O

Current-year SR&ED ITC (total of lines J, K, M, N, and O; enter on line 540 in Part 12) 69,591

* For corporations that are not CCPCs throughout the year, enter "0" on lines J and M.

Part 12 – Calculation of current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year

Deduct:

Credit deemed as a remittance of co-op corporations	510		
Credit expired*	515		
Subtotal		▶	
ITC at the beginning of the tax year	520		

Add:

Credit transferred on amalgamation or wind-up of subsidiary	530		
Total current-year credit	540	69,591	
Credit allocated from a partnership	550		
Subtotal		69,591 ▶	69,591
Total credit available			69,591

Deduct:

Credit deducted from Part I tax (enter on line B2 in Part 30)	560	69,591	
Credit carried back to the previous year(s) (from Part 13)		P	
Credit transferred to offset Part VII tax liability	580		
Subtotal		69,591 ▶	69,591
Credit balance before refund			Q

Deduct:

Refund of credit claimed on expenditures of SR&ED (from Part 14 or 15, whichever applies) 610

ITC closing balance on SR&ED 620

* The credit expires after 20 tax years if it was earned in a tax year ending after 1997 and 10 tax years if it was earned in a tax year ending before 1998.

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day		
1st previous tax year				Credit to be applied	911
2nd previous tax year				Credit to be applied	912
3rd previous tax year				Credit to be applied	913

Total (enter on line P in Part 12)

Name of corporation	Business Number	Tax year-end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2007-12-31

Part 14 – Calculation of refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . . . 650 1 Yes ☐ 2 No ☒

Credit balance before refund (amount Q from Part 12) . . . . . R

Current-year ITC (lines 540 plus 550 from Part 12 **minus** line O from Part 11) S

Refundable credits (amount R or S, whichever is less)* . . . . . T

Amount J from Part 11 . . . . . U

Subtract: Amount T or U, whichever is less V

Net amount (if negative, enter "0") . . . . . W

Amount W x 40 % X

Add: Amount V . . . . . Y

Refund of ITC (amounts X **plus** Y – enter this, or a lesser amount, on line 610 in Part 12) . . . . . Z

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC on line Z.

Part 15 – Calculation of refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined in Part 2.

Credit balance before refund (amount Q from Part 12) . . . . . AA

Amount J from Part 11 . . . . . BB

Subtract: Amount AA or BB, whichever is less CC

Net amount (if negative, enter "0") . . . . . DD

Amount M from Part 11 . . . . . EE

Amount DD or EE, whichever is less x 40 % . . . . . FF

Add : Amount CC above . . . . . GG

Refund of ITC (amounts FF **plus** GG) . . . . . HH

Enter HH, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

RECAPTURE – SR&ED

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997, or in any of the 10 previous tax years, if the credit was earned in a tax year ending before 1998;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note

The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

	Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above **700**	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter this amount on line LL in Part 17) ||

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil at line JJ in Part 16.

A	B	C
Rate percentage that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720**	Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730**	Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740**

Name of corporation	Business Number	Tax year-end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2007-12-31

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED (continued)

Calculation 2 (continued) – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil on line JJ below.

D Amount determined by the formula **(A x B) - C**	E ITC earned by the transferee for the qualified expenditures that were transferred 750	F Amount from column D or E, whichever is less

Subtotal (enter this amount on line MM in Part 17) _____ JJ

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12 on page 5. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line KK below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported on line NN in Part 17) 760 _____ KK

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC for calculation 1 from line II in Part 16 . . . . . _____ LL

Recaptured ITC for calculation 2 from line JJ in Part 16 above . . . . . _____ MM

Recaptured ITC for calculation 3 from line KK in Part 16 above . . . . . _____ NN

Total recapture of SR&ED investment tax credit – Add lines LL, MM and NN . . . . . _____ OO

Enter amount OO at line A1 in Part 29.

PRE-PRODUCTION MINING

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year and after 2002.

List of minerals 800

For each of the minerals reported in column 800 above, identify each project, mineral title, and mining division where title is registered. If there is no mineral title, identify the project and mining division only.

Project name 805	Mineral title 806	Mining division 807

Pre-production mining expenditures *

Pre-production mining expenditures that the corporation incurred in the tax year and after 2002, for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting	810		PP
Geological, geophysical, or geochemical surveys	811		QQ
Drilling by rotary, diamond, percussion, or other methods	812		RR
Trenching, digging test pits, and preliminary sampling	813		SS

Pre-production mining expenditures incurred in the tax year and after 2002 for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping	820		TT
Sinking a mine shaft, constructing an adit, or other underground entry	821		UU

Other pre-production mining expenditures incurred in the tax year and after 2002:

Description 825	Amount 826

Add amounts at column 826 ▶ _____ VV

Total pre-production mining expenditures (add amounts PP to VV) 830 _____

Deduct: Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above 832 _____

Excess (line 830 minus line 832) (if negative, enter "0") _____ WW

Add: Repayments of government and non-government assistance 835 _____ XX

Pre-production mining expenditures (amount WW plus amount XX) _____ YY

* A pre-production mining expenditure is defined under subsection 127(9) and does not include an amount renounced under subsection 66(12.6).

Name of corporation	Business Number	Tax year-end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2007-12-31

Part 19 – Calculation of current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year

Deduct:

Credit deemed as a remittance of co-op corporations 841

Credit expired* 845

Subtotal ▶

ITC at the beginning of the tax year 850

Add:

Credit transferred on amalgamation or wind-up of subsidiary 860

Expenditures from line YY, Part 18, incurred in 2003 865 x 5 % = ZZ

Expenditures from line YY, Part 18, incurred in 2004 867 x 7 % = AAA

Expenditures from line YY, Part 18, incurred after 2004 870 x 10 % = BBB

Total current-year credit (add amounts ZZ, AAA, and BBB) 880 ▶

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line B3 in Part 30) 885

Credit carried back to the previous year(s) (from Part 20) CCC

Subtotal ▶

ITC closing balance from pre-production mining expenditures 890

* The credit expires after 20 tax years if it was earned in a tax year ending after 1997 and 10 tax years if it was earned in a tax year ending before 1998.

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day
1st previous tax year			
2nd previous tax year			
3rd previous tax year			

Credit to be applied 921

Credit to be applied 922

Credit to be applied 923

Total (enter on line CCC in Part 19)

APPRENTICESHIP JOB CREATION

Part 21 – Calculation of total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number or name) appears below? (If not, you cannot claim the tax credit.) . . . . . 611 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the social insurance number (SIN) or the name of the eligible apprentice. Also enter the name of the eligible trade, the eligible salary and wages* payable for employment after May 1, 2006, and 10% of this amount. Then enter the lesser of 10% of eligible salary and wages **or** $2,000.

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
1.					

Total current-year credit (enter at line 640)

* Net of any other government or non-government assistance received or to be received.

Part 22 – Calculation of current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year . . . . .

Deduct:

Credit deemed as a remittance of co-op corporations 612

Credit expired after 20 tax years 615

Subtotal ▶

ITC at the beginning of the tax year 625

Add:

Credit transferred on amalgamation or wind-up of subsidiary 630

ITC from repayment of assistance 635

Total current-year credit (total of column 605) 640

Credit allocated from a partnership 655

Subtotal ▶

Total credit available . . . . .

Deduct:

Credit deducted from Part I tax (enter on line B4 in Part 30) 660

Credit carried back to the previous year(s) (from Part 23) . . . . . DDD

Subtotal ▶

ITC closing balance from apprenticeship job creation expenditures 690

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

Carryback of this credit is restricted to tax years ending after May 1, 2006.

	Year	Month	Day	
1st previous tax year				Credit to be applied 931
2nd previous tax year				Credit to be applied 932
3rd previous tax year				Credit to be applied 933

Total (enter on line DDD in Part 22)

Name of corporation	Business Number	Tax year-end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2007-12-31

CHILD CARE SPACES

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred after March 18, 2007, to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation is not a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	CCA* class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

*CCA: capital cost allowance

Cost of depreciable property from the current tax year 715 _____ EEE

Add: Specified child care start-up expenditures from the current tax year . . . . . 705 _____ FFF

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) . . . . . _____ GGG

Deduct: Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line GGG) . . . . . 725 _____ HHH

Excess (amount GGG **minus** amount HHH) (if negative, enter "0") _____ III

Add: Repayments of government and non-government assistance . . . . . 735 _____ JJJ

Total eligible expenditures for child care spaces (amount III **plus** amount JJJ) . . . . . 745 _____

Part 25 – Calculation of current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred after March 18, 2007, to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (line 745)			x	25 %	=		KKK
Number of child care spaces	755		x	$ 10,000	=		LLL
ITC from child care spaces expenditures (amount KKK or LLL, whichever is less)							MMM

Part 26 – Calculation of current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year			
Deduct:			
Credit deemed as a remittance of co-op corporations	765		
Credit expired after 20 tax years	770		
Subtotal		▶	
ITC at the beginning of the tax year	775		
Add:			
Credit transferred on amalgamation or wind-up of subsidiary	777		
Total current-year credit (amount MMM above)	780		
Credit allocated from a partnership	782		
Subtotal		▶	
Total credit available			
Deduct:			
Credit deducted from Part I tax (enter on line B5 in Part 30)	785		
Credit carried back to the previous year(s) (from Part 27)		NNN	
Subtotal		▶	
ITC closing balance from child care spaces expenditures	790		

Part 27 – Request for carryback of credit from child care space expenditures

	Year	Month	Day			
1st previous tax year	2006-12-31			Credit to be applied	941	
2nd previous tax year	2005-12-31			Credit to be applied	942	
3rd previous tax year	2004-12-31			Credit to be applied	943	
				Total (enter on line NNN in Part 26)		

Name of corporation	Business Number	Tax year-end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2007-12-31

RECAPTURE – CHILD CARE SPACES

Part 28 – Calculating the recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) . . . . . ZZZ

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC . . 795

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property 797

Amount from line 795 or line 797, whichever is less . . . . . OOO

Corporate partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26 on page 13. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line PPP below.

Corporate partner's share of the excess of ITC 799 PPP

Total recapture of child care spaces investment tax credit – Add lines ZZZ, OOO, and PPP
Enter amount QQQ on line A2 in Part 29. . . . . QQQ

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC from line OO in Part 17 on page 8		A1
Recaptured child care spaces ITC from line QQQ in Part 28 above		A2
Total recapture of investment tax credit – Add lines A1 and A2 Enter amount A3 on line 602 on page 7 of the T2 return.		A3

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5)		B1
ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12)	69,591	B2
ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19)		B3
ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22)		B4
ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26)		B5
Total ITC deducted from Part I tax (add lines B1, B2, B3, B4, and B5) Enter amount B6 at line 652 on page 7 of the T2 return.	69,591	B6

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 99

Current year

	Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
	69,591	69,591			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				
2002-12-31				
2001-12-31				
2001-09-30				
2000-09-30				
1999-09-30				
1998-09-30				*
1997-09-30				
1996-09-30				
1995-09-30				
1994-09-30				
1993-09-30				
1992-09-30				
1991-09-30				
1990-09-30				
1989-09-30				
1988-09-30				*
Total				

B+C+D+G **Total ITC utilized** 69,591

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit will only expire at the beginning of the subsequent fiscal period. Consequently, this amount will be posted on line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 of the subsequent fiscal year.

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2007-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business Number 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	Bluewater Power Corporation	89247 0410 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada Revenue Agency / Agence du revenu du Canada

Exhibit 4
Tab 3
Schedule 4
Attachment 2

CLAIM FOR SCIENTIFIC RESEARCH AND EXPERIMENTAL DEVELOPMENT (SR&ED) CARRIED OUT IN CANADA

- Use this form to claim SR&ED carried out in Canada during the year. File it with your return of income.
- If you are filing a T2 corporation return of income, place this form on top of the return so that we can identify your SR&ED claim quickly.
- Use a separate form to support SR&ED expenditures incurred by each partnership of which you are a partner.
- Use Guide T4088, *Claiming Scientific Research and Experimental Development Expenditures*, to help you fill out this form. You can also consult our Web site at **www.cra.gc.ca/sred/** for an online help guide.
- If the SR&ED was performed in the province of Newfoundland and Labrador, Nova Scotia, New Brunswick, Québec, Ontario, Manitoba, Saskatchewan, or British Columbia, or in the Yukon Territory, you may be entitled to a provincial or territorial tax credit.
- Complete schedules A, B, C, D, E and F, if they apply to your situation.
- Prepare and retain schedules to support the breakdown for each expenditure claimed in this form and on the required attachments.
- On this form, references to the Act are to the *Income Tax Act*. References to the Regulations are to the *Income Tax Regulations*.
- All the information requested in this form including the attachments, schedules and any other document supporting your expenditures is prescribed information. You have to file the information that applies to your claim, along with Schedule T2SCH31 or Form T2038(IND), within 12 months of the filing-due date of your return of income for the year you incurred the expenditures. If you do not meet this reporting deadline, we may reject your claim.

Part 1 – General Information

Name of claimant
Bluewater Power Distribution Corporation

Claimant's business address and postal code
855 Confederation Street
PO Box 2140
Sarnia N7T 7L6

Claimant's Web site (if available)
http://www.

Business Number, social insurance number, or partnership identification number
86572 7390 RC0001

Return for tax year from: 2007-01-01 (Year Month Day) to: 2007-12-31 (Year Month Day)

100 Name of contact person
Janice McMichael-Dennis

105 Telephone number/extension
(519) 337-8201

110 Fax number

130 Is this the first time you are claiming for SR&ED?
1 Yes [ ] 2 No [X]

132 If not, when was the last claim? Year 2006

142 Is the claim filed for a partnership? 1 Yes [ ] 2 No [X]

145 If *yes*, what is the name of the partnership?

150 Percentage of SR&ED investment tax credits allocated from the partnership %

155 Name of the person or firm who prepared this claim
KPMG LLP

Certification and Election

I certify that I have examined the information provided on this form, and on the related schedules and attachments and it is true, correct, and complete.

I elect (choose) to use the following method to calculate my SR&ED expenditures and related investment tax credits (ITC) for the year. I understand that my election (choice) is irrevocable for this year.

160 I elect to use the proxy method under clause 37(8)(a)(ii)(B) 1 Yes [X]

162 I choose to use the traditional method 1 Yes [ ]

165 Janice McMichael-Dennis
Name of authorized signing officer of the corporation, authorized partner, or individual

Signature

170 Date

For Canada Revenue Agency use only

490 491 492

T661 E (07)

Canada

Part 2 – Scientific or Technological Project Information

Provide the information requested in Step 1 on separate sheets of paper for each project, and attach them to this form. If you have more than 20 projects, you only need to provide project descriptions for the 20 that are largest in term of dollar value. For step 2, provide the information requested on this form and complete Schedule E. For more information, see Guide T4088, *Claiming Scientific Research and Experimental Development.*

Step 1 – Detailed project description

Identify each of the projects you are claiming and use questions A to E below to help you provide the information we need to process your claim. If the project is continuing from last year and the objective has not changed or been achieved, you can use the same information that you provided last year for questions A, B and C. Include sufficient information to show how your project work meets the requirements of the SR&ED Program.

We recommend that you read Guide T4088 before you answer questions A to E. This will help you understand the type of information the Canada Revenue Agency needs to process your claim and will reduce or eliminate the need for you to submit more information. It will also help you avoid preparing unnecessary information. Most projects can be described in four pages or less. It would be helpful to take into account whether your project involved experimental development work or scientific research work, because the eligibility requirements for these are different. In general, **experimental development** work is done either in or outside a laboratory in order to achieve a technological advancement for creating new, or improving existing materials, devices, products, or processes. Scientific research work is done mostly in a laboratory setting to obtain new scientific knowledge.

A. **Scientific or technological objectives** – What is the scientific or technological objective of your project? Does this project involve scientific research or experimental development?

B. **Technology or knowledge base or level** – If your project work is mostly experimental development, what were the technological limitations of the products or processes before you started your project? If your project work is mostly scientific research, what was the extent of existing scientific knowledge in this area?

C. **Scientific or technological advancement** – What advancement in technology is being sought? What were the problems or challenges that could not be solved using commonly available techniques requiring you to seek an advance in the underlying technology to achieve the objective in A above? or what was the new scientific knowledge sought in your work? To what field of science or technology would the advance contribute?

D. **Description of work in the tax year** – Describe the work, including experiments and analyses, that you did in this tax year to achieve the technological or scientific objectives above. If all or part of the work that you are claiming was performed by contractors, include a description of the work performed on your behalf by the contractors or a copy of the statement of work from the contract.

E. **Supporting information** – What technical records or documents generated over the course of the work, such as records of trials, test results, progress and final reports, minutes of meetings, employee activity records, prototypes, and new products, are available to support your claim?

Step 2 – Project summary information

Total number of projects you are claiming in this tax year. **200** 3

If you received an amount under the Industrial Research Assistance Program (IRAP) for SR&ED type work, please indicate the amount you received. **206**

Complete Schedule E to provide a list of all SR&ED projects for which you are claiming expenditures this year.

Part 3 – Summary of SR&ED Expenditures (nearest dollar)

Step 1 – Allowable SR&ED expenditures for SR&ED carried out in Canada

SR&ED portion of salary or wages of employees directly engaged in SR&ED:			
• employees other than specified employees	300	+	213,564
• specified employees (do not include bonuses or remuneration based on profits) (see guide)	305	+	
Amounts deemed incurred in the year under subsection 78(4) (salary or wages)	310	+	
Unpaid amounts deemed not incurred in the year under subsection 78(4) 315			
Cost of materials consumed in the prosecution of SR&ED	320	+	
Cost of materials transformed in the prosecution of SR&ED	325	+	
SR&ED contracts performed on your behalf (complete Schedule F):			
• arm's length contracts	340	+	4,206
• non-arm's length contracts	345	+	
Lease costs of equipment used:			
• all or substantially all (90% of the time or more) for SR&ED	350	+	
• primarily (more than 50% but less than 90% of the time) for SR&ED. Enter only 50% of the lease costs if you use the proxy method. If you use the traditional method, enter "0".	355	+	
Overhead or other expenditures (enter "0" if you use the proxy method)	360	+	
Subtotal (add lines 300 to 360; do not add line 315)	**365**	=	217,770
Third-party payments (complete Schedule A)	370	+	
Total current SR&ED expenditures (add lines 365 and 370)	380	=	217,770
Capital expenditures (for ASA equipment, see guide)	390	+	
Total allowable SR&ED expenditures (add lines 380 and 390)	400	=	217,770

Step 2 – Pool of deductible SR&ED expenditures

Amount from line 400			217,770
less			
• government and non-government assistance for expenditures included on line 400	430	–	
• SR&ED ITC claimed last year (other than ITC on shared-use equipment)	435	–	95,062
• sale of SR&ED capital assets (see guide) and other deductions	440	–	
add			
• previous year's ending balance in the pool of deductible SR&ED expenditures	450	+	
• amount of ITC recaptured in the preceding tax year	453	+	
• adjustments to the pool of deductible expenditures (complete Schedule B, Section 1)	**454**	+	
Amount available for deduction (If the amount is negative, enter "0" and add to income in the year)	455	=	122,708
Deduction claimed in the year	460	–	122,708
Current year's balance of deductible SR&ED expenditures applicable to future years (line 455 minus line 460)	470	=	

Step 3 – Qualified SR&ED expenditures for ITC purposes
Enter the breakdown between current and capital expenditures for ITC purposes.

		Current Expenditures		Capital Expenditures
Total expenditures for SR&ED (from lines 380 and 390)	492	217,770	496	
add				
• unpaid amounts (other than salaries or wages) from previous years that were paid in the year under subsection 127(26)	500 +			
• prescribed proxy amount (complete Schedule D); enter "0" if you use the traditional method	502 +	130,184		
• expenditures on shared-use-equipment (See Note 1)			504 +	
• qualified expenditures transferred to you (from Form T1146)	508 +		510 +	
less				
• government and non-government assistance, and contract payments	534 –		536 –	
• amounts from lines 552 and 554 of Schedule B, Section 2	552 –		554 –	
• amounts from lines 555 and 556 of Schedule C	555 –		556 –	
Subtotal	557 =	347,954	558 =	
SR&ED qualified expenditure pool (add lines 557 and 558)			559 =	347,954
add				
• Repayments of assistance and contract payments made in the year			560 +	
Total SR&ED expenditures that qualify for ITC purposes (add lines 559 and 560)*			570 =	347,954

*To claim an ITC on this amount, you must complete Schedule T2SCH31 – *Investment Tax Credit – Corporation*, or Form T2038(IND), *Investment Tax Credit (Individuals)*, whichever applies.

Note 1
The expenditure is deemed to be 1/4 of the capital cost of the equipment. Certain adjustments may be required if the equipment was purchased from a non-arm's length supplier (see the explanations for lines 522 and 524 in the guide).

Part 4 – Background Information

This information is used to administer the SR&ED program.

Expenditures for SR&ED performed by you (line 400 minus lines 340, 345, and 370) 605 213,564

A. Sources of funds for SR&ED
From the total you entered on line 605, estimate the percentage of distribution of the sources of funds for SR&ED performed within your organization

		Canadian (%)		Foreign (%)
Internal	600	100.000		
Parent companies, subsidiaries, and affiliated companies	602		604	
Federal grants (do not include funds or tax credits from SR&ED tax incentives)	606			
Federal contracts	608			
Provincial funding	610			
SR&ED contract work performed for other companies on their behalf	612		614	
Other funding (e.g., universities, foreign governments)	616		618	

B. Business personnel
Total number of employees 630 95

SR&ED personnel (full-time SR&ED staff, plus full-time equivalent for staff engaged part-time in this activity):

Scientists and engineers	632	5	Technologists and tehnicians	634	1
Managers and administrators	636	4	Other technical supporting staff	638	19

C. Nature of SR&ED work
From the total you entered on line 605, estimate the approximate distribution of your SR&ED effort:

Basic research (no specific application in view)	650		Applied research (specific practical application in view)	652			
Development of new: product	654		process	656		technical services	658	
Improvement to existing: product	660		process	662	100.000	technical services	664	

D. Specialized field of research
Indicate, if applicable, the percentage of the amount on line 605 attributed to the following fields of research:

Software development	670		Biotechnology	672		Environmental protection	674	

Complete Claim Checklist

To speed up the processing of your claim, make sure you have:

1. Used the current version of Form T661 if you are filing a current-year claim	X
2. Signed the "Certification and Election" section in Part 1 of Form T661	X
3. Indicated the method you have chosen for reporting your SR&ED expenditures in fields 160 or 162 of Part 1	X
4. Provided a summary of information for each project, with a breakdown of expenditures (labour, materials and contracts) as per Schedule E	X
5. Submitted a detailed project description of your 20 largest projects in terms of their dollar value	X
6. Retained documents prepared to support the SR&ED expenditures claimed in Part 3. If you forget to claim an expenditure, you have up to 12 months after the filing-due date of your tax return for the year to submit an amended Form T661	X
7. Completed Part 4 - Background Information	X
8. Completed schedule A, B, C, D, E and F, if they apply to your situation, and attached to form T661	X
9. Filed a completed Schedule T2SCH31, *Investment Tax Credit – Corporations*, or Form T2038 (IND), *Investment Tax Credit (Individuals)*, to claim ITCs on your qualified SR&ED expenditures	X

All the information requested in this form including the attachments, schedules and any other document to support your expenditures is prescribed information. You have to file the information that applies to your claim, along with Schedule T2SCH31 or Form T2038(IND), within 12 months of the filing-due date of your Income tax return for the year you incurred the expenditures. If you do not meet this reporting deadline, your claim may be rejected.

Schedule A – Third-Party Payments for SR&ED

You must complete a Schedule A for each third-party payment for SR&ED (attach to Form T661)

Schedule B – Special Situations (attach to Form T661).

Section 1 – Adjustments to the pool of deductible SR&ED expenditures incurred in Canada

• Repayments of government and non-government assistance (include only the repayments of assistance that previously reduced the deductible SR&ED expenditure pool)	445	+	
• SR&ED expenditure pool transfer from amalgamation or wind-up	452	+	
Total (add lines 445 and 452)	454	=	

Report on line 454 in Part 3, Step 2 of Form T661

Section 2 – Adjustments to the qualified SR&ED expenditures for ITC purposes

		Current Expenditures		Capital Expenditures
• Unpaid amounts (other than salary or wages on line 315) deemed not to be incurred in the year under subsection 127(26)	520	–		
• Current expenditures for SR&ED contract paid or payable to, or for the benefit of a person or partnership that is not a taxable supplier in respect of the expenditures	528	–		
• Prescribed expenditures (Section 2902 of the *Regulations*)	530	–	532	–
• Other deductions (see guide)	548	–	550	–
Total (add lines 520, 528, 530, and 548, also add lines 532 and 550)	552	=	554	=

Report on lines 552 and 554 respectively in Part 3, Step 3 of Form T661

Schedule C – Non-Arm's Length Transactions (attach to Form T661).

Adjustments to the qualified SR&ED expenditures for ITC purposes

		Current Expenditures		Capital Expenditures
• Purchases of goods and services from non-arm's length suppliers (except for shared-use-equipment) (see note 1)	522	–	524	–
• Expenditures for non-arm's length SR&ED contracts (from line 345)	526	–		
• Assistance allocated to you (from Form T1145)	538	–	540	–
• Qualified expenditures you transferred (from Form T1146)	544	–	546	–
Total (add lines 522, 526, 538, and 544, also add lines 524, 540, 546)	555	=	556	=

Report on line 555 and 556 respectively in Part 3, Step 3 of Form T661

Note 1

Subsections 127(11.6) to (11.8) provide rules for determining a taxpayer's expenditures to services rendered by, or property acquired from, a non-arm's length supplier. On line 522, enter the difference, if any, between the amount included in your SR&ED expenditure pool for the purchases of goods and services from non-arm's length suppliers and the expenditure's deemed amount under subsection 127(11.6) (read the Guide).

T661 Schedule D – Calculation of Salary Base and Prescribed Proxy Amount

If you are using the proxy method, complete this calculation table and attach it to Form T661.

This table will help you to calculate the prescribed proxy amount (PPA) to enter on line 502 of Form T661. You can only claim a PPA if you elected in Part 1 of Form T661 (line 160) to use the proxy method for the year.

The PPA is 65% of the salary base determined in Section A. The salary base is the total of salary or wages paid to and incurred for the employees directly engaged in SR&ED in Canada during the year.

Special rules apply for specified employees. Calculate your salary base in Section A, the PPA in Section B, and the salary or wages of specified employees eligible to be included in the salary base in Section C.

Section A – Salary base

Salary or wages of employees directly engaged in SR&ED, other than specified employees (from line 300)	810	+	213,564
Less:			
Remuneration based on profits, bonuses, and taxable benefits under sections 6 and 7 of the Act, included on line 810 above	812	–	13,281
Subtotal (line 810 minus line 812)	814	=	200,283
Plus:			
Total salary or wages of specified employees directly engaged in SR&ED (per Section C, total of column 6 below)	816	+	
Salary base (total of lines 814 and 816)	818	=	200,283

Section B – Prescribed Proxy Amount

Calculate 65 % of the salary base per line 818	820	=	130,184

Report the PPA on line 502 of Part 3, Step 3 of Form T661.

In certain situations, an overall cap on the PPA may limit the amount otherwise determined (see Table 7 in the guide).

Section C – Determining the salary or wages of specified employees

Special rules apply to restrict the amount of salary or wages of specified employees that you can include in the salary base. Use the chart below to calculate this amount.

850	852	854	856		858	860
Column 1	**Column 2**	**Column 3**	**Column 4**	**Column 4a**	**Column 5****	**Column 6**
Name of specified employee	Total salary or wages for the year (SR&ED and non-SR&ED)*	Percentage of time spent on SR&ED in Canada (maximum 75%)	Amount in column 2 multiplied by percentage in column 3	Number of days in taxation year employed (maximum 365 days)	2.5 x A x B ÷365	Amount in column 4 or 5, whichever amount is less
Total (enter total of column 6 amounts on line 816 in Section A above).						

* Do not include bonuses, remuneration based on profits, or taxable benefits under sections 6 and 7 of the *Act*.

** **A** is the year's maximum pensionable earnings (section 18 of the *Canada Pension Plan*) for the calendar year in which your tax year ends. The year's maximum pensionable earnings for 2008 are $44, 900 (total $44, 900 x 2.5 = $112, 250), for 2007 are $43,700 (total $43,700 x 2.5 = $109,250), for 2006 they are $42,100 (total $42,100 x 2.5 = $105,250), and for 2005 they are $41,100 (total $41,100 x 2.5 = $102,750).

B is the number of days in the taxation year that you employ the individual.

T661 Schedule E – List of all SR&ED projects claimed in the year (attach to Form T661)

For each project you are claiming, provide the following information using the table below. Expenditures should be recorded and allocated on a project basis.

	210 Project identification: code or name	212 Start date (yyyy/mm/dd)	214 Finish date (yyyy/mm/dd) Actual or expected	216 Total labour expenditures in tax year	218 Total expenditures of materials in tax year	220 Total contract expenditures in tax year
1.	BWP2006-01-01	2006-01-01	2007-12-31	53,509		
2.	BWP2006-02-01	2006-01-01	2007-12-31	79,067		1,092
3.	BWP2006-03-01	2005-05-01	2007-12-31	80,988		52,211
			Total	213,564		53,303

Use copies of this schedule if you have more than 50 projects and attach them to Form T661.

Ontario CT23 tax return

Exhibit 4, Tab 3, Schedule 5, Attachment 1 details the Ontario CT23 tax return.

Ontario

Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

2007 CT23 Corporations Tax and Annual Return

For taxation years commencing after December 31, 2004

Corporations Tax Act – Ministry of Finance (MOF)
Corporations Information Act – Ministry of Government Services (MGS)

This form is a combination of the Ministry of Finance (MOF) **CT23 Corporations Tax Return** and the Ministry of Government Services (MGS) **Annual Return**. Page 1 is a common page required for both Returns. For tax purposes, depending on which criteria the corporation satisfies, it must complete either the **Exempt from Filing (EFF)** declaration on page 2 or file the **CT23 Return** on pages 3-17. Corporations that **do not** meet the EFF criteria but **do** meet the Short-Form criteria, may request and file the **CT23 Short-Form Return** (see page 2).

The **Annual Return** (common page 1 and MGS Schedule A on pages 18 and 19, and Schedule K on page 20) contains non-tax information collected under the authority of the *Corporations Information Act* for the purpose of maintaining a public database of corporate information. This return must be completed by Ontario share-capital corporations or Foreign-Business share-capital corporations that have an extra-provincial licence to operate in Ontario.

MGS Annual Return Required? *(Not required if already filed or Annual Return exempt. Refer to Guide)* [X] Yes [ ] No **Page 1 of 20**

Ministry Use

Corporation's Legal Name *(including punctuation)*
Bluewater Power Distribution Corporation

Ontario Corporations Tax Account No. (MOF)
7308127

Mailing Address
855 Confederation Street
PO Box 2140
Sarnia
ON CA N7T 7L6

This Return covers the Taxation Year
Start: year month day 2007-01-01
End: year month day 2007-12-31

Has the mailing address changed since last filed CT23 Return? [ ] Yes | Date of Change: year month day

Date of Incorporation or Amalgamation
year month day 2000-10-20

Registered/Head Office Address
855 Confederation Street
PO Box 2140
Sarnia
ON CA N7T 7L6

Ontario Corporation No. (MGS) 1446363

Location of Books and Records
855 Confederation Street
PO Box 2140
Sarnia
ON CA N7T 7L6

Canada Revenue Agency Business No.
If applicable, enter 86572 7390 RC0001

Name of person to contact regarding this CT23 Return	Telephone No.	Fax No.
Janice McMichael-Dennis	(519) 337-8201	

Jurisdiction Incorporated: Ontario

Address of Principal Office in Ontario *(Extra-Provincial Corporations only)* (MGS)
Ontario Canada

If not incorporated in Ontario, indicate the date Ontario business activity commenced and ceased:
Commenced: year month day
Ceased: year month day
[X] *Not Applicable*

Former Corporation Name *(Extra-Provincial Corporations only)* [X] *Not Applicable* (MGS)

Information on Directors/Officers/Administrators must be completed on MGS Schedule A or K as appropriate. If additional space is required for Schedule A, only this schedule may be photocopied. State number submitted (MGS). ▶

No. of Schedule(s)

If there is **no change** to the Directors'/Officers'/Administrators' information previously submitted to MGS, please check (X) this box. Schedule(s) A and K are not required (MGS). ▶ [X] **No Change**

Preferred Language / *Langue de préférence*
[X] English *anglais* [ ] French *français*

Ministry Use

Certification (MGS)

I certify that all information set out in the **Annual Return** is true, correct and complete.

Name of Authorized Person *(Print clearly or type in full)*
Janice McMichael-Dennis

Title D [ ] Director O [X] Officer P [ ] Other individuals having knowledge of the Corporation's business activities

Note: Sections 13 and 14 of the *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

CT23 Corporations Tax Return

Identification continued (for CT23 filers only)

Please check applicable (X) box(es) and complete required information.

Type of corporation

1

1 [X] Canadian-controlled Private (CCPC) all year (Generally a private corporation of which 50% or more shares are owned by Canadian residents.) (fed.s.125(7)(b))

2 [ ] Other Private

3 [ ] Public

4 [ ] Non-share Capital

5 [ ] Other *(specify)* ▼

Share Capital with full voting rights owned by Canadian Residents (nearest percent) 100 %

2

1 [ ] Family Farm corporation s.1(2)

2 [ ] Family Fishing corporation s.1(2)

3 [ ] Mortgage Investment corporation s.47

4 [ ] Credit Union s.51

5 [ ] Bank Mortgage subsidiary s.61(4)

6 [ ] Bank s.1(2)

7 [ ] Loan and Trust corporation s.61(4)

8 [ ] Non-resident corporation s.2(2)(a) or (b)

9 [ ] Non-resident corporation s.2(2)(c)

10 [ ] Mutual Fund corporation s.48

11 [ ] Non-resident owned Investment corporation s.49

12 [ ] Non-resident ship or aircraft under reciprocal agreement with Canada s.28(b)

14 [ ] Bare Trustee corporation

15 [ ] Branch of Non-resident s.63(1)

16 [ ] Financial institution prescribed by Regulation only

17 [ ] Investment Dealer

18 [ ] Generator of electrical energy for sale or producer of steam for use in the generation of electrical energy for sale

19 [X] Hydro successor, municipal electrical utility or subsidiary of either

20 [ ] Producer and seller of steam for uses other than for the generation of electricity

21 [ ] Insurance Exchange s.74.4

22 [ ] Farm Feeder Finance Co-operative corporation

23 [ ] Professional corporation (incorporated professionals only)

[ ] This is the first year filing after incorporation or an amalgamation (If checked, attach Ontario Schedule 24.)

[ ] Amended Return

[ ] Taxation year end change – Canada Revenue Agency approval required

[ ] Final taxation year up to dissolution *(Note: for discontinued businesses, see guide.)*

[ ] Final taxation year before amalgamation

[ ] The corporation has a floating fiscal year end

[ ] There has been a transfer or receipt of asset(s) involving a corporation having a Canadian permanent establishment outside Ontario

[ ] There was an acquisition of control to which subsection 249(4) of the federal *Income Tax Act* (ITA) applies since the previous taxation year

If checked, date control was acquired year month day

[ ] The corporation was involved in a transaction where all or substantially all (90% or more) of the assets of a non-arm's length corporation were received in the taxation year and subsection 85(1) or 85(2) of the federal ITA applied to the transaction (If checked, attach Ontario Schedule 44.)

[ ] First year filing of a parent corporation after winding-up a subsidiary corporation(s) under section 88 of the federal ITA during the taxation year. (If checked, attach Ontario Schedule 24.)

[ ] Section 83.1 of the CTA applies (redirection of payments for certain electricity corporations)

Yes	No	
[ ]	[X]	Was the corporation inactive throughout the taxation year?
[X]	[ ]	Has the corporation's Federal T2 Return been filed with the Canada Revenue Agency?

Are you requesting a refund due to:

[ ]	[X]	the Carry-back of a Loss?
[ ]	[X]	an Overpayment?
[ ]	[X]	a Specified Refundable Tax Credit?
[ ]	[X]	Are you a member of a Partnership or Joint Venture?

Complete if applicable

Ontario Retail Sales Tax Vendor Permit no. (Use head office no.)

Ontario Employer Health Tax Account no. (Use head office no.)

Specify major business activity

Energy infastructur

Allocation – If you carry on a business through a permanent establishment in a jurisdiction outside Ontario, you may allocate that portion of taxable income deemed earned in that jurisdiction to that jurisdiction (s.39) (Int.B. 3008).

DOLLARS ONLY

Net Income (loss) for Ontario purposes (per reconciliation schedule, page 15)	±	From 690	4,222,919 .
Subtract: Charitable donations	–	1	23,061 .
Subtract: Gifts to Her Majesty in right of Canada or a province and gifts of cultural property *(Attach schedule 2)*	–	2	.
Subtract: Taxable dividends deductible, per federal Schedule 3	–	3	.
Subtract: Ontario political contributions *(Attach Schedule 2A)* (Int.B. 3002R)	–	4	.
Subtract: Federal Part VI.1 tax . x 3	–	5	.
Subtract: Prior years' losses applied – Non-capital losses From 715	–	From 704	.
Net capital losses (page 16) . x inclusion rate 50.000000 %	–	714	.
Farm losses	–	From 724	.
Restricted farm losses	–	From 734	.
Limited partnership losses	–	From 754	.
Taxable Income (Non-capital loss)	=	10	4,199,858 .
Addition to taxable income for unused foreign tax deduction for federal purposes	+	11	.
Adjusted Taxable Income 10 + 11 (if 10 is negative, enter 11)	=	20	4,199,858 .

Taxable Income

Number of Days in Taxation Year

From 10 (or 20 if applicable) 4,199,858 . x 30 100.0000 % Ontario Allocation x 12.5 % x (Days after Dec. 31, 2002 and before Jan. 1, 2004: 33 ___ ÷ Total Days 73 365) = + 29 .

From 10 (or 20 if applicable) 4,199,858 . x 30 100.0000 % Ontario Allocation x 14 % x (Days after Dec. 31, 2003: 34 365 ÷ Total Days 73 365) = + 32 587,980 .

Income Tax Payable (before deduction of tax credits) 29 + 32 = 40 587,980 .

Incentive Deduction for Small Business Corporations (IDSBC) (s.41)

If this section is not completed, the IDSBC will be denied.

Did you claim the federal Small Business Deduction (fed.s.125(1)) in the taxation year or would you have claimed the federal Small Business Deduction had the provisions of fed.s.125(5.1) not been applicable in the taxation year? (X) [X] Yes [ ] No

* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a))		50	4,317,981 .
Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b))	+ 51	4,294,920 .	
Add: Losses of other years deducted for federal purposes (fed.s.111)	+ 52	.	
Subtract: Losses of other years deducted for Ontario purposes (s.34)	– 53	.	
	=	4,294,920 . ▶ 54	4,294,920 .
Federal Business limit (line 410 of the T2 Return) for the year before the application of fed.s.125(5.1)		55	400,000 .

Ontario Business Limit Calculation

320,000 x (Days after Dec. 31, 2002 and before Jan. 1, 2004: 31 ___ ÷ ** 365) = + 46 .

400,000 x (Days after Dec. 31, 2003: 34 365 ÷ ** 365) = + 47 400,000 .

Business Limit for Ontario purposes 46 + 47 = 44 400,000 . x (Percentage of Federal Business limit (from T2 Schedule 23). Enter 100% if not associated. 48 100.0000 %) = 45 400,000 .

Income eligible for the IDSBC From 30 100.0000 % ***Ontario Allocation x 56 400,000 . = 60 400,000 .
Least of 50, 54 or 45

* ***Note:*** *Modified by s.41(6) and (7) for corporations that are members of a partnership. (Refer to Guide.)*

** ***Note:*** *Adjust accordingly for a floating taxation year and use 366 for a leap year.*

*** ***Note:*** *Ontario Allocation for IDSBC purposes may differ from* 30 *if Taxable Income is allocated to foreign jurisdictions. See special rules (s.41(4)).*

continued on Page 5

Income Tax *continued from Page 4*

Calculation of IDSBC Rate

Number of Days in Taxation Year

7 % x (Days after Dec. 31, 2002 and before Jan. 1, 2004: 31 ÷ Total Days: 73 / 365) = + 89 .

8.5 % x (Days after Dec. 31, 2003: 34 365 ÷ Total Days: 73 / 365) = + 90 8.5000

DSBC Rate for Taxation Year 89 + 90 = 78 8.5000

Claim From 60 400,000 • x From 78 8.5000 % = 70 34,000 •

Corporations claiming the IDSBC must complete the Surtax section below if the corporation's taxable income (or if associated, the associated group's taxable income) is greater than the amount 400,000 in 114 below.

Surtax on Canadian-controlled Private Corporations (s.41.1)

Applies if you have claimed the Incentive Deduction for Small Business Corporations.

Associated Corporation - The Taxable Income of associated corporations is the taxable income for the taxation year ending on or before the date of this corporation's taxation year end.

*Taxable Income of the corporation From 10 (or 20 if applicable) + 80 4,199,858 •

If you are a member of an associated group (X) 81 X (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	* Taxable Income (if loss, enter nil)
See schedule			+ 82 513,496 •
			+ 83 •
			+ 84 •

Aggregate Taxable Income 80 + 82 + 83 + 84 , etc. = 85 4,713,354 •

Number of Days in Taxation Year

320,000 x (Days after Dec. 31, 2002 and before Jan. 1, 2004: 31 ÷ Total Days: 73 / 365) = + 115 •

400,000 x (Days after Dec. 31, 2003: 34 365 ÷ Total Days: 73 / 365) = + 116 400,000 •

115 + 116 = 400,000 • ▶ – 114 400,000 •

(If negative, enter nil) = 86 4,313,354 •

Calculation of Specified Rate for Surtax

Number of Days in Taxation Year

4.6670 % x (Days after Dec. 31, 2002: 38 365 ÷ Total Days: 73 / 365) = + 97 4.6670

From 86 4,313,354 • x From 97 4.6670 % = 87 201,304 •

From 87 201,304 • x From 60 400,000 • ÷ From 114 400,000 • = 88 201,304 •

Surtax Lesser of 70 or 88 = 100 34,000

* ***Note: Short Taxation Years –*** Special rules apply where the taxation year is less than 51 weeks for the corporation and/or any corporation associated with it.

continued on Page 6

Additional Deduction for Credit Unions (s.51(4)) *(Attach schedule 17)* - - - - - - - - - - - 110

Manufacturing and Processing Profits Credit (M&P) (s.43)

Applies to Eligible Canadian Profits from manufacturing and processing, farming, mining, logging and fishing carried on in Canada, as determined by regulations.

Eligible Canadian Profits from mining are the "resource profits from the mining operations", as determined for Ontario depletion purposes, after deducting depletion and resource allowances but excluding amounts from sale of Canadian resource property, rentals or royalties. If you are claiming this credit, attach a copy of Ontario schedule 27.

The whole of the active business income qualifies as Eligible Canadian Profits if: **a)** your active business income from sources other than manufacturing and processing, mining, farming, logging or fishing is 20% or less of the total active business income and **b)** the total active business income is $250,000 or less.

Eligible Canadian Profits - + 120

Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC) - - - - - - - - - From 56 400,000

Add: Adjustment for Surtax on Canadian-controlled private corporations

From 100 34,000 ÷ From 30 100.0000 % ÷ From 78 8.5000 % = 121 400,000

*Ontario Allocation

Lesser of 56 or 121 - + 122 400,000

120 – 56 + 122 - = 130

Taxable Income - + From 10 4,199,858

Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC) - - - - - - - - - From 56 400,000

Add: Adjustments for Surtax on Canadian-controlled private corporations - - - - - - - - - - - - - - - + From 122 400,000

Subtract: Taxable Income 10 4,199,858 X Allocation % to jurisdictions outside Canada - - - - - - - - - 140

Subtract: Amount by which Canadian and foreign investment income exceeds net capital losses - - - - - - - - - 141

10 – 56 + 122 – 140 – 141 - = 142 4,199,858

Claim

Number of Days in Taxation Year

143 _____ Lesser of 130 or 142 X From 30 100.0000 % Ontario Allocation X 1.5 % X (Days after Dec. 31, 2002 and before Jan. 1, 2004 33 _____ ÷ Total Days 73 365) = + 154

143 _____ Lesser of 130 or 142 X From 30 100.0000 % Ontario Allocation X 2 % X (Days after Dec. 31, 2003 34 365 ÷ Total Days 73 365) = + 156

M&P claim for taxation year 154 + 156 - = 160

* ***Note:*** *Ontario Allocation for M&P Credit purposes may differ from* 30 *if Taxable Income is allocated to foreign jurisdictions. See special rules (s.43(1))*

Manufacturing and Processing Profits Credit for Electrical Generating Corporations = 161

Manufacturing and Processing Profits Credit for Corporations that Produce and Sell Steam for uses other than the Generation of Electricity - - - - - - - - - - - = 162

Credit for Foreign Taxes Paid (s.40)

Applies if you paid tax to a jurisdiction outside Canada on foreign investment income (Int.B. 3001R). *(Attach schedule)* - 170

Credit for Investment in Small Business Development Corporations (SBDC)

Applies if you have an unapplied, previously approved credit from prior years' investments in new issues of equity shares in Small Business Development Corporations. Any unused portion may be carried forward indefinitely and applied to reduce subsequent years' income taxes. (Refer to the former *Small Business Development Corporations Act*)

Eligible Credit 175 _____ Credit Claimed 180 _____

Subtotal of Income Tax 40 – 70 + 100 – 110 – 160 – 161 – 162 – 170 – 180 - - - - = 190 587,980

continued on Page 7

Income Tax *continued from Page 6*

Specified Tax Credits *(Refer to Guide)*

Ontario Innovation Tax Credit (OITC) (s.43.3) ***Applies*** to scientific research and experimental development in Ontario.
Eligible Credit From 5620 OITC Claim Form *(Attach original Claim Form)* + 191 .

Co-operative Education Tax Credit (CETC) (s.43.4) ***Applies*** to employment of eligible students.
Eligible Credit From 5798 CT23 Schedule 113 *(Attach Schedule 113)* + 192 3,000 .

Ontario Film & Television Tax Credit (OFTTC) (s.43.5)
Applies to qualifying Ontario labour expenditures for eligible Canadian content film and television productions. Name of Production 204
Eligible Credit From 5850 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 193 .

Graduate Transitions Tax Credit (GTTC) (s.43.6) No. of Graduates From 6596
Applies to employment of eligible unemployed post secondary graduates, for employment commencing prior to July 6, 2004 and expenditures incurred prior to January 1, 2005. 194
Eligible Credit From 6598 CT23 Schedule 115 *(Attach Schedule 115)* + 195 .

Ontario Book Publishing Tax Credit (OBPTC) (s.43.7)
Applies to qualifying expenditures in respect of eligible literary works by eligible Canadian authors.
Eligible Credit From 6900 OBPTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* + 196 .

Ontario Computer Animation and Special Effects Tax Credit (OCASE) (s.43.8)
Applies to labour relating to computer animation and special effects on an eligible production.
Eligible Credit From 6700 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 197 .

Ontario Business-Research Institute Tax Credit (OBRITC) (s.43.9)
Applies to qualifying R&D expenditures under an eligible research institute contract.
Eligible Credit From 7100 OBRITC Claim Form *(Attach original Claim Form)* + 198 .

Ontario Production Services Tax Credit (OPSTC) (s.43.10)
Applies to qualifying Ontario labour expenditures for eligible productions where the OFTTC has not been claimed.
Eligible Credit From 7300 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 199 .

Ontario Interactive Digital Media Tax Credit (OIDMTC) (s.43.11)
Applies to qualifying labour expenditures of eligible products for the taxation year.
Eligible Credit From 7400 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 200 .

Ontario Sound Recording Tax Credit (OSRTC) (s.43.12)
Applies to qualifying expenditures in respect of eligible Canadian sound recordings.
Eligible Credit From 7500 OSRTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* + 201 .

Apprenticeship Training Tax Credit (ATTC) (s.43.13) No. of Apprentices From 5896
Applies to employment of eligible apprentices. 202 2
Eligible Credit From 5898 CT23 Schedule 114 *(Attach Schedule 114)* + 203 10,000 .

Other (specify) _____ + 203.1 .

Total Specified Tax Credits 191 + 192 + 193 + 195 + 196 + 197 + 198 + 199 + 200 + 201 + 203 + 203.1 = 220 13,000 .

Specified Tax Credits ***Applied to reduce Income Tax*** = 225 13,000 .

Income Tax 190 – 225 **OR Enter NIL if reporting Non-Capital Loss** *(amount cannot be negative)* = 230 574,980 .

To determine if the Corporate Minimum Tax (CMT) is applicable to your Corporation, see **Determination of Applicability** section for the CMT on **Page 8.** If CMT is not applicable, transfer amount in 230 to Income Tax in **Summary** section on **Page 17.**

OR

If CMT is not applicable for the current taxation year but your corporation has CMT Credit Carryovers that you want to apply to reduce income tax otherwise payable, then proceed to and complete the **Application of CMT Credit Carryovers** section part B, on **Page 8.**

DOLLARS ONLY

Total Assets of the corporation	+ 240	64,986,672 •	
Total Revenue of the corporation		+ 241	93,827,815 •

The above amounts include the corporation's and associated corporations' share of any partnership(s) / joint venture(s) total assets and total revenue.

If you are a member of an associated group (X) 242 X (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Total Assets	Total Revenue
See schedule			+ 243 52,110,362 •	+ 244 9,160,990 •
			+ 245 •	+ 246 •
			+ 247 •	+ 248 •

Aggregate Total Assets	240 + 243 + 245 + 247, etc.	= 249	117,097,034 •
Aggregate Total Revenue	241 + 244 + 246 + 248, etc.	= 250	102,988,805 •

Determination of Applicability

Applies if ***either*** Total Assets 249 exceeds $5,000,000 ***or*** Total Revenue 250 exceeds $10,000,000.

Short Taxation Years – Special rules apply for determining total revenue where the taxation year of the corporation or any associated corporation or any fiscal period of any partnership(s) / joint venture(s) of which the corporation or associated corporation is a member, is less than 51 weeks.

Associated Corporation – The total assets or total revenue of associated corporations is the total assets or total revenue for the taxation year ending on or before the date of the claiming corporation's taxation year end.

If CMT is applicable to current taxation year, complete section **Calculation: CMT** below and **Corporate Minimum Tax Schedule 101.**

Calculation: CMT *(Attach Schedule 101.)*

Gross CMT Payable – CMT Base	From Schedule 101	2136	3,241,670 • (If negative, enter zero)	X From	30	100.0000 % (Ontario Allocation)	4 % =	276 129,667 •
Subtract: Foreign Tax Credit for CMT purposes *(Attach Schedule)*							–	277 •
Subtract: Income Tax							– From	190 587,980 •
Net CMT Payable (If negative, enter Nil on Page 17.)							=	280 -458,313 •

If 280 is less than zero and you do not have a CMT credit carryover, transfer 230 from **Page 7** to **Income Tax Summary, on Page 17.**

If 280 is less than zero and you have a CMT credit carryover, complete A & B below.

If 280 is greater than or equal to zero, transfer 230 to **Page 17** and transfer 280 to **Page 17, and** to **Part 4 of Schedule 101: Continuity of CMT Credit Carryovers.**

CMT Credit Carryover available From Schedule 101 From 2333 •

Application of CMT Credit Carryovers

A.

Income Tax (before deduction of specified credits)				+ From 190	587,980 •
Gross CMT Payable	+ From 276	129,667 •			
Subtract: Foreign Tax Credit for CMT purposes	– From 277	•			
If 276 – 277 is negative, enter NIL in 290	=	129,667 •	–	290	129,667 •
Income Tax eligible for CMT Credit			=	300	458,313 •

B.

Income Tax (after deduction of specified credits)	+ From 230		574,980 •
Subtract: CMT credit used to reduce income taxes	–	310	•
Income Tax	=	320	574,980 •

Transfer to page 17

If A & B apply, 310 ***cannot exceed the lesser of*** 230, 300 ***and your CMT credit carryover available*** 2333.

If only B applies, 310 ***cannot exceed the lesser of*** 230 ***and your CMT credit carryover available*** 2333.

Capital Tax *(Refer to Guide and Int.B. 3011R)*

If your corporation is a Financial Institution (s.58(2)), complete lines 480 *and* 430 *on page 10 then proceed to page 13.*

If your corporation is not a member of an associated group and/or partnership and the Gross Revenue and Total Assets as calculated on page 10 in 480 *and* 430 *are both $3,000,000 or less, your corporation is exempt from Capital Tax for the taxation year, except for a branch of a non-resident corporation. A corporation that meets these criteria should disregard all other Capital Tax items (including the calculation of Taxable Capital). Enter NIL in* 550 *on page 12 and complete the return from that point. All other corporations must compute their Taxable Capital in order to determine their Capital Tax payable.*

Members of a partnership (limited or general) or a joint venture, must attach all financial statements of each partnership or joint venture of which they are a member. The Paid-up Capital of each corporate partner must include its share of liabilities that would otherwise be included if the partnership were a corporation. If Investment Allowance is claimed, Total Assets must be adjusted by adding the corporation's share of the partnership's Total Assets and by deducting investments in the partnership as it appears on the corporation's balance sheet, in addition to any other required adjustments (s.61(5)). Special rules apply to limited partnerships (Int.B. 3017R).

Any Assets and liabilities of a corporation that are being utilized in a joint venture must be included along with the corporation's other Assets and liabilities when calculating its Taxable Paid-up Capital.

Special rules and rates apply to Non-Resident corporations (s.63, s.64 and s.69(3)).

Paid-up Capital of Non-resident: Paid-up capital employed in Canada of a non-resident subject to tax by virtue of s.2(2)(a) or 2(2)(b), and whose **business is not carried on solely in Canada** is deemed to be the **greater** of (1) taxable Income in Canada divided by 8 percent or (2) total assets in Canada minus certain indebtedness in accordance with the provisions of s.63(1)(a) (Int.B. 3010).

Paid-up Capital

Paid-up capital stock (Int.B. 3012R and 3015R)	+	350	18,022,105
Retained earnings (if deficit, deduct) (Int.B. 3012R)	±	351	3,970,834
Capital and other surpluses, excluding appraisal surplus (Int.B.3012R)	+	352	
Loans and advances *(Attach schedule)* (Int.B. 3013R)	+	353	21,515,425
Bank loans (Int.B. 3013R)	+	354	
Bankers acceptances (Int.B. 3013R)	+	355	
Bonds and debentures payable (Int.B. 3013R)	+	356	
Mortgages payable (Int.B. 3013R)	+	357	
Lien notes payable (Int.B. 3013R)	+	358	
Deferred credits (including income tax reserves, and deferred revenue where it would also be included in paid-up capital for the purposes of the large corporations tax) (Int.B. 3013R)	+	359	-2,380,000
Contingent, investment, inventory and similar reserves (Int.B. 3012R)	+	360	
Other reserves not allowed as deductions for income tax purposes *(Attach schedule)* (Int.B. 3012R)	+	361	9,412,347
Share of partnership(s) or joint venture(s) paid-up capital *(Attach schedule(s))* (Int.B. 3017R)	+	362	
Subtotal	=	370	50,540,711
Subtract: Amounts deducted for income tax purposes in excess of amounts booked *(Retain calculations. Do not submit.)* (Int.B. 3012R)	−	371	
Deductible R & D expenditures and ONTTI costs deferred for income tax if not already deducted for book purposes (Int.B. 3015R)	−	372	
Total Paid-up Capital	=	380	50,540,711
Subtract: Deferred mining exploration and development expenses (s.62(1)(d)) (Int.B. 3015R)	−	381	
Electrical Generating Corporations Only – All amounts with respect to electrical generating assets, except to the extent that they have been deducted by the corporation in computing its income for income tax purposes for the current or any prior taxation year, that are deductible by the corporation under clause 11(10)(a) of the *Corporations Tax Act*, and the assets are used both in generating electricity from a renewable or alternative energy source and are qualifying property as prescribed by regulation	−	382	
Net Paid-up Capital	=	390	50,540,711

Eligible Investments *(Refer to Guide and Int.B. 3015R)*

Attach computations and list of corporation names and investment amounts. Short-term investments (bankers acceptances, commercial paper, etc.) are eligible for the allowance only if issued for a term of and held for 120 days or more prior to the year end of the investor corporation.

Bonds, lien notes and similar obligations, (similar obligations, e.g. stripped interest coupons, applies to taxation years ending after October 30, 1998)	+	402	
Mortgages due from other corporations	+	403	
Shares in other corporations (certain restrictions apply) *(Refer to Guide)*	+	404	
Loans and advances to unrelated corporations	+	405	
Eligible loans and advances to related corporations (certain restrictions apply) *(Refer to Guide)*	+	406	1,029,240
Share of partnership(s) or joint venture(s) eligible investments *(Attach schedule)*	+	407	
Total Eligible Investments	=	410	1,029,240

continued on Page 10

Total Assets (Int.B. 3015R) ***DOLLARS ONLY***

Total Assets per balance sheet	+	420	64,986,672
Mortgages or other liabilities deducted from assets	+	421	
Share of partnership(s)/joint venture(s) total assets *(Attach schedule)*	+	422	
Subtract: Investment in partnership(s)/joint venture(s)	–	423	
Total Assets as adjusted	=	430	64,986,672
Amounts in 360 and 361 (if deducted from assets)	+	440	9,412,347
Subtract: Amounts in 371, 372 and 381	–	441	
Subtract: Appraisal surplus if booked	–	442	
Add or Subtract: Other adjustments (specify on an attached schedule)	±	443	
Total Assets	=	450	74,399,019

Investment Allowance (410 ÷ 450) x 390 Not to exceed 410 = 460 699,183

Taxable Capital 390 – 460 = 470 49,841,528

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue) 480 93,827,815

Total Assets (as adjusted) From 430 64,986,672

Calculation of Capital Tax for all Corporations except Financial Institutions

Note: *This version (2007) of the CT23 may only be used for a taxation year that commenced after December 31, 2004.*

Financial Institutions use calculations on page 13.

Important: If the corporation is a family farm corporation, family fishing corporation or a credit union that is not a Financial Institution, complete only Section A below.

OR If the corporation is **not** a member of an associated group and/or partnership, complete Section B below, then review only the Capital Tax calculations in Section C on page 11, selecting and completing the one specific subsection (e.g. C3) that applies to the corporation.

OR If the corporation **is** a member of an associated group and/or partnership, complete Section B below and Section D on page 11, and if applicable, complete Section E or Section F on page 12. Note: if the corporation is a member of a connected partnership, please refer to the CT23 Guide for additional instructions before completing the Capital Tax section.

SECTION A

This section applies only if the corporation is a family farm corporation, a family fishing corporation or a credit union that is not a Financial Institution (Int.B. 3018).

Enter NIL in 550 on page 12 and complete the return from that point.

SECTION B

B1. Calculation of Taxable Capital Deduction (TCD)

		Number of Days in Taxation Year					
		Days after Dec. 31, 2004 and before Jan. 1, 2006	Total Days				
7,500,000	x	36	÷ 73	365	= +	501	
		Days after Dec. 31, 2005 and before Jan. 1, 2007	Total Days				
10,000,000	x	37	÷ 73	365	= +	502	
		Days after Dec. 31, 2006 and before Jan. 1, 2008	Total Days				
12,500,000	x	38 365	÷ 73	365	= +	504	12,500,000
		Days after Dec. 31, 2007	Total Days				
15,000,000	x	39	÷ 73	365	= +	505	

Taxable Capital Deduction (TCD) 501 + 502 + 504 + 505 = 503 12,500,000

B2. This section applies to corporations to calculate the prorated capital tax rate.

Calculation of Capital Tax Rate

		Number of Days in Taxation Year					
		Days before Jan. 1, 2007	Total Days				
0.3 %	x	556	÷ 73	365	= +	511	%
		Days after Dec. 31, 2006 and before Jan. 1, 2009	Total Days				
0.285 %	x	557 365	÷ 73	365	= +	512	0.2850 %

Capital Tax Rate 511 + 512 = 516 0.2850 %

continued on Page 11

Capital Tax Calculation *continued from Page 10*

SECTION C

This section applies if the corporation is **not** a member of an associated group and/or partnership.

C1. If 430 and 480 on page 10 are both $3,000,000 or less, enter NIL in 550 on page 12 and complete the return from that point.

C2. If Taxable Capital in 470 is **equal to or less than the TCD** in 503, enter NIL in 550 on page 12 and complete the return from that point.

C3. If Taxable Capital in 470 **exceeds the TCD** in 503, complete the following calculation and transfer the amount from 523 to 543 on page 12, and complete the return from that point.

\+ From 470 _____ •
− From 503 _____ •
= 471 _____ • x From 30 100.0000 % (Ontario Allocation) x From 516 0.2850 % (Capital Tax Rate) x 555 365 / 365 (366 if leap year) (Days in taxation year) *If floating taxation year, refer to Guide.* = + 523 _____ • *Transfer to 543 on page 12 and complete the return from that point*

SECTION D

This section applies ONLY to a corporation that is a member of an associated group (excluding Financial Institutions and corporations exempt from Capital Tax) and/or partnership. You must check either 509 or 524 and complete this section before you can calculate your Capital Tax Calculation under either Section E or Section F.

D1. ☐ 509 (X if applicable)

All corporations that you are associated with do **not** have a permanent establishment in Canada.

If Taxable Capital 470 on page 10 is equal to or less than the TCD 503 on page 10, enter NIL in 550 on page 12 and complete the return from that point.

If Taxable Capital 470 on page 10 exceeds the TCD 503 on page 10, proceed to **Section E**, enter the TCD amount in 542 in Section E, and complete Section E and the return from that point.

D2. ☒ 524 (X if applicable)

One or more of the corporations that you are associated with **maintains** a permanent establishment in Canada.

You and your associated group may continue to allocate the TCD by completing the Calculation below. Or, the associated group **may file an election** under subsection 69(2.1) of the *Corporations Tax Act*, whereby total assets are used to allocate the TCD among the associated group. Once a ss.69(2.1) election is filed, all members of the group will then be required to file in accordance with the election and allocate a portion (portion is henceforth referred to as **Net Deduction**) of the capital tax effect relating to the TCD to each corporation in the group on the basis of the ratio that each corporation's total assets multiplied by its Ontario allocation is to the total assets of the group.

The total asset amounts and Ontario allocation percentages to be used for this calculation must be taken from each corporation's financial information from its last taxation year ending in the immediately preceding calendar year.

In addition, although each corporation in the associated group may deduct its Net Deduction amount as apportioned by the total asset formula, the group may, at the group's option, reallocate the group's total Net Deduction among the group on what ever basis the corporate group wishes, as long as the total of the reallocated amounts does not exceed the group's total Net Deduction amount originally calculated for the associated group.

D2. Calculation is on next page

continued on Page 12

Capital Tax Calculation *continued from Page 11*

DOLLARS ONLY

D2. Calculation Do **not** complete this calculation if ss.69(2.1) election is filed

Taxable Capital From 470 on page 10 - + From 470 _____ •

Determine aggregate taxable capital of an associated group (excluding financial institutions and corporations exempt from capital tax) and/or partnership having a permanent establishment in Canada

Names of associated corporations (excluding Financial Institutions and corporations exempt from Capital Tax) having a permanent establishment in Canada *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Taxable Capital
			+ 531 _____ •
			+ 532 _____ •
			+ 533 _____ •

Aggregate Taxable Capital 470 + 531 + 532 + 533 , etc. - - - - - - - - - - - - - - - - - - = 540 _____ •

If 540 above is equal to or less than the TCD 503 on page 10, the corporation's Capital Tax for the taxation year, is NIL.

Enter NIL in 523 in section E below, as applicable.

If 540 above is greater than the TCD 503 on page 10, the corporation must compute its share of the TCD below in order to calculate its Capital Tax for the taxation year under Section E below.

From 470 _____ • ÷ From 540 _____ • x From 503 _____ • = 541 _____ •

Transfer to 542 *in Section E below*

Ss.69(2.1) Election Filed

X 591 (X if applicable) **Election filed**. *Attach a copy of Schedule 591 with this CT23 Return.* Proceed to **Section F** below.

SECTION E

This section applies if the corporation **is** a member of an associated group and/or partnership whose total **aggregate** Taxable Capital 540 above, exceeds the TCD 503 on page 10.

Complete the following calculation and transfer the amount from 523 to 543, and complete the return from that point.

\+ From 470 _____ •
\- 542 _____ •
= 471 _____ • x From 30 100.0000 % (Ontario Allocation) x From 516 0.2850 % (Capital Tax Rate) x 555 365 / 365 * (366 if leap year) (Days in taxation year) = + 523 _____ • **Total Capital Tax for the taxation year**

Transfer to 543 *and complete the return from that point*

SECTION F

This section applies if a corporation is a member of an associated group and the associated group has filed a ss.69(2.1) election

\+ From 470 49,841,528 • x From 30 100.0000 % (Ontario Allocation) x From 516 0.2850 % (Capital Tax Rate) - - - - - - - = + 561 142,048 •

\- Capital tax deduction from 995 relating to **your corporation's** Capital Tax deduction, on Schedule 591 - - - From 995 18,137 •

= 562 123,911 •

Total Capital Tax for the taxation year

Capital Tax - - - - - - - - 562 123,911 • x 555 365 / 365 * (366 if leap year) (Days in taxation year) - - - - - = 563 123,911 •

Transfer to 543 *and complete the return from that point*

** If floating taxation year, refer to Guide.*

Capital Tax before application of specified credits - - - - - - - - - - - - - - - - - - = 543 123,911 •

Subtract: Specified Tax Credits applied to reduce capital tax payable *(Refer to Guide)* - - - - - - - - - - - - - 546 _____ •

Capital Tax 543 – 546 *(amount cannot be negative)* - - - - - - - - - - - - - - - - - - = 550 123,911 •

Transfer to Page 17

continued on Page 13

Capital Tax *continued from Page 12*

Calculation of Capital Tax for Financial Institutions

1.1 Credit Unions only

For taxation years commencing **after May 4, 1999** enter NIL in [550] on page 12, and complete the return from that point.

1.2 Other than Credit Unions

(Retain details of calculations for amounts in boxes [565] and [570]. Do not submit with this tax return.)

[565] _____ • Lesser of adjusted Taxable Paid Up Capital and Basic Capital Amount in accordance with Division B.1
x [567] _____ % Capital Tax Rate (1) *(Refer to Guide)*
x From [30] 100.0000 % Ontario Allocation
x [555] 365 (Days in taxation year) / * 365 (366 if leap year)
= + [569] _____ •

[570] _____ • Adjusted Taxable Paid Up Capital in accordance with Division B.1 in excess of Basic Capital Amount
x [571] _____ % Capital Tax Rate (2) *(Refer to Guide)*
x From [30] 100.0000 % Ontario Allocation
x [555] 365 (Days in taxation year) / * 365 (366 if leap year)
= + [574] _____ •

Capital Tax for Financial Institutions – other than Credit Unions (before Section 2) [569] + [574] = [575] _____ •

** If floating taxation year, refer to Guide.*

2. Small Business Investment Tax Credit

(Retain details of eligible investment calculation and, if claiming an investment in CSBIF, retain the original letter approving the credit issued in accordance with the Community Small Business Investment Fund Act. Do not submit with this tax return.)

Allowable Credit for Eligible Investments – [585] _____ •

Financial Institutions: Claiming a tax credit for investment in Community Small Business Investment Fund (CSBIF)? (X) ☐ Yes

Capital Tax - Financial Institutions [575] – [585] = [586] _____ •

Transfer to [543] on Page 12

Premium Tax (s.74.2 & 74.3) *(Refer to Guide)*

(1) Uninsured Benefits Arrangements [587] _____ • x 2 % = [588] _____ •

Applies to Ontario-related uninsured benefits arrangements.

(2) Unlicensed Insurance (enter premium tax payable in [588] and attach a detailed schedule of calculations. If subject to tax under (1) above, add both taxes together and enter total tax in [588].)

Applies to Insurance Brokers and other persons placing insurance for persons resident or property situated in Ontario with unlicensed insurers.

Deduct: Specified Tax Credits applied to reduce premium tax *(Refer to Guide)* – [589] _____ •

Premium Tax [588] – [589] = [590] _____ •

Transfer to page 17

DOLLARS ONLY

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

Net Income (loss) for federal income tax purposes, per federal T2 Schedule 1 ± 600 4,317,981 •
Transfer to Page 15

Add:

Federal capital cost allowance	+ 601	3,431,534 •
Federal cumulative eligible capital deduction	+ 602	150,932 •
Ontario taxable capital gain	+ 603	•
Federal non-allowable reserves. Balance beginning of year	+ 604	•
Federal allowable reserves. Balance end of year	+ 605	•
Ontario non-allowable reserves. Balance end of year	+ 606	•
Ontario allowable reserves. Balance beginning of year	+ 607	•
Federal exploration expenses (e.g. CEDE, CEE, CDE, COGPE)	+ 608	•
Federal resource allowance *(Refer to Guide)*	+ 609	•
Federal depletion allowance	+ 610	•
Federal foreign exploration and development expenses	+ 611	•
Crown charges, royalties, rentals, etc. deducted for Federal purposes *(Refer to Guide)*	+ 617	•

Management fees, rents, royalties and similar payments to non-arms' length non-residents ▼

Number of Days in Taxation Year

612 _____ • x 5 / 12.5 x [Days after Dec. 31, 2002 and before Jan. 1, 2004: 33 _____ ÷ Total Days: 73 365] =+ 633 _____ •

612 _____ • x 5 / 14 x [Days after Dec. 31, 2003: 34 365 ÷ Total Days: 73 365] =+ 634 _____ •

Total add-back amount for Management fees, etc. 633 + 634 = _____ •	+ 613	•
Federal Scientific Research Expenses claimed in year from line 460 of fed. form T661 excluding any negative amount in 473 from Ont. CT23 Schedule 161	+ 615	122,708 •
Add any negative amount in 473 from Ont. CT23 Schedule 161	+ 616	•
Federal allowable business investment loss	+ 620	•
Total of other items not allowed by Ontario but allowed federally *(Attach schedule)*	+ 614	•

Total of Additions 601 to 611 + 617 + 613 + 615 + 616 + 620 + 614 = 3,705,174 • ▶ 640 3,705,174 •
Transfer to Page 15

Deduct:

Ontario capital cost allowance (excludes amounts deducted under 675)	+ 650	3,431,534 •
Ontario cumulative eligible capital deduction	+ 651	150,932 •
Federal taxable capital gain	+ 652	•
Ontario non-allowable reserves. Balance beginning of year	+ 653	•
Ontario allowable reserves. Balance end of year	+ 654	•
Federal non-allowable reserves. Balance end of year	+ 655	•
Federal allowable reserves. Balance beginning of year	+ 656	•
Ontario exploration expenses (e.g. CEDE, CEE, CDE, COGPE) *(Retain calculations. Do not submit.)*	+ 657	•
Ontario depletion allowance	+ 658	•
Ontario resource allowance *(Refer to Guide)*	+ 659	•
Ontario current cost adjustment *(Attach schedule)*	+ 661	•
CCA on assets used to generate electricity from natural gas, alternative or renewable resources.	+ 675	•

Subtotal of deductions for this page 650 to 659 + 661 + 675 681 3,582,466 •
Transfer to Page 15

continued on Page 15

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

continued from Page 14

Net Income (loss) for federal income tax purposes, per federal Schedule 1 - - - - - - - - - - - - - - - - From ± 600 4,317,981 •

Total of Additions on page 14 - From = 640 3,705,174 •

Sub Total of deductions on page 14 - From = 681 3,582,466 •

Deduct:

Ontario New Technology Tax Incentive (ONTTI) Gross-up
(***Applies*** only to those corporations whose Ontario allocation is less than 100% in the current taxation year.)

Capital Cost Allowance (Ontario) (CCA) on prescribed qualifying intellectual property deducted in the current taxation year - - - 662 •

ONTTI Gross-up deduction calculation:

Gross-up of CCA

[From 662 • x (100 / From 30 100.0000 Ontario Allocation)] − From 662 • = 663 •

Workplace Child Care Tax Incentive (WCCT)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [665 • x 30 % x (100 / From 30 100.0000 Ontario allocation)] = 666 •

Workplace Accessibility Tax Incentive (WATI)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [667 • x 100 % x (100 / From 30 100.0000 Ontario allocation)] = 668 •

Number of Employees accommodated 669

Ontario School Bus Safety Tax Incentive (OSBSTI)
(***Applies*** to the eligible acquisition of school buses purchased after May 4, 1999 and before January 1, 2006.) *(Refer to Guide)*

Qualifying expenditures: [670 • x 30 % x (100 / From 30 100.0000 Ontario allocation)] = 671 •

Educational Technology Tax Incentive (ETTI)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [672 • x 15 % x (100 / From 30 100.0000 Ontario allocation)] = 673 •

Ontario allowable business investment loss - - - - - - - - - - - - - - - + 678 •

Ontario Scientific Research Expenses claimed in year in 477 **from Ont. CT23 Schedule 161** + 679 217,770 •

Amount added to income federally for an amount that was negative on federal form T661, line 454 or 455 (if filed after June 30, 2003) - - - - - - - - - + 677 •

Total of other deductions allowed by Ontario *(Attach schedule)* - - - - - - - - + 664 •

Total of Deductions 681 + 663 + 666 + 668 + 671 + 673 + 678 + 679 + 677 + 664 = 3,800,236 • ▶ 680 3,800,236 •

Net income (loss) for Ontario Purposes 600 + 640 − 680 - - - - - - - - - - - - - - - - - = 690 4,222,919 •
Transfer to Page 4

Continuity of Losses Carried Forward

DOLLARS ONLY

		Non-Capital Losses (1)	Total Capital Losses	Farm Losses	Restricted Farm Losses	Listed Personal Property Losses	Limited Partnership Losses (6)
Balance at Beginning of Year		700 (2)	710 (2)	720 (2)	730	740	750
Add:	Current year's losses (7)	701	711	721	731	741	751
	Losses from predecessor corporations (3)	702	712	722	732		752
Subtotal		703	713	723	733	743	753
Subtract:	Utilized during the year to reduce taxable income	704 (2)	715 (2) (4)	724 (2)	734 (2) (4)	744 (4)	754 (4)
	Expired during the year	705		725	735	745	
	Carried back to prior years to reduce taxable income (5)	706 (2) to Page 17	716 (2) to Page 17	726 (2) to Page 17	736 (2) to Page 17	746	
Subtotal		707	717	727	737	747	757
Balance at End of Year		709 (8)	719	729	739	749	759

Analysis of Balance at End of Year by Year of Origin

	Year of Origin (oldest year first) year month day	Non-Capital Losses	Non-Capital Losses of Predecessor Corporations	Total Capital Losses from Listed Personal Property only	Farm Losses	Restricted Farm Losses
800	9th preceding taxation year 1999-09-30	817 (9)	860 (9)		850	870
801	8th preceding taxation year 2000-09-30	818 (9)	861 (9)		851	871
802	7th preceding taxation year 2001-09-30	819 (9)	862 (9)		852	872
803	6th preceding taxation year 2001-12-31	820	830	840	853	873
804	5th preceding taxation year 2002-12-31	821	831	841	854	874
805	4th preceding taxation year 2003-12-31	822	832	842	855	875
806	3rd preceding taxation year 2004-12-31	823	833	843	856	876
807	2nd preceding taxation year 2005-12-31	824	834	844	857	877
808	1st preceding taxation year 2006-12-31	825	835	845	858	878
809	Current taxation year 2007-12-31	826	836	846	859	879
Total		829	839	849	869	889

Notes:

(1) Non-capital losses include allowable business investment losses, fed.s.111(8)(b), as made applicable by s.34.

(2) Where acquisition of control of the corporation has occurred, the utilization of losses can be restricted. See fed.s.111(4) through 111(5.5), as made applicable by s.34.

(3) Includes losses on amalgamation (fed.s.87(2.1) and s.87(2.11)) and/or wind-up (fed.s.88(1.1) and 88(1.2)), as made applicable by s.34.

(4) To the extent of applicable gains/income/at-risk amount only.

(5) Generally a three year carry-back applies. See fed.s.111(1) and fed.s.41(2)(b), as made applicable by s.34.

(6) Where a limited partner has limited partnership losses, attach loss calculations for each partnership.

(7) Include amount from 11 if taxable income is adjusted to claim unused foreign tax credit for federal purposes.

(8) Amount in 709 must equal total of 829 + 839.

(9) Include non-capital losses incurred in taxation years ending after March 22, 2004.

Request for Loss Carry-Back (s.80(16))

Applies to corporations requesting a reassessment of the return of one or more previous taxation years under s.80(16) with respect to one or more types of losses carried back.

- If, after applying a loss carry-back to one or more previous years, there is a balance of loss available to carry forward to a future year, it is the corporation's responsibility to claim such a balance for those years following the year of loss within the limitations of fed.s.111, as made applicable by s.34.
- Where control of a corporation has been acquired by a person or group of persons, certain restrictions apply to the carry-forward and carry-back provisions of losses under fed.s.111(4) through 111(5.5), as made applicable by s.34.
- Refunds arising from the loss carry-back adjustment may be applied by the Minister of Finance to amounts owing under **any Act administered by the Ministry of Finance.**
- Any late filing penalty applicable to the return for which the loss is being applied will not be reduced by the loss carry-back.
- The application of a loss carry-back will be available for interest calculation purposes on the day that is the latest of the following:
  1) the first day of the taxation year after the loss year,
  2) the day on which the corporation's return for the loss year is delivered to the Minister, or
  3) the day on which the Minister receives a request in writing from the corporation to reassess the particular taxation year to take into account the deduction of the loss.
- If a loss is being carried back to a **predecessor corporation**, enter the predecessor corporation's account number and taxation year end in the spaces provided under Application of Losses below.

Application of Losses

	Predecessor Ontario Corporation's Tax Account No. (MOF)	Taxation Year Ending year month day	Non-Capital Losses	Total Capital Losses	Farm Losses	Restricted Farm Losses
Total amount of loss			910	920	930	940
Deduct: Loss to be carried back to preceding taxation years and applied to reduce taxable income						
i) 3rd preceding	901	2004-12-31	911	921	931	941
ii) 2nd preceding	902	2005-12-31	912	922	932	942
iii) 1st preceding	903	2006-12-31	913	923	933	943
Total loss to be carried back			From 706	From 716	From 726	From 736
Balance of loss available for carry-forward			919	929	939	949

Summary

Income Tax	+ From 230 or 320	574,980	
Corporate Minimum Tax	+ From 280		
Capital Tax	+ From 550	123,911	
Premium Tax	+ From 590		
Total Tax Payable	= 950	698,891	
Subtract: Payments	– 960	673,616	
Capital Gains Refund (s.48)	– 965		
Qualifying Environmental Trust Tax Credit *(Refer to Guide)*	– 985		
Specified Tax Credits *(Refer to Guide)*	– 955		
Other, specify	–		
Balance	= 970	25,275	
If payment due	Enclosed * 990	25,275	
If overpayment: Refund *(Refer to Guide)*	= 975		
Apply to (year month day)	980		*(Includes credit interest)*

* Make your cheque (drawn on a Canadian financial institution) or a money order in Canadian funds, payable to the **Minister of Finance** and print your Ontario Corporation's Tax Account No. (MOF) on the back of cheque or money order. *(Refer to Guide for other payment methods.)*

Certification

I am an authorized signing officer of the corporation. I certify that this CT23 return, including all schedules and statements filed with or as part of this CT23 return, has been examined by me and is a true, correct and complete return and that the information is in agreement with the books and records of the corporation. I further certify that the financial statements accurately reflect the financial position and operating results of the corporation as required under section 75 of the *Corporations Tax Act*. The method of computing income for this taxation year is consistent with that of the previous year, except as specifically disclosed in a statement attached.

Name *(please print)*

Janice McMichael-Dennis

Title

President & CEO

Full Residence Address

Signature | Date

Note: Section 76 of the *Corporations Tax Act* provides penalties for making false or misleading statements or omissions.

Attached Schedule with Total

Other reserves not allowed as deductions for income tax purposes (Attach schedule) (Int.B. 3012R)

Title Line 361

Description	Amount
NBV	-37,770,012 00
Less: Land	445,817 00
UCC	40,190,560 00
CEC x 4/3	2,673,652 00
Employee future benefits	5,508,399 00
Regulatory asset difference	-1,636,069 00
Total	9,412,347 00

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Bluewater Power Distribution Corporation	7308127	2007-12-31

Part 1: Calculation of CMT Base

Banks – Net income/loss as per report accepted by Superintendent of Financial Institutions (SFI) under the Bank Act (Canada), adjusted so consolidation/equity methods are not used.

Life Insurance corporations – Net income/loss before Special Additional Tax as determined under s.57.1(2)(c) or (d)

Net Income/Loss (unconsolidated, determined in accordance with GAAP)			± 2100	1,641,670
Subtract (to the extent reflected in net income/loss):				
Provision for recovery of income taxes / benefit of current income taxes	+ 2101			
Provision for deferred income taxes (credits) / benefit of future income taxes	+ 2102			
Equity income from corporations	+ 2103			
Share of partnership(s)/joint venture(s) income	+ 2104			
Dividends received/receivable deductible under fed.s.112	+ 2105			
Dividends received/receivable deductible under fed.s.113	+ 2106			
Dividends received/receivable deductible under fed.s.83(2)	+ 2107			
Dividends received/receivable deductible under fed.s.138(6)	+ 2108			
Federal Part VI.1 tax paid on dividends declared and paid, under fed.s.191.1(1)	x 3 + 2109			
Subtotal	=		– 2110	
Add (to extent reflected in net income/loss):				
Provision for current taxes / cost of current income taxes	+ 2111	1,500,000		
Provision for deferred income taxes (debits) / cost of future income taxes	+ 2112	100,000		
Equity losses from corporations	+ 2113			
Share of partnership(s)/joint venture(s) losses	+ 2114			
Dividends that have been deducted to arrive at net income per Financial Statements s.57.4(1.1) (excluding dividends under fed.s.137(4.1))	+ 2115			
Subtotal	=	1,600,000	+ 2116	1,600,000
Add/Subtract:				
Amounts relating to s.57.9 election/regulations for disposals etc. of property for current/prior years				
** Fed.s.85	+ 2117		or – 2118	
** Fed.s.85.1	+ 2119		or – 2120	
** Fed.s.97	+ 2121		or – 2122	
** Amounts relating to amalgamations (fed.s.87) as prescribed in regulations for current/prior years	+ 2123		or – 2124	
** Amounts relating to wind-ups (fed.s.88) as prescribed in regulations for current/prior years	+ 2125		or – 2126	
** Amounts relating to s.57.10 election/regulations for replacement re fed.s13(4), 14(6) and 44 for current/prior years	+ 2127		or – 2128	
Interest allowable under ss.20(1)(c) or (d) of ITA to the extent not otherwise deducted in determining CMT adjusted net income			– 2150	
Capital gains on eligible donations of publicly-listed securities and ecologically sensitive land made after May 1, 2006 (to the extent reflected in net income/loss)			– 2155	
Subtotal (Additions)	=		+ 2129	
Subtotal (Subtractions)	=		– 2130	
** Other adjustments			± 2131	
Subtotal ± 2100 – 2110 + 2116 + 2129 – 2130 ± 2131			= 2132	3,241,670
** Share of partnership(s)/joint venture(s) **adjusted** net income/loss			± 2133	
Adjusted net income (loss) (if loss, transfer to 2202 in ***Part 2: Continuity of CMT Losses Carried Forward.***)			= 2134	3,241,670
Deduct: * CMT losses: pre-1994 Loss	+ From 2210			
* CMT losses: other eligible losses	+ 2211			
	=		– 2135	

* CMT losses applied cannot exceed adjusted net income or increase a loss

** *Retain calculations. Do not submit with this schedule.*

CMT Base	= 2136	3,241,670

Transfer to CMT Base on Page 8 of the CT23 or Page 6 of the CT8

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Bluewater Power Distribution Corporation	7308127	2007-12-31

Part 2: Continuity of CMT Losses Carried Forward

Balance at Beginning of year NOTES (1), (2)				+ 2201	
Add: Current year's losses	+ 2202				
Losses from predecessor corporations on amalgamation NOTE (3)	+ 2203				
Losses from predecessor corporations on wind-up NOTE (3)	+ 2204				
Amalgamation (X) 2205 ☐ Yes Wind-up (X) 2206 ☐ Yes					
Subtotal	=		▶	+ 2207	
Adjustments (attach schedule)				± 2208	
CMT losses available 2201 + 2207 ± 2208				= 2209	
Subtract: Pre-1994 loss utilized during the year to reduce adjusted net income	+ 2210				
Other eligible losses utilized during the year to reduce adjusted net income NOTE (4)	+ 2211				
Losses expired during the year	+ 2212				
Subtotal	=		▶	− 2213	
Balances at End of Year NOTE (5) 2209 − 2213				= 2214	

Notes:

(1) Pre-1994 CMT loss (see s.57.1(1)) should be included in the balance at beginning of the year. Attach schedule showing computation of pre-1994 CMT loss.

(2) Where acquisition of control of the corporation has occurred, the utilization of CMT losses can be restricted. (see s.57.5(3) and a 57.5(7))

(3) Include and indicate whether CMT losses are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.57.5(8) and s.57.5(9))

(4) CMT losses must be used to the extent of the lesser of the adjusted net income 2134 and CMT losses available 2209.

(5) Amount in 2214 must equal sum of 2270 + 2290.

Part 3: Analysis of CMT Losses Year End Balance by Year of Origin

For a pre-1994 loss, use the date of the last taxation year end before your corporation's first taxation year commencing after 1993.

	Year of Origin (oldest year first) year month day	CMT Losses of Corporation	CMT Losses of Predecessor Corporations
2240	9th preceding taxation year 1999-09-30	2260	2280
2241	8th preceding taxation year 2000-09-30	2261	2281
2242	7th preceding taxation year 2001-09-30	2262	2282
2243	6th preceding taxation year 2001-12-31	2263	2283
2244	5th preceding taxation year 2002-12-31	2264	2284
2245	4th preceding taxation year 2003-12-31	2265	2285
2246	3rd preceding taxation year 2004-12-31	2266	2286
2247	2nd preceding taxation year 2005-12-31	2267	2287
2248	1st preceding taxation year 2006-12-31	2268	2288
2249	Current taxation year 2007-12-31	2269	2289
Totals		2270	2290

The sum of amounts 2270 + 2290 ***must equal amount in*** 2214.

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Bluewater Power Distribution Corporation	7308127	2007-12-31

Part 4: Continuity of CMT Credit Carryovers

Balance at Beginning of year NOTE (1) . . . . . + 2301

Add: Current year's CMT Credit (280 on page 8 of the CT23 or 347 on page 6 of the CT8. If negative, enter NIL) + From 280 or 347

Gross Special Additional Tax NOTE (2) 312 on page 5 of CT8. (Life Insurance corporations only. Others enter NIL.) . . . . . + From 312

Subtract Income Tax (190 on page 6 of the CT23 or page 4 of the CT8) . . . . . – From 190

Subtotal (If negative, enter NIL) . . . = ▶ – 2305

Current year's CMT credit (If negative, enter NIL) 280 or 347 – 2305 . . . = ▶ + 2310

CMT Credit Carryovers from predecessor corporations NOTE (3) . . . . . + 2325

Amalgamation (X) 2315 ☐ Yes Wind-up (X) 2320 ☐ Yes

Subtotal 2301 + 2310 + 2325 . . . . . = 2330

Adjustments *(Attach schedule)* . . . . . ± 2332

CMT Credit Carryover available 2330 ± 2332 . . . . . = 2333

Transfer to Page 8 of the CT23 or Page 6 of the CT8

Subtract: CMT Credit utilized during the year to reduce income tax (310 on page 8 of the CT23 or 351 on page 6 of the CT8.) + From 310 or 351

CMT Credit expired during the year . . . . . + 2334

Subtotal . . . . . = ▶ – 2335

Balance at End of Year NOTE (4) 2333 – 2335 . . . . . = 2336

Notes:

(1) Where acquisition of control of the corporation has occurred, the utilization of CMT credits can be restricted. (see s.43.1(5))

(2) The CMT credit of life insurance corporations can be restricted (see s.43.1(3)(b)).

(3) Include and indicate whether CMT credits are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.43.1(4))

(4) Amount in 2336 must equal sum of 2370 + 2390 .

Part 5: Analysis of CMT Credit Carryovers Year End Balance by Year of Origin

	Year of Origin (oldest year first) year month day	CMT Credit Carryovers of Corporation	CMT Credit Carryovers of Predecessor Corporation(s)
2340	9th preceding taxation year 1999-09-30	2360	2380
2341	8th preceding taxation year 2000-09-30	2361	2381
2342	7th preceding taxation year 2001-09-30	2362	2382
2343	6th preceding taxation year 2001-12-31	2363	2383
2344	5th preceding taxation year 2002-12-31	2364	2384
2345	4th preceding taxation year 2003-12-31	2365	2385
2346	3rd preceding taxation year 2004-12-31	2366	2386
2347	2nd preceding taxation year 2005-12-31	2367	2387
2348	1st preceding taxation year 2006-12-31	2368	2388
2349	Current taxation year 2007-12-31	2369	2389
Totals		2370	2390

The sum of amounts 2370 + 2390 ***must equal amount in*** 2336 .

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Bluewater Power Distribution Corporation	7308127	2007-12-31

CMT Losses Carried Forward Workchart

(i) Continuity of Pre-1994 CMT Losses

	Corporation's Pre-1994 Loss	Predecessors' Pre-1994 Loss Amalgamation	Predecessors' Pre-1994 Loss Wind-Up
Date of the last tax year end before the corp's 1st tax year commencing after 1993			
Pre-1994 Loss (per schedule)			
Less: Claimed in prior taxation years commencing after 1993			
Pre-1994 Loss available for the current year			
Less: Deducted in the current year (max. = adj. net income for the year)			
Expired after 10 years			
Pre-1994 Loss Carryforward			

(ii) Continuity of Other Eligible CMT Losses – Filing Corporation (for losses occurring in tax years commencing after 1993)

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1998-09-30					
9th Prior Year	1999-09-30					
8th Prior Year	2000-09-30					
7th Prior Year	2001-09-30					
6th Prior Year	2001-12-31					
5th Prior Year	2002-12-31					
4th Prior Year	2003-12-31					
3rd Prior Year	2004-12-31					
2nd Prior Year	2005-12-31					
1st Prior Year	2006-12-31					
	Total					

Predecessor Corporations Only – Amalgamation

Indicate the amounts of eligible CMT losses from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1998-09-30						
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
Total						

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Bluewater Power Distribution Corporation	7308127	2007-12-31

CMT Losses Carried Forward Workchart (continued)

Predecessor Corporations Only – Wind-Up

Indicate the amounts of eligible CMT losses from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1998-09-30						
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
Total						

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Bluewater Power Distribution Corporation	7308127	2007-12-31

CMT Credit Carryovers Workchart

Filing Corporation

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1998-09-30					
9th Prior Year	1999-09-30					
8th Prior Year	2000-09-30					
7th Prior Year	2001-09-30					
6th Prior Year	2001-12-31					
5th Prior Year	2002-12-31					
4th Prior Year	2003-12-31					
3rd Prior Year	2004-12-31					
2nd Prior Year	2005-12-31					
1st Prior Year	2006-12-31					
	Total					

Predecessor Corporations Only – Amalgamation

Indicate the amounts of CMT credit carryovers from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1998-09-30						
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
Total						

Predecessor Corporations Only – Wind-Up

Indicate the amounts of CMT credit carryovers from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1998-09-30						
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
Total						

Ontario

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Corporations Tax
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PO Box 620
Oshawa ON L1H 8E9

Surtax on Canadian-Controlled Private Corporations

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Bluewater Power Distribution Corporation	7308127	2007-12-31

Name of Associated Corporation (Canadian and Foreign)	Corporations Tax Number	Taxation Year End	Taxation Income (if loss, enter nil)
Sarnia Power Corporation	7308103	2007-12-31	+
Bluewater Power Corporation	7307761	2007-12-31	+
Sarnia Hydro Energy Services Corporation	7308115	2007-12-31	+
Blackwell Renewable Energy Inc	5763316	2007-12-31	+
Electek Power Services Inc.	6080275	2007-12-31	+ 508,924
Bluewater Power Generation Corporation	5763328	2007-12-31	+ 4,572
			+
			+
			+

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Oshawa ON L1H 8E9

Corporate Minimum Tax - Associated Corporations

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Bluewater Power Distribution Corporation	7308127	2007-12-31

Name of Associated Corporation (Canadian and Foreign)	Corporations Tax Number	Taxation Year End	Total Assets	Total Revenue
Sarnia Power Corporation	7308103	2007-12-31	+ 16,067,346	+ 550,720
Bluewater Power Corporation	7307761	2007-12-31	+ 25,689,813	+ 7,007,100
Sarnia Hydro Energy Services Corporation	7308115	2007-12-31	+ 19,376	+
Blackwell Renewable Energy Inc	5763316	2007-12-31	+ 4,928,698	+ 10,988
Electek Power Services Inc.	6080275	2007-12-31	+ 1,189,301	+ 1,569,273
Bluewater Power Generation Corporation	5763328	2007-12-31	+ 4,215,828	+ 22,909
			+	+
			+	+
			+	+
			+	+
			+	+
			+	+
			+	+
			+	+
			+	+
			+	+
			+	+
			+	+
			+	+
			+	+
			+	+
			+	+
			+	+
			+	+
		Totals	= 52,110,362	= 9,160,990

Transfer to 249 *of the CT23* *Transfer to* 250 *of the CT23*

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Paid-Up Capital: Loans and Advances

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Bluewater Power Distribution Corporation	7308127	2007-12-31

Loans or Advances Credited or Advanced to Corporation
(includes accounts payable to related parties outstanding at the taxation year end for 120 days or more, and accounts payable to non-related parties outstanding for 365 days or more at the taxation year end)

Long Term Debt	+	19,377,604
Customer deposits - current	+	787,096
Customer deposits - long-term	+	1,350,725
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
Total *Transfer to* 353 *of the CT23*	=	21,515,425

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Ontario Charitable Donations and Gifts

Schedule 2

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Bluewater Power Distribution Corporation	7308127	2007-12-31

- For use by a corporation to claim any of the following:
  - Charitable donations;
  - Gifts to Her Majesty in right of Ontario, to Ontario crown agencies, or to Ontario Crown foundations;
  - Gifts to Canada or a province;
  - Gifts of certified cultural property; or
  - Gifts of certified ecologically sensitive land.
- The donations and gifts are eligible for a five year carry-forward.
- Use this schedule to show a credit transfer following an amalgamation or wind-up of subsidiary as described under subsection 87(1) and 88(1) of the federal *Income Tax Act* (Canada).
- For donations and gifts made after March 22, 2004, subsection 34(1.1) of the *Corporations Tax Act* parallels subsection 110.1(1.2) of the *Income Tax Act* and provides as follows:
  - where a particular corporation has undergone a change of control, for taxation years that end on or after the change of control, no corporation can claim a deduction for a gift made by a particular corporation to a qualified donee before the change of control;
  - if a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the change of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- File one completed copy of this schedule with your CT23.

Part 1 – Charitable Donations

Charitable Donations at end of preceding taxation year			+	A
Deduct: Donations expired after 5 taxation years			–	B
Charitable donations at beginning of taxation year			=	C
Add: Donations transferred on amalgamation or wind-up of subsidiary	+	D		
Total current year charitable donations made	+	23,061 E		
Subtotal D + E	=	23,061	▶	23,061 F
Deduct: Adjustment for an acquisition of control (for donations made after March 22, 2004)			–	G
Total donations available **C + F – G**			=	23,061 H
Deduct: Amount applied against taxable income (amount **U**, Part 2)			–	23,061 U
Charitable donations closing balance			=	I

Part 2 – Maximum Deduction Calculation for Donations

Ontario net income for tax purposes multiplied by 75%			=	3,167,189 J
Note: *For credit unions the Ontario net income for tax purposes is the amount before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.*				
Ontario taxable capital gains arising in respect of gifts of capital property	+	K		
Ontario taxable capital gain in respect of deemed gifts of non-qualifying securities per subsection 40(1.01) ITA	+	L		

Add the lesser of:

1. The amount of the recapture of capital cost allowance in respect of charitable gifts — M
2. **The lesser of:**
   - 2a. Proceeds of dispositions less outlays and expenses — N
   - 2b. The capital cost — O
   - The lesser of **N** and **O** — ▶ P
   - The lesser of **M** and **P** — ▶ + Q
   - **Subtotal K + L + Q** = R
   - 25% X R = S

Maximum deduction allowable J + S	=	3,167,189 T	
Claim for charitable donations (not exceeding the lesser of **H** from Part 1, **T** and net income for tax purposes)		23,061 U	

Enter in 1 *of the CT23*

Ontario Charitable Donations and Gifts

Schedule 2

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Bluewater Power Distribution Corporation	7308127	2007-12-31

Part 3 – Gifts to Her Majesty in right of Ontario

For use by a corporation claiming gifts to Her Majesty in right of Ontario, to Ontario Crown Agencies, or to Ontario Crown Foundations.

Gifts to Ontario Crown Agency or Ontario Crown Foundation at end of the preceding taxation year	+		
Deduct: Gifts expired after 5 years	–		
Gifts to Ontario Crown Agency or Ontario Crown Foundation at the beginning of the taxation year	=		
Add: Gifts transferred on amalgamation or wind-up of a subsidiary	+		
Total current year gifts	+		
Subtotal	=		▶
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	–		
Total gifts available	=		
Deduct: Amount applied against taxable income [2] of the CT23	–		
Gifts to Ontario Crown Agency or Ontario Crown Foundation closing balance	=		

Foundation Name	Date of Donation	Amount $
Total gifts to Her Majesty in right of Ontario	=	

Part 4 – Maximum Deduction Calculation for Gifts to Her Majesty in Right of Ontario

Deduction is the lesser of:

1. Ontario Net Income before deductions of gifts after deducting charitable donations and gifts to Her Majesty in right of Canada or a province other than Ontario . . . . . 4,199,858 **V**
2. **Lesser of:**
   - 2a. Ontario Net Income for the taxation year . . . . . 4,222,919 **W**
   - 2b. Gifts made in the taxation year or any of the five preceding taxation years to Her Majesty in Right of Ontario, an Ontario Crown Agency or an Ontario Crown Foundation . . . . . **X**
   - The lesser of **W** and **X** . . . . . ▶ **Y**

Maximum deduction allowable the lesser of **V** and **Y** . . . . . **Z**

Transfer to [2] *of the CT23*

Part 5 – Gifts to Canada or a province other than Ontario

Gifts to Canada or a province other than Ontario at the end of the preceding year	+		
Deduct: Gifts to Canada or a province other than Ontario expired after five taxation years	–		
Gifts to Canada or a province other than Ontario at the beginning of the taxation year	=		
Add: Gifts to Canada or a province other than Ontario transferred on amalgamation or wind-up of a subsidiary	+		
Total current year Gifts to Canada or a province other than Ontario *(Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date.)*	+		
Subtotal	=		▶
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	–		
Total gifts to Canada or a province other than Ontario available	=		
Deduct: Amount applied against taxable income	–		
Gifts to Canada or a province other than Ontario closing balance	=		

Ontario Charitable Donations and Gifts

Schedule 2

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Bluewater Power Distribution Corporation	7308127	2007-12-31

Part 6 – Gifts of certified cultural property

Gifts of certified cultural property at the end of the preceding taxation year	+	
Deduct: Gifts of certified cultural property expired after five years	–	
Gifts of certified cultural property at the beginning of the taxation year	=	
Add: Gifts of certified cultural property transferred on amalgamation or wind-up of a subsidiary	+	
Total current year gifts of certified cultural property	+	
Subtotal	=	▶
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	–	
Total gifts of certified cultural property available	=	
Deduct: Amount applied against taxable income	–	
Gifts of certified cultural property closing balance	=	

Part 7 – Gifts of certified ecologically sensitive land

Gifts of certified ecologically sensitive land at the end of the preceding taxation year	+	
Deduct: Gifts of certified ecologically sensitive land expired after five years	–	
Gifts of certified ecologically sensitive land at the beginning of the taxation year	=	
Add: Gifts of certified ecologically sensitive land transferred on amalgamation or wind-up of a subsidiary	+	
Total current year gifts of certified ecologically sensitive land	+	
Subtotal	=	▶
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	–	
Total gifts of certified ecologically sensitive land available	=	
Deduct: Amount applied against taxable income	–	
Gifts of certified ecologically sensitive land closing balance	=	

Part 8 – Analysis of balance by year of origin

Year of origin	Charitable donations	Gifts to Her Majesty in right of Ontario	Gifts to Canada or a province other than Ontario	Gifts of certified cultural property	Gifts of certified ecologically sensitive land
2006-12-31					
2005-12-31					
2004-12-31					
2003-12-31					
2002-12-31					
2001-12-31					
Totals					

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Ontario Capital Cost Allowance
Schedule 8

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Bluewater Power Distribution Corporation	7308127	2007-12-31

Is the corporation electing under regulation 1101(5q)? 1 ☐ Yes 2 ☒ No

1 Class number	2 Ontario undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of the prior year's CCA schedule)	3 Cost of acquisitions during the year (new property must be available for use) See note 1 below	4 Net adjustments (show negative amounts in brackets)	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 Ontario undepreciated capital cost (column 2 plus column 3 or minus column 4 minus column 5)	7 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) See note 2 below	8 Reduced undepreciated capital cost (column 6 minus column 7)	9 CCA rate %	10 Recapture of capital cost allowance	11 Terminal loss	12 Ontario capital cost allowance (column 8 multiplied by column 9; or a lower amount)	13 Ontario undepreciated capital cost at the end of the year (column 6 minus column 12)
1	18,321,745	189,714		0	18,511,459	94,857	18,416,602	4	0	0	736,664	17,774,795
2	13,456,228			0	13,456,228		13,456,228	6	0	0	807,374	12,648,854
8	1,736,557	193,304		0	1,929,861	96,652	1,833,209	20	0	0	366,642	1,563,219
10	1,354,864	292,958		552	1,647,270	146,203	1,501,067	30	0	0	450,320	1,196,950
12	265,477	476,300		0	741,777	238,150	503,627	100	0	0	503,627	238,150
45	288,363			0	288,363		288,363	45	0	0	129,763	158,600
50		353,265		0	353,265	176,633	176,632	55	0	0	97,148	256,117
47	3,014,757	2,473,985		3,600	5,485,142	1,235,193	4,249,949	8	0	0	339,996	5,145,146
	998,420	1,208,729	-998,420	0	1,208,729	604,365	604,364	0	0	0		1,208,729
Totals	39,436,411	5,188,255	-998,420	4,152	43,622,094	2,592,053	41,030,041				3,431,534	40,190,560

Note 1. 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) of the *Income Tax Act* (Canada).

Note 2. The net cost of acquisitions is the cost of acquisitions plus or minus certain adjustments from column 4.

Note 3. If the taxation year is shorter than 365 days, prorate the CCA claim.

Note 4. Ontario recapture should be included in net income after deducting the federal recapture and the Ontario terminal loss is deducted from net income after including the federal terminal loss.

Enter in boxes 650 . . . . 650 . . . . 650 on the CT23.

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Ontario Cumulative Eligible Capital Deduction
Schedule 10 Page 1 of 2

For taxation years 2002 and later

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Bluewater Power Distribution Corporation	7308127	2007-12-31

- **For use by a corporation that has eligible capital property.**
- **A separate cumulative eligible capital account must be kept for each business.**

Part 1 – Calculation of current year deduction and carry-forward

Ontario Cumulative eligible capital – balance at end of preceding taxation year *(if negative, enter zero)* . . . . . = + 2,156,171 **A**

Add: Cost of eligible capital property acquired during the taxation year + _____ **B**

Other adjustments . . . . . + _____ **C**

B + C . . . . . = _____ x 3 / 4 = _____ **D**

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 . . . . . _____ x 1 / 2 = – _____ **E**

D minus E *(if negative, enter zero)* . . . . . = _____ ▷ + _____ **F**

Amount transferred on amalgamation or wind-up of subsidiary . . . . . + _____ **G**

Subtotal A + F + G . . . . . = 2,156,171 **H**

Deduct: Ontario proceeds of sales (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year . . . . . + _____ **I**

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) of the *Income Tax Act* (Canada) . . . . . + _____ **J**

Other adjustments . . . . . + _____ **K**

I + J + K . . . . . = _____ x 3 / 4 . . . . . = – _____ **L**

Ontario cumulative eligible capital balance H minus L . . . . . = 2,156,171 **M**

*If **M** is negative, enter zero at line **Q** and proceed to **Part 2**, page 2.*

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business . . . . . _____ **N**

From **M** 2,156,171

From **N** – _____

Current year deduction M minus N . . . . . = 2,156,171 x 7 % = + 150,932 **O**

N + O . . . . . = 150,932 ▷ – 150,932 **P**

Note: *The maximum current year deduction is 7%. Any amount up to the maximum deduction of 7% may be claimed. For taxation years starting after December 21, 2000, the deduction may not exceed the maximum amount prorated for the number of days in the taxation year divided by 365 or 366 days.*

Enter amount in box 651 *of the CT23*

Ontario cumulative eligible capital - closing balance M minus P *(if negative, enter zero)* . . . . . = 2,005,239 **Q**

See page 2 - Part 2

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Bluewater Power Distribution Corporation	7308127	2007-12-31

Part 2 – Amount to be included in income arising from disposition

Complete this part only if the amount at line M is negative.

Amount from line M above. *Show this as a positive amount; not negative.* . . . . . R

Total cumulative eligible capital deductions from income for taxation years beginning after June 30, 1988 . . . . . + 1

Total of all amounts which reduced cumulative eligible capital in the current or prior years under subsection 80(7) of the ITA . . . . . + 2

Total of cumulative eligible capital deductions claimed for taxation years beginning before July 1, 1988 . . . . . + 3

Negative balances in the cumulative eligible capital account that were included in income for taxation years beginning before July 1, 1988 . . . . . − 4

Deduct line 4 from line 3 *(if negative, enter zero)* . . . . . = ▷ + 5

Total lines 1 + 2 + 5 . . . . . = 6

Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line **1** 7

Amounts at **Line Z** from Ontario Schedule 10 of previous taxation years ending after February 27, 2000
*(This will be **Line T** in earlier versions of this schedule.)* . . . . . + 8

Total lines 7 + 8 . . . . . = ▷ − 9

Deduct line 9 from line 6 *(if negative, enter zero)* . . . . . = ▷ − S

R minus S *(if negative, enter zero)* . . . . . = T

From Line **5** _____ x 1 / 2 . . . . . = − U

T minus U *(if negative, enter zero)* . . . . . = V

From **V** _____ x 2 / 3 . . . . . = W

Lesser of **R** and **S** . . . . . = + Z

Amount to be included in income W + Z . . . . . =

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Ontario Scientific Research and Experimental Development Expenditures
CT23 Schedule 161

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Bluewater Power Distribution Corporation	7308127	2007-12-31

This schedule is used to calculate Ontario Scientific Research and Experimental Development Expenditures (SR & ED). The rules used in the calculation of Ontario SR & ED follow the federal rules with the exception of the new Ontario measure introduced in the 2001 Ontario Budget and implemented in Bill 127 which received Royal Assent on December 5, 2001.

This schedule must be completed by all corporations performing qualified Ontario SR & ED in a "specified taxation year" or in the taxation year immediately preceding the first specified taxation year of the corporation and filed with the current CT23 or CT8. Other corporations may use this schedule, if they have claimed or are claiming a different SR & ED amount for Ontario than for federal income tax purposes.

- **"Specified Taxation Year" (STY)** is the taxation year of the corporation that begins after February 29, 2000 **and** ends after December 31, 2000.
- **"Investment Tax Credit Amount" (ITC)** means, in respect of a corporation for a taxation year, an amount deducted by the corporation for a preceding taxation year under subsection 127(5) or (6) of the *Income Tax Act* (Canada) (ITA).
- **"Qualified Ontario SR & ED Expenditure" (QORD)** means,
  - A. A qualified expenditure within the meaning of subsection 12(1) of the *Corporations Tax Act* (CTA) that is made or incurred by a corporation in a STY or in the taxation year immediately preceding the first STY of the corporation, or
  - B. An expenditure made or incurred by a partnership in a fiscal period that ends in a STY of a corporation if,
    - the corporation is member of the partnership at any time in the STY, and
    - the expenditure would be a qualified expenditure within the meaning of subsection 12(1) of the CTA if it were made by a corporation.
- **"Ontario Allocation Factor" (OAF)** has the meaning given to that expression by subsection 12(1) of the CTA.

- If a corporation includes a federal ITC amount in determining the amount of the Ontario pool of deductible SR & ED expenditures for a STY, the following amounts are adjusted by the OAF:
  - Amount of recaptured federal ITC relating to QORD for property disposed of in the preceding taxation year in 442 on page 2.
  - Amount of federal ITC relating to QORD claimed federally in the preceding taxation year(s) in 462 on page 2.
  - Amount of federal ITC relating to QORD allocated from partnerships in the current taxation year in 465 on page 2.

- Federal ITCs earned on shared-use equipment (SUE) reduce the capital cost of the property acquired for federal and Ontario income tax purposes in the taxation year after the taxation year in which the ITC is claimed federally. The amount of the federal ITC that relates to QORD on SUE is added to the SR & ED pool for Ontario purposes in the taxation year after the taxation year in which the ITC is claimed federally.

Ontario Scientific Research and Experimental Development Expenditures
CT23 Schedule 161

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Bluewater Power Distribution Corporation	7308127	2007-12-31

Ontario Pool of Deductible SR & ED Expenditures for the current taxation year

Total allowable SR & ED expenditures (capital and current)
(From line 400 federal T661 (T2 SCH32)) . . . . . + 400 **217,770.**

Less: Government and non-government assistance
(From line 430 federal T661 (T2 SCH32)) . . . . . − 430

Preceding year's amount of federal ITC claimed for SR & ED
(From line 435 federal T661 (T2 SCH32)) . . . . . − 435 **95,062.**

Sale of SR & ED capital assets and other deductions
(From line 440 federal T661 (T2 SCH32)) . . . . . − 440

Amount of recaptured federal ITC (From line 453 federal T661 (T2 SCH32))
relating to QORD for property disposed of in the preceding taxation year 442

Gross-up for Ontario allocation factor From 442 ÷ 100.0000 % - - - = − 444
(From 30 of the CT23 or CT8)

Subtotal: 400 − 430 − 435 − 440 − 444 . . . . . = 445 **122,708.**

Add: Repayments of government and non-government assistance
(From line 445 federal T661 (T2 SCH32)) . . . . . + 446

SR & ED expenditure pool transferred on amalgamation or wind-up
(From line 452 federal T661 (T2 SCH32)) . . . . . + 452

Amount of federal ITC recaptured in the preceding taxation year
(From line 453 federal T661 (T2 SCH32)) . . . . . + 453

Preceding year's balance in pool of deductible Ontario SR & ED expenditures
(From 480 of the preceding taxation year) . . . . . + 460

Federal ITC relating to QORD **claimed** federally in the preceding
taxation year(s) . . . . . + 462 **95,062.**
(From 575 on Page 3)

Amount of federal ITC relating to QORD allocated from partnerships
in the current taxation year . . . . . + 465

Subtotal 462 + 465 . . . . . = 468 **95,062.**

Gross-up for Ontario allocation factor From 468 **95,062.** ÷ 100.0000 % - - - = + 470 **95,062.**
(From 30 of the CT23 or CT8)

Subtotal: 445 + 446 + 452 + 453 + 460 + 470

(If the amount in 473 is negative, enter zero, in 475 , 477 and add 473 to 615 of the 2002 CT23 or CT8
or 616 of the 2003 or later CT23 or CT8. If the amount in 473 is positive, enter the amount in 475 .) = 473 **217,770.**

Amount available for deduction . . . . . = 475 **217,770.**

Deduction claimed in the taxation year for Ontario
(Enter the SR & ED expenditure pool deduction claimed in the taxation year in 679 of the CT23 or CT8) . . . . − 477 **217,770.**

Ontario current taxation year closing balance
in pool of deductible SR & ED expenditures 475 − 477 . . . . . = 480

(Transfer this amount to 460 as the carry forward amount for the next taxation year.)

Ontario Scientific Research and Experimental Development Expenditures
CT23 Schedule 161

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Bluewater Power Distribution Corporation	7308127	2007-12-31

Calculation of Preceding Taxation Year Amount and Account Balances - Federal ITC from SR & ED Expenditures relating to QORD.

- This page is used to calculate the amount of the federal ITC that relates to SR & ED performed in Ontario for certain taxation years and is used to increase the amount of the Ontario SR & ED pool on page 2.
- All amounts on this page are based on the preceding taxation year since the amount of the federal ITC that relates to QORD can only be used to increase the Ontario pool for SR & ED in the current taxation year if there was a federal ITC claimed for federal purposes in the preceding taxation year that related to QORD.
- **Do not include amounts** of federal ITCs that relate to QORD that were **allocated from a partnership.** These amounts are added to your SR & ED pool for Ontario in the taxation year that they are allocated from a partnership to a corporation, not in the year after they are claimed federally.

Opening Balance:

(Enter amount 590 from Schedule 161 of the preceding taxation year, if any) . . . . . + 500

Add: Amount of federal ITC earned, relating to QORD
(QORD portion of line 540 federal T2 SCH31 for the preceding taxation year) . . . . . + 510 95,062.

Amount of federal ITC earned, relating to QORD, transferred on amalgamation or wind-up
(QORD portion of line 530 federal T2 SCH31 for the preceding taxation year) . . . . . + 520

Subtotal: 500 + 510 + 520 . . . . . = 535 95,062.

Deduct: Amount of federal ITC, relating to QORD, claimed federally
(QORD portion of line 560 federal T2 SCH31 for the preceding taxation year) . . . . . + 540 95,062.

Amount of federal ITC, relating to QORD, carried back federally to a preceding taxation year(s)
(QORD portion of line P federal T2 SCH31 for the preceding taxation year . . . . . + 550

A refund of federal ITC, relating to QORD, claimed federally
(QORD portion of line 610 federal T2 SCH31 for the preceding taxation year) . . . . . + 560

Amount of federal ITC, relating to QORD, deemed as a remittance of co-op corporations
(QORD portion of line 510 federal T2 SCH31 for the preceding taxation year) . . . . . + 570

Subtotal: 540 + 550 + 560 + 570 . . . . . = 575 95,062.

(Transfer this amount to 462 on Page 2)

Deduct: Amount of federal ITC, relating to QORD, expired per the ITA after 10 taxation years . . . . . .
(QORD portion of line 515 federal T2 SCH31 for the preceding taxation year) . . . . . – 580

Closing Balance: 535 – 575 – 580 . . . . . = 590

(Transfer this amount to 500 as the opening balance for the next taxation year.)

Ontario Scientific Research and Experimental Development Expenditures
CT23 Schedule 161

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Bluewater Power Distribution Corporation	7308127	2007-12-31

Continuity Schedule for Federal ITC relating to SR & ED Expenditures for the Preceding Taxation Year

- All amounts on this page are based on the preceding taxation year.
- Amounts on this page should tie into Part 12 of federal T2 SCH31 completed for the preceding taxation year.

Yr. of Origin (Oldest yr. first) yyyy mm dd	Opening Balance	Additions	Deductions (other than amounts that were allocated from a partnership)	Deductions (only amounts that were allocated from a partnership)	Closing Balance
1997-09-30					
1998-09-30					
1999-09-30					
2000-09-30					
2001-09-30					
2001-12-31					
2002-12-31					
2003-12-31					
2004-12-31					
2005-12-31					
2006-12-31		95,062	95,062		
Totals (see note 1, 2 and 3)	725	740 95,062	755 95,062	770	785

Notes:

1. The amount in 725 should equal the amount of the investment tax credit at the end of the preceding taxation year less line 515 in Part 12 of the federal T2 SCH31 for the preceding taxation year.
2. The amount in 785 should equal the closing balance in line 620 in Part 12 of the federal T2 SCH31 for the preceding taxation year.
3. It is important that the amounts in the deductions columns on this page correctly reflect the year of origin of the federal ITC claimed because only amounts relating to QORD can be used to increase the Ontario SR & ED pool.

Ontario Scientific Research and Experimental Development Expenditures
CT23 Schedule 161

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Bluewater Power Distribution Corporation	7308127	2007-12-31

Continuity Schedule for the Amount of Federal ITC from SR & ED Expenditures relating to QORD for the Preceding Taxation Year

- This page is required to record the amount of the ITC that relates to QORD by year of origin.
- All amounts on this page are based on the preceding taxation year.
- **Do not** include amounts of federal ITCs that relate to QORD that were **allocated from a partnership** (see text at the top of page 3).

Yr. of Origin (Oldest yr. first) yyyy mm dd	Opening Balance	Additions	Deductions	Closing Balance
2000-09-30				
2001-09-30				
2001-12-31				
2002-12-31				
2003-12-31				
2004-12-31				
2005-12-31				
2006-12-31		95,062	95,062	
Totals (see note 1 - 6)	825	840 95,062	855 95,062	870

Notes:

1. The amount in [825] should equal [500] on page 3.
2. The amount in [840] should equal the total of [510] and [520] on page 3.
3. The amount in [855] should equal [575] on page 3.
4. The amount in [870] should equal [590] on page 3.
5. Any deductions that are recorded in the deduction column on this page must be taken out of the same year of origin as indicated in the deduction column on page 4. These deductions must be related to QORD and must not have been allocated from a partnership.
6. The amount of federal ITC relating to QORD will expire if the federal ITC it relates to expires before it is claimed federally.

Ontario

Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

2007 Capital Tax Election of Associated Group Agreement for Allocation of Taxable Capital Deduction (TCD)

CT23 SCHEDULE 591

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Bluewater Power Distribution Corporation	7308127	2007-12-31

The following associated group of corporations includes all the corporations in this associated group (excluding financial institutions and corporations exempt from capital tax) having a permanent establishment in Canada and are hereby making an election under subsection 69(2.1) of the *Corporation Tax Act* to allocate the tax effect of the group's taxable capital deduction (TCD) as calculated in section B1 on page 10 of the CT23 for all taxation years which end in the 2007 calendar year, based on each corporation's total assets and Ontario allocation factor from each corporation's last taxation year ending in the 2006 calendar year.

Applies to taxation years ending in the 2007 calendar year.

Corporation having a permanent establishment in Canada	Last taxation year ending in 2006 calendar year	Ontario Allocation **A**	Total Assets **T**	Net Deduction **A x TE x (T÷X) ND**	Allocation of Net Deduction **AND**
Corporation Tax Account Number (if applicable)	YEAR MONTH DAY				995
7308127	2006-12-31	100.0000	64,947,152	23,015	18,137
Corporation Name: Bluewater Power Distribution Corporation					
Tax Effect (TE) of Taxable Capital Deduction From CT23, Page 10, Section B: **TCD** 503 12,500,000 x **Capital Tax Rate** 516 0.285 = **TE** 35,625					
Corporation Tax Account Number (if applicable)	YEAR MONTH DAY				995
7308103	2006-12-31	100.0000	16,049,480	5,687	
Corporation Name: Sarnia Power Corporation					
Tax Effect (TE) of Taxable Capital Deduction From CT23, Page 10, Section B: **TCD** 503 12,500,000 x **Capital Tax Rate** 516 0.285 = **TE** 35,625					
Corporation Tax Account Number (if applicable)	YEAR MONTH DAY				995
7307761	2006-12-31	100.0000	18,586,210	6,586	1,667
Corporation Name: Bluewater Power Corporation					
Tax Effect (TE) of Taxable Capital Deduction From CT23, Page 10, Section B: **TCD** 503 12,500,000 x **Capital Tax Rate** 516 0.285 = **TE** 35,625					
Corporation Tax Account Number (if applicable)	YEAR MONTH DAY				995
See Schedule			951,210	337	15,821
Corporation Name:					
Tax Effect (TE) of Taxable Capital Deduction From CT23, Page 10, Section B: **TCD** 503 x **Capital Tax Rate** 516 = **TE**					

If insufficient space, attach list.

Total Assets of Associated Group having permanent establishments in Canada **X** 100,534,052 959

Total Net Deductions of Associated Group having permanent establishments in Canada . . . **TND** 35,625 994

Total Allocated Net Deductions of Associated Group having permanent establishments in Canada . . . . . **TAND** 35,625

2007 Capital Tax Election of Associated Group Agreement for Allocation of Taxable Capital Deduction (TCD)

CT23 SCHEDULE 591

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Bluewater Power Distribution Corporation	7308127	2007-12-31

Corporation having a permanent establishment in Canada	Last taxation year ending in 2006 calendar year	Ontario Allocation A	Total Assets T	Net Deduction A x TE x (T÷X) ND	Allocation of Net Deduction AND
Corporation Tax Account Number (if applicable)	YEAR MONTH DAY				995
7308115	2006-12-31	100.0000	19,376	7	57
Corporation Name					
Sarnia Hydro Energy Services Corporation					
Tax Effect (TE) of Taxable Capital Deduction From CT23, Page 10, Section B:					
TCD 503 12,500,000 x **Capital Tax Rate** 516 0.285 = **TE** 35,625					
Corporation Tax Account Number (if applicable)	YEAR MONTH DAY				995
5763316					13,078
Corporation Name					
Blackwell Renewable Energy Inc					
Tax Effect (TE) of Taxable Capital Deduction From CT23, Page 10, Section B:					
TCD 503 12,500,000 x **Capital Tax Rate** 516 0.285 = **TE** 35,625					
Corporation Tax Account Number (if applicable)	YEAR MONTH DAY				995
6080275		100.0000	931,834	330	2,643
Corporation Name					
Electek Power Services Inc.					
Tax Effect (TE) of Taxable Capital Deduction From CT23, Page 10, Section B:					
TCD 503 12,500,000 x **Capital Tax Rate** 516 0.285 = **TE** 35,625					
Corporation Tax Account Number (if applicable)	YEAR MONTH DAY				995
5763328					43
Corporation Name					
Bluewater Power Generation Corporation					
Tax Effect (TE) of Taxable Capital Deduction From CT23, Page 10, Section B:					
TCD 503 12,500,000 x **Capital Tax Rate** 516 0.285 = **TE** 35,625					

Total Assets of Associated Group having permanent establishments in Canada **X** 951,210 959

Total Net Deductions of Associated Group having permanent establishments in Canada . . . **TND** 337 994

Total Allocated Net Deductions of Associated Group having permanent establishments in Canada . . . . . **TAND** 15,821

Ontario

Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Cooperative Education Tax Credit (CETC)
CT23 Schedule 113

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Bluewater Power Distribution Corporation	7308127	2007-12-31

Instructions for completing the CETC Claim Form

- Enter the relevant details for each qualifying work placement, including the amount of tax credit.
- Your total tax credit for the taxation year is equal to the sum of the tax credits for each qualifying work placement.
- Enter the total tax credit claimed on line 192, page 7 of the CT23 Long, or page 4 of the CT23 Short, or page 4 of the CT8.
  - The maximum amount of credit that can be claimed in respect of each work placement is $1,000.
- Ensure you have the following documentation (Do not include with the form or tax return.):
  - a letter of certification from the Ontario college, university other post-secondary institution, containing information as specified by the Minister, stating that the student is enrolled in a qualifying education program; or
  - a voucher for leading-edge technology programs, other than an apprenticeship, stating that the educational program meets the definition of a qualifying program in leading-edge technology and that the work performed by that student during the work placement is in a related field.
- The credit is **considered government assistance** and is therefore **to be included in income** in the year the credit is claimed.

Summary of Co-operative Education Tax Credit Claimed

Complete a separate entry for each student work placement which ended during the corporation's taxation year. The tax credit is for co-op work placements and leading-edge technology work placements. A work placement is generally considered to be a full-time work assignment for up to 4 months in duration.

Example: If a corporation, with a December 31, 2001 taxation year end, hires an eligible student from September 1, 2001 until April 30, 2002, this would be considered 2 work placements. The first work placement is September 1, 2001 to December 31, 2001 and would be claimed in the 2001 taxation year. The second placement is January 1, 2002 to April 30, 2002 and must be claimed in the 2002 taxation year.

Qualifying Work Placements

Name of University/ College and Education Program	Name of Student	Social Insurance No. of Student	Work Placement Start and End Dates (year month day)	Eligible Costs of Placement (ECP)	* Credit Claimed (See notes below) (max. $1,000 per work placement)
Cambrain College Powerline Technician	Andrew Miller	538 887 563	From 2007-05-14 To 2007-08-31	14,875	1,000
Cambrain College Powerline Technician	Brad Hull	503 612 335	From 2007-05-14 To 2007-08-31	15,514	1,000
Cambrain College Powerline Technician	Blair Thompson	541 143 160	From 2007-09-04 To 2007-12-14	13,786	1,000
If insufficient space, attach schedule			**Totals**	5774 44,175	5798 3,000

Transfer to 192 *on Page 7 of the CT23 Long or Page 4 of the CT23 Short, or Page 4 of the CT8*

Note: Enter corporation's salaries & wages paid in the preceding taxation year A $ 6,000,000 •

If A is $600,000 or greater use 10%. If A is $400,000 or less use 15%.

If A is over $400,000 but less than $600,000 use the following formula to calculate the rate:

Rate =.15 – [.05 (From A 6,000,000 • – $400,000) ÷ $200,000]

Indicate rate used: 10.0000 %. ***Credit claimed equals ECP multiplied by rate.**

Ontario

Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Apprenticeship Training Tax Credit (ATTC)

CT23 Schedule 114

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Bluewater Power Distribution Corporation	7308127	2007-12-31

Instructions for completing the ATTC Claim Form

- Enter the relevant details for each eligible apprentice, including the amount of tax credit.
- Your total tax credit for the taxation year is equal to the sum of the tax credits for each eligible apprentice.
- Enter the total tax credit claimed on line 203, page 7 of the CT23 Long, or page 4 of the CT23 Short, or page 4 of the CT8.
- Enter the total number of apprentices hired on line 202, page 7 of the CT23 Long, or page 4 of the CT23 Short, or page 4 of the CT8.
- Corporations are eligible for a 25% (30% in the case of corporations with payroll not exceeding $400,000) refundable tax credit on wages and salaries paid or payable for services performed after May 18, 2004 by an eligible apprentice during the first 36 months of an apprenticeship.
- The maximum amount of credit that can be claimed in respect of each eligible apprentice is $5,000 per year to a maximum of $15,000 over the first 36 months of the apprenticeship. The maximum annual tax credit of $5,000 is pro-rated for the number of days the apprentice was employed during the taxation year.
- The credit is *considered government assistance* and is therefore *to be included in income* in the year the credit is claimed.

Summary of Apprenticeship Training Tax Credit Claimed

Complete a separate entry for each eligible apprentice that is in a qualifying skilled trade and hired before January 1, 2008. This credit applies to **salaries and wages paid after May 18, 2004 and before January 1, 2011** to eligible apprentices during the first 36 months of an apprenticeship.

Example: A taxpayer, with a December 31, 2004 taxation year end, hires an otherwise eligible apprentice on June 1, 2004 at a salary of $3,500 per month. The taxpayer's salaries and wages in the preceding taxation year were $700,000. The credit claimed is the lesser of ***(1)** 25% of salaries paid to the apprentice during the period of employment (25% x $3,500 x 7 = $6,125), and ***(2)** $5,000 multiplied by the number of days the apprentice was employed during the taxation year, divided by the total number of days in the calendar year ($5,000 x 214/366 = $2,923). Hence, the credit claimed in the 2004 taxation year is $2,923.

Eligible Apprenticeship

Trade Code	Description of Apprenticeship Program	Apprentice Name and Social insurance No. (SIN)	Registration Date of Apprenticeship Contract or Training Agreement year month day	Contract or Agreement No.	Employment Period year month day	Eligible Expenditures (EE)	* Credit Claimed (see notes below)
434a	Lineworker	Name Dan Petric SIN 499 326 320	2004-08-04	A85322	From 2007-01-01 To 2007-12-31	23,671	5,000
434a	Lineworker	Name Jeff Kelly SIN 118 168 103	2005-03-03	A85787	From 2007-01-01 To 2007-12-31	78,770	5,000
		Name SIN			From To		
If insufficient space, attach schedule					**Totals**	5874 102,441	5898 10,000

Transfer to 203 *on Page 7 of the CT23 Long or Page 4 of the CT23 Short, or Page 4 of the CT8*

Corporation's salaries & wages paid in the preceding taxation year A $ 6,000,000 •

- If A is $600,000 or greater use 25%.
- If A is $400,000 or less use 30%.
- If A is over $400,000 but less than $600,000 use the following formula to calculate the specified percentage:

  Specified percentage = .30 – [.05 (From A 6,000,000 • – $400,000) ÷ $200,000]

Indicated specified percentage used 25.0000 %

*** Credit claimed equals lesser of:**

(1) EE multiplied by the specified percentage, and

(2) $5,000 x number of days the apprentice was employed in the taxation year
365 (366 if leap year)

Total Number of Apprentices . . . . . = 5896 2 •

Transfer to 202 *on Page 7 of the CT23 Long or Page 4 of the CT23 Short, or Page 4 of the CT8*

Corporate Taxpayer Summary

Corporate information

Corporation's name . . . . . Bluewater Power Distribution Corporation

Taxation Year . . . . . 2007-01-01 to 2007-12-31

Jurisdiction . . . . . Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
☐	☐	☐	☐	X	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐

Corporation is associated . . . . . Y

Corporation is related . . . . . Y

Number of associated corporations . . . 6

Type of corporation . . . . . Canadian-Controlled Private Corporation

Total amount due (refund) federal and provincial* 25,275

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income	4,317,981
Taxable income	4,294,920
Donations	23,061
Calculation of income from an active business carried on in Canada	4,317,981
Dividends paid	6,921,200
Balance of the low rate income pool at the end of the previous year	
Balance of the low rate income pool at the end of the year	
Balance of the general rate income pool at the end of the previous year	2,995,720
Balance of the general rate income pool at the end of the year	5,916,266
Part I tax (base amount)	1,632,070
Surtax	48,103

Credits against part I tax		Summary of tax		Refunds/credits	
Small business deduction		Part I	880,446	ITC refund	
M&P deduction		Part I.3		Dividends refund	
Foreign tax credit		Part IV		Instalments	880,446
Political contributions		Part III.1		Surtax credit	
Investment tax credits	69,591	Other*		Other*	
Abatement/Other*	730,136	Provincial or territorial tax			
				Balance due/refund (–)	

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

Summary of federal carryforward/carryback information

Carryback amounts

Investment tax credits	
Non-capital loss	
Capital loss	
Farm loss	
Restricted farm loss	
Surtax credit	
Part I tax credit (Schedule 42)	
Federal foreign non-business income tax credit	

Carryforward balances

RDTOH	
Charitable donations	
Gifts to Canada, a province or a territory	

Summary of federal carryforward/carryback information (continued)

Gifts of certified cultural property	
Gifts of certified ecologically sensitive land	
Gifts of medicine	
Investment tax credits	
Non-capital losses	
Capital/L.P.P. losses	
Farm losses	
Restricted farm losses	
Current year's balance of SR&ED expenditures (T661)	
Foreign business tax credit	
Unused surtax credit (Schedule 37)	21,119
Capital dividend amount	
Part I tax credit (Schedule 42)	
Cumulative eligible capital	2,005,239
Capital gains reserves	
Financial statement reserve	
Other reserves	
Balance of patronage dividends	
Continuity of exemption of accumulated income	

Summary of provincial information – provincial income tax payable

	Ontario (CT-23)	Québec (CO-17)	Alberta (AT1)
Net income	4,222,919		
Taxable income	4,199,858		
% Allocation	100.00		
Attributed taxable income	4,199,858		
Surtax	34,000	N/A	N/A
Tax payable before deduction*	587,980		
Deductions and credits	47,000		
Net tax payable	574,980		
Attributed taxable capital	49,841,528		N/A
Capital tax payable**	123,911		N/A
Total tax payable***	698,891		
Instalments and refundable credits	673,616		
Balance due/Refund (-)	25,275		

* For Québec, this includes special taxes.
** For Québec, this includes compensation tax and registration fee.
*** For Ontario, this includes corporate minimum tax and premium tax.

	British Columbia	Saskatchewan	Manitoba
% Allocation			
Attributed taxable income			
Tax payable before deduction			
Deductions and credits			
Tax payable or refundable credit			
Attributed taxable capital			
Capital tax payable			
Instalments and refundable credits			
Balance due/Refund (-)			

Summary of provincial information – provincial income tax payable (continued)

	Newfoundland and Labrador	Prince Edward Island	Nova Scotia	New Brunswick
% Allocation				
Attributed taxable income				
Tax payable before deduction				
Deductions and credits				
Tax payable or refundable credit				
Attributed taxable capital				
Capital tax payable				
Instalments and refundable credits				
Balance due/Refund (-)*				

* Only applies in the case of bank, a loan corporation or a trust corporation.

	Yukon	Northwest Territories	Nunavut
% Allocation			
Attributed taxable income			
Tax payable before deduction			
Deductions and credits			
Tax payable or refundable credit			

Summary of provincial carryforward amounts

	Ontario	Québec	Alberta
Non-capital losses			
Net capital/L.P.P. losses			
Farm losses			
Restricted farm losses			
Donations			
Capital gains reserves			
Financial statement reserves			
Other reserves			
Eligible capital	2,005,239	2,005,239	2,005,239

Other carryforward amounts

Ontario

Continuity of other eligible CMT losses – Filling Corporation – OCMT101

Predecessor corporations only – Amalgamation – OCMT101

Predecessor corporations only – Wind-up – OCMT101

CMT credit carryovers workchart – Filling Corporation – OCMT101

CMT credit carryovers workchart – Predecessor corporations only – Amalgamation

CMT credit carryovers workchart – Wind-up – OCMT101

Ontario current taxation year closing balance in pool of deductible SR&ED expenditures – O161

Continuity Schedule for Federal ITC relating to SR&ED Expenditures for the Preceding Taxation Year – O161

Continuity Schedule for the Amount of Federal ITC from SR&ED Expenditures relating to QORD for the Preceding Taxation Year – O161

Québec

R&D expenditures not deducted at the end of the year – RD-222

Foreign non-business income tax credits – CO-17S.39

Development work expenses – FM220.3

Excess development work expenses – FM220.3

Balance of patronage dividends – CO-786

Alberta

Unclaimed SR&ED expenditure pool deduction balance – A16

British Columbia

Scientific research and experimental development – Schedule 425

Manufacturing and processing – Schedule 426

Manitoba

Research and development – Schedule 380

Manufacturing investment – Schedule 381

Co-operative education – Schedule 384

Odour control – Schedule 385

Saskatchewan

Manufacturing and processing investment – Schedule 402

Research and development – Schedule 403

Newfoundland and Labrador

Direct equity tax – Schedule 303

Prince Edward Island

Investment – Schedule 321

Nova Scotia

Energy efficiency tax credit – Schedule 342

Manufacturing and processing investment – Schedule 344

New Brunswick

Research and development – Schedule 360

Nunavut

Investment – Schedule 480

DEFERRAL VARIANCE ACCOUNTS

Description of Deferral and Variance Accounts

Bluewater Power is seeking approval to dispose of certain deferral account principal balances as of December 31, 2007 along with carrying charges accumulated to April 30, 2009. The total amount proposed to be disposed of is a credit of $(3,974,344) as indicated by Exhibit 5, Tab 1, Schedule 2, Attachment 2.

The disposition is planned to be provided over a three year period commencing May 1, 2009 to April 30, 2012. The annual amount to be credited to customers is $(1,324,781). Bluewater Power is proposing a three year disposition in order to maintain rate stability over the term of the incentive rate mechanism plan.

The amount to be dispersed is calculated using the December 31, 2007 principal balance along with carrying charges projected to April 30, 2009 with one exception:

- Bluewater Power is making a claim for LRAM and SSM which is discussed in Exhibit 5, Tab 1, Schedule 3. For presentation purposes, the amount claimed for LRAM and SSM has been included without carrying charges in the total noted above to be dispersed over the three year period. Account 1505 has been used as a holding account in the spreadsheet to display the balances.

Bluewater Power is cognizant of the OEB's letter dated February 19, 2008 regarding initiative EB-2008-0046 'Deferral Account Review Initiative'. Given this pending review the OEB has deferred other LDCs' request for disposition of the deferral and variance account balances. Bluewater Power, however, has seen the balance in Account 1588 grow in a credit balance over the last two years. As demonstrated, the balances are significant and we feel it is in our customers' best interest to rebate the accumulated credit balance beginning May 1, 2009.

Descriptions of the accounts proposed for disposition by Bluewater Power are set out below.

Account Type	Name	Description
Commodity Accounts	1588 – Retail Settlement Variance Account (RSVA) – Power	This account is used to record the net difference between the energy amount billed to customers and the energy charge to a distributor using the settlement invoiced from the IESO for electricity commodity charges.
	1588 – RSVA Power – Sub Account Global Adjustment (shown as account 2425 in Attachments 1 and 2, for presentation purposes)	Effective January 1, 2005 this account reflects the monthly difference between the IESO amount charged to customers, which is a preliminary amount calculate by the IESO for billing purposes, and the final amount charged or credited by the IESO on the monthly settlement invoice for Global Adjustment.
Non-Commodity Accounts	1584 – RSVA Retail Transmission Network Charge	This account reflects the net amount charged by the IESO, based on the Settlement Invoice entries, for transmission network charge and the amount billed to customers using Board approved rates
	1586 – RSVA Retail Transmission Connection charge	This account records the net of the amount charged by the IESO based on Settlement Invoice entries, for transmission connection charges, and the amount billed to customers using Board approved rates.
	1580 – RSVA Wholesale Market Service Charge	This account reflects the net amount based on the settlement invoice entries for wholesale market service charges, and the amount billed to customer using Board approved rates
Utility Deferral accounts	1508 – Other Regulatory Accounts	This account tracks OEB Assessment Costs and OMERS cash pension contributions for the period January 1, 2005 to April 30, 2006.
	1525 – Miscellaneous Deferred Debits	This account has the residual balance for costs for rebate credits issued in December 2005.
	1550 - LV Variance account	This account records the variance between the amount charged by to BWP by Hydro One for low voltage services and the amount billed to customers based on BWP's approved LV rate.

The balances in Accounts 1580 RSVA – Wholesale Market Service charge and 1588 RSVA – Power have increasingly grown in a credit position since 2005. Bluewater Power believes the growth is related to its distribution loss factor. As part of the Bluewater Power 2006 EDR application, the loss factor was increased from 1.0373 to 1.0446 (Secondary metered customers < 5000 kW) to reflect the 2002 to 2004 average loss factor. In this application, Bluewater Power is proposing to decrease the distribution loss factor to 1.0356. Bluewater Power has seen significant improvements in its loss factor and this application represents a decrease of 0.9% over the current level. The expectation is that the lower distribution loss factor will prevent these

particular deferral accounts from increasing in a credit position any further, but the balances are available to be returned to customers.

The other two RSVA accounts, 1584 – RSVA Transmission Network, and 1586 RSVA – Transmission Connection have remained fairly stable over the last three years.

Calculation of Balances by Account

Exhibit 5, Tab 1, Schedule 2, Attachment 1 contains the opening and closing principal and interest balances, and the changes throughout each year from January 1, 2005 to December 31, 2007 for each variance and deferral account that Bluewater Power tracks.

Exhibit 5, Tab 1, Schedule 2, Attachment 2 contains the list of the deferral and variance accounts Bluewater Power seeks disposition of, with the proposed balance as of December 31, 2007 along with the projected interest to April 30, 2009.

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Deferral/Variance Account Balances

Deferral / Variance Account	1-Jan-2005 to 31-Dec-2005					
	Open. Principal	Changes	End. Principal	Open. Interest	Changes	End. Interest
1505-LRAM and SSM (holding account only)						
1508-Other Regulatory Assets	35,655	410,650	446,304		8,798	8,798
1510-Preliminary Survey and Investigation Charges						
1515-Emission Allowance Inventory						
1516-Emission Allowances Withheld						
1518-RCVARetail						
1520-Power Purchase Variance Account						
1525-Miscellaneous Deferred Debits		447	447		3	3
1530-Deferred Losses from Disposition of Utility Plant						
1540-Unamortized Loss on Reacquired Debt						
1545-Development Charge Deposits/ Receivables						
1548-LV Apr 1'08 to Oct 31/'0 Hydro One RAR 2005 variance (holding account only)						
1550-LV Variance Account						
1555-Smart Meters Capital Variance Account						
1556-Smart Meters OM&A Variance Account						
1560-Deferred Development Costs						
1562-Deferred Payments in Lieu of Taxes		(234,207)	(234,207)		(10,869)	(10,869)
1563-Account 1563 - Deferred PILs Contra Account						
1565-Conservation and Demand Management Expenditures and Recoveries						
1566-CDM Contra Account						
1570-Qualifying Transition Costs						
1571-Pre-market Opening Energy Variance						
1572-Extraordinary Event Costs						
1574-Deferred Rate Impact Amounts						
1580-RSVAWMS	(1,170)	701,407	700,237		10,536	10,536
1582-RSVAONE-TIME						
1584-RSVANW	40,787	(97,121)	(56,334)		(1,971)	(1,971)
1586-RSVACN	72,755	(349,944)	(277,189)		(15,484)	(15,484)
1588-RSVAPOWER		(419,914)	(419,914)		(19,493)	(19,493)
1592-2006 PILs/Taxes Variance						
2425-Sub account of 1588 Global Adjustment (holding account only)		(499,490)	(499,490)		(39,199)	(39,199)
TOTAL	**148,027**	**(488,172)**	**(340,145)**		**(67,679)**	**(67,679)**

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Deferral/Variance Account Balances

Deferral / Variance Account	1-Jan-2006 to 31-Dec-2006					
	Open. Principal	Changes	End. Principal	Open. Interest	Changes	End. Interest
1505-LRAM and SSM (holding account only)						
1508-Other Regulatory Assets	446,304	144,753	591,057	8,798	24,629	33,428
1510-Preliminary Survey and Investigation Charges						
1515-Emission Allowance Inventory						
1516-Emission Allowances Withheld						
1518-RCVARetail						
1520-Power Purchase Variance Account						
1525-Miscellaneous Deferred Debits	447		447	3	24	27
1530-Deferred Losses from Disposition of Utility Plant						
1540-Unamortized Loss on Reacquired Debt						
1545-Development Charge Deposits/ Receivables						
1548-LV Apr 1'08 to Oct 31/'0 Hydro One RAR 2005 variance (holding account only)						
1550-LV Variance Account		16,336	16,336		83	83
1555-Smart Meters Capital Variance Account		(55,516)	(55,516)		(812)	(812)
1556-Smart Meters OM&A Variance Account		11,155	11,155		106	106
1560-Deferred Development Costs						
1562-Deferred Payments in Lieu of Taxes	(234,207)	4,594	(229,613)	(10,869)	(12,514)	(23,383)
1563-Account 1563 - Deferred PILs Contra Account						
1565-Conservation and Demand Management Expenditures and Recoveries						
1566-CDM Contra Account						
1570-Qualifying Transition Costs						
1571-Pre-market Opening Energy Variance						
1572-Extraordinary Event Costs						
1574-Deferred Rate Impact Amounts						
1580-RSVAWMS	700,237	(1,208,707)	(508,470)	10,536	12,520	23,056
1582-RSVAONE-TIME						
1584-RSVANW	(56,334)	82,203	25,869	(1,971)	(3,656)	(5,627)
1586-RSVACN	(277,189)	(118,351)	(395,540)	(15,484)	(19,006)	(34,490)
1588-RSVAPOWER	(419,914)	(1,100,241)	(1,520,155)	(19,493)	(73,466)	(92,959)
1592-2006 PILs/Taxes Variance						
2425-Sub account of 1588 Global Adjustment (holding account only)	(499,490)	1,112,994	613,504	(39,199)	20,664	(18,535)
TOTAL	**(340,145)**	**(1,110,781)**	**(1,450,926)**	**(67,679)**	**(51,428)**	**(119,107)**

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Deferral/Variance Account Balances

Deferral / Variance Account	1-Jan-2007 to 31-Dec-2007					
	Open. Principal	Changes	End. Principal	Open. Interest	Changes	End. Interest
1505-LRAM and SSM (holding account only)						
1508-Other Regulatory Assets	591,057		591,057	33,428	27,942	61,370
1510-Preliminary Survey and Investigation Charges						
1515-Emission Allowance Inventory						
1516-Emission Allowances Withheld						
1518-RCVARetail						
1520-Power Purchase Variance Account						
1525-Miscellaneous Deferred Debits	447		447	27	21	48
1530-Deferred Losses from Disposition of Utility Plant						
1540-Unamortized Loss on Reacquired Debt						
1545-Development Charge Deposits/ Receivables						
1548-LV Apr 1'08 to Oct 31/'0 Hydro One RAR 2005 variance (holding account only)						
1550-LV Variance Account	16,336	(49,477)	(33,141)	83	(12)	71
1555-Smart Meters Capital Variance Account	(55,516)	(116,678)	(172,194)	(812)	(5,260)	(6,072)
1556-Smart Meters OM&A Variance Account	11,155	27,071	38,226	106	880	986
1560-Deferred Development Costs						
1562-Deferred Payments in Lieu of Taxes	(229,613)		(229,613)	(23,383)	(10,855)	(34,238)
1563-Account 1563 - Deferred PILs Contra Account						
1565-Conservation and Demand Management Expenditures and Recoveries						
1566-CDM Contra Account						
1570-Qualifying Transition Costs						
1571-Pre-market Opening Energy Variance						
1572-Extraordinary Event Costs						
1574-Deferred Rate Impact Amounts						
1580-RSVAWMS	(508,470)	(1,209,477)	(1,717,947)	23,056	(50,076)	(27,020)
1582-RSVAONE-TIME						
1584-RSVANW	25,869	85,823	111,692	(5,627)	5,369	(258)
1586-RSVACN	(395,540)	67,632	(327,908)	(34,490)	(17,958)	(52,448)
1588-RSVAPOWER	(1,520,155)	(1,006,388)	(2,526,543)	(92,959)	(109,476)	(202,435)
1592-2006 PILs/Taxes Variance						
2425-Sub account of 1588 Global Adjustment (holding account only)	613,504	(413,909)	199,595	(18,535)	21,157	2,622
TOTAL	**(1,450,926)**	**(2,615,403)**	**(4,066,329)**	**(119,107)**	**(138,268)**	**(257,374)**

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Deferral/Variance Account Balances

Deferral / Variance Account	31-Dec-2007 Balance			1-Jan-08 to 30-Apr-08		
	Principal	Interest	Total	Interest	Other	Balance
1505-LRAM and SSM (holding account only)						
1508-Other Regulatory Assets	591,057	61,370	652,427	9,605		662,032
1510-Preliminary Survey and Investigation Charges						
1515-Emission Allowance Inventory						
1516-Emission Allowances Withheld						
1518-RCVARetail						
1520-Power Purchase Variance Account						
1525-Miscellaneous Deferred Debits	447	48	495	7		502
1530-Deferred Losses from Disposition of Utility Plant						
1540-Unamortized Loss on Reacquired Debt						
1545-Development Charge Deposits/ Receivables						
1548-LV Apr 1'08 to Oct 31/'0 Hydro One RAR 2005 variance (holding account only)					5,691	5,691
1550-LV Variance Account	(33,141)	71	(33,070)	(539)		(33,609)
1555-Smart Meters Capital Variance Account	(172,194)	(6,072)	(178,266)	(2,798)		(181,064)
1556-Smart Meters OM&A Variance Account	38,226	986	39,212	621		39,833
1560-Deferred Development Costs						
1562-Deferred Payments in Lieu of Taxes	(229,613)	(34,238)	(263,851)	(3,731)		(267,582)
1563-Account 1563 - Deferred PILs Contra Account						
1565-Conservation and Demand Management Expenditures and Recoveries						
1566-CDM Contra Account						
1570-Qualifying Transition Costs						
1571-Pre-market Opening Energy Variance						
1572-Extraordinary Event Costs						
1574-Deferred Rate Impact Amounts						
1580-RSVAWMS	(1,717,947)	(27,020)	(1,744,967)	(27,917)		(1,772,884)
1582-RSVAONE-TIME						
1584-RSVANW	111,692	(258)	111,434	1,815		113,249
1586-RSVACN	(327,908)	(52,448)	(380,356)	(5,329)		(385,685)
1588-RSVAPOWER	(2,526,543)	(202,435)	(2,728,978)	(41,056)		(2,770,034)
1592-2006 PILs/Taxes Variance						
2425-Sub account of 1588 Global Adjustment (holding account only)	199,595	2,622	202,217	3,243		205,460
TOTAL	**(4,066,329)**	**(257,374)**	**(4,323,703)**	**(66,078)**	**5,691**	**(4,384,090)**

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Deferral/Variance Account Balances

Deferral / Variance Account	1-May-08 to 31-Dec-08			1-Jan-09 to 30-Apr-09		
	Interest	Other	Balance	Interest	Other	Balance
1505-LRAM and SSM (holding account only)					130,666	130,666
1508-Other Regulatory Assets	13,200		675,232	6,600		681,832
1510-Preliminary Survey and Investigation Charges						
1515-Emission Allowance Inventory						
1516-Emission Allowances Withheld						
1518-RCVARetail						
1520-Power Purchase Variance Account						
1525-Miscellaneous Deferred Debits	10		512	5		517
1530-Deferred Losses from Disposition of Utility Plant						
1540-Unamortized Loss on Reacquired Debt						
1545-Development Charge Deposits/ Receivables						
1548-LV Apr 1'08 to Oct 31/'0 Hydro One RAR 2005 variance (holding account only)	127	34,146	39,964	445		40,409
1550-LV Variance Account	(740)		(34,349)	(370)		(34,719)
1555-Smart Meters Capital Variance Account	(3,846)		(184,910)	(1,923)		(186,833)
1556-Smart Meters OM&A Variance Account	854		40,687	427		41,114
1560-Deferred Development Costs						
1562-Deferred Payments in Lieu of Taxes	(5,128)		(272,710)	(2,564)		(275,274)
1563-Account 1563 - Deferred PILs Contra Account						
1565-Conservation and Demand Management Expenditures and Recoveries						
1566-CDM Contra Account						
1570-Qualifying Transition Costs						
1571-Pre-market Opening Energy Variance						
1572-Extraordinary Event Costs						
1574-Deferred Rate Impact Amounts						
1580-RSVAWMS	(38,367)		(1,811,251)	(19,184)		(1,830,435)
1582-RSVAONE-TIME						
1584-RSVANW	2,494		115,743	1,247		116,991
1586-RSVACN	(7,323)		(393,008)	(3,662)		(396,669)
1588-RSVAPOWER	(56,426)		(2,826,460)	(28,213)		(2,854,674)
1592-2006 PILs/Taxes Variance						
2425-Sub account of 1588 Global Adjustment (holding account only)	4,458		209,918	2,229		212,147
TOTAL	**(90,688)**	**34,146**	**(4,440,631)**	**(44,962)**	**130,666**	**(4,354,928)**

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Deferral/Variance Account Balances

	31-Dec-07 Balance + Interest to 30-Apr-09			1-May-09 to 31-Dec-09		
Deferral / Variance Account	**31-Dec-07**	**Interest**	**Total**	**Interest**	**Other**	**Balance**
1505-LRAM and SSM (holding account only)				2,918		133,584
1508-Other Regulatory Assets	652,427	29,405	681,832	13,200		695,033
1510-Preliminary Survey and Investigation Charges						
1515-Emission Allowance Inventory						
1516-Emission Allowances Withheld						
1518-RCVARetail						
1520-Power Purchase Variance Account						
1525-Miscellaneous Deferred Debits	495	22	517	10		527
1530-Deferred Losses from Disposition of Utility Plant						
1540-Unamortized Loss on Reacquired Debt						
1545-Development Charge Deposits/ Receivables						
1548-LV Apr 1'08 to Oct 31/'0 Hydro One RAR 2005 variance (holding account only)		572	572	890		41,299
1550-LV Variance Account	(33,070)	(1,649)	(34,719)	(740)		(35,459)
1555-Smart Meters Capital Variance Account	(178,266)	(8,567)	(186,833)	(3,846)		(190,678)
1556-Smart Meters OM&A Variance Account	39,212	1,902	41,114	854		41,967
1560-Deferred Development Costs						
1562-Deferred Payments in Lieu of Taxes	(263,851)	(11,423)	(275,274)	(5,128)		(280,402)
1563-Account 1563 - Deferred PILs Contra Account						
1565-Conservation and Demand Management Expenditures and Recoveries						
1566-CDM Contra Account						
1570-Qualifying Transition Costs						
1571-Pre-market Opening Energy Variance						
1572-Extraordinary Event Costs						
1574-Deferred Rate Impact Amounts						
1580-RSVAWMS	(1,744,967)	(85,468)	(1,830,435)	(38,367)		(1,868,802)
1582-RSVAONE-TIME						
1584-RSVANW	111,434	5,557	116,991	2,494		119,485
1586-RSVACN	(380,356)	(16,313)	(396,669)	(7,323)		(403,993)
1588-RSVAPOWER	(2,728,978)	(125,696)	(2,854,674)	(56,426)		(2,911,100)
1592-2006 PILs/Taxes Variance						
2425-Sub account of 1588 Global Adjustment (holding account only)	202,217	9,930	212,147	4,458		216,604
TOTAL	**(4,323,703)**	**(201,728)**	**(4,525,431)**	**(87,007)**		**(4,441,935)**

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Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

Proposed Deferral /Variance Account Balance Recoveries

Deferral / Variance Account	Recover Balance as at?	Additional Interest to 30 Apr/09?	Balance for Recovery (Principle and Interest to Dec 31, 2007)	Additional Interest for Recovery (Interest only from Jan 1/08 to Apr 30/09)	Total Recovery Amount
1505-LRAM and SSM (holding account only)	4/30/2009	YES	130,666	0	130,666
1508-Other Regulatory Assets	12/31/2007	YES	652,427	29,405	681,832
1510-Preliminary Survey and Investigation Charges	No Recovery	NO	0	0	0
1515-Emission Allowance Inventory	No Recovery	NO	0	0	0
1516-Emission Allowances Withheld	No Recovery	NO	0	0	0
1518-RCVARetail	No Recovery	NO	0	0	0
1520-Power Purchase Variance Account	No Recovery	NO	0	0	0
1525-Miscellaneous Deferred Debits	12/31/2007	YES	495	22	517
1530-Deferred Losses from Disposition of Utility Plant	No Recovery	NO	0	0	0
1540-Unamortized Loss on Reacquired Debt	No Recovery	NO	0	0	0
1545-Development Charge Deposits/ Receivables	No Recovery	NO	0	0	0
1548-LV Apr 1'08 to Oct 31/'0 Hydro One RAR 2005 variance (holding account only)	No Recovery	NO	0	0	0
1550-LV Variance Account	12/31/2007	YES	(33,070)	(1,649)	(34,719)
1555-Smart Meters Capital Variance Account	No Recovery	NO	0	0	0
1556-Smart Meters OM&A Variance Account	No Recovery	NO	0	0	0
1560-Deferred Development Costs	No Recovery	NO	0	0	0
1562-Deferred Payments in Lieu of Taxes	No Recovery	NO	0	0	0
1563-Account 1563 - Deferred PILs Contra Account	No Recovery	NO	0	0	0
1565-Conservation and Demand Management Expenditures and Recoveries	No Recovery	NO	0	0	0
1566-CDM Contra Account	No Recovery	NO	0	0	0
1570-Qualifying Transition Costs	No Recovery	NO	0	0	0
1571-Pre-market Opening Energy Variance	No Recovery	NO	0	0	0
1572-Extraordinary Event Costs	No Recovery	NO	0	0	0
1574-Deferred Rate Impact Amounts	No Recovery	NO	0	0	0
1580-RSVAWMS	12/31/2007	YES	(1,744,967)	(85,468)	(1,830,435)
1582-RSVAONE-TIME	No Recovery	NO	0	0	0
1584-RSVANW	12/31/2007	YES	111,434	5,557	116,991
1586-RSVACN	12/31/2007	YES	(380,356)	(16,313)	(396,669)
1588-RSVAPOWER	12/31/2007	YES	(2,728,978)	(125,696)	(2,854,674)
1592-2006 PILs/Taxes Variance	No Recovery	NO	0	0	0
2425-Sub account of 1588 Global Adjustment (holding account only)	12/31/2007	YES	202,217	9,930	212,147
Sub-Total for Recovery					**(3,974,344)**
1590-Recovery of Regulatory Asset Balances (residual)	No Recovery	NO	0	0	0
Total Recoveries Required					**(3,974,344)**
Annual Recovery Amounts # years:	**3**				**(1,324,781)**

LRAM and SSM

On May 31, 2004, the Minister of Energy granted approval to all distributors in Ontario to apply to the Ontario Energy Board for an increase in 2005 rates in the amount of the third installment of their incremental market adjusted revenue requirement ("MARR"). The approval was conditional on a commitment to reinvest an equivalent amount in CDM activities.

On March 15, 2005, the OEB granted approval to Bluewater Power to proceed with a Conservation and Demand Management Plan with funding in the amount of $657,600 (RP-2004-0203/EB-2004-0423). Given the success of the CDM programs, Bluewater Power applied for and received approval for an incremental amount of $250,000 as part of the 2006 EDR Decision (RP-2005-0020/EB-2005-0430) to be spent on further CDM programs. Finally, Bluewater Power has also participated in all four Ontario Power Authority funded conservation programs in 2007.

As a result of the successful implementation of these numerous conservation programs, Bluewater Power has experienced a loss of distribution revenue, and therefore is applying for recovery through the LRAM and for approval of funds through the SSM.

Determination of LRAM and SSM Amounts

LRAM amounts being applied for pertain to OEB approved programs funded through distribution rates for the period of 2005 to 2007 inclusive, as well as the OPA sponsored programs for the years 2006 and 2007. SSM amounts pertain to OEB approved programs only.

The LRAM amount of $102,709 has been calculated based on the kWh load reduction for each of the years the programs were in place multiplied by the volumetric rate for the applicable year and applicable rate class. The volumetric rate excludes the regulatory asset rate rider. All calculations were adjusted to include the impact of 'free ridership'. Bluewater Power has used the Total Resource Cost Guidelines ("TRC") dated October 2, 2006 for all inputs and assumptions with the following two exceptions.

Firstly, a program by the name of 'Cool Shops' was implemented in 2006 as part of the 2006 incremental funding. Four of the nine lighting technologies were not listed in the OEB's TRC Guidelines. Bluewater Power received a final evaluation report from Cool Shops and has included its empirical data to support the net kWh's saved, and the NPV Benefit dollars.

Secondly, Bluewater Power implemented the OPA funded 'Summer Savings 'program in 2007. The LRAM calculation for this program entailed using the net savings for all eligible customers (as defined in the OPA Schedule "C"), multiplied by the volumetric rate. A 10% free-ridership impact was applied which corresponds with the OEB Decision on Toronto Hydro's LRAM recovery application (EB-2007-0096) where it was stated on page 6:

> *"The Board finds that it is not within the scope of this proceeding to revise free ridership rates that have been determined by the Board previously. To do so would be to violate an important regulatory principle which requires that notice of the proceeding ought to give interested parties a clear picture as to what is under consideration in the proceeding. There is also an important issue of fairness. Where a utility has relied on a clear pronouncement by the regulator, it ought not to be subject to retroactive revision, except in the most compelling case. With respect to the Summer Challenge program, the Board had previously established a 10 percent free-ridership rate. The Board will not revise that rate in this proceeding"*

The SSM claim in the amount of $27,957 has been calculated in accordance with the TRC guideline which provides for a 5% return on the net savings as established by the TRC test. Detailed calculations can be found at the end of this schedule as follows:
Exhibit 5, Tab 1, Schedule 3, Attachment 1 entitled Calculation of LRAM amounts, and Exhibit 5, Tab 1, Schedule 3, Attachment 2 entitled Calculation of SSM amounts.

In addition to the LRAM and SSM calculations, Bluewater Power submits the following evidence to support the proposed recovery, in accordance with Section 9 of the March 28, 2008 document entitled "Guidelines for Electricity Distributor Conservation and Demand Management".

- Per section 7.4 of the Guidelines, an Evaluation Report produced by the Conservation Officer at Bluewater Power which documents each program and how the participation levels were derived. This report includes the information on the OPA sponsored programs in addition to the programs funded through distribution rates. This report is found as Exhibit 5, Tab 1, Schedule 3, Attachment 3 entitled Conservation & Demand Management Evaluation Report.
- Per section 7.5 of the Guidelines, a Third Party Audit Report produced by ERA which is considered a final review of the programs implemented by Bluewater Power and an assessment of the LRAM and SSM claims. This report is found as Exhibit 5, Tab 1, Schedule 3, Attachment 4.

Relief Requested

Bluewater Power proposes that a total claim amount of $130,666 comprised of a LRAM amount of $102,709 and a SSM amount of $27,957 be recovered through the total disposition of deferral accounts rate rider. The LRAM/SSM specific rate rider will be allocated to the Residential, General Service <50 and General Service >50 rate classes according to the projected lost revenue attributable to each rate class for the 2009 forecast period, divided by the projected kWh for the respective rate classes. The resulting rate riders are proposed to form part of the overall deferral/variance account disposition, however Table 5.1.3.1 below depicts the portion of the overall rate rider (credit) related to LRAM/SSM.

Table 5.1.3.1

Proposed Rate Riders for LRAM/SSM Recovery

Rate Class	LRAM Amount	SSM Amount	Total Amount	Billing Units (2009 Normalized)	Billing Determinant		LRAM	SSM	One Year Rate Rider	Three Year Rate Rider
	$	$	$				$/kWh or $/kW	$/kWh or $/kW	$/kWh or $/kW	$/kWh or $/kW
Residential	95,187	16,061	111,248	266,434,436	kWh		0.0004	0.0001	0.0005	0.0002
GS<50	5,046	4,024	9,070	120,544,382	kWh		0.0000	0.0000	0.0000	0.0000
GS>50	2,476	7,872	10,348	593,516	kW		0.0042	0.0133	0.0175	0.0058
Total	102,709	27,957	130,666							

Calculation of LRAM

Program Details

Rate Class	Evaluation Report Reference	Program	Technology	Funding Mechanism	Year Implemented	# units	Measure Life	Total Energy Savings (kWh)	Total Energy Savings (kW)	Total Energy Savings with # units	Free Ridership	Net kWh or kW saved
Residential	Section 1,7	Community Outreach	CFL 15w screw in	3rd Tranche MARR	2005	480	4	104		50,112	10%	45,101
Residential	Section 1,7	Low Income Consumers - 2005	Energy Star Dishwasher	3rd Tranche MARR	2005	1	13	100		100	10%	90
Residential	Section 1,7	Low Income Consumers - 2005	Energy Star Clothes washer	3rd Tranche MARR	2005	1	14	480		480	10%	432
Residential	Section 1,7	Low Income Consumers - 2005	Energy Star CAC	3rd Tranche MARR	2005	1	14	351		351	10%	316
Residential	Section 1,7	Seasonal LED Lights	LED Christmas Light	3rd Tranche MARR	2005	100	30	19		1,886	5%	1,791
GS>50	Section 1,7	Green Team	High BayT5 Lamps	3rd Tranche MARR	2005	21	5	328	0.29	6.2	10%	5.6
2005 Programs												
Residential	Section 1,7	Low Income Consumers - 2006	Energy Star Dishwasher	3rd Tranche MARR	2006	1	13	100		100	10%	90
Residential	Section 1,7	Low Income Consumers - 2006	Energy Star Clothes washer	3rd Tranche MARR	2006	1	14	480		480	10%	432
Residential	Section 2	Lighting Programs -2006 Incremental	CFL 15w screw in	2006 Incremental Funding	2006	20500	4	104		2,140,200	10%	1,926,180
Residential	Section 2	Lighting Programs -2006 Incremental	LED Christmas Lights	2006 Incremental Funding	2006	500	30	19		9,428	5%	8,957
Residential	Section 3	OPA EKC Coupons - spring 2006	Programmable thermostat	OPA 2006	2006	149	18	159		23,704	10%	21,333
Residential	Section 3	OPA EKC Coupons - spring 2006	Timer	OPA 2006	2006	112	20	292		32,704	10%	29,434
Residential	Section 3	OPA EKC Coupons - spring 2006	CFL	OPA 2006	2006	3447	4	104		359,867	10%	323,880
GS<50	Section 4	Lighting Programs -2006 Incremental	Cool Shops 15w cfl	2006 Incremental Funding	2006	672	4	104		70,157	10%	63,141
GS<50	Section 4	Lighting Programs -2006 Incremental	Cool Shops LED Exit	2006 Incremental Funding	2006	444	25	237		105,015	10%	94,513
GS<50	Section 4	Lighting Programs -2006 Incremental	Cool Shops11w cfl	2006 Incremental Funding	2006	50	3	67		3,350	10%	3,015
GS<50	Section 4	Lighting Programs -2006 Incremental	Cool Shops 27w cfl	2006 Incremental Funding	2006	2	3	170		340	10%	306
GS<50	Section 4	Lighting Programs -2006 Incremental	Cool Shops BR 15w	2006 Incremental Funding	2006	29	2.46	146		4,234	10%	3,811
GS<50	Section 4	Lighting Programs -2006 Incremental	Cool Shops BR 16w	2006 Incremental Funding	2006	30	2.46	143		4,290	10%	3,861
GS<50	Section 4	Lighting Programs -2006 Incremental	Cool Shops PAR 20w	2006 Incremental Funding	2006	102	2.46	228		23,256	10%	20,930
GS<50	Section 4	Lighting Programs -2006 Incremental	Cool Shops PAR 23w	2006 Incremental Funding	2006	2	2.46	221		442	10%	398
GS<50	Section 4	Lighting Programs -2006 Incremental	Cool Shops 13w cfl	2006 Incremental Funding	2006	118	3	67		7,906	10%	7,115
2006 Programs												
Residential	Section 3	OPA EKC Coupons - fall 2006	Programmable thermostat	OPA 2006	2007	382	18	159		60,770	10%	54,693
Residential	Section 3	OPA EKC Coupons - fall 2006	LED lights	OPA 2006	2007	4749	20	19		89,551	5%	85,073
Residential	Section 3	OPA EKC Coupons - fall 2006	Dimmer	OPA 2006	2007	198	10	139		27,562	10%	24,805
Residential	Section 3	OPA EKC Coupons - fall 2006	CFL	OPA 2006	2007	4044	4	104		422,194	10%	379,974
Residential	Section 3	OPA EKC Coupons - fall 2006	Motion detector	OPA 2006	2007	69	10	209		14,407	10%	12,966
Residential	Section 5	OPA Programs - Fridge	2007 Great Refrigerator Round-up - Refrige	OPA 2007	2007	732	6	1,199		877,668	10%	789,901
Residential	Section 5	OPA Programs - Fridge	2007 Great Refrigerator Round-up - Freeze	OPA 2007	2007	147	6	901		132,447	10%	119,202
Residential	Section 5	OPA Programs - Summer Savings	2007 Summer Savings Program	OPA 2007	2007	5588	1	2,124,147		2,124,147	10%	1,911,732
GS>50	Section 6	Lighting Programs -2006 Incremental	Business Incentive Program-T8	2006 Incremental Funding	2007	2106	5	288	0.76	1,604.8	10%	1,444.3
GS>50	Section 6	Lighting Programs -2006 Incremental	Business Incentive Program-Exit Lighting	2006 Incremental Funding	2007	75	25	237	0.32	23.7	10%	21.3
2007 Programs												
Total Residental										6,368,157		5,736,384
Total GS <50										218,990		197,091
Total GS>50										1,635		1,471
Grand Total										6,588,781		5,934,946

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				Calculation of LRAM												
Rate Class	**Evaluation Report Reference**	**Program**		**Net 2005 kWh or kW saved**	**Rate $/kWh or $/kW**	**Lost Revenue $**	**2006 kWh or kW saved**	**Rate $/kWh or $/kW**	**Lost Revenue $**	**2007 kWh or kW saved**	**Rate $/kWh or $/kW**	**Lost Revenue $**	**Total kWh or kW**	**Total Lost Revenue**
Residential	Section 1,7	Community Outreach		45,101	0.0101	$ 456	45,101	0.0117	$ 528	45,101	0.0117	$ 528	**135,302**	**$ 1,511**
Residential	Section 1,7	Low Income Consumers - 2005		90	0.0101	$ 1	90	0.0117	$ 1	90	0.0117	$ 1	**270**	**$ 3**
Residential	Section 1,7	Low Income Consumers - 2005		432	0.0101	$ 4	432	0.0117	$ 5	432	0.0117	$ 5	**1,296**	**$ 14**
Residential	Section 1,7	Low Income Consumers - 2005		316	0.0101	$ 3	316	0.0117	$ 4	316	0.0117	$ 4	**947**	**$ 11**
Residential	Section 1,7	Seasonal LED Lights		1,791	0.0101	$ 18	1,791	0.0117	$ 21	1,791	0.0117	$ 21	**5,374**	**$ 60**
GS>50	Section 1,7	Green Team		5.6	1.3598	$ 8	5.6	1.6252	$ 79	5.6	1.6241	$ 9	**17**	**$ 96**
2005 Programs			Total 2005	47,735		490	47,735		638	47,735		567	**143,206**	**1,695**
Residential	Section 1,7	Low Income Consumers - 2006					90	0.0117	$ 1	90	0.0117	$ 1	**180**	**$ 2**
Residential	Section 1,7	Low Income Consumers - 2006					432	0.0117	$ 5	432	0.0117	$ 5	**864**	**$ 10**
Residential	Section 2	Lighting Programs -2006 Incremental					1,926,180	0.0117	$ 22,536	1,926,180	0.0117	$ 22,536	**3,852,360**	**$ 45,073**
Residential	Section 2	Lighting Programs -2006 Incremental					8,957	0.0117	$ 105	8,957	0.0117	$ 105	**17,914**	**$ 210**
Residential	Section 3	OPA EKC Coupons - spring 2006					21,333	0.0117	$ 250	21,333	0.0117	$ 250	**42,666**	**$ 499**
Residential	Section 3	OPA EKC Coupons - spring 2006					29,434	0.0117	$ 344	29,434	0.0117	$ 344	**58,867**	**$ 689**
Residential	Section 3	OPA EKC Coupons - spring 2006					323,880	0.0117	$ 3,789	323,880	0.0117	$ 3,789	**647,760**	**$ 7,579**
GS<50	Section 4	Lighting Programs -2006 Incremental					63,141	0.0128	$ 808	63,141	0.0128	$ 808	**126,282**	**$ 1,616**
GS<50	Section 4	Lighting Programs -2006 Incremental					94,513	0.0128	$ 1,210	94,513	0.0128	$ 1,210	**189,027**	**$ 2,420**
GS<50	Section 4	Lighting Programs -2006 Incremental					3,015	0.0128	$ 39	3,015	0.0128	$ 39	**6,030**	**$ 77**
GS<50	Section 4	Lighting Programs -2006 Incremental					306	0.0128	$ 4	306	0.0128	$ 4	**612**	**$ 8**
GS<50	Section 4	Lighting Programs -2006 Incremental					3,811	0.0128	$ 49	3,811	0.0128	$ 49	**7,621**	**$ 98**
GS<50	Section 4	Lighting Programs -2006 Incremental					3,861	0.0128	$ 49	3,861	0.0128	$ 49	**7,722**	**$ 99**
GS<50	Section 4	Lighting Programs -2006 Incremental					20,930	0.0128	$ 268	20,930	0.0128	$ 268	**41,861**	**$ 536**
GS<50	Section 4	Lighting Programs -2006 Incremental					398	0.0128	$ 5	398	0.0128	$ 5	**796**	**$ 10**
GS<50	Section 4	Lighting Programs -2006 Incremental					7,115	0.0128	$ 91	7,115	0.0128	$ 91	**14,231**	**$ 182**
2006 Programs			Total 2006				2,507,397		29,553	2,507,397		29,553	**5,014,793**	**59,107**
Residential	Section 3	OPA EKC Coupons - fall 2006								54,693	0.0117	$ 640	**54,693**	**$ 640**
Residential	Section 3	OPA EKC Coupons - fall 2006								85,073	0.0117	$ 995	**85,073**	**$ 995**
Residential	Section 3	OPA EKC Coupons - fall 2006								24,805	0.0117	$ 290	**24,805**	**$ 290**
Residential	Section 3	OPA EKC Coupons - fall 2006								379,974	0.0117	$ 4,446	**379,974**	**$ 4,446**
Residential	Section 3	OPA EKC Coupons - fall 2006								12,966	0.0117	$ 152	**12,966**	**$ 152**
Residential	Section 5	OPA Programs - Fridge								789,901	0.0117	$ 9,242	**789,901**	**$ 9,242**
Residential	Section 5	OPA Programs - Fridge								119,202	0.0117	$ 1,395	**119,202**	**$ 1,395**
Residential	Section 5	OPA Programs - Summer Savings								1,911,732	0.0117	$ 22,367	**1,911,732**	**$ 22,367**
GS>50	Section 6	Lighting Programs -2006 Incremental								1,444.3	1.6241	$ 2,346	**1,444**	**$ 2,346**
GS>50	Section 6	Lighting Programs -2006 Incremental								21.3	1.6241	$ 35	**21**	**$ 35**
2007 Programs			Total 2007							3,379,814		41,907	**3,379,814**	**41,907**
Total Residental			Total Residental											**$ 95,187**
Total GS <50			Total GS<50											**$ 5,046**
Total GS>50			Total GS>50											**$ 2,476**
Grand Total			Grand Total	**47,735**	**$**	**490**	**2,555,132**		**$ 30,191**	**5,934,946**		**$ 72,028**	**8,537,813**	**$ 102,709**

Calculation of SSM

Rate Class	Program	Technology	# units	Free Ridership Rate	NPV Benefit per unit $	Incremental Equipment Cost $ (from TRC guide)	Utility Program Costs	Total Benefits $ (NPV)	Total Costs $	Net Benefits $ (NPV)	Benefit Cost Ratio	SSM Amount $
Residential	Community Outreach CFL	CFL 15w screw in	480	10%	$ 26.51	$ -	$ 7,118	$ 11,453	$ 7,118	$ 4,336	1.61	$ 217
Residential	Inn to Win - 2005	Energy Star Dishwasher	1	10%	$ 65.80	$ -	$ 7,740	$ 59	$ 7,740	$ (7,680)	0.01	$ (384)
Residential	Inn to Win - 2005	Energy Star Clothes washer	1	10%	$ 315.82	$ -	$ 7,740	$ 284	$ 7,740	$ (7,455)	0.04	$ (373)
Residential	Inn to Win - 2005	Energy Star CAC	1	10%	$ 250.39	$ -	$ 7,740	$ 225	$ 7,740	$ (7,514)	0.03	$ (376)
Residential	Seasonal LED	LED Christmas Light	100	5%	$ 18.89	$ -	$ 727	$ 1,794	$ 727	$ 1,068	2.47	$ 53
Residential	Inn to Win - 2006	Energy Star Dishwasher	1	10%	$ 65.80	$ -	$ 14,696	$ 59	$ 14,696	$ (14,636)	0.00	$ (732)
Residential	Inn to Win - 2006	Energy Star Clothes washer	1	10%	$ 315.82	$ -	$ 14,696	$ 284	$ 14,696	$ (14,411)	0.02	$ (721)
Residential	Lighting Programs -2006 Incremental	CFL 15w screw in	20500	10%	$ 26.51	$ -	$ 125,719	$ 489,147	$ 125,719	$ 363,428	3.89	$ 18,171
Residential	Lighting Programs -2006 Incremental	LED Christmas Lights	500	5%	$ 18.89	$ -	$ 4,843	$ 8,971	$ 4,843	$ 4,128	1.85	$ 206
GS<50	Cool Shops	15w cfl	672	10%	$ 26.51		$ 50,000	$ 16,033	$ 50,000	$ (33,967)	2.56	$ (1,698)
GS<50	Cool Shops	LED Exit	444	10%	$ 269.26	$ -		$ 107,597	$ -	$ 107,597		$ 5,380
GS<50	Cool Shops	11w cfl	50	10%	$ 13.27	$ 2.25		$ 597	$ 101	$ 496		$ 25
GS<50	Cool Shops	27w cfl	2	10%	$ 33.51	$ 5.00		$ 60	$ 9	$ 51		$ 3
GS<50	Cool Shops	BR 15w	29	10%	$ 27.52	$ 7.89		$ 718	$ 206	$ 512		$ 26
GS<50	Cool Shops	BR 16w	30	10%	$ 27.00	$ 7.89		$ 729	$ 213	$ 516		$ 26
GS<50	Cool Shops	PAR 20w	102	10%	$ 52.27	$ 8.95		$ 4,798	$ 822	$ 3,976		$ 199
GS<50	Cool Shops	PAR 23w	2	10%	$ 50.72	$ 10.95		$ 91	$ 20	$ 72		$ 4
GS<50	Cool Shops	13w cfl	118	10%	$ 13.27	$ 2.25		$ 1,410	$ 239	$ 1,171		$ 59
GS>50	Lighting Programs -2006 Incremental	Business Incentive Program-T8	2106	10%	$ 128.11	$ 36.00	$ 16,498	$ 242,815	$ 84,733	$ 158,082	2.86	$ 7,904
GS>50	Lighting Programs -2006 Incremental	Business Incentive Program-Exit Lighting	75	10%	$ 269.26	$ 95.00		$ 18,175	$ 6,413	$ 11,763		$ 588
GS>50	Power Smart Team - High bay lighting	T5 Lamps	21	10%	$ 115.02		$ 14,574.30	$ 2,174	$ 14,574	$ (12,400)	0.15	$ (620)
Total Residential												$ 16,061
Total GS<50												$ 4,024
Total GS>50												$ 7,872
Grand Total								**$ 907,476**	**$ 348,345**	**$ 559,131**		**$ 27,957**

Note: the sections outlined in boxes represent programs that the utility costs are for the entire program, not by technology.

Conservation & Demand Management Evaluation Report

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Conservation & Demand Side Management Evaluation Report Introduction

Bluewater Power Distribution Corporation ("Bluewater Power") is a progressive utility providing electrical distribution and related services to approximately 35,000 customers in Southwestern Ontario. Bluewater Power was formed in 2000 upon completion of a merger of the Sarnia Hydro-Electric Commission, Petrolia Public Utilities Commission, Point Edward Public Utilities Commission, Warwick Hydro-Electric Commission, Alvinston Public Utilities Commission and Oil Springs Hydro-Electric Commission.

Bluewater Power participated in Conservation and Demand Side Management ("CDM") initiatives in response to a request made by the Ontario government to local distribution companies to assist in the creation of a "culture of conservation" among provincial electricity consumers. Funding for electricity conservation programs was approved as part of the 2006 EDR; (RP-2005-0020/EB-2005-0340); thus the programs were entirely funded through distribution rates and followed established guidelines for the delivery of CDM programs.

Bluewater Power's goal was to position itself as the leader in energy efficiency and energy conservation expertise for Sarnia-Lambton. The initial focus was on educational programs and increasing awareness of the environmental and social benefits of energy conservation among all rate classifications of customers. Bluewater Power delivered multiple print and radio advertising campaigns as well as engaging customers at community outreach events that targeted the mass residential market. Trade fairs and breakfast meetings were sponsored to promote energy conservation among Bluewater Power's commercial and industrial customers. An in-house "Power Smart Team" was established to increase employee awareness of the importance of energy conservation in the office and at home. Bluewater Power representatives delivered a conservation seminar to elementary school children while another pilot program was designed specifically with seniors in mind.

This summary will outline an evaluation of the above-mentioned educational-based programs and initiatives and provide market support assessment criteria as contained within the Ontario Energy Board's Total Resource Cost Guide.

Section 1 - Discussion of the Programs

Bluewater Power Green Team ("Power Smart Team")

Bluewater Power established its Power Smart Team with representatives from all areas of the corporation whose mandate was to develop and implement an energy conservation plan for employees. Furthermore, the Power Smart Team identified energy saving opportunities within Bluewater Power and developed a plan of action to take advantage of these opportunities. Electricity consumption data was collected for benchmarking purposes and a load inventory was completed. The focus was to heighten employee awareness of the importance of energy conservation through a signage campaign pertaining to building lighting, office printers and computers, and building air conditioning. The Power Smart Team was responsible for implementing policy changes within the organization that would reduce electricity consumption. The Team identified garage lighting as an area for improvement; 21 fixtures changed from 400 watt metal halide to T5 lamps resulted in a yearly energy savings of 6,888 kWh and a total demand savings of 6.2 kW. This energy savings will be detailed in a section specific to T5 lighting within the Evaluation Report.

All Power Smart Team goals were met and were documented within the 2005 Conservation & Demand Side Management Annual Report.

Proposed Budget	Actual Expenditure	Variance
$55,000.00	**$45,161.00**	**$9,839.00**

Distributed Generation

Bluewater Power initially focused on the deployment of a showcase micro-generation project to highlight alternative energy technology and to improve public awareness. In the early stages of this initiative the Sarnia Lambton Economic Partnership was exploring the possibility of hydrogen as the basis of economic diversification; however, after no viable projects could be identified a feasibility study was undertaken for landfill gas electricity generation. This shift in focus led to increased internal labour costs and third party consulting costs. Negotiation with the owners of the landfill was required as well. Bluewater Power proposed that the results of the landfill gas feasibility study and an educational component would be shared with Lambton College and its Alternative Energy Program and this still remains our intent.

Proposed Budget	Actual Expenditure	Variance
$90,000.00	**$108,417.00**	**($18,417.00)**

Community Outreach

Bluewater Power recognized that its community outreach program was a conservation initiative that would differentiate the corporation from other utilities. While the corporation acknowledges that

perhaps this was not the most cost effective approach to reach our customers, the Energy Conservation Community Tent Events positioned Bluewater Power as a good local corporate citizen and earned the utility tremendous positive response from the public. The Community Tent Events demonstrated Bluewater Power's commitment to the citizens of its community in assisting them in reducing their energy consumption.

Radio and print media advertising was utilized for mass market messaging regarding the Community Tent Events. These events were held in all shareholder municipalities, and in addition town hall style meetings were held at various multi-residential buildings specifically targeting senior citizens. In return for electricity consumption survey data collected at these events, a customer was given a free CFL. Bluewater Power distributed 480 CFL's which represented a yearly energy savings of 50,112 kWh. This energy savings will be detailed in a section specific to CFL's within the Evaluation Report.

In partnership with Chatham Kent Hydro, Bluewater Power launched the "Energize your Minds" energy conservation program targeted towards elementary school children. This program was presented to over 1,000 children in Lambton County schools within Bluewater Power's service area. Although not a component of our original program design, this program proved to be a very rewarding experience. However, participation in this program did contribute to expenditures exceeding the proposed budget.

Proposed Budget	Actual Expenditure	Variance
$26,100.00	**$53,438.00**	**($27,338.00)**

Web Based Energy Toolbox

Bluewater Power proposed the design and implementation of an internet based toolbox to be housed at www.bluewaterpower.com. The web-based Energy Services E-Resource Centre officially launched on April 5th 2006. The Centre provides information for both residential and commercial customers; the web site features energy conservation tips, an energy use calculator for homes and business, energy management news and a learning centre for children. The web site registered close to 30,000 visitors in the first year, however, consulting fees and third party development cost over-runs led to the expenditure exceeding the budget.

Proposed Budget	Actual Expenditure	Variance
$13,000.00	**$28,314.00**	**($15,314.00)**

Seasonal LED Lights ("SLED's" or LED Christmas Lights)

Bluewater Power partnered with the Sarnia Celebration of Lights to retrofit one of the seasonal light displays with LED's and sponsored a new energy efficiency lighting competition category. Signage was erected at the Celebration of Lights site indicating the energy savings realized if customers used SLED's rather than incandescent holiday lights. Furthermore, all Bluewater Power shareholders were offered an incentive to purchase SLED's for use in their municipalities; 100% of the corporation's shareholders accepted this offer. Incentive levels were very generous and in retrospect the incentives

should have been lower given that expenditures exceeded the proposed budget. However, this was Bluewater Power's first foray into providing incentives to its customers. The SLED energy savings will be detailed in a section specific to SLED's in the Evaluation report.

Proposed Budget	Actual Expenditure	Variance
$15,000.00	**$19,647.00**	**($4647.00)**

Streetlighting

Bluewater Power purchased two LED streetlight fixtures which were installed for pilot project purposes in the Village of Point Edward and the Village of Oil Springs. The pilot project indicated rather quickly that the lighting levels were too low and the LED streetlights have since been removed. Increased labour and truck costs resulted from the installation and subsequent replacement of the LED streetlights in the field.

Proposed Budget	Actual Expenditure	Variance
$15,000.00	**$16,701.00**	**($1701.00)**

Fridge/Air Conditioner Exchange

Bluewater Power decided to act on the advice of other local distribution companies and non-governmental organizations before proceeding with the fridge/air conditioner exchange program. Therefore, upon written request to the OEB, permission was given to re-allocate funds from this initiative to other programs within the CDM portfolio. As a result no monies were spent on the fridge/air Conditioner program. Subsequent to this decision the Ontario Power Authority launched "The Great Refrigerator Round-Up" in June of 2007.

Business Programs

Bluewater Power proposed a program that would enable business organizations to reduce energy costs. A major component of this initiative was education and focused on raising awareness of how to reduce energy consumption within the business community. To educate businesses Bluewater Power partnered with the Sarnia Lambton Chamber of Commerce and the IESO to deliver an energy conservation breakfast seminar for 37 commercial customers.

Bluewater Power hosted a Business Customer Energy Conservation Trade Fair in partnership with the Chamber of Commerce and the Ontario Ministry of Economic Development and Trade. The trade fair initially began as an opportunity to work with the local Chamber of Commerce to promote energy conservation among local businesses. However, when the attendance of then Ontario Minister of Energy Donna Cansfield was confirmed the event became much larger in scope. This caused the expenditures to exceed the proposed budget; however, Bluewater Power gained tremendous positive feedback from all attendees, trade fair exhibitors and presenters. An estimated three hundred fifty visitors attended the trade fair throughout the day-long event. Concurrent with the trade show

Bluewater Power sponsored a Natural Resources Canada "Dollars to Sense" energy conservation workshop with 19 attendees.

A town hall style meeting was held with Steeves and Rozema, a large local property management and development company to provide education on energy conservation. Bluewater Power also facilitated a workshop in Sarnia on behalf of the Association of Major Power Consumers of Ontario.

Proposed Budget	Actual Expenditure	Variance
$23,000.00	**$49,873.00**	**($26,873.00)**

Low and Fixed Income Consumers

Bluewater Power partnered with the Inn of the Good Shepherd (the "Inn") on the development of educational programs for low income electricity consumers. An energy conservation workshop was organized at the Inn; however, there were no registrations so the workshop was cancelled.

Also in partnership with the Inn, Bluewater Power sponsored the "Inn to Win" lottery and purchased energy saving appliances for part of the Inn's "Inn to Win" lottery prize board. The Energy Star-rated appliances were displayed prominently in the Lambton Mall along with energy conservation information. Close to 5,000 tickets were sold in year one of the lottery which helped the Inn with fundraising efforts. The Energy Star dishwasher has an energy savings of 101 kWh per year; the Energy Star clothes washer has an energy savings of 481 kWh per year; and the Energy Star central air conditioning unit has an energy savings of 351 kWh per year. These energy savings will be detailed in a section specific to Energy Star appliances in the Evaluation Report.

Bluewater Power partnered with the Canadian Centre for Pollution Prevention ("C2P2") on a pilot program entitled Senior Ambassadors for Energy Conservation. This program consisted of free energy conservation workshops for seniors on fixed incomes.

Proposed Budget	Actual Expenditure	Variance
$60,000.00	**$52,609.00**	**$7,391.00**

Memberships

Memberships in various energy conservation associations allowed Bluewater Power an opportunity to leverage on existing conservation programs and resulted in partnerships with entities possessing experience delivering the message of conservation. In addition, these partnerships provided excellent networking opportunities. The Seniors Ambassadors program offered by Bluewater Power was a result of the membership in the Canadian Centre for Pollution Prevention, and Bluewater Power's association with the Canadian Energy Efficiency Alliance resulted in participation in the nationally recognized "Switch to Cold" campaign. Over 500 Bluewater Power customers participated in this program.

Proposed Budget	Actual Expenditure	Variance
$5,000.00	**$5,539.00**	**($539.00)**

Load Control

Budgeted funds were re-allocated upon approval from OEB. No monies were spent on this initiative.

Energy Data Management

Bluewater Power proposed the implementation of an integrated system to report on time based consumption data and export this data to the customer billing module. This system will give Bluewater Power the capacity to manage time-of-use ("TOU") data assigned to specific accounts and the ability to forecast and plot TOU consumption for presentation and reporting.

Proposed Budget	Actual Expenditure	Variance
$200,000.00	**$174,262.00**	**$25,738.00**

Smart Meter Pilot

Bluewater Power proposed a pilot program of between 250-500 smart meters in order to gain the experience and understanding of smart meter installations, communication, data flow and impact to the customer. The Smart Meter Pilot Project was launched in Watford November 2005 with the Ontario Minister of Energy in attendance. Once the pilot project was complete Bluewater Power hosted a public meeting in Watford to report on findings. Following this meeting Bluewater Power staff hosted two information sessions at the Watford Public Library to discuss smart metering with customers on a one-on-one basis.

Proposed Budget	Actual Expenditure	Variance
$35,000.00	**$29,662.00**	**$5,338.00**

Energy Audit Program

Bluewater Power re-allocated funds from other initiatives in the CDM portfolio to create the Energy Audit Program. The program was modeled after on Natural Resources Canada's "Dollars to Sense" workshops and provided analysis of consumption and demand profile for commercial customers.

Proposed Budget	Actual Expenditure	Variance
$100,000.00	**$73,464.00**	**$26,536.00**

Lessons Learned

In the early stages of planning and delivering CDM programs Bluewater Power's focus was to enter the marketplace quickly and engage our customers with educational based programming.

However, there existed a very real lack of experience within the utility regarding CDM program delivery. To overcome this deficiency many of the Bluewater Power programs were based on initiatives that were successful in other jurisdictions. Although some areas were overspent, Bluewater Power created momentum in the marketplace for energy conservation and received very positive feedback on the programs. Because of the momentum and positive feedback it was determined that it would be worthwhile to continue along the chosen route with respect to which energy conservation programs to offer.

A further lesson learned was that some Bluewater Power customers viewed the energy conservation programs with a measure of skepticism; customers had experienced unsuccessful CDM initiatives previously with the former Ontario Hydro and therefore were reluctant to participate initially.

Bluewater Power found that there was a great deal of messaging directed at customers from a number of stakeholders (utilities, government, private business, etc.) These multiple sources of messaging at times caused confusion for Bluewater Power customers. However, being the area's long time trusted source of electricity delivery, Bluewater Power positioned itself very quickly as the local expert in the area of electricity conservation and energy efficiency.

Conclusion

Under the direction of the Ontario provincial government, Bluewater Power submitted a Conservation and Demand Side Management Program proposal. The proposed spending was approved and Bluewater Power set out to implement the initiatives contained within the approved proposal. Bluewater Power succeeded in "rolling out" a conservation plan that adhered to the guiding principles of Conservation and Demand Side Management delivery. The programs took a balanced approach, allowed for customer participation and were designed to address all rate classifications. Bluewater Power is committed to providing CDM initiatives to its customers and it is our contention that we delivered on that commitment.

Section 2 - Incremental Lighting Programs

Incremental Lighting Program - Residential

Introduction

Bluewater Power Distribution Corporation ("Bluewater Power") began its promotion of Conservation and Demand Side Management ("CDM") initiatives in response to the Ontario government's mandate to create a "culture of conservation" among Ontario electricity consumers. As the energy management expert for its customers, Bluewater Power's residential lighting program was intended to increase the awareness and knowledge of residential customers of the energy efficiency of compact fluorescent light bulbs ("CFL's") and seasonal light-emitting diode light strings ("SLED's" or LED Christmas lights) and promote the changeover from traditional lighting to energy efficient lighting. The target segment for the program was all residential customers of Bluewater Power with a focus on ease of participation.

The residential lighting program was approved as part of the 2006 EDR (RP-2005-0020/EB-2005-0340); thus was funded through distribution rates and followed established guidelines for the delivery of CDM programs.

Program Description

The residential lighting program was launched with the "Get Lit for a Loonie" event in partnership with Lambton College's Alternative Energy Program. This involved the purchase by Bluewater Power of 20,000 Energy Star rated 15w CFL's in increments of 5,000 lights from a local electrical products wholesaler.

The 15w CFL's were sold for a discounted price of one dollar at the event. The sale was heavily promoted as a limited time offer and included a maximum limit of 20 CFL's per customer. Print media and radio advertised the event and also served to further educate customers on the benefits of CFL's.

Each customer was required to provide name, location and number of units purchased as evidence of participation levels. The event commenced at 10:00 a.m. on a Saturday morning; approximately 500 customers were lined up out the door by 9:30 a.m. Ten thousand CFL's were sold by the noon hour.

Bluewater Power partnered with Sarnia's Celebration of Lights for a second residential energy efficient lighting promotion held outdoors at the Dow People Place during the Christmas season. Bluewater Power purchased 500 boxes of SLED's from a local supplier. Customers were required to exchange two strings of incandescent lights in working order for one string of SLED's at no charge. Print media and radio advertised the event and also served to further educate customers on the benefits of SLED's.

Each customer was required to provide name, location and number of exchanged strings as evidence of participation levels. The event commenced at 9:00 a.m. on a Saturday morning and once

again customers were lined up in advance. The 500 boxes of SLED's had been distributed by the noon hour and many customers exchanged more incandescent light strings than was required. Bluewater Power made arrangements with a local company to recycle the old incandescent light strings.

Table 1 – Budget vs. Actual

	Budget	Actual	Variance
# of customers/units	No target stipulated	20,500 CFL's/500 boxes SLED	n/a
kWh savings	2,482,000	2,149,628	332,372
Cost	$62,500	$130,562	$68,062
Total Resource Cost	7.83	5.74	2.09

Program Discussion

The budgeted cost was based on the total OEB approved 2006 Incremental Lighting Budget of $250,000 funded through distribution rates, of which approximately 25% was allocated to residential programs. The budgeted kWh savings and TRC are from the same 2006 Incremental Lighting projections prepared by Bluewater Power's consultants Summit Blue.

The actual participation levels are supported by purchase invoices from Bluewater Power suppliers, and the record of customer names, location and units purchased. Additionally, in the case of the CFL promotion the participation levels are supported with cash receipts.

The actual kWh savings is based on the Ontario Energy Board Assumptions and Measures list found in the Total Resource Cost Guide released in October 2006. It reflects energy savings prior to a free ridership rate of 10% for CFL's and 5% for SLED's. Actual kWh savings and TRC results were provided within annual reports to the OEB in adherence to established reporting guidelines.

The actual expenditure of $130,562 is fully allocated while $62,500 simply represents 25% of the total 2006 CDM expenditure and may not be fully allocated. Summit Blue's submission to Bluewater Power proposed rebates for residential customers to adopt CFL's and SLED's. The average rebate would be $1.00 per CFL and $1.00 per string of SLED's. However, Bluewater Power offered greater incentive levels; by offering CFL's for $1.00, the customer received almost a $2.00 discount. Furthermore, the customer was offered a much greater incentive level per string of SLED's; at a unit cost of $7.67 plus tax to Bluewater Power the customer received the SLED's at no cost other than providing the old incandescent light strings.

By providing a SLED's exchange, Bluewater Power incurred additional labour costs to sort and load lights. Also, special containers were required by the recycler and a rental truck was required to transport lights to recycler.

The Ontario Power Authority introduced Every Kilowatt Counts ("EKC") discount coupons to all Bluewater Power customers on CFL's and SLED's, and offered discounts on other energy efficient products. To increase awareness of and participation in the EKC campaign, Bluewater Power chose to market CFL's and SLED's via heavily advertised community events.

Lessons Learned

In terms of goals and objectives Bluewater Power promoted the installation of high efficiency lighting systems and made participation simple for its customers. Bluewater Power encouraged local electrical wholesalers and trade allies such as Lambton College to promote energy efficient lighting incentive programs. The creation of a channel partner network was new to Bluewater Power but provided valuable insight regarding the benefits of establishing win-win relationships.

Bluewater Power increased the awareness and knowledge of residential customers on the benefits of CFL's and SLED's with print media and radio promotion. Advertising, however, is expensive and it is difficult to determine what energy savings can be directly attributed to the promotion of energy efficient technology via the media.

Given the overwhelming response to the "Get Lit for a Loonie" event Bluewater Power recognized that the price point of the CFL's was low. In an effort to simplify the purchase process and to capitalize on marketing Bluewater Power set the price at one dollar. Going forward Bluewater Power would increase pricing whereby the customer would still receive a discounted price and would also be educated on the benefits of energy efficient lighting.

A concern of Bluewater Power is that when the price is too low the customer perception is that the product is inferior or "cheap" and the impact to incent customers to switch to energy efficiency lighting is diminished. By increasing the price the perception is that the product is of greater value and the emphasis is on energy efficiency rather than cost of the product. By increasing the price the cost to Bluewater Power is lowered and the TRC is improved.

The original Bluewater Power CDM proposal was to rebate each customer $1.00 per CFL. When the OPA entered the marketplace with the 2006 spring and fall EKC coupons, Bluewater Power felt that customers needed an alternative approach to incent the switch to CFL's and SLED's. Bluewater Power felt that customers would become confused with multiple coupon campaigns running simultaneously. Bluewater Power created tremendous excitement in the community during the "Get Lit for a Loonie" and subsequent SLED's exchange event. Bluewater Power garnered significant positive feedback within the community on the energy efficient lighting promotions and from a cost-benefit perspective the benefit was immeasurable.

Section 3 - OPA 2006 Spring and Fall Every Kilowatt Counts Coupons

Introduction

In the spring of 2006 the Ontario Power Authority (the "OPA") unveiled the first of its CDM programs entitled Every Kilowatt Counts ("EKC"). The program was education-based but also provided customers with energy saving product discount coupons that could be redeemed at participating retailers. At the behest of the Electricity Distributors Association ("EDA"), local distribution companies were informed that while the program is funded by the OPA, their participation is required in the event a Lost Revenue Adjustment Mechanism ("LRAM") filing is submitted.

Program Description

To participate in the EKC program local distribution companies were required to register with the OPA and provide a high resolution company logo. Bluewater Power was then requested to provide a customer mailing list and a bulk metered mailing list including the applicable number of units.

Bluewater Power was selected to be the site of a regional EKC program launch and therefore worked closely with the OPA's public relations firm to create a media launch at a local "big box" retail store.

An EKC coupon addressed direct mail piece was sent to every Bluewater Power customer with over 2,500 active retailers participating across the province. The coupons contained in the mail piece were bar coded specific to each local distribution company for redemption tracking purposes. Customers were offered incentives on a range of energy efficient products such as compact fluorescent lights, dimmers, motion sensors and programmable thermostats. Coupons are also made available in store at point of purchase.

Table 1 Actual Data
Direct mail piece sent to ~31,080 customers

Energy Efficient Technology	# of units	Total Energy savings (kWh)
Programmable thermostat	531	84,474
Timer	112	32,704
CFL	7491	782,061
Dimmer	198	27,562
Motion Sensor	69	14,407
Seasonal LED	4749	89,551

Program Discussion

The number of units purchased and uptake of the energy efficient products was reported to Bluewater Power by the Ontario Power Authority as part of the OPA's responsibility to track and monitor the Every Kilowatt Counts program. The number of units also includes coupons redeemed at retail stores within the Bluewater Power service territory. The energy savings was calculated using the Ontario Energy Board's Assumptions and Measures list.

Local distribution companies were requested to "audit" local retail stores to determine employees' knowledge of energy efficient products and ensure that coupons were available at point of purchase. Bluewater Power conducted a number of site visits and reported that most employees were unfamiliar with the EKC program and that with the exception of compact fluorescent light bulbs energy efficient products were difficult to locate within the store. Bluewater Power recommended that more training be provided to employees and that EKC products are displayed together if possible in a highly visible area with an ample supply of coupons.

While this program was funded by the OPA there were some costs incurred by Bluewater Power; the IT department was required to pull the mailing lists, the customer service department experienced higher call volumes, and a Bluewater Power staff person was required to assist in coordinating the media event and to conduct store visits. None of these costs were allocated to the OPA.

Lessons Learned

When the Ontario Power Authority entered the mass market with its residential education and incentive program the program was developed and implemented within a very aggressive timeline. Bluewater Power responded to a request to be a willing partner with the OPA and demonstrated flexibility in responding to these timelines. Bluewater Power contributed to the program launch on time and to the overall success of the campaign.

Bluewater Power provided input to improve upon the success of the program. Bluewater Power recognized that a critical piece of the program was retailer participation, and a Bluewater Power staff member personally contacted retailers to survey their experience with the EKC program and provided access to smaller independent retailers to participate in the campaign. Bluewater Power recommended that all store staff be trained properly and noted that often part-time weekend staff differed from weekday staff, which contributed to a lack of knowledge. Consideration should also be given to contracting a third party display management service provider to ensure that materials are visible and properly displayed.

Bluewater Power also requested longer lead times; since Bluewater Power was already in the middle of its own CDM initiatives, adequate notice of upcoming programs should be given in order to allow Bluewater Power to coordinate OPA programs with its own CDM activities.

Section 4 - "Cool Shops"

Introduction

Bluewater Power partnered with the Clean Air Foundation to deliver an energy efficiency program that specifically targeted the small commercial sector. The Clean Air Foundation is a not-for-profit organization dedicated to developing and implementing energy conservation programs that lead to measurable energy savings and emission reductions with the goal of improving air quality and protecting the climate.

Program Description

The Cool Shops program included the delivery of a Palm Pilot-assisted energy audit with a focus on lighting and the installation of two compact fluorescent bulbs and a free LED exit sign retrofit kit. In addition, businesses were provided with direct access to discounts on energy efficient products. The Clean Air Foundation hired two university student "street team" members and one university student coordinator to work in the Bluewater Power service area during the summer months.

The target was to conduct 300 audits of small street-facing businesses and to generate media coverage and awareness. The street team provided one-on-one engagement and education with business owners on the importance of energy efficiency. A stakeholder workshop was held in partnership with the Sarnia Chamber of Commerce and a local retail store was chosen as the site for a media launch and provided a testimonial regarding energy retrofits. Bluewater Power's coordinator worked closely with the local Chamber of Commerce, small business network groups and the Sarnia Lambton Economic Development office to promote the program across the Bluewater Power service territory.

By the end of the program over 400 small businesses were visited by the Cool Shops street team, thus exceeding the target of 300 audits.

Table 1- Budget vs. Actual

	Budget	Actual	Variance
# of customers	300	305	5
kWh savings	140,680	218,990	78,310
KW savings	32.96	48.6	15.64
Cost	$55,085	$55,085	$0

Program Discussion

The Cool Shops program was the only program of its kind in Canada and has a specific niche within the small commercial energy conservation marketplace. The Palm Pilot-based software allowed for ease of participation and provided the Clean Air Foundation and Bluewater Power significant data about retrofit opportunities in the small commercial sector.

The free CFL provided to business owners was an important element since it acted as an incentive to allow the street team access to the business. The CFL also acts as a reminder of energy

conservation to business owners and their employees. Not only did the free CFL help the street team engage business owners, it also created instant energy savings upon implementation.

The energy savings presented in Table 1 were provided to Bluewater Power by the Clean Air Foundation. Names of audited participants were provided to Bluewater Power by the Clean Air Foundation on a frequent basis throughout the summer months. Energy audit data was collected and provided to Bluewater Power in the form of a final report in October 2006. All input assumptions and the basis for energy savings calculations are contained within this report. A final workshop was held in Toronto with all participating local distribution companies and stakeholders (provincial and federal government, private enterprise) to provide recommendations for the enhancement of the Cool Shops program.

Lessons Learned

Bluewater Power learned that businesses that are provided free energy audits typically do not follow up with making energy efficient changes to their business. Also, only a very small percentage of businesses are willing to pay for or take the time to invest in undertaking a comprehensive full-scale energy audit.

Retail business owners wanted discounts off energy efficient products and also wanted a way to facilitate their purchase and installation. Bluewater Power also learned that education and awareness needed to be provided in a manner that required the shortest amount of time possible. Pre- booked appointments proved to be very useful. This method allowed for the appropriate person to be engaged and more time could be allotted at the visit.

Bluewater Power learned that many of the businesses operate in a building that they do not own and therefore do not have the authority to change lighting fixtures. Many of the business sites also possessed specialized lighting which was not compatible with CFL's.

Section 5 - OPA Summer Conservation Programs - The Great Refrigerator Round Up & Summer Savings Program

Introduction

The Ontario Power Authority launched its first summer conservation programs in 2007 consisting of four programs collectively known as the LDC Conservation and Demand Management Program. Upon entering into a Master Agreement with the OPA, local distribution companies were then able to submit applications to participate in each program.

The OPA approved Bluewater Power's applications for all four programs, however, only The Great Refrigerator Round-Up and the Summer Savings program have been considered for LRAM at this time. These programs were entirely funded by the Ontario Power Authority.

Program Description

Refrigerators and freezers are among the top energy consumers in a home. The goal of the Great Refrigerator Round Up program was to retire older, secondary refrigerators and freezers and recycle them in an environmentally responsible manner. The program was centrally administered by the OPA. Bluewater Power promoted the program through local community activities.

Customers were able to arrange for a free pick up by calling toll-free or booking an appointment online. The removal of an inefficient refrigerator or freezer provided the customer an opportunity to save money on their electricity bill and helped the customer qualify for the Summer Challenge incentive. In addition, customers were assured the old appliances would be recycled.

The Summer Challenge program offered a financial incentive for consumers who reduced electricity use by 10% in the summer months compared to the same period in 2006. The program also helped build awareness of Ontario's growing summer electricity requirements, especially when air conditioning dramatically increases demand. This program was promoted and delivered by Bluewater Power; the OPA provided the methodology to apply to both the 2007 consumption and the 2006 baseline consumption to determine which customers qualified for the financial incentive.

Table 1 Budget vs. Actual
The Great Refrigerator Round Up

	Budget	Actual	Variance
Cost	$60,178	$47,119.03	$13,058.97
# of Units	600	879	279
Energy savings	n/a	1,010,115 kWh	n/a

The proposed program budget was submitted by Bluewater Power and approved by the OPA. Actual costs were invoiced by Bluewater Power to the OPA. The number of actual units collected was tracked by the OPA and provided to Bluewater. The amount of energy savings realized by removing

these units from the electricity system was calculated using the Ontario Energy Board's Assumptions and Measures list.

Table 2 Budget vs. Actual
Summer Challenge Program

	Budget	Actual	Variance
Cost	$150,709.40	$115,170.04	$35,539.36
# of participants	6200	5588	(612)
Energy Savings	n/a	2,124,147 kWh	n/a

The proposed program budget was submitted by Bluewater Power and approved by the OPA. Actual costs were invoiced by Bluewater Power to the OPA. The target number of participants in the program was 20% of the total number of Bluewater Power residential customers. The actual number of eligible customers who qualified for the incentive was approximately 18% of the total number of residential customers. The energy savings realized by the program was calculated using a query developed for Bluewater Power by its consultant Deloitte. This query was submitted to and approved by the OPA.

Program Discussion

The timelines to enter into a Master Agreement and submit proposed budgets and marketing plans for these programs was very tight and the negotiation process that took place between the LDC's and the OPA was rigorous.

Bluewater Power delivered The Great Refrigerator Round Up program under budget and exceeded the target number of units collected. Bluewater Power provided unique marketing and promotional activities at local community events such as the Petrolia Rodeo and the Sarnia Highland Games which served to generate greater interest in the program. Bluewater Power also had a refrigerator mascot custom designed for promotional use.

In order to participate in the Summer Savings program Bluewater Power was required to produce a query that could calculate the amount of energy savings based on the methodology provided by the OPA. To do this, it was necessary for Bluewater Power to contract with a third party service provider which caused costs to increase. In addition, because of the very tight deadlines, many customers complained to Bluewater Power that they did not receive adequate notice of the Summer Savings program in order for them to participate. Since Bluewater Power invoices customers on a bi-monthly basis, many customers did not receive their bill insert until mid-summer. A more effective but more expensive alternative would have been a direct mail notice to customers, however, that option was declined by the OPA.

Lessons Learned

The success of The Great Refrigerator Round Up program was proof of the effectiveness of Bluewater Power's marketing activities. Bluewater Power took a unique and creative approach to marketing the program that was extremely successful. Two other local distribution companies in fact requested to borrow Bluewater Power's fridge mascot for use at their community events.

Bluewater Power found that many customers were not aware of the Summer Savings program even among those who qualified for the financial incentive. The program lacked a "call to action" and for many, sacrificing air conditioning in the hot summer months in exchange for approximately $20 was not worthwhile. To be effective Bluewater Power needed to get the program's message out to customers prior to the summer months but the timeline between registration for the program with the OPA and the acceptance of the Bluewater Power application did not allow for a lengthy marketing campaign.

The fact that Bluewater Power did not possess the "in-house" capability to create a query for the Summer Savings program greatly contributed to the high actual costs of the program. However, even with the increased costs associated with the creation of the query Bluewater Power did deliver this program under budget.

Section 6 - Business Incentive Program

Introduction

One of the guiding principles of CDM delivery is to provide programs for all rate classifications. Schedule 3-4 of Bluewater Power's 2006 Rate Application proposed a lighting program specific for commercial customers. The Business Incentive Program ("BIP") provided incentives or rebates to commercial, industrial and institutional customers for installing energy efficient lighting systems. The majority of the program impacts were expected to come from customers replacing standard efficiency lighting systems (T12 lamps and magnetic ballasts) with T8 lamps and electronic ballasts.

Program Description

Bluewater Power received approval from the Ontario Energy Board to fund this program through distribution rates. The program required the calculation of a Total Resource Cost test ("TRC") to demonstrate that the BIP program provided excellent value to the end use customer. As such, Bluewater Power contracted Summit Blue consultants to conduct the TRC.

Bluewater Power modeled the BIP after a similar Hydro One program. Bluewater Power representatives attended lighting symposiums at the invitation of the Ontario Power Authority in order to familiarize and educate staff on the application, implementation and merit of energy efficient lighting systems. A designated Bluewater Power staff person provided program administration, marketing, vendor referrals, incentive processing, consumer education and technical support.

Bluewater Power initiated a channel partnership process with electrical wholesalers and contractors to support delivery of the Business Incentive Program in co-operation with the Sarnia Lambton Chamber of Commerce. The Chamber of Commerce Showcase event was chosen as the launch for the program with the focus on T8 lighting and LED exit lighting.

Table 1 Budget vs. Actual

	Budget	Actual	Variance
# of customers	No target stipulated	10	n/a
kWh savings	1,295,000	628,440	(666,560)
Cost	$187,500	$12,933	$174,567
TRC	4.4	3.2	(1.2)

Program Discussion

The program budget was based on the total OEB-approved incremental lighting budget of $250,000 funded through distribution rates. Bluewater Power estimated that 75% of the funds would be allocated to commercial programs. The budgeted kWh savings and TRC are from the same 2006 incremental lighting projections prepared by Bluewater Power's consultants Summit Blue.

The actual kWh savings was 610,740 kWh for T8 lighting retrofits while the LED Exit lighting provided a further 17,700 kWh in energy savings to our customers. For LRAM purposes the energy

savings convert to 1604.8 kW of demand savings for the T8 lights while the LED Exit Lights provide a further 23.7 kW of demand savings. Energy and demand savings have been calculated using the Ontario Energy Board's Assumptions and Measures list.

The participation levels in the program are supported by invoices supplied to Bluewater Power by the end use customer. Upon completion Bluewater Power arranged for a site visit to inspect the retrofit. When the customer presented proof of purchase to Bluewater Power the customer was then reimbursed for the energy efficient lighting upgrades. It was the customer's responsibility to ensure the retrofit was completed in adherence to local and provincial building codes.

Budgeted costs were fully allocated while the actual costs reflect only incentive costs. When the Ontario Power Authority introduced the Electricity Retrofit Incentive Program ("ERIP") in 2007 the decision was made to replace the BIP program with the ERIP program. Bluewater Power felt that two programs offering similar incentives on similar technologies would create confusion in the marketplace. The result is lower actual costs on the BIP as compared to the Residential Incremental Lighting programs. As a direct result the kWh savings was lower than forecast.

Lessons Learned

Since this was Bluewater Power's first foray into a Business Incentive Program it was critical to model its BIP after an existing program. Several local distribution companies had commenced initiatives such as this under third tranche funding and it appeared that Hydro One's program was a good fit.

Bluewater Power did not possess any experience with channel partnerships and did not fully understand or appreciate the expectations of such a relationship; this was an entirely new undertaking for Bluewater Power.

The expectation was that the BIP would sell itself; that the uptake would be significant immediately upon launch and that contractors and end use customers would embrace the program. While all the contractors/wholesalers seemed to welcome the BIP, very few applications were received as a direct result of the channel partnership. Customers were reluctant to spend money on capital projects that did not have an immediate return on investment. Customers were uncertain what specific lighting technology was applicable or appropriate to their needs and questioned why the incentives did not take labour into consideration. Bluewater Power acknowledges that more promotion and education was a requirement to ensure the success of the program.

Bluewater Power limited the applicant to a $5,000 cap on incentive rebates so that a large lighting retrofit project did not absorb the entire budget. Of the 10 applicants that received funding only one actually received the maximum rebate. One other was over $4,000 while the remainder received small rebates. Given the energy savings reported here and in the 2007 Annual CDM report filed with the Ontario Energy Board it appears in retrospect that Bluewater Power could have relaxed that requirement.

Section 7 – Third Tranche MARR

As stated earlier in Section 1 much of Bluewater Power's CDM delivery was educational-based, however, there was a small element of activities that resulted in energy savings for Bluewater customers that warrants consideration under an LRAM submission.

Section 7.1 Community Outreach

Technology	# of units	Energy Savings
CFL 15w	480	50,112 kWh

Section 7.2 Low Income Consumers

Technology	# of units	Energy Savings
Energy Star Dishwasher	2	202 kWh
Energy Star Clothes Washer	2	962 kWh
Energy Star CAC	1	351 kWh

Section 7.3 Seasonal LED

Technology	# of units	Energy Savings
LED Christmas lights	100	1886 kWh

Section 7.4 Bluewater Power Green Team "Power Smart"

Technology	# of units	Energy Savings	Demand Savings
High Bay T5	21	6,888 kWh	6.2 kW

Each of these sections was reported to the OEB in the Bluewater Power Annual CDM Report in adherence to the OEB guidelines. The numbers of units are supported by purchase invoices. Additionally, survey data was collected at the Community Tent Events in return for a free compact fluorescent light bulb. Energy savings was calculated for each technology using the Ontario Energy Board's Assumptions and Measures list found in the Total Resource Guide released in 2006. In the original Bluewater Power Third Tranche CDM Program submission no targets were stated, merely a projected budget in dollars.

Appendix 1 - Program Summary

	Proposed Budget	**Actual Expenditure**
Green Team	$55,000	$45,161
Distributed Generation	$90,000	$108,417
Community Outreach	$26,100	$53,438
Web Based Toolbox	$13,000	$28,314
Seasonal LED	$15,000	$19,647
Streetlighting	$15,000	$16,701
Business Products	$23,000	$49,873
Low Income Consumers	$60,000	$52,609
Memberships	$5,000	$5,539
EDM System	$200,000	$174,262
Smart Meter Pilot	$35,000	$29,662
Energy Audit Program	$100,000	$73,464
Totals	**$657,600**	**$657,710**

***Note* Bluewater Power remained within $110 of its proposed budget.**

List of References

1. Cool Shops Final Report
2. Smart Meter Pilot Document
3. Landfill Gas Utilization Assessment
4. Bluewater Power Distributor Conservation & Demand Management Proposal (DCDM) – 3rd Tranche
5. Bluewater Power Distribution Corporation 2006 Rate Application – Schedule 3-4 Conservation and Demand Management
6. OEB Annual Reports 2005, 2006 & 2007 Third Tranche and CDM Funded Through Rates
7. OEB Total Resource Cost Guide
8. OPA Reporting Documents
    a. The Great Refrigerator Round Up
    b. Summer Savings Query
    c. Every Kilowatt Counts

The Methodology and Third Party Audit Report for Bluewater Power CDM Activities

A Report Prepared by
Elenchus Research Associates Inc.

On Behalf of
Bluewater Power

August 15, 2008

elenchus
Research Associates

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1 INTRODUCTION

This report develops evaluation guidelines and a methodology that will allow Bluewater Power to demonstrate a robust tracking process and an evaluation of CDM efforts that will quantify the energy savings for the purposes of the collection of LRAM and SSM.

The approach is sensitive to delivering a cost-effective solution that acknowledges Bluewater Power staff is working with expert advice, to ensure results that prudently balance cost and precision.

The overall objective is to validate kWh savings, apply the simplified evaluation methodology and demonstrate suitable review to support LRAM and SSM. The report also fulfills the requirements of the third party review that is a fundamental requirement established for the 2007 set of CDM programs.

2 STANDARD EVALUATION METHODOLOGY

Traditional evaluations focus on process and impact of the programs under review. With programs that are well established, or those designed by a third party, many of the input assumptions are fixed in advance, there is very little uncertainty association with the actual savings or free rider estimates. Therefore the bulk of the evaluation effort is limited to tracking the savings for each program and ensuring a comprehensive discussion of variances between planning assumptions and actual results, where any such variation is possible.

As per the OEB guidelines an evaluation report should include the following sections:

- **Introduction** –identifies the LDC approach to CDM and any overarching themes for the portfolio of programs.
- **Evaluation of the CDM Plans** – this is an assessment of the individual programs, including detailed process and impact analysis, where relevant. This should include discussion of input assumptions, and variations if any from the Board approved values.
- **Lessons Learned** – as a bookend to the introduction, this section identifies the overall success of the program portfolio in meeting its intended goals, including the delivery of cost-effective energy savings to customers.
- **Conclusion –** including a summary of its performance relative to the CDM Plan approved by the Board focusing on the energy savings achieved throughout the years under review.

A comprehensive evaluation report is the companion document to the program plan, and the compilation of the information provided in the Annual CDM reports prepared by each LDC. The following sections outlined information to be included as part of the evaluation document to meet the OEB guidelines and to demonstrate a continued commitment to the portfolio of CDM programs.

2.1 PROGRAM DESIGN AND IMPLEMENTATION

This section includes description of the program, eligible and target market, delivery channels and conditions for participation. It is also intended to identify any other unique elements of the program.

2.2 INPUT ASSUMPTIONS

This section includes total kWh savings calculated based on program participation, number of measures installed, energy savings per measure and free riders. Most inputs will be based on values pre-approved by OEB. In the event that some input assumptions vary from these values, they should be clearly identified with sources documented and an understanding of the related program impacts. The other input assumption that has a material impact on energy savings is free riders. A free rider is defined as:

> *The standard definition of a free rider is "a program participant who would have installed a measure on his or her own initiative even without the program". This participant simply uses the program to offset the cost of installing or undertaking the energy efficient initiative. (EB-2008-003, Section 3.4.1 pg 14)*

All results reported in the evaluation should be net of free riders, as defined by the OEB. This ensures that the LDC is not claiming credit for energy savings and costs that are not directly attributable to their program efforts. Since the majority of program inputs are fixed by the OEB guidelines, the only variable related to energy savings calculations is program participation.

2.3 PROGRAM PARTICIPATION

In order to be verifiable, program participation needs to have a demonstrated and defensible tracking methodology. This is generally achieved through a review of program participation documentation including application forms and any follow up surveys conducted with program participants.

2.4 PROGRAM COSTS

Program delivery and admin costs should be tracked, by program where possible. Variance between planned and actual should be discussed, especially focusing on large variances, which have a material impact on cost-effectiveness and TRC results. In selected cases, program administration costs span more than one customer group or program delivery mechanism; all assumptions used to allocate dollars should be reflected in the evaluation documentation.

2.5 LRAM AND SSM CALCULATIONS

In addition to standard evaluation requirements, there is a need to demonstrate defense of these calculations for the purposes of LRAM and SSM recovery.

In addition to valid savings, and cost-effective programs an LDC must demonstrate attribution to ensure that the impact in the region is a result of efforts undertaken by the company. The guidelines laid out by the OEB identify the following:

> *Attribution of benefits as between a distributor and a non-rate regulated third party will be determined on a case-by-case basis. In order for the distributor to claim 100% attribution of benefits, the distributor should demonstrate that its role was 'central' to the program. Centrality is established by the distributor if its financial contribution is greater than 50% of program funding or, where the distributor's financial contribution is less than 50% of program funding, the distributor initiated the partnership, initiated the program or initiated the implementation of the program. Where the distributor's financial contribution is less than 50%, the Board expects that the distributor will provide supporting documentation outlining its role in the program. (EB-2008-003, Section 3.4.2 p. 15)*

This can be demonstrated by the type of information and level of detail that is included in the evaluation report prepared by the utility and review in this audit.

2.6 LRAM

As outlined by the Board, an application for LRAM should include:

- *kW or kWh impacts (both gross & net of free riders) of each program and for each class;*
- *free rider rate applied to each program and where applicable any differences by technology;*
- *Verification of the participation levels;*
- *Duration of the program in years (or months);*
- *Verification that all input assumption are consistent with those provide by the OEB, or justification for any deviations, where relevant;*
- *A calculation of the impact of the CDM program on distribution revenues in each class including distribution across rate classes and the relevant rates (EB-2008-003, Section 9.2, pg 34-35).*

Much of this information, can and should be provided in an Evaluation Report and any corresponding reviews conducted by an independent third party.

2.7 SSM

Similar to LRAM, an application for SSM must demonstrate proven and verifiable energy savings but is not limited only to those that are demonstrated to be cost-effective. However, SSM is only available for programs funded by the LDC or through co-operation with other LDCs, but not programs funded through the OPA.

When calculating the amount to be included in the SSM calculation, the TRC impacts of all programs should be included – with the addition of both positive and negative TRC results.

3 INDEPENDENT THIRD PARTY REVIEW

The major additional requirement introduced for 2007 is the need for an independent third party review to validate the information presented in the LRAM and SSM claim. This is mostly intended to validate that the participation levels and input assumptions are consistent with those used by the OPA/OEB. Additionally, the third party will comment on the overall evaluation approach and delivery of the portfolio of programs. For programs funded through distribution rates, the guidelines identify the role of the third party is to:

- *Provide opinions of the cost effectiveness results that are material to the LRAM and SSM amounts proposed;*
- *Verify participation levels;*
- *Confirm that the input assumptions are those posted on the Board's website [or review the reasonableness of values that may differ];*
- *Recommend any forward looking evaluation work to be considered; and,*
- *Recommend any improvements to the program to enhance program design, performance, and uptake by customers. (EB-2008-003, Section 7.5 pg.29)*

3.1 IMPLICATIONS FROM PREVIOUS DECISIONS

In order to be eligible to recover LRAM, an LDC must be able to demonstrate that CDM programs were delivered cost-effectively, that energy savings and free riders assumptions were consistent with pre-approved values and that program participation rates are measurable.

In reviewing examples of submissions that have been accepted and those that have not, the key differentiator is the amount of information that is made available and the level of documentation that is provided. In the case of Oshawa PUC Networks Inc. Decision (EB-2007-0710) the Board staff review of evidence and interrogatories left them unable to determine whether amounts claimed were accurate since the reports filed did not provide sufficient information or clarity on the calculations submitted. In the case of other decisions submitted on this matter, the Board has requested clarification and may choose to disagree with positions taken, but with sufficient information and additional data requests through interrogatories, sufficient information has been made available to create this clarity. A list of decision reviews is included in the annotated Bibliography.

A successful portfolio of programs should be able to demonstrate costs effectiveness in both program plans and actual savings. This includes validation of all input assumptions, to demonstrate that they are in keeping with the guidelines set out by the OEB.

3.2 REQUIREMENTS FOR SIMPLIFIED METHODOLOGY

The need for a large or complex evaluation as traditionally completed for previous CDM programs in both natural gas and electricity is somewhat mitigated based on the fact that these new electricity programs do not present either new information or significantly differentiated delivery channels. Most programs are being delivered in accordance to OPA guidelines, with few if any custom measures. As such, very little uncertainty exists in either the technology details or related energy savings.

3.3 IMPLICATIONS FOR BLUEWATER POWER

Through the course of the third party review it is clear that Bluewater is using standard OEB methodology and approved OEB inputs and assumptions. By demonstrating effective tracking of program participation, no uncertainty in information has been uncovered through the course of the independent third party review.

The majority of the program design was conducted through OPA with much of the tracking also provided through this mechanism. The Bluewater program evaluation documentation and subsequent audit demonstrates that the information presented in the Bluewater evidence is appropriate; and suitable evaluation has been conducted to support the collection of LRAM and SSM. By working with an independent party, Bluewater has been able to ensure accurate representation of raw data and results.

4 FINDINGS OF THE THIRD PARTY REVIEW

The Bluewater team collected and submitted a report to defend the program tracking elements of the program evaluation. The LDC provided tables of input assumptions with sources as under the guidelines included in Appendix A with instructions on the type of information that will be required for the review. The ERA team reviewed input assumptions, TRC results and source data to ensure consistency and accuracy of information provided.

The sections that follow include the full scope and assessment of the evaluation report and support documentation. Also included in Appendix B are the detailed findings of the audit in spreadsheet format.

4.1 APPROACH AND METHODOLOGY

As part of the evaluation audit, ERA reviewed the information provided by Bluewater as per the guidelines set out by the OEB.

Although the independent audit is a strict requirement for 2007 only, with the co-operation of Bluewater, ERA conducted a full audit of all input and output assumptions for CDM programs for the period 2005-2007. Select programs are still in the field in 2008, so program evaluations are focused on historic results only.

4.2 AUDIT PARAMETERS AND GUIDELINES

In order to perform a comprehensive review and audit, the ERA team focused on the following assumptions:

- **Free rider rates**– differentiating between commercial and residential applications, or delivery mechanism, where relevant;
- **Equipment costs** – by technology or program bundle;
- **Equipment life** – differentiating between commercial and residential applications, where relevant;
- **Program costs** – by program and fully loaded, where available;
- **Energy savings** – kwh and KW;
- **Participation** – no. of units, household or sites, as appropriate; and
- **TRC analysis** including **discount rates**.

All reviews included a check for internal consistency, integrity of the calculations and consistency with published OEB or OPA approved values. Where utility specific information was provided, source documents were reviewed to ensure

that the information has been applied appropriately to the program or technology. For inputs that do not come from published sources (e.g. participation or number of units), the audit team reviewed customer submissions, manufacturer invoices, company accounting system summaries, and billing system analysis to ensure sufficient evidence was available to demonstrate accurate tracking. The evaluation audit also focused on determinants of attribution to demonstrate that the role the Bluewater team played in broadening customer awareness was sufficient to influence behaviour.

Bluewater Power delivered programs in 3 broad categories:

- **OPA programs** that were designed and developed by the OPA, where tracking of results was delivered through the OPA and cost-effectiveness analysis was conducted by the OPA or with OPA inputs
- **Third party program** that were funded by the OPA but delivered through other established third parties
- **LDC programs** designed and delivered by the LDC directly based on technologies identified and approved by the OEB

There were no custom projects in the 3 year CDM portfolio under review in this evaluation. The audit analysis and subsequent documentation focuses on general use of input assumptions and an assessment of attribution.

4.3 INPUT ASSUMPTIONS

All input assumptions are consistent with OEB documentation, where available. For those technologies where information did not exist, the Bluewater team used input assumptions for similar technologies and followed an approach that was conservative in using the lower energy savings estimate. As part of the audit, TRC results were compared to LRAM/SSM schedules, and to source documents. The spreadsheet in Appendix C is a comprehensive cross reference of all input and output assumptions completed through the course of the audit. It identifies value and source for all information relevant to the evaluation analysis.

Summary Table for OPA Program Review

Parameters for Review	Audit Comments
Program Name(s)	Every Kilowatt Counts Coupons Great Refrigerator Round Up Summer Savings
No. of Units	OPA data provided thru OPA tracking process - coupons redeemed, by booklet and store used as participant numbers; no. of units for Summer

	Savings based on billing analysis and application of eligibility criteria
Energy Savings	Confirmed use of OEB inputs; Summer Savings calculated using billing data – based on methodology and parameters provided by OPA -- spreadsheet reviewed
Free riders	Confirmed use of OEB inputs
Equipment Costs	No equipment costs were used in NPV analysis
Equipment Life	Confirmed use of OEB inputs
Program Costs	No costs were allocated specifically to this program – not relevant for analysis of LRAM only (small incremental cost reflected in other utility costs)
Net Benefits (TRC results)	Although TRC results were validated to ensure accurate use of input assumptions and net societal benefit, these programs are not eligible for SSM;

Summary Table for Third Party Program Review

Parameters for Review	**Audit Comments**
Program Name(s)	Cool Shops
No. of Units	Reviewed proposal and final report, to ensure consistency in input assumptions and cross reference with spreadsheets
Energy Savings	Confirmed use of OEB inputs where available; for other technologies, used consultant report (Summerhill Group) NPV analysis, as outlined in final report
Free riders	Confirmed use of OEB inputs where available, for others used assumptions for similar technologies – application is relevant and appropriate
Equipment Costs	Analysis includes no equipment cost, these costs are reflected in the lump sum program costs
Equipment Life	Confirmed use of OEB inputs where available, for others used assumptions for similar technologies –

	application is relevant and appropriate
Program Costs	Includes equipment cost and cost of delivering the program thru third party delivery mechanism
Net Benefits (TRC results)	Cool Shops uses different discount rate; where available Bluewater has used the LDC specific discount rate therefore NPV for similar technologies may differ from consultant report

Summary Table for LDC Program Review

Parameters for Review	**Audit Comments**
Program Name(s)	Green Team Seasonal LED (SLED) Inn to Win Business Incentive Program (BIP)
No. of Units	Collected through survey results, and participant application forms (see notes below)
Energy Savings	Confirmed use of OEB inputs where available, for others used assumptions for similar technologies – application is relevant and appropriate
Free riders	Confirmed use of OEB inputs where available, for others used assumptions for similar technologies – application is relevant and appropriate
Equipment Costs	Confirmed use of OEB inputs where available; select programs share equipment costs that are reflected in program costs, this has been identified and will be addressed in future evaluations
Equipment Life	Confirmed use of OEB inputs where available. For others, used assumptions for similar technologies – application is relevant and appropriate
Program Costs	Some program costs include equipment costs, and differ from the information provided in CDM Annual report, to reflect allocations
Net Benefits (TRC results)	Note: discount rates vary by year, depending on

	value used by Bluewater and cost of capital in a given year (2005-2007)

5 IMPLICATIONS AND RECOMMENDATIONS

It is the finding of this evaluation audit that Bluewater Power calculated TRC results as per the OEB guidelines, for all eligible programs. The sections below address key components of the audit process and any issues that were uncovered, along with some overall recommendations for the future.

5.1 CUSTOMER PARTICIPATION AND ATTRIBUTION

The Bluewater team worked very hard to ensure that the energy savings claimed were clearly attributable to the program undertaken. For those programs delivered by the LDC directly to customers a comprehensive tracking methodology was followed including:

BIP – T8 and Exit Lighting (An Example)

- Customer information and awareness created through program
- Customers contact LDC before proceeding to clarify rules and requirements for program participation, in advance of installing technologies
- Customer provides purchase invoice for prescribed technologies at fixed rates and LDC reviews invoice for eligible technologies, cheque provided for incentive
- List of cheques issued in 2007 for incentive payments, reflect summary from financial systems
- Each customer had site visit to validate installation and ongoing use of identified technology

For other programs, the Bluewater team collected information on participating customers and ensured that those participating were aware of the goals and objectives of the program. For LDC programs this included but was not limited to:

- Customer list, for giveaways and purchase invoices from distributor
- List of customers who participated, by event and day
- Purchase order for bulbs distributed at individual events, tracking by event via staff reports (improvements made to formal documentation in subsequent years)
- Purchase orders for measures in 100 and 200 unit increments, unused bulbs were used for subsequent events
- Survey data with direct links back to specific customers
- Cash receipts – to clients, and from LDC (Green Team T5)
- Purchase invoices for items purchased by LDC, and those of customers (Bluewater submitted unique and numbered invoices)

Although some customers may not have been strictly inside Bluewater territory, savings are reflected in Ontario-wide demand reduction and free rider rate more than covers the implications for LRAM/SSM. The LDC required a minimum customer contribution to ensure that technologies would be installed; as opposed to giveaways where installation rates are sometime lower (built into program

design objectives). Potential savings from information programs was not reflected in the CDM results for programs in any year, although incremental savings were the intention of the program.

5.2 ASSESSMENT OF ANALYSIS

There were no material errors found in the analysis of either LRAM or SSM tables. The LRAM tables were vetted against the source data to ensure consistency. The SSM parameters used were audited against those in the LRAM for the same technology and were consistent.

A few general comments on the format, formulas and the approach used for documentation throughout the evaluation materials. Formulas, while correct, are generally inconsistent - in the same row, pointers go both to internal rows and separate 'Calculation' pages. In the future, evaluation documentation should clearly reference source documents. For example, the lines from the OEB TRC guide -- reference the line number in the technology description. This would help distinguish between the technologies from the Residential, Industrial, Commercial applications. Striving to standardize the formulas will make it easier to set-up the tracking mechanism, and also to audit the results.

5.3 IMPLICATIONS FOR NPV ANALYSIS - TRC RESULTS

As part of the evaluation audit ERA looked at the source documents for all the TRC tests. The Bluewater team followed all the OEB guidelines using the appropriate avoided costs and methodology. As part of the comprehensive review, ERA reviewed input assumptions to:

- Validate avoided costs, discount factors, and free riders;
- Ensure data was used as per OEB guidelines, with exception of those technologies which were not represented on OEB website, as noted above;
- Free riders applied to discount participants and equipment costs;
- Validated energy savings, equipment cost and equipment life;
- Energy savings and equipment life as per OEB guidelines;
- Equipment costs – for selected technologies, equipment cost is reflected as a program cost for the TRC analysis; in a few examples technologies share a program cost that is bundled;
- Program costs are fully allocated for LRAM/SSM, not for original CDM Annual Reports;
- Verify participation levels across all programs including review of paper trail to reflect documentation for participants;
- Further audit against company records, and invoices, where available.

Below are a few items that need to be addressed in future TRC analysis both planning and evaluation stages.

- Ensure that all programs have equipment cost whether the payments are made by the LDC, or the customer directly – incremental equipment costs should be reflected in the societal analysis.
- Ensure that equipment costs are reflected in NPV as such, and not lumped into program costs – this has an implication for TRC treatment of free riders. Societal benefits are understated using the current methodology.

Overall approach to TRC results is consistent with OEB guidelines. All technologies had a TRC test, whether calculated directly by the LDC or sourced through a third party expert (and remitted to OEB as part of the annual reporting requirements).

6 RECOMMENDATIONS FOR PROGRAM IMPROVEMENTS

In reviewing the lessons learned sections of the 2008 evaluation report, it is clear that the Bluewater team has been making program modifications throughout the 3 year window that is covered in this report. Programs have been modified or eliminated to ensure maximum societal benefit. Some examples include eliminating non-cost-effective programs like Inn to Win and T5 lighting in business markets. Recent CDM efforts seem to focus on more established programs, delivered through robust delivery mechanisms.

7 RECOMMENDATIONS FOR FUTURE EVALUATION WORK

The Bluewater team completed a comprehensive evaluation using internal resources and external experts. Through the course of the audit there were a few areas for improvement that could be implemented in future evaluations. These include:

- Complete evaluations report annually
- Annotated spreadsheets with source for inputs, and assumptions
- Consistency in format for reporting, establish during planning phased with planning assumptions and use as comparison point for actual values at time of evaluation
- Formalize tracking, perhaps consider purchase or build of a more formal tracking system

As noted before, these recommendations do not materially change the results or findings. The value of these recommendations is that they will make both future evaluations and the accompanying third party review more robust and time efficient. It will also introduce more transparency in findings.

8 FINAL ASSESSMENT – AN AUDITOR'S NOTE

After reviewing both input and output assumptions, conducting a site visit and multiple meetings with the Bluewater team, verifying assumptions with source documents and against data provided through the OEB reports, it is our opinion that Bluewater has demonstrated suitable support for the numbers being put forward in their claim for LRAM and SSM. They have met all the requirements as set out in the most recent guidelines from the OEB and as further elaborated in most recent rate case decisions.

9 BIBLIOGRAPHY

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Toronto Hydro-Electric System Limited Decision and Order (EB-2007-0096). Ontario Energy Board. September 11, 2007. <> (May 2, 2008)

Toronto Hydro-Electric System Limited Supplementary Application 2007 Rates Manager's Summary. March 23, 2007 (EB-2007-0582). March 23, 2007. <> (May 2, 2008)

a) Total Resource Cost Guide. Ontario Energy Board. October 2, 2006. <> (May 2, 2008)

10 LIST OF REFERENCE

This is a list of the material reviewed during the course of the audit and while on site with Bluewater team.

1. LRAM spreadsheet detailing Program, Technology, Number of Units, Energy Savings, Free Ridership and Lost Revenue. All input and output assumptions were reviewed.
2. SSM spreadsheet detailing Program, Technology, Free Ridership, Costs and Benefits (NPV) All input and output assumptions were reviewed.
3. NPV analysis contained within LRAM and SSM spreadsheet reviewed for all technologies.
4. Compact fluorescent lamps “Get Lit for a Loonie”- reviewed Bluewater Power documentation on list of participating customers.
5. SLED Exchange - reviewed Bluewater Power documentation on list of participating customers.
6. Cool Shops Final Report prepared by Clean Air Foundation. Reviewed input and output assumptions for the program including TRC analysis including additional assumptions provided by Summerhill Group.
7. Business Incentive Program (BIP) reviewed folder containing customer applications and distributor invoices.
8. Bluewater Power SAP query for financial incentive cheques paid to BIP customers.
9. Bluewater Power’s CDM Evaluation Report – summary of CDM activities.
10. Ontario Power Authority’s (OPA) 2006 Spring & Fall Every Kilowatt Counts Campaign – participation levels.
11. Ontario Power Authority’s 2007 Great Refrigerator Round Up Program Final Report – participation levels.
12. Bluewater Power’s Summer Savings spreadsheet – participation levels confirmed by the OPA. Query designed by Deloitte.
13. Ontario Energy Board’s Inputs and Assumptions for Calculating Total Resource Cost.

11 APPENDIX A – DETAILED AUDIT FINDINGS – SPREADSHEET OF INPUT AND OUTPUT ASSUMPTIONS

Findings of the Bluewater Audit including site visit August 7, 2008

Detailed LRAM Audit Results – Part I (next page)

Detailed LRAM Audit Results

Technology	Year Implemented	# units		Measure Life		Total Energy Savings (kWh)		Total Energy Savings (kW)		Total Energy Savings with # units		Free Ridership		Net kWh or kW saved	
		Value	Source	Value	Source	Value	Source	Value	Source	Value	Source	Value	Source	Value	Source
CFL 15w screw in	2005	480	Company Data	4	OEB Website	104	OEB Website			50,112	Calculation Validated	10%	OEB Website	45,101	Calculation Validated
Energy Star Dishwasher	2005	1	Company Data	13	OEB Website	100	OEB Website			100	Calculation Validated	10%	OEB Website	90	Calculation Validated
Energy Star Clothes washer	2005	1	Company Data	14	OEB Website	480	OEB Website			480	Calculation Validated	10%	OEB Website	432	Calculation Validated
Energy Star CAC	2005	1	Company Data	14	OEB Website	351	OEB Website			351	Calculation Validated	10%	OEB Website	316	Calculation Validated
LED Christmas Light	2005	100	Company Data	30	OEB Website	19	OEB Website			1,886	Calculation Validated	5%	OEB Website	1,791	Calculation Validated
High BayT5 Lamps	2005	21	Company Data	5	OEB Website	328	OEB Website	0.29	Calculation Validated	6.2	Calculation Validated	10%	OEB Website	5.6	Calculation Validated
Energy Star Dishwasher	2006	1	Company Data	13	OEB Website	100	OEB Website			100	Calculation Validated	10%	OEB Website	90	Calculation Validated
Energy Star Clothes washer	2006	1	Company Data	14	OEB Website	480	OEB Website			480	Calculation Validated	10%	OEB Website	432	Calculation Validated
CFL 15w screw in	2006	20500	Company Data	4	OEB Website	104	OEB Website			2,140,200	Calculation Validated	10%	OEB Website	1,926,180	Calculation Validated
LED Christmas Lights	2006	500	Company Data	30	OEB Website	19	OEB Website			9,428	Calculation Validated	5%	OEB Website	8,957	Calculation Validated
Programmable thermostat	2006	149	OPA Report	18	OEB Website	159	OEB Website			23,704	Calculation Validated	10%	OEB Website	21,333	Calculation Validated
Timer	2006	112	OPA Report	20	OEB Website	292	OEB Website			32,704	Calculation Validated	10%	OEB Website	29,434	Calculation Validated
CFL	2006	3447	OPA Report	4	OEB Website	104	OEB Website			359,867	Calculation Validated	10%	OEB Website	323,880	Calculation Validated
Cool Shops 15w cfl	2006	672	Consultant Report	4	OEB Website	104	OEB Website			70,157	Calculation Validated	10%	OEB Website	63,141	Calculation Validated
Cool Shops LED Exit	2006	444	Consultant Report	25	OEB Website	237	OEB Website			105,015	Calculation Validated	10%	OEB Website	94,513	Calculation Validated
Cool Shops11w cfl	2006	50	Consultant Report	3	OEB Website	67	OEB Website			3,350	Calculation Validated	10%	OEB Website	3,015	Calculation Validated
Cool Shops 27w cfl	2006	2	Consultant Report	3	OEB Website	170	OEB Website			340	Calculation Validated	10%	OEB Website	306	Calculation Validated
Cool Shops BR 15w	2006	29	Consultant Report	2.46	Consultant Report	146	Consultant Report			4,234	Calculation Validated	10%	Consultant Repo	3,811	Calculation Validated
Cool Shops BR 16w	2006	30	Consultant Report	2.46	Consultant Report	143	Consultant Report			4,290	Calculation Validated	10%	Consultant Repo	3,861	Calculation Validated
Cool Shops PAR 20w	2006	102	Consultant Report	2.46	Consultant Report	228	Consultant Report			23,256	Calculation Validated	10%	Consultant Repo	20,930	Calculation Validated
Cool Shops PAR 23w	2006	2	Consultant Report (CR)	2.46	Consultant Report	221	Consultant Report			442	Calculation Validated	10%	Consultant Repo	398	Calculation Validated
Cool Shops 13w cfl	2006	118	OEB Website, CFL 11	3	OEB Website, CFL 11	67	OEB Website, CFL 11			7,906	Calculation Validated	10%	Consultant Repo	7,115	Calculation Validated
Programmable thermostat	2007	382	CR Sarnia & 4 territories	18	OEB Website	159	OEB Website			60,770	Calculation Validated	10%	OEB Website	54,693	Calculation Validated
LED lights	2007	4749	CR Sarnia & 4 territories	20	< OEB Website	19	OEB Website			89,551	Calculation Validated	5%	OEB Website	85,073	Calculation Validated
Dimmer	2007	198	CR Sarnia & 4 territories	10	OEB Website	139	OEB Website			27,562	Calculation Validated	10%	OEB Website	24,805	Calculation Validated
CFL	2007	4044	CR Sarnia & 4 territories	4	OEB Website	104	OEB Website			422,194	Calculation Validated	10%	OEB Website	379,974	Calculation Validated
Motion detector	2007	69	CR Sarnia & 4 territories	10	OEB Website	209	OEB Website			14,407	Calculation Validated	10%	OEB Website	12,966	Calculation Validated
2007 Great Refrigerator Round-up - Refrige	2007	732	OPA Report	6	< OEB Website	1,199	OEB Website			877,668	Calculation Validated	10%	OEB Website	789,901	Calculation Validated
2007 Great Refrigerator Round-up - Freeze	2007	147	OPA Report	6	< OEB Website	901	OEB Website			132,447	Calculation Validated	10%	OEB Website	119,202	Calculation Validated
2007 Summer Savings Program	2007	5588	Consultant Analysis	1	Consultant Report	2,124,147	Billing Analysis			2,124,147	Calculation Validated	10%	OEB Website	1,911,732	Calculation Validated
Business Incentive Program-T8	2007	2106	Company Data	5	OEB Website	288	OEB Website	0.76	Calculation Validated	1,604.8	Calculation Validated	10%	OEB Website	1,444.3	Calculation Validated
Business Incentive Program-Exit Lighting	2007	75	Company Data	25	OEB Website	237	OEB Website	0.32	Calculation Validated	23.7	Calculation Validated	10%	OEB Website	21.3	Calculation Validated
										6,368,157	Calculation Validated			5,736,384	Calculation Validated
										218,990	Calculation Validated			197,091	Calculation Validated
										1,635	Calculation Validated			1,471	Calculation Validated
										6,588,781	Calculation Validated			5,934,946	Calculation Validated

Detailed LRAM Audit Results – Part II

	Net 2005 kWh or kW saved	Rate $/kWh or $/kW	Lost Revenue $	2006 kWh or kW saved	Rate $/kWh or $/kW	Lost Revenue $	2007 kWh or kW saved	Rate $/kWh or $/kW	Lost Revenue $	Total kWh or kW	Total Lost Revenue	Comments
	45,101	0.0101	$ 456	45,101	0.0117	$ 528	45,101	0.0117	$ 528	**135,302**	**$ 1,511**	
	90	0.0101	$ 1	90	0.0117	$ 1	90	0.0117	$ 1	**270**	**$ 3**	
	432	0.0101	$ 4	432	0.0117	$ 5	432	0.0117	$ 5	**1,296**	**$ 14**	
	316	0.0101	$ 3	316	0.0117	$ 4	316	0.0117	$ 4	**947**	**$ 11**	
	1,791	0.0101	$ 18	1,791	0.0117	$ 21	1,791	0.0117	$ 21	**5,374**	**$ 60**	
	5.6	1.3598	$ 8	5.6	1.6252	$ 79	5.6	1.6241	$ 9	**17**	**$ 96**	
Total 2005	47,735		490	47,735		638	47,735		567	**143,206**	**1,695**	**All Calculations Validated**
				90	0.0117	$ 1	90	0.0117	$ 1	**180**	**$ 2**	
				432	0.0117	$ 5	432	0.0117	$ 5	**864**	**$ 10**	
				1,926,180	0.0117	$ 22,536	1,926,180	0.0117	$ 22,536	**3,852,360**	**$ 45,073**	
				8,957	0.0117	$ 105	8,957	0.0117	$ 105	**17,914**	**$ 210**	
				21,333	0.0117	$ 250	21,333	0.0117	$ 250	**42,666**	**$ 499**	
				29,434	0.0117	$ 344	29,434	0.0117	$ 344	**58,867**	**$ 689**	
				323,880	0.0117	$ 3,789	323,880	0.0117	$ 3,789	**647,760**	**$ 7,579**	
				63,141	0.0128	$ 808	63,141	0.0128	$ 808	**126,282**	**$ 1,616**	
				94,513	0.0128	$ 1,210	94,513	0.0128	$ 1,210	**189,027**	**$ 2,420**	
				3,015	0.0128	$ 39	3,015	0.0128	$ 39	**6,030**	**$ 77**	
				306	0.0128	$ 4	306	0.0128	$ 4	**612**	**$ 8**	
				3,811	0.0128	$ 49	3,811	0.0128	$ 49	**7,621**	**$ 98**	
				3,861	0.0128	$ 49	3,861	0.0128	$ 49	**7,722**	**$ 99**	
				20,930	0.0128	$ 268	20,930	0.0128	$ 268	**41,861**	**$ 536**	
				398	0.0128	$ 5	398	0.0128	$ 5	**796**	**$ 10**	
				7,115	0.0128	$ 91	7,115	0.0128	$ 91	**14,231**	**$ 182**	
Total 2006				2,507,397		29,553	2,507,397		29,553	**5,014,793**	**59,107**	**All Calculations Validated**
							54,693	0.0117	$ 640	**54,693**	**$ 640**	
							85,073	0.0117	$ 995	**85,073**	**$ 995**	
							24,805	0.0117	$ 290	**24,805**	**$ 290**	
							379,974	0.0117	$ 4,446	**379,974**	**$ 4,446**	
							12,966	0.0117	$ 152	**12,966**	**$ 152**	
							789,901	0.0117	$ 9,242	**789,901**	**$ 9,242**	
							119,202	0.0117	$ 1,395	**119,202**	**$ 1,395**	
							1,911,732	0.0117	$ 22,367	**1,911,732**	**$ 22,367**	
							1,444.3	1.6241	$ 2,346	**1,444**	**$ 2,346**	
							21.3	1.6241	$ 35	**21**	**$ 35**	
Total 2007							3,379,814		41,907	**3,379,814**	**41,907**	**All Calculations Validated**
Total Residental											**$ 95,187**	
Total GS<50											**$ 5,046**	
Total GS>50											**$ 2,476**	
Grand Total	**47,735**		**$ 490**	**2,555,132**		**$ 30,191**	**5,934,946**		**$ 72,028**	**8,537,813**	**$ 102,709**	**All Calculations Validated**

Detailed SSM Audit Results

Detailed SSM Audit Results

Rate Class	Technology	# units		Free Ridership Rate		NPV Benefit per unit $		Incremental Equipment Cost $ (from TRC guide)		Utility Program Costs		Total Benefits $ (NPV)	Total Costs $	Net Benefits $ (NPV)	Benefit Cost Ratio	SSM Amount $	Comments
		Value	Source	Value	Source	Value	Source	Value	Source	Value	Source						
Residential	CFL 15w screw in	480	Company Data	10%	OEB Website	$ 26.51	Verified TRC Analysis	$ -	Included in Program Cost	$ 7,118	Audited against Invoice	$ 11,453	$ 7,118	$ 4,336	1.61	$ 217	All Calculations Validated
Residential	Energy Star Dishwasher	1	Company Data	10%	OEB Website	$ 65.80	Verified TRC Analysis	$ -	Included in Program Cost	$ 7,740	Audited against Invoice	$ 59	$ 7,740	$ (7,680)	0.01	$ (384)	All Calculations Validated
Residential	Energy Star Clothes washer	1	Company Data	10%	OEB Website	$ 315.82	Verified TRC Analysis	$ -	Included in Program Cost	$ 7,740	Audited against Invoice	$ 284	$ 7,740	$ (7,455)	0.04	$ (373)	All Calculations Validated
Residential	Energy Star CAC	1	Company Data	10%	OEB Website	$ 250.39	Verified TRC Analysis	$ -	Included in Program Cost	$ 7,740	Audited against Invoice	$ 225	$ 7,740	$ (7,514)	0.03	$ (376)	All Calculations Validated
Residential	LED Christmas Light	100	Company Data	5%	OEB Website	$ 18.89	Verified TRC Analysis	$ -	Included in Program Cost	$ 727	Audited against Invoice	$ 1,794	$ 727	$ 1,068	2.47	$ 53	All Calculations Validated
Residential	Energy Star Dishwasher	1	Company Data	10%	OEB Website	$ 65.80	Verified TRC Analysis	$ -	Included in Program Cost	$ 14,696	Audited against Invoice	$ 59	$ 14,696	$ (14,636)	0.00	$ (732)	All Calculations Validated
Residential	Energy Star Clothes washer	1	Company Data	10%	OEB Website	$ 315.82	Verified TRC Analysis	$ -	Included in Program Cost	$ 14,696	Audited against Invoice	$ 284	$ 14,696	$ (14,411)	0.02	$ (721)	All Calculations Validated
Residential	CFL 15w screw in	20500	Company Data	10%	OEB Website	$ 26.51	Verified TRC Analysis	$ -	Included in Program Cost	$ 125,719	Audited against Invoice	$ 489,147	$ 125,719	$ 363,428	3.89	$ 18,171	All Calculations Validated
Residential	LED Christmas Lights	500	Company Data	5%	OEB Website	$ 18.89	Verified TRC Analysis	$ -	Included in Program Cost	$ 4,843	Audited against Invoice	$ 8,971	$ 4,843	$ 4,128	1.85	$ 206	All Calculations Validated
GS<50	15w cfl	672	Consultant Report	10%	OEB Website	$ 26.51	Verified TRC Analysis		Included in Program Cost	$ 50,000	Audited against Invoice	$ 16,033	$ 50,000	$ (33,967)	2.56	$ (1,698)	All Calculations Validated
GS<50	LED Exit	444	Consultant Report	10%	OEB Website	$ 269.26	Verified TRC Analysis	$ -	Included in Program Cost		Included above	$ 107,597	$ -	$ 107,597		$ 5,380	All Calculations Validated
GS<50	11w cfl	50	Consultant Report	10%	OEB Website	$ 13.27	Verified TRC Analysis	$ 2.25	OEB Website		Included above	$ 597	$ 101	$ 496		$ 25	All Calculations Validated
GS<50	27w cfl	2	Consultant Report	10%	OEB Website	$ 33.51	Verified TRC Analysis	$ 5.00	OEB Website		Included above	$ 60	$ 9	$ 51		$ 3	All Calculations Validated
GS<50	BR 15w	29	Consultant Report	10%	Consultant Report	$ 27.52	Verified TRC Analysis	$ 7.89	Valudated with Summerhill		Included above	$ 718	$ 206	$ 512		$ 26	All Calculations Validated
GS<50	BR 16w	30	Consultant Report	10%	Consultant Report	$ 27.00	Verified TRC Analysis	$ 7.89	Valudated with Summerhill		Included above	$ 729	$ 213	$ 516		$ 26	All Calculations Validated
GS<50	PAR 20w	102	Consultant Report	10%	Consultant Report	$ 52.27	Verified TRC Analysis	$ 8.95	Valudated with Summerhill		Included above	$ 4,798	$ 822	$ 3,976		$ 199	All Calculations Validated
GS<50	PAR 23w	2	Consultant Report	10%	Consultant Report	$ 50.72	Verified TRC Analysis	$ 10.95	Valudated with Summerhill		Included above	$ 91	$ 20	$ 72		$ 4	All Calculations Validated
GS<50	13w cfl	118	Consultant Report	10%	OEB Website, CFL 11	$ 13.27	Verified TRC Analysis	$ 2.25	OEB Website		Included above	$ 1,410	$ 239	$ 1,171		$ 59	All Calculations Validated
GS>50	Business Incentive Program-T8	2106	Company Data	10%	OEB Website	$ 128.11	Verified TRC Analysis	$ 36.00	OEB Website	$ 16,498	Audited against Invoice	$ 242,815	$ 84,733	$ 158,082	2.86	$ 7,904	All Calculations Validated
GS>50	Business Incentive Program-Exit Lighting	75	Company Data	10%	OEB Website	$ 269.26	Verified TRC Analysis	$ 95.00	OEB Website		Included above	$ 18,175	$ 6,413	$ 11,763		$ 588	All Calculations Validated
GS>50	T5 Lamps	21	Company Data	10%	OEB Website	$ 115.02	Verified TRC Analysis		Included in Program Cost	$ 14,574.30	Audited against Invoice	$ 2,174	$ 14,574	$ (12,400)	0.15	$ (620)	All Calculations Validated
Total Residential																$ 16,063	All Calculations Validated
Total GS<50																$ 4,021	All Calculations Validated
Total GS>50																$ 7,872	All Calculations Validated
Grand Total												**$ 907,476**	**$ 348,345**	**$ 559,131**		**$ 27,957**	**All Calculations Validated**

Smart Meters

The Ontario Government has committed to have smart meters installed in every home and small business by 2010. The intention of smart meters is to record the energy consumed according to the time of day that it was consumed in order to support the implementation of Time of Use ("TOU") commodity pricing.

Thirteen distributors have been authorized to install smart meters and have been authorized to recover the costs through the distribution rates. Bluewater Power is not one of the thirteen authorized distributors; however Bluewater Power has been working through the planning process in order to be in a position to install smart meters within its service territory over the 2009 to 2010 timeframe. Bluewater Power has joined 32 other LDC's in the London Hydro RFP process. On May 26, 2008, London Hydro held a meeting in Toronto in cooperation with the Ministry of Energy to overview the RFQ process and released the results of the RFP to each LDC who participated.

The results of the RFP involved scoring of each of the vendors. The results were based on a rigorous scoring process involving technical aspects, costs and other factors such as quality management systems, longevity of the meter provider, and competencies and experiences of the meter company. Bluewater Power has selected the vendor that ranked the highest, and is now in a position to proceed to the detailed planning stage.

Bluewater Power currently has an OEB approved rate rider of $.26 per month per metered customer related to smart metering, which was the equivalent to $.30 per residential customer in the 2006 EDR process. The revenue received is being booked to the variance account 1555. The balances in the revenue and expense variance accounts are as follows as of December 31, 2007.

Table 5.1.4.1

Smart Meter Variance Account Balances

Account	Principal as of December 31, 2007	Interest as of December 31, 2007
1555 – Smart Meter Capital Variance Account	($172,194)	($6,072)
1556 – Smart Meter OM& Variance Account	$38,226	$986

In 2009, Bluewater Power will be preparing a comprehensive smart meter plan. On June 28, 2008 the government filed an amendment to regulation O.Reg.427/06 *Smart Meters: Discretionary Metering Activity and Procurement Principles* which will:

- Authorize metering activities pursuant to the Request for Proposal (RFP) for Advanced Metering Infrastructure (AMI) – Phase 1 Smart Meter Deployment issued August 14, 2007 by London Hydro Inc. This would include distributors named in the RFP and those distributors that procure AMI pursuant to the parameters established by the RFP;
- Allow previously authorized distributors to continue to move forward with metering activities beyond the original procurement process, provided subsequent procurements meet the standards prescribed by regulation.

Bluewater Power is one of the named distributors in the RFP, and is reviewing a proposal to work with other interested LDCs to jointly be involved in planning, collective RFP's, procurement coordination, project planning and installation support.

In order to mitigate future rate shock, Bluewater Power requests that the rate adder be increased to $1 per meter commencing May 1, 2009.

2009 Rate Rider

Bluewater Power proposes to dispose of the deferral/variance account balances and the LRAM/SSM recovery through a rate rider which is proposed to be in effect from May 1, 2009 to April 30, 2012. A three year rate rider will match the term of the base rates proposed in this application, and will provide customers with more stable rates over that period. Table 5.1.5.1 details the proposed rate rider for each rate class.

Table 5.1.5.1 - Proposed Rate Riders

Rate Classification	Proposed Rate Rider	Per kWh or kW
Residential	(0.0009)	kWh
General Service <50 kW	(0.0011)	kWh
General Service 50 to 999 kW	(0.4555)	kW
General Service 1,000 to 4,999 kW	(0.6174)	kW
Large	(0.8908)	kW
Unmetered Scattered Load	(0.0008)	kWh
Sentinel Lighting	(0.3737)	kW
Street Lighting	(0.3256)	kW

Exhibit 5, Tab 1, Schedule 5, Attachment 1 details the proposed rate rider per rate class.

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Rate Riders

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Residential	General Service <50 kW	General Service 50 to 999 kW	General Service 1,000 to 4,999 kW
1505-LRAM and SSM (holding account only)	130,666	$ for LRAM	111,248	9,070	10,348	
1508-Other Regulatory Assets	681,832	Distribution Revenue (proposed rates)	351,144	111,821	105,309	36,769
1510-Preliminary Survey and Investigation Charges						
1515-Emission Allowance Inventory						
1516-Emission Allowances Withheld						
1518-RCVARetail						
1520-Power Purchase Variance Account						
1525-Miscellaneous Deferred Debits	517	kWh's	123	56	100	84
1530-Deferred Losses from Disposition of Utility Plant						
1540-Unamortized Loss on Reacquired Debt						
1545-Development Charge Deposits/ Receivables						
1548-LV Apr 1'08 to Oct 31/'0 Hydro One RAR 2005 variance (holding account only)						
1550-LV Variance Account	(34,719)	Transmission Connection Revenue	(9,771)	(3,960)	(7,439)	(5,479)
1555-Smart Meters Capital Variance Account						
1556-Smart Meters OM&A Variance Account						
1560-Deferred Development Costs						
1562-Deferred Payments in Lieu of Taxes						
1563-Account 1563 - Deferred PILs Contra Account						
1565-Conservation and Demand Management Expenditures and Recoveries						
1566-CDM Contra Account						
1570-Qualifying Transition Costs						
1571-Pre-market Opening Energy Variance						
1572-Extraordinary Event Costs						
1574-Deferred Rate Impact Amounts						
1580-RSVAWMS	(1,830,435)	kWh's	(436,273)	(197,385)	(354,073)	(296,557)
1582-RSVAONE-TIME						
1584-RSVANW	116,991	kWh's	27,884	12,616	22,630	18,954
1586-RSVACN	(396,669)	kWh's	(94,544)	(42,775)	(76,730)	(64,266)
1588-RSVAPOWER	(2,854,674)	kWh's	(680,394)	(307,834)	(552,198)	(462,498)
1592-2006 PILs/Taxes Variance						
2425-Sub account of 1588 Global Adjustment (holding account only)	212,147	kWh's	50,564	22,877	41,037	34,371
Sub-Total for recovery	**(3,974,344)**		**(680,019)**	**(395,516)**	**(811,016)**	**(738,622)**
1590-Recovery of Regulatory Asset Balances (residual)						

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Rate Riders

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Large	Unmetered Scattered Load	Sentinel Lighting	Street Lighting
1505-LRAM and SSM (holding account only)	130,666	$ for LRAM				
1508-Other Regulatory Assets	681,832	Distribution Revenue (proposed rates)	57,441	3,979	1,089	14,280
1510-Preliminary Survey and Investigation Charges						
1515-Emission Allowance Inventory						
1516-Emission Allowances Withheld						
1518-RCVARetail						
1520-Power Purchase Variance Account						
1525-Miscellaneous Deferred Debits	517	kWh's	149	1	0	4
1530-Deferred Losses from Disposition of Utility Plant						
1540-Unamortized Loss on Reacquired Debt						
1545-Development Charge Deposits/ Receivables						
1548-LV Apr 1'08 to Oct 31/'0 Hydro One RAR 2005 variance (holding account only)						
1550-LV Variance Account	(34,719)	Transmission Connection Revenue	(7,754)	(72)	(16)	(228)
1555-Smart Meters Capital Variance Account						
1556-Smart Meters OM&A Variance Account						
1560-Deferred Development Costs						
1562-Deferred Payments in Lieu of Taxes						
1563-Account 1563 - Deferred PILs Contra Account						
1565-Conservation and Demand Management Expenditures and Recoveries						
1566-CDM Contra Account						
1570-Qualifying Transition Costs						
1571-Pre-market Opening Energy Variance						
1572-Extraordinary Event Costs						
1574-Deferred Rate Impact Amounts						
1580-RSVAWMS	(1,830,435)	kWh's	(527,164)	(3,584)	(1,120)	(14,278)
1582-RSVAONE-TIME						
1584-RSVANW	116,991	kWh's	33,693	229	72	913
1586-RSVACN	(396,669)	kWh's	(114,241)	(777)	(243)	(3,094)
1588-RSVAPOWER	(2,854,674)	kWh's	(822,144)	(5,590)	(1,747)	(22,268)
1592-2006 PILs/Taxes Variance						
2425-Sub account of 1588 Global Adjustment (holding account only)	212,147	kWh's	61,098	415	130	1,655
Sub-Total for recovery	**(3,974,344)**		**(1,318,921)**	(5,398)	(1,835)	(23,017)
1590-Recovery of Regulatory Asset Balances (residual)						

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Rate Riders

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Residential	General Service <50 kW	General Service 50 to 999 kW	General Service 1,000 to 4,999 kW
Total Recoveries Required (3 years)	**(3,974,344)**		**(680,019)**	**(395,516)**	**(811,016)**	**(738,622)**
Annual Recovery Amounts	(1,324,781)		(226,673)	(131,839)	(270,339)	(246,207)
Annual Volume			266,434,436	120,544,382	593,516	398,767
Proposed Rate Rider per			**($0.0009)** kWh	**($0.0011)** kWh	**($0.4555)** kW	**($0.6174)** kW

[1] per sheet C6

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Rate Riders

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Large	Unmetered Scattered Load	Sentinel Lighting	Street Lighting
Total Recoveries Required (3 years)	**(3,974,344)**		**(1,318,921)**	(5,398)	(1,835)	(23,017)
Annual Recovery Amounts	(1,324,781)		(439,640)	(1,799)	(612)	(7,672)
Annual Volume			493,510	2,188,838	1,637	23,562
Proposed Rate Rider			**($0.8908)**	**($0.0008)**	**($0.3737)**	**($0.3256)**
per			kW	kWh	kW	kW

[1] per sheet C6

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Rate Riders

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Residential	General Service <50 kW	General Service 50 to 999 kW	General Service 1,000 to 4,999 kW
Allocators	**Data Source**	**2009 Projection Total**	**Residential**	**General Service <50 kW**	**General Service 50 to 999 kW**	**General Service 1,000 to 4,999 kW**
Customers / Connections	C1	47,147	32,006	3,924	396	16
kWh's	C1	1,117,857,569	266,434,436	120,544,382	216,234,424	181,109,127
Distribution Revenue (existing rates)	C4	16,588,118	8,356,025	2,727,702	2,534,750	1,200,383
Distribution Revenue (proposed rates)	F4	20,707,479	10,664,352	3,396,027	3,198,270	1,116,692
Transmission Connection Revenue	C2	4,705,961	1,324,414	536,794	1,008,265	742,624
Number of customer accounts						
$ for LRAM		130,666	111,248	9,070	10,348	
Approved Recoveries	C5	100.0%	97.1%	14.2%	7.3%	-15.0%

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Rate Riders

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Large	Unmetered Scattered Load	Sentinel Lighting	Street Lighting
Allocators	**Data Source**	**2009 Projection Total**	**Large**	**Unmetered Scattered Load**	**Sentinel Lighting**	**Street Lighting**
Customers / Connections	C1	47,147	4	266	526	10,009
kWh's	C1	1,117,857,569	321,942,304	2,188,838	684,138	8,719,920
Distribution Revenue (existing rates)	C4	16,588,118	1,429,147	68,172	19,320	252,618
Distribution Revenue (proposed rates)	F4	20,707,479	1,744,517	120,839	33,081	433,701
Transmission Connection Revenue	C2	4,705,961	1,050,979	9,747	2,195	30,944
Number of customer accounts						
$ for LRAM		130,666				
Approved Recoveries	C5	100.0%	-3.4%	0.8%	0.3%	-1.4%

Method of Recovery

Bluewater Power seeks to dispose of a total balance of $(3,974,344) or $(1,324,781) per year for each of three years related to the variance/deferral accounts outlined in Exhibit 5, Tab 1, Schedule 2. The calculation of the rate rider is determined as follows.

An appropriate allocator (i.e. number of customers, kW, kWh) is assigned to each of the nine variance/deferral account to be disposed of. The projected balance to be disposed of is then apportioned to each customer class based on the test year volume projections for the allocator defined for each account. For example, if kWh's are assigned as the allocator for the account, and the load forecast indicates that 30% of the kWh's will be consumed by the residential customer class, then 30% of the account balance is allocated to the residential class.

For each customer class, the sum of all allocated balances over all accounts selected for disposition is calculated. For each customer class the sum of the allocated balances is divided by the number of years proposed to clear the balance. Bluewater Power is proposing to dispose of the balances over a three year period to be consistent with the proposed rates.

Finally, for each customer class, the rate rider is calculated as the annual recovery amount divided by the test year forecast for the distribution rate volume metric to arrive at the rate rider expressed as $/kWh or $/kW depending on the rate class.

COST OF CAPITAL AND RATE OF RETURN

Overview of Cost of Capital and Return

The purpose of this evidence is to summarize the method and cost of financing Bluewater Power's capital requirements for the 2009 test year.

Capital Structure

Bluewater Power has a current capital structure of 53.3% debt and 46.7% equity, as approved by the OEB in the 2008 IRM Application (EB-2007-0862), and a return on equity of 9.0% as approved by the OEB in the 2006 EDR file (EB-2005-0340).

Bluewater Power is requesting OEB approval of a capital structure of 56.7% debt and 43.3% equity, including a return on equity of 8.57% which is the last Board approved rate based on Consensus Forecasts and published Bank of Canada data for January 2008. The weighted average cost of capital is 7.71% as summarized below.

		Current Application				***2006 EDR Approved***	
	Deemed Portion	***Effective Rate***	***Return Amount***	***Deemed Portion***	***Effective Rate***	***Return Amount***
Short-Term Debt	4.00%	4.47%				
Long-Term Debt	52.67%	7.25%		50.00%	7.25%	
Total Equity	43.33%	8.57%		50.00%	9.00%	
Regulated Rate of Return	**100.00%**	**7.71%**		**100.00%**	**8.13%**	
Rate Base [2]			53,158,483			46,642,942
Regulated Return on Capital			**4,098,944**			**3,789,739**
Deemed Interest Expense			*2,124,815*			*1,690,807*
Deemed Return on Equity			*1,974,129*			*2,098,932*

Cost of Debt

Bluewater Power's long-term debt lies in the form of Promissory Notes with its municipal shareholders. A copy of the Promissory Note with the City of Sarnia is attached as Exhibit 6, Tab 1, Schedule 2, Attachment 1. These Promissory Notes have been in place since incorporation of Bluewater Power and the transfer of assets carried out under Transfer By-laws passed by each municipal shareholder. These Promissory Notes are embedded in rates at a cost of 7.25% per annum as approved by the OEB under Bluewater Power's 2006 EDR application.

The "Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors" dated December 20, 2006 (hereinafter referred to as the "OEB Cost of Capital Report") states on pages 12 and 13*:*

> *"…for ratemaking purposes the term of the debt should be assumed to be compatible with the life of the asset"*
>
> *"the asset life can extend beyond 30 years"*
>
> *"The Board has determined that for embedded debt the rate approved in prior Board decisions shall be maintained for the life of each active instrument, unless a new rate is negotiated, in which case it will be treated as new debt."; and*
>
> *"For all variable-rate debt and all affiliate debt that is callable on demand the Board will use the current deemed long-term debt rate."*

The Promissory Notes do not refer to a specific expiry date because it was clearly understood at the time that the notes had a legislative term of 10 years in accordance with O.Reg 438/97 which regulation prescribes permitted investments under the Municipal Act, 2001. Bluewater Power's Promissory Note relied on that legislative expiry date, but went on to say that the note was also callable on 18 months' written notice. In other words, they are not simply "callable on demand"; rather, the Promissory Notes were understood at the time to have a 10 year term but were "callable on notice".

In the interest of a fulsome discussion, it should be pointed out that the Promissory Notes can be modified upon 12 months' written notice. Therefore, the notes could be interpreted to be callable on notice of 12 months plus one day instead of 18 months. What is important for this discussion is that either interpretation qualifies these Promissory Notes as long-term debt. That fact is made clear in Bluewater Power's financial statements, audited each year by KPMG, wherein these Promissory Notes have been classified as long-term debt.

In addition, the intention of the signing parties was that the note would be used to finance the long-term assets of the utility. There is no plan either in the short-term or in the long-term, to change that original intention of the Promissory Note. Moreover, if the OEB were to make a decision not to permit recovery of the full interest cost in rates and if the holders of the Promissory Notes were to call the debt and if the notice period were waived, it is not conceivable in a practical sense that the debt could be refinanced within the 2009 projected test year. Therefore, it is with certainty that we can state that the cost of long-term debt in 2009 will be at 7.25%.

The OEB Cost of Capital Report permits certain forms of callable debt to be considered long-term debt recovered at its face value, but purports to distinguish between debt that is callable by an affiliate and debt that is callable by a third party. There is no jurisdictional basis to make that distinction. Moreover, there is no factual basis in the case of the debt of Bluewater Power because the Promissory Notes have been treated at all times as if they were third party debt. These Promissory Notes were negotiated at market rates at the time they were established, and Bluewater Power continues to consider 7.25% an acceptable market-based rate for long-term

financing.[1] These notes have been honoured to the letter as binding legal agreements since their creation and they have not been modified or amended for any reason. Interest has been paid in full at 7.25%, with no interest forgiveness; in particular, despite the fact that Bluewater Power did not collect through rates the full interest cost during the years 2000 and 2001, Bluewater Power paid full interest under the Promissory Notes because the notes were treated as legal and binding documents as if they were with a third party.

Accordingly, Bluewater Power has included debt costs in this 2009 rebasing application at the embedded debt rate of 7.25% in accordance with the OEB Cost of Capital Report.

The following is Exhibit 6, Tab 1, Schedule 2, Attachment 1.

[1] This rate was recognized by the OEB as a market-based long-term debt by in the 2006 Electricity Distribution Rate Handbook at the bottom of page 32, wherein the approved rate for debt held by an affiliate, including a municipal shareholder, "is the lower of the actual debt rate and the deemed debt rate at the time of issuance" and for debt issued between March 2000 and May 12, 2005, the rates shown in Table 3-1 on page 3-7 of the 2000 Handbook remain in effect.

PROMISSORY NOTE

FOR VALUE RECEIVED, Bluewater Power Distribution Corporation ("BPDC") hereby promises to pay to or to the order of The Corporation of the City of Sarnia (the "City") the principal sum of Sixteen Million Seven Hundred and Twenty-Nine Thousand Six Hundred and Thirty Six Dollars ($16,729,636) with interest at the rate specified herein, on a date which is no later than eighteen (18) months from the date of demand in writing by the City (the "Maturity Date").

The outstanding principal sum of this Promissory Note shall bear interest from time to time at the Permitted Rate calculated quarterly not in advance. Interest at the Permitted Rate shall accrue from the Interest Commencement Date until the principal sum is paid in full, with interest on overdue interest at the said rate. Interest at the Permitted Rate shall be payable in quarterly installments with the first of such payments commencing three (3) months following the Interest Commencement Date, provided that the City may elect to waive payment of interest in its sole discretion. Further provided that the Interest determined to be due in the year 2001 shall be payable commencing three (3) months following December 31, 2001. As at the date of this Promissory Note, the Permitted Rate is seven and one quarter percent (7.25%) per annum. In this paragraph, Permitted Rate and Interest Commencement Date have the meanings set out in Schedule "A".

The payment of the principal amount and all interest on this Promissory Note is subordinated in accordance with the Shareholders Agreement dated November 1, 2000 to debt issued by BPDC from time to time to a financial institution or other third party for the purposes of BPDC and the City shall execute such documents as may reasonably be required by BPDC to evidence the subordination.

At the option of the City, on twelve (12) months prior written notice to BPDC, the Maturity Date and any of the terms of this Promissory Note may be revised, changed or restated by the City in consultation with BPDC.

The terms of this Promissory Note are subject to the adjustment provisions of the Transfer By-law passed by the City on October 30, 2000 as By-law No.169 of 2000 and of a Merger Agreement entered into with the City as of October 30, 2000.

This Promissory Note is not assignable by the City without the consent of BPDC.

DATED as of the 27th Day of March 2002.

BLUEWATER POWER DISTRIBUTION CORPORATION

By: _____

By: _____

SCHEDULE "A"

Definitions

"Interest Commencement Date" means the earlier of (i) the date of the opening of the Ontario electricity market as announced by the Ontario Minister of Energy, Science and Technology, and (ii) March 1, 2001.

"Permitted Rate" means the actual interest rate which the Ontario Energy Board or its successor may, from time to time, permit regulated distribution corporations to recover for rate making purposes.

Return on Equity

The methodology used to determine the return on equity ("ROE") is taken from the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation of Ontario's Electricity Distributors (the "Board Report"). The Board's Report sets out the formulas to be used to determine the return on equity and the deemed costs of long term and short term debt and sets out the process by which these figures will be updated.

Bluewater Power has used a return on equity rate of 8.57% for this application, and Bluewater Power anticipates this rate will be updated by the OEB prior to rate approval.

CALCULATION OF REVENUE DEFICIENCY OR SURPLUS

Determination of Revenue Deficiency or Surplus

This exhibit shows the calculation of the forecasted revenue deficiency for Bluewater Power during the 2009 test year if existing rates are continued. The calculation is based on the following:

- The utility income of $492,229 is based on total net revenues for 2009 based on current rates, along with projected OM&A, depreciation, and taxes.
- The utility rate base projected for the 2009 test year.
- The indicated rate of return is 0.93% as compared to the proposed rate of return of 7.71% which leads to a net revenue deficiency after PILs of $(4,843,712).

Table 7.1.1.1 Revenue Deficiency

	2009 Projection
Utility Income	492,229
Utility Rate Base	53,158,483
Indicated Rate of Return	0.93%
Requested / Approved Rate of Return	7.71%
Sufficiency / (Deficiency) in Return	(6.78%)
Net Revenue Sufficiency / (Deficiency)	**(3,606,715)**
Provision for PILs/Taxes	(1,236,997)
Gross Revenue Sufficiency / (Deficiency)	**(4,843,712)**
Deemed Overall Debt Rate	*7.05%*
Deemed Cost of Debt	*2,124,815*
Utility Income less Deemed Cost of Debt	*(1,632,586)*
Return On Deemed Equity	*(7.09%)*

UTILITY INCOME

Total Net Revenues	16,592,364
OM&A Expenses	11,358,419
Depreciation & Amortization	4,358,109
Taxes other than PILs / Income Taxes	297,750
Total Costs & Expenses	16,014,278
Utility Income before Income Taxes / PILs	578,086
PILs / Income Taxes	85,857
Utility Income	**492,229**

COST ALLOCATION

Proposed Method (if different from Board Approved Method)

On September 29, 2006 the Ontario Energy Board issued directions on Cost Allocation Methodology for Electricity Distributors ("the Directions"). On November 15, 2006 the OEB also issued the Cost Allocation Information Filing Guidelines for Electricity Distributors ("the Guidelines"), the Cost Allocation Model ("the Model") and User Instruction ("the Instructions") for the Model. Bluewater Power prepared this information filing consistent with its understanding of the Directions, the Guidelines, the Model and the Instructions. The main purpose of the cost allocation filing was to provide evidence to identify Bluewater Power rate classifications that are being subsidized by other classes and those rate classifications that are over-contributing based on the assumptions of the Model.

The Bluewater Power filing was comprised of a first run ("Run 1") and a second run ("Run 2"). Run 1 reflected the rate classifications as they were prior to May 1, 2006. Prior to that date, the Unmetered Scattered Load ("USL") customers were included in the General Service < 50 kW rate classification. Run 2 had the USL customers pulled out of the General Service < 50 kW class to form a class of their own which is consistent with the current rate classifications used by Bluewater Power.

Revenue to Cost Ratios

The cost allocation study carried out in 2006 resulted in the calculation of revenue to cost ratios for each customer class served by Bluewater Power. The ratio is the percentage of distribution revenue collected compared to the costs allocated to each class. A result of 100% for a class would indicate that revenue collected from that class would exactly equal the distribution costs attributable to that customer class. A result of less than 100% for a class would indicate that the revenue recovered from the class does not cover the costs of supplying distribution services to those customers. A result of more than 100% indicates that the revenues collected are higher than the costs associated with electricity distribution for that class.

Bluewater Power consulted with Elenchus Research Associates ("ERA") in order to determine whether a full update of the cost allocation study previously submitted in January 2007 was warranted for this application. After assessing Bluewater Power's cost allocation filing it was determined that a simplified update was preferable over a full update of the cost allocation study for a number of reasons, as listed in the ERA report titled "Update of Bluewater Power's 2006 Cost Allocation Study" which is attached as Exhibit 8, Tab 1, Schedule 1, Attachment 1. A simplified update to the original cost allocation filing is warranted in order to account for a large use customer that was moved to the Intermediate rate class given the customer's significant reduction in demand. Further discussion of this customer's load reduction is detailed at Exhibit 3, Tab 2, Schedule 2.

The results of the original cost allocation filing from 2007 and the simplified update as calculated by the ERA analysis are presented in table 8.1.1.1. The greatest impact is on the Large Use class whereby the original revenue to cost ratio was 1.30, and the resulting simplified revenue to cost ratio is 1.26. This correctly places the revenues and costs for the customer that moved into the current rate category.

Table 8.1.1.1

Customer Class Name	Revenue to Cost Ratios	
	Original Informational Filing Run 2	Simplified Updated Cost Allocation
Residential	0.99	1.00
General Service <50 kW	1.07	1.07
General Service 50 to 999 kW	0.88	0.88
General Service 1,000 to 4,999 kW	1.40	1.41
Large	1.30	1.26
Unmetered Scattered Load	0.65	0.65
Sentinel Lighting	0.33	0.33
Street Lighting	0.44	0.44
TOTAL		

The following is Exhibit 8, Tab 1, Schedule 1, Attachment 1 – Update of Bluewater Power's 2006 Cost Allocation Study.

Update of Bluewater Power's 2006 Cost Allocation Study

A Report Prepared by
John Todd, President
Elenchus Research Associates Inc.

On Behalf of
Bluewater Power

September 2008

elenchus
Research Associates

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1 INTRODUCTION

Bluewater Power Distribution Corporation ("Bluewater" or "BP") has prepared its 2009 EDR Application as a cost of service rate application based on a forward test year. The relevant filing requirements for this Application are set out in Chapter 2 of the OEB's November 14, 2006 document entitled *Ontario Energy Board, Filing Requirements for Transmission and Distribution Applications* ("Filing Requirements"). Section 2.9 of this document sets out the expectations of the Ontario Energy Board ("OEB") with respect to Exhibit 8: Cost Allocation of cost of service applications. The Filing Requirements state:

> *A completed Board approved cost allocation must be filed whether the utility proposes to use it or not.* (p. 20)

Bluewater asked me[1] to advise it on the steps that it should take in order to comply with the Filing Requirements as they pertain to Exhibit 8: Cost Allocation and to assist it in providing an appropriate cost allocation. In addressing this issue, ERA was guided by the November 28, 2007 *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667) ("CA Application Report") which "sets out the Board's policies in relation to specific cost allocation matters for electricity distributors" (p. 1).

The CA Application Report observes at page 2 that:

> *The Board is cognizant of factors that currently limit or otherwise affect the ability or desirability of moving immediately to a cost allocation framework that might, from a theoretical perspective, be considered the ideal. These influencing factors include data quality issues and limited modelling experience, and are discussed in greater detail in section 2.3 of this Report. The Board also recognizes however, that cost allocation is, by its very nature, a matter that calls for the exercise of some judgment, both in terms of the cost allocation methodology itself and in terms of how and where cost allocation principles fit within the broader spectrum of rate setting principles that apply to – and the objectives sought to be achieved in – the setting of utility rates. The existence of the influencing factors does not outweigh the merit in moving forward on cost allocation. Rather, the Board considers that it is both important and appropriate to implement cost allocation policies at this time, and believes that the policies set out in this Report are directionally sound. With better quality data, greater experience with cost allocation modeling and further*

[1] This evidence has been prepared by John D Todd, President, Elenchus Research Associates Inc.

developments in relation to other rate design issues, the policies will be refined as required.

The "influencing factors" discussed in 2.3 of the report are:

- **Quality of the data:** The Board notes "that accounting and load data can be improved." (p. 5) While progress has been made in improving accounting data, the comments of the Board regarding load data remain valid.

> *… load data and load analysis contribute to important cost allocators; namely, the coincident peak and the non-coincident peak. The Board recognizes the significant work done by distributors, and Hydro One Networks Inc. in particular, in obtaining a set of load data as part of the cost allocation informational filings. However, the Board acknowledges that some of the information is based on estimates from a statistical model and may not be completely representative of current loads due to sampling errors and current market characteristics.*
> *…*
> *With respect to load data and load analysis, the Board anticipates that the installation of smart meters, with their more exact load data, will provide opportunities for better analysis in the future and, as a result, will provide better cost allocators for the cost allocation model. (page 5)*

- **Limited modelling experience:** The Board observed that "the cost allocation model is complex, and the data required for the model was not always readily available for modelling." (p. 6) With respect to modelling improvements in the future the Board stated:

> *The Board anticipates that, as distributors become more familiar with cost allocation concepts, they will better understand the blending of operating statistics and practice with accounting data, and they will more effectively and consistently use the models in the preparation of their rate applications. The Board also expects distributors to review their allocation factors as better load data become available from smart meters. (page 6)*

- **Status of current rate classes:** The Board points out that "Any changes in customer classification or load data could have a significant impact on future cost allocation studies" (p. 6) and goes on to state :

> *An initiative is currently under way to examine the rate design for electricity distributors (consultation process EB-2007-003) (the "Rate Review"). The Rate Review covers both customer classification and rate structure issues, and its results could affect the way in which rates are set in the future. (p. 6)*

- **Managing the movement of rates closer to allocated costs:** The report states that:

> *The Board considers it appropriate to avoid premature movement of rates in circumstances where subsequent applications of the model or changes in circumstances could lead to a directionally different movement. Rate instability of this nature is confusing to consumers, frustrates their energy cost planning and undermines their confidence in the rate making process. (page 6)*
>
> *…*
> *The Board expects to address these concerns as and when they arise in the context of individual rate applications. Distributors should endeavour to move their revenue-to-cost ratios closer to one if this is supported by improved cost allocations. However, if a large increase is required to move closer to one, rate mitigation plans should be proposed by the distributor. Distributors should not move their revenue-to-cost ratios further away from one. (page 7)*

These comments pertain not only to the 2006 Cost Allocation Information Filings ("2006 CA Filing") of the distributors, but also to any other cost allocation studies that can be prepared by distributors at this time.

BP filed its 2006 CA Filing in January 2007. This filing relied on the Ontario Energy Board's ("OEB") 2006 Cost Allocation Model ("2006 CA Model") and was prepared in accordance with the September 29, 2006 Board report entitled *Cost Allocation: Board Directions on Cost Allocation Methodology for Electricity Distributors* ("the Directions"), the subsequent (November 15, 2006) *Cost Allocation Informational Filing Guidelines for Electricity Distributors* ("the Guidelines"), and the *Cost Allocation Review: User Instruction for the Cost Allocation Model for Electricity Distributors* ("the Instructions").

Producing a fully updated cost allocation model at this time would be a significant undertaking for any distributor as it would entail:

- Reviewing the methodology used to classify and functionalize all costs, as directed in the Filing Requirements worksheet E1: Categorization in the 2006 CA Model) to ensure that the methodology is given the specific circumstances of Bluewater;

- Repopulating the 2006 CA Model with current trial balance, asset, expense, revenue, customer and load information;
- Collecting updated information on electrical space heating, water heating and air conditioning saturation information for the residential class;
- Re-estimating the weather sensitive and non-weather sensitive loads for other rate classes and weather-normalizing actual demand for an historical year;
- Developing updated hourly load shapes by class and the derivation of updated demand allocators (1-CP; 4-CP; 12 CP; 1-NCP; 4-NCP and 12-NCP) for use in the model based on the information resulting from the two preceding bullet points; and
- Reviewing and updating, as appropriate, all other allocators.

In weighing the cost and benefits of LDCs updating their cost allocation models for use in their 2009 rate rebasing filings, I concluded that it would be prudent to consider the need for an update on a case-by-case basis. At the heart of my reasoning is the concern that, in general, fully updating an LDC's cost allocation filing at this time would provide little, if any, improvement in the information available for determining the extent to which rates need to be rebalanced among classes. Far better cost allocation studies will be available within a couple of years. Consequently, current cost allocation results should be used only as an indicator of significant directional changes that are required. This cautious approach is a clear message in the OEB's CA Application Report. Since the "new, improved" cost allocation studies are still a couple of years away, it is my view that it would be a poor use of ratepayer funds to update the 2006 CA Filing at this time unless there is evidence that the results of the 2006 CA Filing would be misleading in the absence of an update.

In the case of Bluewater Power, there is a customer that was in the Large User class in 2006 that has recently reduced its demand and moved to the Intermediate class. This shift between classes has an impact on allocated costs that is too significant to be ignored. The remainder of the evidence explains the analysis behind this conclusion and the approach used to adjust for this shift in load between classes.

2 ASSESSING BLUEWATER'S 2006 CA MODEL

The first step in responding to Bluewater's request for advice on the cost allocation information to include in its 2009 EDR Application was an assessment of the merit of undertaking a full update of the Bluewater 2006 CA Model to produce a 2009 Test Year Model. My advice on this matter was based on an assessment of the overall value to the regulatory process of having a fully updated cost allocation study as part of the 2009 EDR Application in light of the costs of producing such a study in terms of the regulatory process and the financial costs that would ultimately be visited on ratepayers.

Recognizing the requirements for a full update of their 2006 CA Model, which are listed above, it was my recommendation to Bluewater (and all of ERA's clients preparing cost of service filings for their 2009 EDR Applications) that there would be little value in preparing a fully updated CA Model at this time. The reasons are as follows.

1. Significant in-house resources would be required to complete an updated cost allocation study. Based on the experience of the distributors that filed cost of service rate applications for 2008, it was evident from the outset that the LDCs filing cost of service applications for 2009 would be challenged to complete their applications by August 15, 2008, even without the added demands of preparing fully updated CA model. The added workload associated with fully updating its CA Model for an LDC that was completing its first-ever cost of service application would risk compromising both the timeliness and the quality of its cost of service application.

2. In addition to the increased demands on internal resources, any distributor that chose to update its CA Model fully would face the prospect of significant incremental regulatory costs associated with external consulting support and the costs associated with a more complex and extensive public process. While these costs, which would ultimately be borne by ratepayers, were clearly not prohibitive, they should, in my view, be considered in the context of the value to the regulatory process of preparing an updated CA Model at this time. For the reasons outlined below, the value of an updated model would be minimal at this time.

3. A fully updated cost of service application would require an updated hourly load profile by rate class. ERA explored alternatives for updating the hourly load profiles by rate class comparable to the estimated load profiles that Hydro One prepared for the LDCs for their 2006 CA Models. Hydro One advised that they no longer have the capacity to produce a significant number of LDC-specific hourly load profiles. As far as I am aware, no other entity has the necessary information and models to produce comparable quality hourly load profiles for Ontario LDCs. It therefore was not practical for distributors to update their hourly load profiles by class except in exceptional circumstances.

4. With the widespread rollout of smart meters and the collection of smart meter data, Ontario distributors will have far superior hourly load profile by class data than the estimates that Hydro One is able to provide. Unless there is evidence of a significant change in circumstances, investing in new hourly load profile by class estimates would be a questionable use of ratepayer funds when far superior hourly load profile information will be available in the next few years at minimal incremental cost.

5. The OEB's Rate Design Review is progressing well and is expected to result in a Board Report in the coming year. Given the rate design possibilities that will arise as a result of the widespread rollout of smart meters, it is conceivable, if not likely, that new class definitions and new approaches will result from this process. As a consequence, a current cost allocation is likely to be of little, if any, relevance within a couple of years. Unless there are serious anomalies, investing in an updated cost allocation study at this time does not appear to be a wise use of ratepayer funds.

6. Both time-of-use commodity pricing and changes to the design of distribution rates can be expected to alter demand and, as a result, some key allocators used in cost allocation studies. A fully updated cost allocation study prepared at this time cannot be expected to produce reliable indicators of the changes in relative rates that will be required to ensure that the resulting rate design recovers costs from customers in a manner that improves inter-class and intra-class equity. At best, a current study will provide an indicator of serious anomalies or inequities that justify immediate

rectification. If the 2006 CA Model is a reasonable proxy for a 2009 cost allocation study, an updated study is unlikely to provide better guidance for rate changes.

7. As noted above, a fully updated cost allocation study should include a careful review of the methodology in the context of the specific distributors conducting the study. The 2006 Cost Allocation Model was a generic model that was completed by distributors for information purposes. These models have never been subjected to the rigorous review of a public hearing process. A new LDC-specific cost allocation study that is filed as part of a 2009 EDR Application would be open to being fully reviewed and tested by all stakeholders. Since the methodology will not be robust, for the reasons discussed above, it would not be an efficient use of ratepayer funds to engage in a detailed review of a cost allocation methodology that will be outdated with a year or two.

8. To the extent that (i) the hourly load shapes by class (ii) categorization of costs (rate base and expenses) in relative terms, and (iii) customer data are fairly stable, the results (revenue-to-cost ratios and relative cost responsibility by class) would not change appreciably. The revenue-to-cost ratio bands set out in the CA Application Report appear to recognize the lack of precision in cost allocation studies at this time. An update at this time would produce changes in cost responsibility that are small relative to the tolerances that are necessary given the imprecision of the allocated costs at this time. The 2006 CA Model results can be expected to provide appropriate guidance for purposes of adjusting rates for classes so as to achieve a more equitable basis for recovering the revenue requirement.

9. In general, cost allocation studies are quite robust and stable in the absence of significant changes in a distributor's cost structures or loads. Small increases in rate base and operating expenses that cut across the various cost categories will have little impact on the relative cost responsibilities of customer classes or their relative revenue-to-cost ratios. Similarly, small changes in the relative loads of customer classes will result in small changes to the allocators. The resulting small change in revenue cost ratios will not affect the distributor's rate design where the existing revenue-to-ratios are significantly above or below the ranges endorsed by the OEB

in the CA Application Report or where they are comfortably within the ranges. A small change will only affect customer rates if the revenue-to-cost ratios are close to either the upper or lower limits of the ranges.

Having concluded that there is little value in imposing the costs of preparing a fully updated CA study on ratepayers as a matter of course, the next step in providing my advice was to determine whether there are any circumstances specific to Bluewater that would justify either a partial or full update to the cost allocation model. Of particular concern in this regard was the possibility that an update would produce a significant change in the proportion of the distributor's total revenue requirement that is appropriate to recover from each class.

For example, a problem will arise in the event that one class experiences a significant decline in volume throughput while other classes do not in the years after 2004, which was the basis for the 2006 CA Model. In this case, if the CA Model is not updated, the proportion of costs allocated to each class would be based on the outdated throughput data, while class revenues would be based on the current forecast. A 50% decline in key cost drivers (kW, kWh and customer count) in a class, for example, would result in a similar decline in forecast revenue, but in the absence of an update to the CA Model there would be no reduction in the proportion of costs allocated to the class. The calculated revenue to cost ratio for the test year would therefore be artificially low – in this example, roughly 50% below the "true" value. The "true" revenue-to-cost ratios would not be significantly affected by changes in the relative throughput for different classes assuming the loss of load does not significantly alter the load profile of the classes and directly allocated cost are not a major factor in the cost allocation study. Subject to these caveats, changes in allocated costs and changes in revenues will be similar and the resulting revenue-to-cost ratios will be fairly stable even if there are significant changes in the throughput of one or more classes.

The implication of the foregoing concern is that an analysis of the stability of the relative throughput of the various customer classes is required in order to determine whether the 2006 CA Model results can be viewed as a good proxy for a fully updated cost allocation study. The issue of the stability of these parameters can be addressed by

examining the stability of Bluewater's infrastructure, operations, customer count and class shares of billed kWh and kW.

2.1 ASSESSING THE STABILITY OF BLUEWATER'S RATE BASE

The information on Bluewater's rate base in Exhibit 2 of its 2009 EDR Application Filing shows that the underlying infrastructure has been fairly stable since the 2006 EDR which was used as the basis for the 2006 CA Model and Application.

Table 1 below summarizes the 2006 EDR approved and 2009 forecast net book values by asset account of the assets included in Bluewater's rate base. The values in Table 1 correspond to the values set out n Exhibit 2, Tab 2, Schedule 1, Attachment 1 of the Bluewater Application. The proportions of the total rate base as well as the net book values are shown for each asset account.

Table 1: Net Book Values of Assets, 2006 EDR vs. 2009

	2006 EDR Approved		2009 Balance	
	$	%	$	%
1805-Land	445,817	1.3%	445,817	1.1%
1806-Land Rights	61,541	0.2%	5,101	0.0%
1820-Distribution Station Equipment - Normally Primary below 50 kV	2,169,269	6.2%	2,841,482	7.0%
1830-Poles, Towers and Fixtures		0.0%	1,808,826	4.5%
1835-Overhead Conductors and Devices	11,781,847	33.6%	11,514,740	28.5%
1840-Underground Conduit		0.0%	229,035	0.6%
1845-Underground Conductors and Devices	9,364,980	26.7%	8,618,545	21.3%
1850-Line Transformers	5,435,158	15.5%	5,855,493	14.5%
1855-Services		0.0%	419,918	1.0%
1860-Meters	2,413,137	6.9%	3,282,258	8.1%
1908-Buildings and Fixtures	2,310,999	6.6%	3,921,754	9.7%
1915-Office Furniture and Equipment	66,818	0.2%	102,053	0.3%
1920-Computer Equipment - Hardware	574,734	1.6%	825,753	2.0%
1925-Computer Software	1,356,398	3.9%	3,023,262	7.5%
1930-Transportation Equipment	306,534	0.9%	656,707	1.6%
1935-Stores Equipment	11,422	0.0%	-22,773	-0.1%
1940-Tools, Shop and Garage Equipment	99,377	0.3%	213,175	0.5%
1945-Measurement and Testing Equipment	8,380	0.0%	18,785	0.0%
1955-Communication Equipment	32,653	0.1%	14,875	0.0%
1960-Miscellaneous Equipment	40,653	0.1%	174,678	0.4%
1970-Load Management Controls - Customer Premises	39,157	0.1%	-2,526	0.0%

1975-Load Management Controls - Utility Premises	545,836	1.6%		0.0%
1980-System Supervisory Equipment		0.0%	509,267	1.3%
1995-Contributions and Grants - Credit	-2,049,843	-5.9%	-4,029,509	-10.0%
TOTAL	35,014,869	100.0%	40,426,717	100.0%

The assets can be grouped together into groups that are categorized in the same way in the 2006 CA Model. The proportions of the rate base attributable to each grouping are shown in Table 2.

Table 2: Distribution of Assets by Classification Group, 2006 EDR vs. 2009

		2006 EDR	2009 Balance
Group		%	%
A	1805/1806/1820	7.6	8.1
B	1830/1835/1840/1845	60.4	54.8
C	1850	15.5	14.5
D	1855/1860	6.9	9.2
E	1908/1915/1920/1925/1930/1935/1940/ 1945/1955/1960/1970/1975/1980	15.4	23.3
F	1995	-5.9	-10.0

Given the modest differences in the allocators used to allocate these costs to rate classes and the stability of the costs, relative to the revenue-to-cost ranges contained in the CA Application Report, it can be concluded that the shift in the relative proportions of rate base from poles and wires accounts (Group B) to the administrative and maintenance accounts (Group E) will not have a large impact on the overall allocation of costs. Given the inherent lack of precision in the CA studies of Ontario electricity LDCs at this time, it is reasonable to conclude that Bluewater's 2006 CA Model does not need to be adjusted to account for changes in the structure of its rate base.

2.2 ASSESSING THE STABILITY OF BLUEWATER'S OPERATING COSTS

The information on Bluewater's operating and maintenance costs in Exhibit 4 of its 2009 EDR Application Filing shows that the cost by account grouping have changed significantly since 2004. This can be seen from the comparison of 2006 EDR and 2009 that is provided in Table 3 below.

Table 3: Operating Cost by Account Grouping, 2006 EDR vs. 2009

Account Grouping	2006 EDR Approved	2009 Projection
3500-Distribution Expenses – Operation	280,776	3,535,352
3550-Distribution Expenses – Maintenance	256,425	157,640
3650-Billing and Collecting	267,288	1,497,443
3700-Community Relations	189,005	216,871
3800-Administrative and General Expenses	8,187,189	5,951,113
3950-Taxes Other Than Income Taxes	139,687	297,750
TOTAL	**9,320,370**	**11,656,169**

However, as explained in Bluewater's evidence (see Exhibit 4, Tab 2, Schedule 3, pages 22-23 discussing 2006 EDR vs. 2007 Variances), the changes are the result of changes in the accounting treatment of certain costs in 2007 and subsequent years as compared to the 2006 EDR. The shift in payroll costs from the Administration and General Expenses account group to other account groupings is not reflective of a change in the allocation of costs, since Bluewater's 2006 CA Model classified and allocated salary costs at a sub-account level that appropriately classified and allocated these costs. The underlying operating costs have exhibit stability similar to Bluewater's rate base.

Given the inherent lack of precision in the CA studies of Ontario electricity LDCs at this time, it is reasonable to conclude that Bluewater's 2006 CA Model does not need to be adjusted to account for changes in the structure of its operating costs.

2.3 ASSESSING THE STABILITY OF BLUEWATER'S CUSTOMER BASE/DEMAND

Exhibit 3 in Bluewater's 2009 EDR Application shows that the customer count has been stable except for the loss of one of five Large Users. This decline results from the reduction of demand by one of Bluewater's Large User customers leading to the customers being reclassified as a General Service 1,000 – 4,999 kW (Intermediate) customer. As Tales 4 and 5 below show, kWh and kW decline in the Large User class, while Intermediate kWh and kW have increased, but by a smaller amount.

Table 4: kWh Class Shares, 2006 EDR vs. 2009

Customer Class Name	2006 EDR Approved kWh	2006 EDR Approved Share by Class	2009 Normalized kWh	2009 Normalized Share by Class
Residential	269,172,954	23.4%	266,434,436	23.8%
General Service <50 kW	126,666,633	11.0%	120,544,382	10.8%
General Service 50 to 999 kW	219,392,039	19.1%	216,234,424	19.3%
General Service 1,000 to 4,999 kW	170,944,308	14.9%	181,109,127	16.2%
Large	351,679,464	30.6%	321,942,304	28.8%
Unmetered Scattered Load	2,956,878	0.3%	2,188,838	0.2%
Sentinel Lighting	649,471	0.1%	684,138	0.1%
Street Lighting	8,769,187	0.8%	8,719,920	0.8%
TOTAL	1,150,230,934	100.0%	1,117,857,569	100.0%

Table 5: kW Class Shares, 2006 EDR vs. 2009

Customer Class Name	2006 EDR Approved kW	2006 EDR Approved Share by Class	2009 Normalized kW	2009 Normalized Share by Class
General Service 50 to 999 kW	467,580	34.6%	593,516	39.3%
General Service 1,000 to 4,999 kW	294,070	21.8%	398,767	26.4%
Large	563,939	41.8%	493,510	32.7%
Sentinel Lighting	1,558	0.1%	1,637	0.1%
Street Lighting	23,274	1.7%	23,562	1.6%
TOTAL	1,350,421	100.0%	1,510,992	100.0%

It is evident that the loss of the one Large User reduces the revenue of the class by about 10%. In the absence of an adjustment to the 2006 CA Model, the proportion of costs allocated to this class will not decline correspondingly and as a result, the calculated revenue-to-cost ratio will be understated by about 10%. The magnitude of this change and its estimated impact on the revenue-to-cost ratio for the class suggests that using the share of total costs allocated to rate classes as determined by the 2006 CA Model could significantly over-allocate cost to the Large User class and under-allocate cost to the Intermediate class.

Although there is reason to believe that it would be prudent to update the 2006 CA Model with respect to the energy and demand allocators, Bluewater's infrastructure and operations are sufficiently stable relative to the acceptable revenue-to-cost ratio ranges recommended by the Board in *Application of Cost Allocation for Electricity Distributors,*

Report of the Board (EB-2007-0667) that it can be expected that completing a full cost allocation study for the 2009 test year is not necessary because:

- the proportions of kWh and kW attributable to the intermediate and large users classes are changes that could result in a significant error in the revenue-to-cost ratio calculation for the 2009 test year if the cost allocation study is not adjusted to reflect the reduction in the demand of one former large user;
- Bluewater's capital and operating cost do not exhibit any significant discontinuities;
- the revenue-to-cost ratios for all classes are within the Board-approved ranges except lighting (USL, Sentinel, Streetlighting (which is being increased as shown in the table belwo); hence, small changes in the calculated revenue-to-cost ratios would not require changes in the proposed rates;

Rate Class	Original Cost Allocation Filing Results (Revenue to Cost Ratio's)	Scenario - moving 1/3 toward Floor	OEB Target - Floor Revenue to Cost Ratio	OEB Target - Ceiling Revenue to Cost Ratio
USL	0.65	0.70	0.80	1.20
Sentinel	0.33	0.45	0.70	1.20
Streetlighting	0.44	0.53	0.70	1.20

- Bluewater will be implementing smart meters in the near future, which will provide a significantly improved basis (e.g., a direct measure of the hourly demand of each rate class) for quantifying the allocators used in the cost allocation study than the Hydro One estimates that must be relied on at this time; hence, it is prudent to defer updating Bluewater's cost allocation study until this information is available;
- it is expected that the Board's current Rate Design Review will result in changes to rate classes necessitating new cost allocation studies; hence, an updated cost allocation study will be required in the near-future in any case.

2.4 UPDATING THE 2006 CA MODEL

As an alternative to completing a fully updated 2009 CA Model, which would involve the steps outlined at page 4 above, an updated 2006 CA Model can be produced. An updated 2006 CA Model would be identical to the 2006 Cost Allocation Information filing in that the rate base and expenses are unchanged. In addition, customer load information is unchanged except for extraordinary changes in customer demand. Put simply, the case of Bluewater's movement of one customer from the Large User class to the Intermediate class, the updated 2006 CA Model would be adjusted to reflect a scenario where this customer's load shift had occurred prior to the 2004 fiscal year which was used as the basis for the 2006 CA Model.

This approach was taken to updating Bluewater's 2006 CA Model. The methodology and results are described in the next section.

3 METHODOLOGY

This section documents ERA's methodology for updating Bluewater Power's ("BP") 2006 Cost Allocation Information Filing to reflect the impact of the reduction in power consumption by former Large User Customer ID 15, that is now an Intermediate customer, with a load reduction of 50% projected for the 2009 test year. As a result of the demand reduction, the customer moves from the Large Customer class to the Intermediate class.

3.1 ANALYSIS OF BLUEWATER LARGE USER CLASS

BP provided the hourly load data for each of its 5 Large Users for the period October 1, 2002 through April 30, 2006. The hourly load data for 2004 was used as the basis for modifying the load data provided by HONI (step 2 below) as input to the 2006 Cost Allocation Model (step 3 below). The following data were derived from these data.

- Total kWh for each hour of the year (8784 hours in 2004 since 2004 was a leap year)
- Total kWh with uplift (uplift factor = 0.45%).
- An Adjustment Factor, being the ratio, by hour, with and without Customer ID15.

Hourly Adjustment Factor = (kWh without ID15) / (kWh with ID15)

The ratios for each hour in 2004 were used to adjust the HONI load data file (step 2 below).

3.2 REVISE LOAD DATA PROVIDED BY HONI, RUN 2

For Bluewater's 2006 CA Filing, HONI provided a load data file (Load Data from HONI, RUN 2) with three worksheets.

- Data summary: actual and weather normalized monthly kWh by class, disaggregated by weather sensitive and non-weather sensitive load for relevant classes.

- Hourly load shape by class: GWh by class for each hour in 2004.
- Input to Cost Allocation Model (1CP; 4CP; 12CP; 1NCP; 4NCP; 12NCP) derived from the hourly load shape.

A modified file was created (2006 Adjusted Load Data from HONI, RUN 2) as follows.

1. The hourly load shape by class was modified by adjusting each hour in the year to calculate the revised load shape by class for each hour and for each scenario.
   - Multiply the Large User load by the Hourly Adjustment Factor (remove ID15) to derive the Revised Large User hourly load
   - Add ½ of the reduction in Large User load to the Intermediate load to derive the Revised Intermediate load (used in scenario A)
   - Calculate total load by adding the loads for each class using the revised Large User load and the Revised Intermediate load
2. On the Hourly Load Shape by Rate Class worksheet, the 12 monthly coincident and non-coincident peaks were identified for each rate class. The hours in which the total peak occurred are required in order to derive the coincident peak demand.
   - The peaks for each month were identified for each class (base case and revised) and for the total demand for the base case and revised case.
     - The monthly peaks for the revised case occurred in the same hours as in the base case in all months except March.
   - The 12 NCP values for each class were calculated by adding the 12 monthly peaks for each class (base case and revised).
   - The total 12 NCP values are the total of the class 12 NCP values. The Revised Large User and Revised Intermediate 12 NCP values were used.
   - The 12 CP values for each class were derived by adding the hourly demands for the 12 hours during which the monthly system peaks occurred. As noted above, the monthly peaks occurred in different hours for some months in Scenarios A and B as compared to the base case.

- The calculation methodology was verified since the derived base case values matched the HONI results.

3. On the Hourly Load Shape by Rate Class worksheet, the 4 CP and 4 NCP values were determined for each rate class (base case and revised) and for the total base demand (base case and each scenario). The hours in which the total 4 CPs (base case and each scenario) occurred are used to derive the 4 CP value.

- The four highest monthly peaks were identified for each class (including the revised Large User and Intermediate classes). The 4 NCP values are the sum of the four highest monthly peaks for each rate class. The total 4 NCP is the sum across the rate classes for the base case and each scenario,

- The four highest monthly peaks were used to determine the 4 CP for total demand (base case and each scenario). The hours in which the four peaks occurred were then used to determine the 4 CP values for each rate class.

4. On the Hourly Load Shape by Rate Class worksheet, the 1 CP and 1 NCP values were determined for each rate class (base case and revised) and for the total base demand (base case and revised). The hours in which the total 1 CPs (base case and revised) occurred are used to derive the 1 CP values for each rate class.

- The single highest monthly peak was identified for each class (including the revised Large User and Intermediate classes). The 1 NCP values are the highest monthly peak for each rate class. The total 1 NCP is the sum across the relevant rate classes for the base case and revised,

- The single highest monthly peak was the 1 CP value for total demand (base case and revised). The hour in which the total 1 CP occurred was then used to determine the 1 CP values for each rate class.

5. The relevant CP and NCP values were then copied onto tables on the Input to CA Model worksheet, with the base case table being repeated for each scenario.

6. The 30 year weather normalized amounts by rate class were also added into the tables on the Input to CA Model worksheet. The values used were the summations

of the hourly data by class, including the revised amounts for the Large User and Intermediate classes.

3.3 REVISED COST ALLOCATION MODEL

On sheet I8, the revised values from the HONI Load Data RUN 2 were entered on rows 40 (rows 38 and 39 match), 45 (rows 43 and 44 match), 50 (rows 48 and 49 match), 55 (row 56 updates), 61 (row 62 updates) and 67 (row 68 updates). This revises the demand data in the CA Model.

1. On sheet I6:
   - Row 56 was updated with the revised kWh – 30 year normalized amount from the HONI Load Data RUN 2
   - Rows 10 and 21 were revised to reflect the revised Large User and Intermediate loads (kWhs)
   - Rows 13, 22 and 23 were revised to reflect the revised Large User and Intermediate loads (kWs)
   - Row 29 was revised by making adjustments to the revenue that were proportional to the change in energy (kWhs) and demand (kWs).
   - Rows 38 and 40 were updated to reflect the reduction in Large Users from 5 to 4 and the increase in Intermediate customers by one.
2. On Sheet O1:
   - The adjusted revenue of each class was calculated by scaling up the calculated revenue to offset the revenue loss due to the reduced demand of customer ID15. See row 81.
   - The adjusted Revenue to Expense ratios are calculated using the adjusted revenues by class. See row 82. In effect, rates are scaled up through an across the board increase so that the overall revenue to cost ratio is 100%.

4 IMPACT ON CLASS REVENUE REQUIREMENTS

The class revenues and the class revenue-to-cost ratios as determined in the original Bluewater cost allocation model are shown in the table below.

	Total	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
Revenue Requirement (includes NI)	**$17,808,908**	$9,255,455	$2,839,671	$2,752,110	$664,857	$1,384,016	$694,571	$62,481	$155,747
Revenue to Expense %	**100.00%**	99.21%	107.14%	88.34%	139.77%	129.73%	44.17%	32.83%	64.71%

The revised class revenues and revenue-to-cost ratios are shown in the following table.

	Total	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
Adjusted Revenue	**$17,808,908**	$9,234,303	$3,059,593	$2,445,686	$1,035,388	$1,603,471	$308,491	$20,626	$101,351
Adjusted Revenue to Expense %	**100.00%**	**99.58%**	**107.47%**	**88.44%**	**141.32%**	**125.51%**	**44.42%**	**33.01%**	**65.02%**

The revised revenue-to-cost ratios have been used by Bluewater as the reference ratios in its cost of service filing.

Summary of Results and Proposed Changes

Proposed Changes to Revenue and Cost Ratios

The results in Table 8.1.1.1 suggest that the residential rate class has a neutral revenue to cost ratio, and the GS<50 kW, GS 1,000 to 4,999 kW and Large rate classifications are subsidizing the GS 50 to 999 kW, USL, Sentinel and Street Lighting rate classifications.

The Report of the Board on Application of Cost Allocation for Electricity Distributors (EB-2007-0667), presented Target Floor and Ceiling ranges for the revenue to cost ratios. Many Board Decisions on 2008 Rate applications have directed LDCs to move towards the target ranges, and at a minimum, in the first year move 50% towards the Floor if the revenue to cost ratio is lower than the floor. However, Bluewater Power believes it is appropriate to consider rate impacts that customers would face by moving 50% towards the Floor level in the first year. Therefore, Bluewater Power has proposed to move one third towards the Floor level in this application for the USL, Sentinel and Streetlighting customers. Further justification and sensitivity analysis on the various revenue to cost ratio movements contemplated is provided in Exhibit 9, Tab 1, Schedule 4 – Rate Mitigation.

Bluewater Power proposes the revenue to cost ratio's indicated in Table 8.1.2.1.

Table 8.1.2.1

	Rate Application (2009 Test Year)			Updated Cost Allocation		OEB Target Range	
Customer Class Name	**Allocated Revenue**	**Allocated Cost**	**Revenue to Cost Ratio**	**Revenue to Cost Ratio**	**Variance**	**Floor**	**Ceiling**
Residential	10,664,352	10,708,278	1.00	1.00	0.00	0.85	1.15
General Service <50 kW	3,396,027	3,296,423	1.03	1.07	(0.04)	0.80	1.20
General Service 50 to 999 kW	3,198,270	3,240,448	0.99	0.88	0.10	0.80	1.80
General Service 1,000 to 4,999 kW	1,116,692	867,607	1.29	1.41	(0.13)	0.80	1.80
Large	1,744,517	1,530,278	1.14	1.26	(0.12)	0.85	1.15
Unmetered Scattered Load	120,839	172,628	0.70	0.65	0.05	0.80	1.20
Sentinel Lighting	33,081	73,513	0.45	0.33	0.12	0.70	1.20
Street Lighting	433,701	818,305	0.53	0.44	0.09	0.70	1.20
TOTAL	20,707,479	20,707,478					

RATE DESIGN

Rate Design Overview

This exhibit documents the calculation of Bluewater Power's proposed distribution rates by rate class for the 2009 test year based on rate design as proposed below.

Bluewater Power has determined its total 2009 service revenue requirement to be $21,436,076. The total revenue offsets amount to $728,598 and serves to reduce Bluewater Power's total service revenue requirement to a base revenue requirement of $20,707,479, which is used to determine the proposed distribution rates. The base revenue requirement is derived from the 2009 capital and operating forecasts, weather normalized consumption, forecasted customer counts, and the regulated return on rate base. As requested by the Board, also displayed in Table 9.1.1.1 is the 2006 EDR components of the revenue requirement.

Table 9.1.1.1

	2009 Projection	2006 EDR
OM&A Expenses	11,656,169	9,322,200
3850-Amortization Expense	4,358,109	3,130,369
Total Distribution Expenses	16,014,278	12,452,569
Regulated Return On Capital	4,098,944	3,789,739
PILs (with gross-up)	1,322,854	1,151,955
Service Revenue Requirement	**21,436,076**	**17,394,263**
Less: Revenue Offsets	728,598	1,931,374
Base Revenue Requirement	**20,707,479**	**15,462,889**
Add: Recovery of Transformer Allowance	559,364	594,269
Add: Recovery of Low Voltage Charges	189,602	179,624
Gross Base Revenue Requirement	**21,456,445**	**16,236,782**

In addition to the base revenue requirement, distribution rates need to include the allowance for transformer ownership and recovery of low voltage charges.

Table 9.1.1.2 below indicates that the gross base revenue requirement, including these two factors, is $21,456,445.

Table 9.1.1.2

Customer Class Name	Total Base Revenue Requirement	Transformer Allowance Recovery	Low Voltage Revenue Required	Gross Base Revenue Requirement
Residential	10,664,352		53,360	10,717,712
General Service <50 kW	3,396,027		21,627	3,417,654
General Service 50 to 999 kW	3,198,270	85,150	40,623	3,324,043
General Service 1,000 to 4,999 kW	1,116,692	218,530	29,920	1,365,143
Large	1,744,517	255,684	42,344	2,042,545
Unmetered Scattered Load	120,839		393	121,232
Sentinel Lighting	33,081		88	33,169
Street Lighting	433,701		1,247	434,948
TOTAL	**20,707,479**	**559,364**	**189,602**	**21,456,445**

Percentage of Revenue Generated by Class

The projected customer counts by customer class for the 2009 test year is found at Exhibit 3, Tab 2, Schedule 4. The forecast of normalized consumption by customer class is found at Exhibit 3, Tab 2, Schedule 3. These forecasts were utilized to calculate distribution revenues by rate class using current distribution rates in order to determine the current fixed/variable revenue allocation. The calculations are shown below.

Table 9.1.1.3

	2009 Projected Data			Base Revenues at current rates		
Customer Class Name	**Customers (Connections)**	**Volume kWh**	**Volume kW**	**Fixed**	**Variable**	**Total**
Residential	32,006	266,434,436		$ 5,238,742	$3,117,283	$8,356,025
General Service <50 kW	3,924	120,544,382		$ 1,184,734	$1,542,968	$2,727,702
General Service 50 to 999 kW	396		593,516	$ 1,570,821	$ 963,929	$2,534,750
General Service 1,000 to 4,999 kW	16		398,767	$592,184	$ 608,199	$1,200,383
Large	4		493,510	$865,016	$ 564,131	$1,429,147
Unmetered Scattered Load	266	2,188,838		$ 40,155	$28,017	$68,172
Sentinel Lighting	526		1,637	$ 11,425	$7,895	$19,320
Street Lighting	10,009		23,562	$164,548	$88,070	$252,618
Total	**47,147**	**389,167,656**	**1,510,992**	**$9,667,625**	**$6,920,493**	**$16,588,118**

Percentage of Revenue Allocated by Customer Class

The totals from Table 9.1.1.3 by rate class and rate component (fixed/variable) were used along with the total revenue to determine the percentages of the total revenue contributed by customer class and rate component to the total collected.

Table 9.1.1.4

Customer Class Name	Percentage of Total Revenue Collected	Fixed %	Variable %	Total
Residential	50.4%	62.7%	37.3%	100.0%
General Service <50 kW	16.4%	43.4%	56.6%	100.0%
General Service 50 to 999 kW	15.3%	62.0%	38.0%	100.0%
General Service 1,000 to 4,999 kW	7.2%	49.3%	50.7%	100.0%
Large	8.6%	60.5%	39.5%	100.0%
Unmetered Scattered Load	0.4%	58.9%	41.1%	100.0%
Sentinel Lighting	0.1%	59.1%	40.9%	100.0%
Street Lighting	1.5%	65.1%	34.9%	100.0%
Total	**100.0%**			**100.0%**

Recovery of Revenue Requirement by Class

The percentages by rate component for each class (Table 9.1.1.4) were applied to the distribution revenue requirement of $21,456,445 (Table 9.1.1.2) to determine the portion of the requirement to be collected from each customer class (Table 9.1.1.5). This total requirement is net of Other Revenues. There is a variance of $4,485 ($21,456,445 - $21,451,960) related to rounding in the precise calculation of the rates.

Table 9.1.1.5

Customer Class	**Fixed Revenue**	Variable Revenue	Total Revenue	
Residential	$6,721,260	$3,996,517	$10,717,777	kWh
General Service <50 kW	$1,484,214	$1,928,710	$3,412,924	kWh
General Service 50 to 999 kW	$2,059,944	$1,264,070	$3,324,015	kW
General Service 1,000 to 4,999 kW	$673,465	$691,661	$1,365,126	kW
Large	$1,236,285	$806,247	$2,042,532	kW
Unmetered Scattered Load	$71,405	$49,906	$121,311	kWh
Sentinel Lighting	$19,630	$13,555	$33,185	kW
Street Lighting	$283,455	$151,636	$435,090	kW
TOTAL	$12,549,659	$8,902,302	$21,451,960	

Proposed 2009 Distribution Rates

The distribution revenues to be collected from each class by rate component were used to determine the fixed and variable rates for each class, before the smart meter or deferral/variance account rate adders are included.

Table 9.1.1.6
Current and Proposed Fixed Rates (before rate adders)

Customer Class Name	Current Fixed Rate	Proposed Fixed Rate
Residential	$13.64	$17.50
General Service <50 kW	$25.16	$31.52
General Service 50 to 999 kW	$330.56	$433.49
General Service 1,000 to 4,999 kW	$3,084.29	$3,507.63
Large	$18,021.16	$25,755.94
Unmetered Scattered Load	$12.58	$22.37
Sentinel Lighting	$1.81	$3.11
Street Lighting	$1.37	$2.36

Table 9.1.1.7
Current and Proposed Variable Rates (Before Rate Adders)

Customer Class Name	Existing Variable Rate	Proposed Variable Rate
Residential	$0.0117	$0.0150
General Service <50 kW	$0.0128	$0.0160
General Service 50 to 999 kW	$1.6241	$2.1298
General Service 1,000 to 4,999 kW	$1.5252	$1.7345
Large	$1.1431	$1.6337
Unmetered Scattered Load	$0.0128	$0.0228
Sentinel Lighting	$4.8230	$8.2803
Street Lighting	$3.7378	$6.4356

Bluewater Power submits that it is appropriate to maintain the same fixed/variable proportions as calculated in Table 9.1.1.4. This matter is discussed further below.

In September 2006 the OEB completed its Cost Allocation Review and issued the Board Directions on Cost Allocation Methodology for Electricity Distributors, RP-2005-0317. Bluewater Power completed the cost allocation study and it was submitted in January 2007.

On November 28, 2007 the OEB issued its Report on Application of Cost Allocation for Electricity Distributors, and addressed a number of other rate matters, including the treatment of the fixed rate component (the Monthly Service Charge) of the bill.

At page 12 of the report:

> *"…The Board considers it to be inappropriate to make significant changes to the ceiling for the MSC at this time, given the number of issues that remain to be examined. The appropriateness of the methodologies cited above, used to set the MSC is an issue that will be examined within the scope of the Rate Review. The Rate Review will also examine the role of rate design in achieving various objectives, including conservation of energy. Both of these undertakings will have determinative impacts on the fixed/variable ratio policy.*
>
> *In the interim, the Board does not expect distributors to make changes to the MSC that result in a charge that is greater than the ceiling as defined in the Methodology for the MSC. Distributors that are currently above this value are not required to make changes to their current MSC to bring it to or below this level at this time."*

Given this pending Rate Review process, Bluewater Power proposes to leave the fixed/variable ratios as they are.

Transformer Allowance

Bluewater Power currently credits customers who own their own transformation facilities an amount of ($.60) per kW of demand. Bluewater Power proposes that this credit continue until further rate design initiatives are completed.

Table 9.1.1.8
Forecast Transformer Allowance

Rate Class	2009 Projected kW for Customers with own Transformer	2009 Projected Transformer Allowance
General Service 50 - 999 kW	141,916	$85,150
General Service 1000 - 4999 kW	364,217	$218,530
Large	426,141	$255,684
TOTAL	932,274	$559,364

Reconciliation of Rate Class Revenue to Total Revenue Requirement

The table below details the breakdown of revenue requirement by rate class based on the forecasted number of connections, usage and projected rates.

Table 9.1.2.1
Revenue Requirement by Rate Class

2009 Projection	Customers (Connections)	kWh's per Customer (Connection)	kW's per Customer (Connection)	Dist. Rate per kWh	Dist. Rate per kW	Monthly Service Charge	Distribution Revenue
Residential	32,006	8,325		$0.0150		$17.50	10,717,712
General Service <50 kW	3,924	30,720		$0.0160		$31.52	3,417,654
General Service 50 to 999 kW	396	546,047	1,499		$2.1298	$433.49	3,324,043
General Service 1,000 to 4,999 kW	16	11,319,320	24,923		$1.7345	$3,507.63	1,365,143
Large	4	80,485,576	123,378		$1.6337	$25,755.94	2,042,545
Unmetered Scattered Load	266	8,229		$0.0228		$22.37	121,232
Sentinel Lighting	526	1,301	3		$8.2803	$3.11	33,169
Street Lighting	10,009	871	2		$6.4356	$2.36	434,948
Gross Revenue (before Transformer Allowances)							**21,456,445**
Transformer Allowances							(559,364)
Total Revenue							**20,897,081**
Less: Low voltage charges embedded in distribution rates							(189,602)
DISTRIBUTION REVENUE							**20,707,479**

Table 9.1.2.2 below details the components of the Other Distribution Revenue and when added to the Distribution Revenue projected in Table 9.1.2.1, reconciles to the total Service Revenue Requirement of $21,436,077.

Table 9.1.2.2
Other Revenue

Other Operating Revenue	**2009 Projection**
4080-Distribution Services Revenue	84,603
4082-Retail Services Revenues	68,097
4084-Service Transaction Requests (STR) Revenues	5,091
4090-Electric Services Incidental to Energy Sales	
4210-Rent from Electric Property	136,320
4225-Late Payment Charges	225,433
4230-Sales of Water and Water Power	
4235-Miscellaneous Service Revenues	135,840
4325-Revenues from Merchandise, Jobbing, Etc.	361,084
4330-Costs and Expenses of Merchandising, Jobbing, Etc.	(92,578)
4355-Gain on Disposition of Utility and Other Property	15,026
4390-Miscellaneous Non-Operating Income	33,318
4405-Interest and Dividend Income	(243,636)
TOTAL OTHER OPERATING REVENUE	**728,598**
Total Distribution Revenue (see 9.1.2.1)	**20,707,479**
TOTAL DISTRIBUTION REVENUES	**21,436,077**

Cost Allocation Comparison on Revenue Requirement

Bluewater Power has compared the class revenues based on full cost allocation, and at existing rates. Attachment 1 summarizes this comparison. Columns A and D reflect the implementation of full cost allocation as if each customer class were paying for the actual cost to service that class. Columns B and E reflect the recovery of the revenue requirement under existing rates, and columns C and F reflect the proposed recovery of the revenue requirement.

Exhibit 9, Tab 1, Schedule 3, Attachment 1 details the comparison.

Cost Allocation Comparison - Dollar Impact

	A	B	C	D	E	F	G	H
	Outstanding Base Revenue Requirement %			Outstanding Base Revenue Requirement $			Directly	Total Base
Customer Class Name	Cost Allocation	Existing Rates	Rate Application	Cost Allocation	Existing Rates	Rate Application	Assigned Revenues	Revenue Requirement
Residential	51.71%	50.37%	51.50%	$ 10,708,278	$ 10,431,093	$ 10,664,352	0	$ 10,664,352
General Service <50 kW	15.92%	16.44%	16.40%	$ 3,296,423	$ 3,405,078	$ 3,396,027	0	$ 3,396,027
General Service 50 to 999 kW	15.65%	15.28%	15.45%	$ 3,240,448	$ 3,164,210	$ 3,198,270	0	$ 3,198,270
General Service 1,000 to 4,999 kW	4.19%	7.24%	5.39%	$ 867,607	$ 1,498,477	$ 1,116,692	0	$ 1,116,692
Large	7.39%	8.62%	8.42%	$ 1,530,278	$ 1,784,050	$ 1,744,517	0	$ 1,744,517
Unmetered Scattered Load	0.83%	0.41%	0.58%	$ 172,628	$ 85,102	$ 120,839	0	$ 120,839
Sentinel Lighting	0.36%	0.12%	0.16%	$ 73,513	$ 24,118	$ 33,081	0	$ 33,081
Street Lighting	3.95%	1.52%	2.09%	$ 818,305	$ 315,351	$ 433,701	0	$ 433,701
TOTAL	**100.00%**	**100.00%**	**100.00%**	**$ 20,707,478**	**$ 20,707,479**	**$ 20,707,479**	**$ -**	**$ 20,707,479**

Rate Mitigation

Bluewater Power has proposed rates that will achieve the allowed rate of return, and that it submits are just and reasonable.

Table 9.1.4.1 displays the proposed monthly bill impacts at average consumption levels for each rate class. The Sentinel and Street Lighting bill impacts indicate a 'per connection' impact, thus to determine the full monthly dollar impact, the number of connections must be brought into the calculation.

Table 9.1.4.1
Average Monthly Bill Impact $ and %

Rate Class	kWh	kW	Total Bill $ Change	Total Bill % Change
Residential	1,000		$6.35	6.0%
GS<50	2,000		$9.99	4.7%
GS 50 to 999 kW	52,000	135	$79.94	1.6%
GS 1000 to 4999 kW	1,700,000	3,532	($1,935.72)	-1.4%
Large	4,446,000	6,900	$4,974.14	1.4%
USL	1,000		$18.34	17.9%
Sentinel (per connection)	176	0.46	$2.63	15.6%
Street Lighting (per connection)	99	0.21	$1.44	15.6%

All customers, with the exception of the USL, Sentinel and Street Lighting customers (the "Lighting Customers") are proposed to have total bill impacts of less than 10%. The impact on the Lighting Customers lies between 15% to 20% and is driven primarily by Cost Allocation. As detailed in Exhibit 8, Tab 1, Schedule 2, Bluewater Power is proposing to move one-third towards the Floor level of the OEB's target revenue to cost ratio's for the USL, Sentinel and Street Lighting customers in this rate application, in order to mitigate higher rate impact. Bluewater Power intends to propose an additional one-third movement towards the Floor level in the 2010 application, and a final one-third movement towards the Floor level in the 2011 application.

A number of sensitivities were performed to determine the rate impacts to these customers by moving 50% toward the target range, moving 100% to the target range and not moving at all towards the target range. The tables below detail the results of the sensitivity analysis.

Table 9.1.4.2
Moving 1/3 Towards Floor Revenue to Cost Ratio

Rate Class	Scenario - moving 1/3 toward Floor	Average kWh per connection	Average kW per connection	Bill Impact - $ per month per connection	Bill Impact - % per month per connection
USL	0.70	1000		$18.34	17.9%
Sentinel	0.45	176	0.46	$2.63	15.6%
Street Lighting	0.53	99	0.21	$1.44	15.6%

Table 9.1.4.2 is Bluewater Power's proposed option. Moving 1/3 towards the floor range will still have a very material impact on the largest Street Lighting customer, being approximately $11,000 per month or approximately $130,000 annually.

Table 9.1.4.3
Moving 50% Towards Floor Revenue to Cost Ratio

Rate Class	Scenario - moving 50% to Floor	Average kWh per connection	Average kW per connection	Bill Impact - $ per month per connection	Bill Impact - % per month per connection
USL	0.80	1000		$20.20	20%
Sentinel	0.70	176	0.46	$3.71	22%
Street Lighting	0.70	99	0.21	$1.72	19%

The above scenario would have a monthly impact of approximately $13,000 per month or $156,000 per year on the largest Street Lighting customer.

Table 9.1.4.4
Moving 100% to the Floor Revenue to Cost Ratio

Rate Class	Scenario - moving all the way to Floor	Average kWh per connection	Average kW per connection	Bill Impact - $ per month per connection	Bill Impact - % per month per connection
USL	0.80	1000		$18.93	33.6%
Sentinel	0.70	176	0.46	$6.51	38.7%
Street Lighting	0.70	99	0.21	$2.64	28.6%

The above scenario would have a monthly impact of approximately $20,000 per month or $239,000 annually on the largest Street Lighting customer.

Given the analysis performed, Bluewater Power feels it is in the customer's best interest to mitigate the large rate impacts which would materialize should Bluewater Power move 50% towards the Floor range as indicated in previous Board Decisions. However, Bluewater Power is striving to meet both the Board's requirements and the financial needs of its customers. Therefore, Bluewater Power requests the Board allow a movement of one-third towards the Floor range for the USL, Sentinel and Street Lighting customers.

Existing Rate Classes

Residential Customers

All service supplied to single-family dwelling units for domestic or household purposes shall be classed as Residential service. Where electricity service is provided for combined residential and business purposes (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Bluewater Power and shall be based on such considerations as the estimated predominant consumption or the municipal tax roll classification. A Residential customer may be found in a detached, semi-detached, linear row housing, apartment building or mixed-use building. Where more than one dwelling is served by a single meter, that service shall be considered as a General Service customer.

General Service Less than 50 kW

This classification applies to a customer not designated as Residential, and that over a twelve month period has, or is forecast to have, an average monthly peak demand less than 50 kW, and has a monthly peak demand that never exceeds 100 kW. Bluewater Power shall review this rate class designation on an annual basis and the customer's designated rate class may change as a result.

General Service 50 to 999 kW

This classification applies to a customer not designated as Residential, and that over a twelve month period has, or is forecast to have, an average monthly peak demand equal to or greater than 50 kW and less than 1,000 kW. This rate class designation is reviewed on an annual basis and the customer's designated rate class may change as a result.

General Service 1,000 to 4,999 kW

This classification applies to a customer not designated Residential, and that: over a twelve month period has, or is forecast to have, an average monthly peak demand equal to or greater than 1,000 kW and less than 5,000 kW. This rate class designation is reviewed on an annual basis and the customer's designated rate class may change as a result.

Large Use

This classification applies to a customer not designated as Residential, and that over 12 consecutive billing periods has, or is forecast to have, an average monthly peak demand equal to or greater than 5,000 kW. This rate class designation is reviewed on an annual basis and the customer's designated rate class may change as a result.

Unmetered Scattered Load

This classification applies to an account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by Bluewater Power and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption.

Sentinel Lighting

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

Street Lighting

This classification 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 multiplied by the required lighting times established in the approved OEB street lighting load shape template.

Existing Rate Schedule

The existing rate schedule is found at Exhibit 1, Tab 1, Schedule 4, and is also presented for comparison in Exhibit 9, Tab 1, Schedule 8 – Proposed Rate Schedule.

Proposed Rate Classes (if different than existing)

Bluewater Power is proposing to maintain the existing rate classes.

Proposed Rate Schedule

Exhibit 9, Tab 1, Schedule 8, Attachment 1 details the Proposed Rate Schedule.

Monthly Rates and Charges

		Effective May 1/09	*Existing Rate*
Residential			
Service Charge	$	18.50	*13.90*
Distribution Volumetric Rate	$/kWh	0.0150	*0.0117*
Regulatory Asset Recovery	$/kWh	(0.0009)	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0047	*0.0047*
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0048	*0.0048*
Wholesale Market Service Rate	$/kWh	0.0052	*0.0052*
Rural Rate Protection Charge	$/kWh	0.0010	*0.0010*
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	*0.25*
General Service <50 kW			
Service Charge	$	32.52	*25.42*
Distribution Volumetric Rate	$/kWh	0.0160	*0.0128*
Regulatory Asset Recovery	$/kWh	(0.0011)	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043	*0.0043*
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043	*0.0043*
Wholesale Market Service Rate	$/kWh	0.0052	*0.0052*
Rural Rate Protection Charge	$/kWh	0.0010	*0.0010*
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	*0.25*
General Service 50 to 999 kW			
Service Charge	$	434.49	*330.82*
Distribution Volumetric Rate	$/kW	2.1298	*1.6241*
Regulatory Asset Recovery	$/kW	(0.4555)	
Retail Transmission Rate – Network Service Rate	$/kW	1.7399	*1.7399*
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6988	*1.6988*
Wholesale Market Service Rate	$/kWh	0.0052	*0.0052*
Rural Rate Protection Charge	$/kWh	0.0010	*0.0010*
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	*0.25*
General Service 1,000 to 4,999 kW			
Service Charge	$	3,508.63	*3,084.55*
Distribution Volumetric Rate	$/kW	1.7345	*1.5252*
Regulatory Asset Recovery	$/kW	(0.6174)	
Retail Transmission Rate – Network Service Rate	$/kW	1.8479	*1.8479*
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.8623	*1.8623*
Wholesale Market Service Rate	$/kWh	0.0052	*0.0052*
Rural Rate Protection Charge	$/kWh	0.0010	*0.0010*
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	*0.25*

Monthly Rates and Charges

		Effective May 1/09	***Existing Rate***
Large			
Service Charge	$	25,756.94	*18,021.42*
Distribution Volumetric Rate	$/kW	1.6337	*1.1431*
Regulatory Asset Recovery	$/kW	(0.8908)	
Retail Transmission Rate – Network Service Rate	$/kW	2.0461	*2.0461*
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.1296	*2.1296*
Wholesale Market Service Rate	$/kWh	0.0052	*0.0052*
Rural Rate Protection Charge	$/kWh	0.0010	*0.0010*
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	*0.25*
Unmetered Scattered Load			
Service Charge (per connection)	$	22.37	*12.58*
Distribution Volumetric Rate	$/kWh	0.0228	0.0128
Regulatory Asset Recovery	$/kWh	(0.0008)	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043	0.0043
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0010	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	0.25

Monthly Rates and Charges

		Effective May 1/09	***Existing Rate***
Sentinel Lighting			
Service Charge (per connection)	$	3.11	*1.81*
Distribution Volumetric Rate	$/kW	8.2803	4.8230
Regulatory Asset Recovery	$/kW	(0.3737)	
Retail Transmission Rate – Network Service Rate	$/kW	1.3188	1.3188
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3407	1.3407
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0010	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	0.25
Street Lighting			
Service Charge (per connection)	$	2.36	*1.37*
Distribution Volumetric Rate	$/kW	6.4356	3.7378
Regulatory Asset Recovery	$/kW	(0.3256)	
Retail Transmission Rate – Network Service Rate	$/kW	1.3122	1.3122
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3133	1.3133
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0010	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	0.25

Monthly Rates and Charges

		Effective May 1/09	***Existing Rate***
Specific Service Charges			
Income tax letter	$	15.00	*15.00*
Returned Cheque charge (plus bank charges)	$	15.00	*15.00*
Legal letter charge	$	15.00	*15.00*
Account set up charge / change of occupancy charge	$	10.00	*10.00*
Late Payment - per month	%	1.50	*1.50*
Collection of account charge – no disconnection	$	30.00	*30.00*
Disconnect/Reconnect at meter – during regular hours	$	65.00	*65.00*
Disconnect/Reconnect at meter – after regular hours	$	185.00	*185.00*
Specific Charge for Access to the Power Poles – per pole/year	$	22.35	*22.35*
Retailer Service Agreement -- monthly fixed charge (per retailer)	$	20.00	20.00
Retailer Service Agreement -- monthly variable charge (per customer)	$	0.50	0.50
Distributor-Consolidated Billing -- monthly charge (per customer)	$	0.30	0.30
Retailer-Consolidated Billing -- monthly credit (per customer)	$	(0.30)	(0.30)
Service Transaction Request -- request fee (per request)	$	0.25	0.25
Service Transaction Request -- processing fee (per processed request)	$	0.50	0.50
Interval Meter Load Management Tool	$	50.00	50.00
Allowances			
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)	*(0.60)*
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)	*(1.00)*
LOSS FACTORS			
Secondary Metered Customer < 5000 kW		1.0356	*1.0446*
Secondary Metered Customer > 5000 kW		1.0145	*1.0145*
Primary Metered Customer < 5000 kW		1.0253	1.0342
Primary Metered Customer > 5000 kW		1.0045	1.0045

Rate Impacts

Table 9.1.9.1 presents the summary of the rate impacts by rate class.

Exhibit 9, Tab 1, Schedule 9, Attachment 1 details the rate impacts by volume for each rate class.

Exhibit 9, Tab 1, Schedule 9, Attachment 2 details the rate impacts for Residential customers using 1000 kWh per month, and General Service <50 kW using 2000 kWh per month, with a percentage change and dollar per month change on the 'delivery line charges' as per a request from the Board. Delivery line charges include fixed charges, variable charges, deferral/variance account disposition and retail transmission network and retail transmission connection charges.

Table 9.1.9.1 – Summary of Rate Impacts

Residential

Volume		RPP	Distribution Charges		Total Bill	
kWh *	kW	Rate Class	$ change	% change	$ change	% change
500		Summer	$6.25	31.6%	$5.50	9.6%
1,000		Summer	$7.90	30.9%	$6.35	6.0%
1,500		Summer	$9.55	30.4%	$7.19	4.7%
500		Winter	$6.25	31.6%	$5.50	9.6%
1,000		Winter	$7.90	30.9%	$6.35	6.2%
1,500		Winter	$9.55	30.4%	$7.19	4.8%

General Service <50 kW

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP	$ change	% change	$ change	% change
1,000		Non-res.	$10.30	26.9%	$8.55	7.4%
2,000		Non-res.	$13.50	26.5%	$9.99	4.7%
5,000		Non-res.	$23.10	25.8%	$14.29	2.8%
10,000		Non-res.	$39.10	25.5%	$21.45	2.2%
15,000		Non-res.	$55.10	25.3%	$28.64	1.9%

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General Service 50 to 999 kW

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP	$ change	% change	$ change	% change
52,000	135	Non-res.	$171.94	31.3%	$79.94	1.6%
165,000	355	n/a	$283.19	31.2%	$31.33	0.2%
430,000	860	n/a	$538.57	31.2%	($88.07)	(0.3%)

General Service 1,000 to 4,999 kW

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP	$ change	% change	$ change	% change
427,000	1,028	n/a	$639.24	13.7%	($226.13)	(0.6%)
1,700,000	3,532	n/a	$1,163.33	13.7%	($1,935.72)	(1.4%)
2,860,000	4,477	n/a	$1,361.12	13.7%	($2,948.03)	(1.3%)

Large

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP	$ change	% change	$ change	% change
7,256,000	10,389	n/a	$12,832.36	42.9%	$3,577.84	0.6%
11,709,000	17,801	n/a	$16,468.69	42.9%	$611.56	0.1%
4,446,000	6,900	n/a	$11,120.66	42.9%	$4,974.14	1.4%
3,465,000	6,000	n/a	$10,679.12	42.9%	$5,334.32	1.9%

Unmetered Scattered Load

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP	$ change	% change	$ change	% change
500		Non-res.	$14.79	77.9%	$14.09	25.0%
1,000		Non-res.	$19.79	78.0%	$18.34	17.9%
5,000		Non-res.	$59.79	78.1%	$52.48	10.7%
15,000		Non-res.	$159.79	78.1%	$137.83	9.4%
950,000		Non-res.	$9,509.79	78.1%	$8,118.81	8.8%

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1

Sentinel Lighting (Impact per connection)

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP	$ change	% change	$ change	% change
176	0.46	Non-res.	$2.89	71.7%	$2.63	15.6%
318	0.45	Non-res.	$2.86	71.7%	$2.53	9.7%
63	0.21	Non-res.	$2.03	71.8%	$1.92	25.5%
48	0.13	Non-res.	$1.75	71.8%	$1.68	28.3%

Street Lighting (Impact per connection)

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP	$ change	% change	$ change	% change
99	0.21	Non-res.	$1.56	72.2%	$1.44	15.6%
81	0.18	Non-res.	$1.48	72.2%	$1.38	17.5%
83	0.18	Non-res.	$1.48	72.2%	$1.38	17.2%
102	0.22	Non-res.	$1.58	72.2%	$1.46	15.5%
81	0.18	Non-res.	$1.48	72.2%	$1.38	17.5%
65	0.14	Non-res.	$1.37	72.2%	$1.30	19.9%
92	0.20	Non-res.	$1.53	72.2%	$1.41	16.2%

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Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

Residential

Volume		RPP	Distribution Charges		Total Bill	
kWh *	kW	Rate Class	$ change	% change	$ change	% change
500		Summer	$6.25	31.6%	$5.50	9.6%
1,000		Summer	$7.90	30.9%	$6.35	6.0%
1,500		Summer	$9.55	30.4%	$7.19	4.7%
500		Winter	$6.25	31.6%	$5.50	9.6%
1,000		Winter	$7.90	30.9%	$6.35	6.2%
1,500		Winter	$9.55	30.4%	$7.19	4.8%

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

Residential **RPP: Summer**

500 kWh's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
Monthly Service Charge				$13.90			$18.50	$4.60	33.1%
Distribution	kWh	500	$0.0117	$5.85	500	$0.0150	$7.50	$1.65	28.2%
Sub-Total (Distribution)				**$19.75**			**$26.00**	**$6.25**	**31.6%**
Deferral/Variance	kWh	500			500	($0.0009)	($0.45)	($0.45)	
Electricity (Commodity)	kWh	522	RPP-Summer	$26.12	518	RPP-Summer	$25.89	($0.23)	(0.9%)
Transmission - Network	kWh	522	$0.0047	$2.45	518	$0.0047	$2.43	($0.02)	(0.8%)
Transmission - Connection	kWh	522	$0.0048	$2.51	518	$0.0048	$2.49	($0.02)	(0.8%)
Wholesale Market Service	kWh	522	$0.0052	$2.72	518	$0.0052	$2.69	($0.03)	(1.1%)
Rural Rate Protection	kWh	522	$0.0010	$0.52	518	$0.0010	$0.52		
Debt Retirement Charge	kWh	500	$0.0070	$3.50	500	$0.0070	$3.50		
TOTAL BILL				**$57.57**			**$63.07**	**$5.50**	**9.6%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

Residential **RPP: Summer**

1,000 kWh's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
Monthly Service Charge				$13.90			$18.50	$4.60	33.1%
Distribution	kWh	1,000	$0.0117	$11.70	1,000	$0.0150	$15.00	$3.30	28.2%
Sub-Total (Distribution)				**$25.60**			**$33.50**	**$7.90**	**30.9%**
Deferral/Variance	kWh	1,000			1,000	($0.0009)	($0.90)	($0.90)	
Electricity (Commodity)	kWh	1,045	RPP-Summer	$56.23	1,036	RPP-Summer	$55.70	($0.53)	(0.9%)
Transmission - Network	kWh	1,045	$0.0047	$4.91	1,036	$0.0047	$4.87	($0.04)	(0.8%)
Transmission - Connection	kWh	1,045	$0.0048	$5.01	1,036	$0.0048	$4.97	($0.04)	(0.8%)
Wholesale Market Service	kWh	1,045	$0.0052	$5.43	1,036	$0.0052	$5.39	($0.04)	(0.7%)
Rural Rate Protection	kWh	1,045	$0.0010	$1.04	1,036	$0.0010	$1.04		
Debt Retirement Charge	kWh	1,000	$0.0070	$7.00	1,000	$0.0070	$7.00		
TOTAL BILL				**$105.22**			**$111.57**	**$6.35**	**6.0%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

Residential **RPP: Summer**

1,500 kWh's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
Monthly Service Charge				$13.90			$18.50	$4.60	33.1%
Distribution	kWh	1,500	$0.0117	$17.55	1,500	$0.0150	$22.50	$4.95	28.2%
Sub-Total (Distribution)				**$31.45**			**$41.00**	**$9.55**	**30.4%**
Deferral/Variance	kWh	1,500			1,500	($0.0009)	($1.35)	($1.35)	
Electricity (Commodity)	kWh	1,567	RPP-Summer	$87.05	1,553	RPP-Summer	$86.25	($0.80)	(0.9%)
Transmission - Network	kWh	1,567	$0.0047	$7.36	1,553	$0.0047	$7.30	($0.06)	(0.8%)
Transmission - Connection	kWh	1,567	$0.0048	$7.52	1,553	$0.0048	$7.46	($0.06)	(0.8%)
Wholesale Market Service	kWh	1,567	$0.0052	$8.15	1,553	$0.0052	$8.08	($0.07)	(0.9%)
Rural Rate Protection	kWh	1,567	$0.0010	$1.57	1,553	$0.0010	$1.55	($0.02)	(1.3%)
Debt Retirement Charge	kWh	1,500	$0.0070	$10.50	1,500	$0.0070	$10.50		
TOTAL BILL				**$153.60**			**$160.79**	**$7.19**	**4.7%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

Residential **RPP: Winter**

500 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	Volume	Rate	Charge	Volume	Rate	Charge	$	%
Monthly Service Charge				$13.90			$18.50	$4.60	33.1%
Distribution	kWh	500	$0.0117	$5.85	500	$0.0150	$7.50	$1.65	28.2%
Sub-Total (Distribution)				**$19.75**			**$26.00**	**$6.25**	**31.6%**
Deferral/Variance	kWh	500			500	($0.0009)	($0.45)	($0.45)	
Electricity (Commodity)	kWh	522	RPP-Winter	$26.12	518	RPP-Winter	$25.89	($0.23)	(0.9%)
Transmission - Network	kWh	522	$0.0047	$2.45	518	$0.0047	$2.43	($0.02)	(0.8%)
Transmission - Connection	kWh	522	$0.0048	$2.51	518	$0.0048	$2.49	($0.02)	(0.8%)
Wholesale Market Service	kWh	522	$0.0052	$2.72	518	$0.0052	$2.69	($0.03)	(1.1%)
Rural Rate Protection	kWh	522	$0.0010	$0.52	518	$0.0010	$0.52		
Debt Retirement Charge	kWh	500	$0.0070	$3.50	500	$0.0070	$3.50		
TOTAL BILL				**$57.57**			**$63.07**	**$5.50**	**9.6%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

Residential **RPP: Winter**

1,000 kWh's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
Monthly Service Charge				$13.90			$18.50	$4.60	33.1%
Distribution	kWh	1,000	$0.0117	$11.70	1,000	$0.0150	$15.00	$3.30	28.2%
Sub-Total (Distribution)				**$25.60**			**$33.50**	**$7.90**	**30.9%**
Deferral/Variance	kWh	1,000			1,000	($0.0009)	($0.90)	($0.90)	
Electricity (Commodity)	kWh	1,045	RPP-Winter	$52.63	1,036	RPP-Winter	$52.10	($0.53)	(1.0%)
Transmission - Network	kWh	1,045	$0.0047	$4.91	1,036	$0.0047	$4.87	($0.04)	(0.8%)
Transmission - Connection	kWh	1,045	$0.0048	$5.01	1,036	$0.0048	$4.97	($0.04)	(0.8%)
Wholesale Market Service	kWh	1,045	$0.0052	$5.43	1,036	$0.0052	$5.39	($0.04)	(0.7%)
Rural Rate Protection	kWh	1,045	$0.0010	$1.04	1,036	$0.0010	$1.04		
Debt Retirement Charge	kWh	1,000	$0.0070	$7.00	1,000	$0.0070	$7.00		
TOTAL BILL				**$101.62**			**$107.97**	**$6.35**	**6.2%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

Residential **RPP: Winter**

1,500 kWh's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
Monthly Service Charge				$13.90			$18.50	$4.60	33.1%
Distribution	kWh	1,500	$0.0117	$17.55	1,500	$0.0150	$22.50	$4.95	28.2%
Sub-Total (Distribution)				**$31.45**			**$41.00**	**$9.55**	**30.4%**
Deferral/Variance	kWh	1,500			1,500	($0.0009)	($1.35)	($1.35)	
Electricity (Commodity)	kWh	1,567	RPP-Winter	$83.45	1,553	RPP-Winter	$82.65	($0.80)	(1.0%)
Transmission - Network	kWh	1,567	$0.0047	$7.36	1,553	$0.0047	$7.30	($0.06)	(0.8%)
Transmission - Connection	kWh	1,567	$0.0048	$7.52	1,553	$0.0048	$7.46	($0.06)	(0.8%)
Wholesale Market Service	kWh	1,567	$0.0052	$8.15	1,553	$0.0052	$8.08	($0.07)	(0.9%)
Rural Rate Protection	kWh	1,567	$0.0010	$1.57	1,553	$0.0010	$1.55	($0.02)	(1.3%)
Debt Retirement Charge	kWh	1,500	$0.0070	$10.50	1,500	$0.0070	$10.50		
TOTAL BILL				**$150.00**			**$157.19**	**$7.19**	**4.8%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

General Service <50 kW

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
1,000		Non-res.	$10.30	26.9%	$8.55	7.4%
2,000		Non-res.	$13.50	26.5%	$9.99	4.7%
5,000		Non-res.	$23.10	25.8%	$14.29	2.8%
10,000		Non-res.	$39.10	25.5%	$21.45	2.2%
15,000		Non-res.	$55.10	25.3%	$28.64	1.9%

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

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General Service <50 kW **RPP: Non-res.**

1,000 kWh's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
Monthly Service Charge				$25.42			$32.52	$7.10	27.9%
Distribution	kWh	1,000	$0.0128	$12.80	1,000	$0.0160	$16.00	$3.20	25.0%
Sub-Total (Distribution)				**$38.22**			**$48.52**	**$10.30**	**26.9%**
Deferral/Variance	kWh	1,000			1,000	($0.0011)	($1.10)	($1.10)	
Electricity (Commodity)	kWh	1,045	RPP-Non-res.	$54.88	1,036	RPP-Non-res.	$54.35	($0.53)	(1.0%)
Transmission - Network	kWh	1,045	$0.0043	$4.49	1,036	$0.0043	$4.45	($0.04)	(0.9%)
Transmission - Connection	kWh	1,045	$0.0043	$4.49	1,036	$0.0043	$4.45	($0.04)	(0.9%)
Wholesale Market Service	kWh	1,045	$0.0052	$5.43	1,036	$0.0052	$5.39	($0.04)	(0.7%)
Rural Rate Protection	kWh	1,045	$0.0010	$1.04	1,036	$0.0010	$1.04		
Debt Retirement Charge	kWh	1,000	$0.0070	$7.00	1,000	$0.0070	$7.00		
TOTAL BILL				**$115.55**			**$124.10**	**$8.55**	**7.4%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

General Service <50 kW **RPP: Non-res.**

2,000 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	Volume	Rate	Charge	Volume	Rate	Charge	$	%
Monthly Service Charge				$25.42			$32.52	$7.10	27.9%
Distribution	kWh	2,000	$0.0128	$25.60	2,000	$0.0160	$32.00	$6.40	25.0%
Sub-Total (Distribution)				**$51.02**			**$64.52**	**$13.50**	**26.5%**
Deferral/Variance	kWh	2,000			2,000	($0.0011)	($2.20)	($2.20)	
Electricity (Commodity)	kWh	2,089	RPP-Non-res.	$116.51	2,071	RPP-Non-res.	$115.45	($1.06)	(0.9%)
Transmission - Network	kWh	2,089	$0.0043	$8.98	2,071	$0.0043	$8.91	($0.07)	(0.8%)
Transmission - Connection	kWh	2,089	$0.0043	$8.98	2,071	$0.0043	$8.91	($0.07)	(0.8%)
Wholesale Market Service	kWh	2,089	$0.0052	$10.86	2,071	$0.0052	$10.77	($0.09)	(0.8%)
Rural Rate Protection	kWh	2,089	$0.0010	$2.09	2,071	$0.0010	$2.07	($0.02)	(1.0%)
Debt Retirement Charge	kWh	2,000	$0.0070	$14.00	2,000	$0.0070	$14.00		
TOTAL BILL				**$212.44**			**$222.43**	**$9.99**	**4.7%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

General Service <50 kW **RPP: Non-res.**

5,000 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	Volume	Rate	Charge	Volume	Rate	Charge	$	%
Monthly Service Charge				$25.42			$32.52	$7.10	27.9%
Distribution	kWh	5,000	$0.0128	$64.00	5,000	$0.0160	$80.00	$16.00	25.0%
Sub-Total (Distribution)				**$89.42**			**$112.52**	**$23.10**	**25.8%**
Deferral/Variance	kWh	5,000			5,000	($0.0011)	($5.50)	($5.50)	
Electricity (Commodity)	kWh	5,223	RPP-Non-res.	$301.41	5,178	RPP-Non-res.	$298.75	($2.66)	(0.9%)
Transmission - Network	kWh	5,223	$0.0043	$22.46	5,178	$0.0043	$22.27	($0.19)	(0.8%)
Transmission - Connection	kWh	5,223	$0.0043	$22.46	5,178	$0.0043	$22.27	($0.19)	(0.8%)
Wholesale Market Service	kWh	5,223	$0.0052	$27.16	5,178	$0.0052	$26.93	($0.23)	(0.8%)
Rural Rate Protection	kWh	5,223	$0.0010	$5.22	5,178	$0.0010	$5.18	($0.04)	(0.8%)
Debt Retirement Charge	kWh	5,000	$0.0070	$35.00	5,000	$0.0070	$35.00		
TOTAL BILL				**$503.13**			**$517.42**	**$14.29**	**2.8%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

General Service <50 kW **RPP: Non-res.**

10,000 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	Volume	Rate	Charge	Volume	Rate	Charge	$	%
Monthly Service Charge				$25.42			$32.52	$7.10	27.9%
Distribution	kWh	10,000	$0.0128	$128.00	10,000	$0.0160	$160.00	$32.00	25.0%
Sub-Total (Distribution)				**$153.42**			**$192.52**	**$39.10**	**25.5%**
Deferral/Variance	kWh	10,000			10,000	($0.0011)	($11.00)	($11.00)	
Electricity (Commodity)	kWh	10,446	RPP-Non-res.	$609.56	10,356	RPP-Non-res.	$604.25	($5.31)	(0.9%)
Transmission - Network	kWh	10,446	$0.0043	$44.92	10,356	$0.0043	$44.53	($0.39)	(0.9%)
Transmission - Connection	kWh	10,446	$0.0043	$44.92	10,356	$0.0043	$44.53	($0.39)	(0.9%)
Wholesale Market Service	kWh	10,446	$0.0052	$54.32	10,356	$0.0052	$53.85	($0.47)	(0.9%)
Rural Rate Protection	kWh	10,446	$0.0010	$10.45	10,356	$0.0010	$10.36	($0.09)	(0.9%)
Debt Retirement Charge	kWh	10,000	$0.0070	$70.00	10,000	$0.0070	$70.00		
TOTAL BILL				**$987.59**			**$1,009.04**	**$21.45**	**2.2%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

General Service <50 kW **RPP: Non-res.**

15,000 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	Volume	Rate	Charge	Volume	Rate	Charge	$	%
Monthly Service Charge				$25.42			$32.52	$7.10	27.9%
Distribution	kWh	15,000	$0.0128	$192.00	15,000	$0.0160	$240.00	$48.00	25.0%
Sub-Total (Distribution)				**$217.42**			**$272.52**	**$55.10**	**25.3%**
Deferral/Variance	kWh	15,000			15,000	($0.0011)	($16.50)	($16.50)	
Electricity (Commodity)	kWh	15,669	RPP-Non-res.	$917.72	15,534	RPP-Non-res.	$909.76	($7.96)	(0.9%)
Transmission - Network	kWh	15,669	$0.0043	$67.38	15,534	$0.0043	$66.80	($0.58)	(0.9%)
Transmission - Connection	kWh	15,669	$0.0043	$67.38	15,534	$0.0043	$66.80	($0.58)	(0.9%)
Wholesale Market Service	kWh	15,669	$0.0052	$81.48	15,534	$0.0052	$80.78	($0.70)	(0.9%)
Rural Rate Protection	kWh	15,669	$0.0010	$15.67	15,534	$0.0010	$15.53	($0.14)	(0.9%)
Debt Retirement Charge	kWh	15,000	$0.0070	$105.00	15,000	$0.0070	$105.00		
TOTAL BILL				**$1,472.05**			**$1,500.69**	**$28.64**	**1.9%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

General Service 50 to

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
52,000	135	Non-res.	$171.94	31.3%	$79.94	1.6%
165,000	355	n/a	$283.19	31.2%	$31.33	0.2%
430,000	860	n/a	$538.57	31.2%	($88.07)	(0.3%)

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

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General Service 50 to 999 kW **RPP: Non-res.**

52,000 kWh's
135 kW's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
Monthly Service Charge				$330.82			$434.49	$103.67	31.3%
Distribution	kW	135	$1.6241	$219.25	135	$2.1298	$287.52	$68.27	31.1%
Sub-Total (Distribution)				**$550.07**			**$722.01**	**$171.94**	**31.3%**
Deferral/Variance	kW	135			135	($0.4555)	($61.49)	($61.49)	
Electricity (Commodity)	kWh	54,319	RPP-Non-res.	$3,198.08	53,851	RPP-Non-res.	$3,170.47	($27.61)	(0.9%)
Transmission - Network	kW	135	$1.7399	$234.89	135	$1.7399	$234.89		
Transmission - Connection	kW	135	$1.6988	$229.34	135	$1.6988	$229.34		
Wholesale Market Service	kWh	54,319	$0.0052	$282.46	53,851	$0.0052	$280.03	($2.43)	(0.9%)
Rural Rate Protection	kWh	54,319	$0.0010	$54.32	53,851	$0.0010	$53.85	($0.47)	(0.9%)
Debt Retirement Charge	kWh	52,000	$0.0070	$364.00	52,000	$0.0070	$364.00		
TOTAL BILL				**$4,913.16**			**$4,993.10**	**$79.94**	**1.6%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

General Service 50 to 999 kW **RPP: n/a**

165,000 kWh's
355 kW's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT	CHANGE IMPACT %
Monthly Service Charge				$330.82			$434.49	$103.67	31.3%
Distribution	kW	355	$1.6241	$576.56	355	$2.1298	$756.08	$179.52	31.1%
Sub-Total (Distribution)				**$907.38**			**$1,190.57**	**$283.19**	**31.2%**
Deferral/Variance	kW	355			355	($0.4555)	($161.70)	($161.70)	
Electricity (Commodity)	kWh	172,359	$0.0545	$9,393.57	170,874	$0.0545	$9,312.63	($80.94)	(0.9%)
Transmission - Network	kW	355	$1.7399	$617.66	355	$1.7399	$617.66		
Transmission - Connection	kW	355	$1.6988	$603.07	355	$1.6988	$603.07		
Wholesale Market Service	kWh	172,359	$0.0052	$896.27	170,874	$0.0052	$888.54	($7.73)	(0.9%)
Rural Rate Protection	kWh	172,359	$0.0010	$172.36	170,874	$0.0010	$170.87	($1.49)	(0.9%)
Debt Retirement Charge	kWh	165,000	$0.0070	$1,155.00	165,000	$0.0070	$1,155.00		
TOTAL BILL				**$13,745.31**			**$13,776.64**	**$31.33**	**0.2%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

General Service 50 to 999 kW **RPP: n/a**

430,000 kWh's
860 kW's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT	CHANGE IMPACT %
Monthly Service Charge				$330.82			$434.49	$103.67	31.3%
Distribution	kW	860	$1.6241	$1,396.73	860	$2.1298	$1,831.63	$434.90	31.1%
Sub-Total (Distribution)				**$1,727.55**			**$2,266.12**	**$538.57**	**31.2%**
Deferral/Variance	kW	860			860	($0.4555)	($391.73)	($391.73)	
Electricity (Commodity)	kWh	449,178	$0.0545	$24,480.20	445,308	$0.0545	$24,269.29	($210.91)	(0.9%)
Transmission - Network	kW	860	$1.7399	$1,496.31	860	$1.7399	$1,496.31		
Transmission - Connection	kW	860	$1.6988	$1,460.97	860	$1.6988	$1,460.97		
Wholesale Market Service	kWh	449,178	$0.0052	$2,335.73	445,308	$0.0052	$2,315.60	($20.13)	(0.9%)
Rural Rate Protection	kWh	449,178	$0.0010	$449.18	445,308	$0.0010	$445.31	($3.87)	(0.9%)
Debt Retirement Charge	kWh	430,000	$0.0070	$3,010.00	430,000	$0.0070	$3,010.00		
TOTAL BILL				**$34,959.94**			**$34,871.87**	**($88.07)**	**(0.3%)**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

General Service 50 to 999 kW **RPP:**

kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge									
Distribution	kW		$1.6241			$2.1298			
Sub-Total (Distribution)									
Deferral/Variance	kW					($0.4555)			
Electricity (Commodity)	kWh		RPP-	--		RPP-	--	--	--
Transmission - Network	kW		$1.7399			$1.7399			
Transmission - Connection	kW		$1.6988			$1.6988			
Wholesale Market Service	kWh		$0.0052			$0.0052			
Rural Rate Protection	kWh		$0.0010			$0.0010			
Debt Retirement Charge	kWh		$0.0070			$0.0070			
TOTAL BILL				--			--	--	--

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

General Service 1,00

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
427,000	1,028	n/a	$639.24	13.7%	($226.13)	(0.6%)
1,700,000	3,532	n/a	$1,163.33	13.7%	($1,935.72)	(1.4%)
2,860,000	4,477	n/a	$1,361.12	13.7%	($2,948.03)	(1.3%)

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

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General Service 1,000 to 4,999 kW **RPP: n/a**

427,000 kWh's
1,028 kW's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
Monthly Service Charge				$3,084.55			$3,508.63	$424.08	13.7%
Distribution	kW	1,028	$1.5252	$1,567.91	1,028	$1.7345	$1,783.07	$215.16	13.7%
Sub-Total (Distribution)				**$4,652.46**			**$5,291.70**	**$639.24**	**13.7%**
Deferral/Variance	kW	1,028			1,028	($0.6174)	($634.69)	($634.69)	
Electricity (Commodity)	kWh	441,603	$0.0545	$24,067.39	437,803	$0.0545	$23,860.27	($207.12)	(0.9%)
Transmission - Network	kW	1,028	$1.8479	$1,899.64	1,028	$1.8479	$1,899.64		
Transmission - Connection	kW	1,028	$1.8623	$1,914.44	1,028	$1.8623	$1,914.44		
Wholesale Market Service	kWh	441,603	$0.0052	$2,296.34	437,803	$0.0052	$2,276.58	($19.76)	(0.9%)
Rural Rate Protection	kWh	441,603	$0.0010	$441.60	437,803	$0.0010	$437.80	($3.80)	(0.9%)
Debt Retirement Charge	kWh	427,000	$0.0070	$2,989.00	427,000	$0.0070	$2,989.00		
TOTAL BILL				**$38,260.87**			**$38,034.74**	**($226.13)**	**(0.6%)**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

General Service 1,000 to 4,999 kW **RPP: n/a**

1,700,000 kWh's
3,532 kW's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
Monthly Service Charge				$3,084.55			$3,508.63	$424.08	13.7%
Distribution	kW	3,532	$1.5252	$5,387.01	3,532	$1.7345	$6,126.25	$739.25	13.7%
Sub-Total (Distribution)				**$8,471.56**			**$9,634.88**	**$1,163.33**	**13.7%**
Deferral/Variance	kW	3,532			3,532	($0.6174)	($2,180.66)	($2,180.66)	
Electricity (Commodity)	kWh	1,758,140	$0.0545	$95,818.63	1,743,010	$0.0545	$94,994.05	($824.58)	(0.9%)
Transmission - Network	kW	3,532	$1.8479	$6,526.78	3,532	$1.8479	$6,526.78		
Transmission - Connection	kW	3,532	$1.8623	$6,577.64	3,532	$1.8623	$6,577.64		
Wholesale Market Service	kWh	1,758,140	$0.0052	$9,142.33	1,743,010	$0.0052	$9,063.65	($78.68)	(0.9%)
Rural Rate Protection	kWh	1,758,140	$0.0010	$1,758.14	1,743,010	$0.0010	$1,743.01	($15.13)	(0.9%)
Debt Retirement Charge	kWh	1,700,000	$0.0070	$11,900.00	1,700,000	$0.0070	$11,900.00		
TOTAL BILL				**$140,195.08**			**$138,259.35**	**($1,935.72)**	**(1.4%)**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

General Service 1,000 to 4,999 kW **RPP: n/a**

2,860,000 kWh's
4,477 kW's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
Monthly Service Charge				$3,084.55			$3,508.63	$424.08	13.7%
Distribution	kW	4,477	$1.5252	$6,828.32	4,477	$1.7345	$7,765.36	$937.04	13.7%
Sub-Total (Distribution)				**$9,912.87**			**$11,273.99**	**$1,361.12**	**13.7%**
Deferral/Variance	kW	4,477			4,477	($0.6174)	($2,764.10)	($2,764.10)	
Electricity (Commodity)	kWh	2,957,812	$0.0545	$161,200.75	2,932,358	$0.0545	$159,813.51	($1,387.24)	(0.9%)
Transmission - Network	kW	4,477	$1.8479	$8,273.05	4,477	$1.8479	$8,273.05		
Transmission - Connection	kW	4,477	$1.8623	$8,337.52	4,477	$1.8623	$8,337.52		
Wholesale Market Service	kWh	2,957,812	$0.0052	$15,380.62	2,932,358	$0.0052	$15,248.26	($132.36)	(0.9%)
Rural Rate Protection	kWh	2,957,812	$0.0010	$2,957.81	2,932,358	$0.0010	$2,932.36	($25.45)	(0.9%)
Debt Retirement Charge	kWh	2,860,000	$0.0070	$20,020.00	2,860,000	$0.0070	$20,020.00		
TOTAL BILL				**$226,082.62**			**$223,134.59**	**($2,948.03)**	**(1.3%)**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

Large

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
7,256,000	10,389	n/a	$12,832.36	42.9%	$3,577.84	0.6%
11,709,000	17,801	n/a	$16,468.69	42.9%	$611.56	0.1%
4,446,000	6,900	n/a	$11,120.66	42.9%	$4,974.14	1.4%
3,465,000	6,000	n/a	$10,679.12	42.9%	$5,334.32	1.9%

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

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Large **RPP: n/a**

7,256,000 kWh's
10,389 kW's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
Monthly Service Charge				$18,021.42			$25,756.94	$7,735.52	42.9%
Distribution	kW	10,389	$1.1431	$11,875.67	10,389	$1.6337	$16,972.51	$5,096.84	42.9%
Sub-Total (Distribution)				**$29,897.09**			**$42,729.45**	**$12,832.36**	**42.9%**
Deferral/Variance	kW	10,389			10,389	($0.8908)	($9,254.52)	($9,254.52)	
Electricity (Commodity)	kWh	7,288,652	$0.0545	$397,231.53	7,288,652	$0.0545	$397,231.53		
Transmission - Network	kW	10,389	$2.0461	$21,256.93	10,389	$2.0461	$21,256.93		
Transmission - Connection	kW	10,389	$2.1296	$22,124.41	10,389	$2.1296	$22,124.41		
Wholesale Market Service	kWh	7,288,652	$0.0052	$37,900.99	7,288,652	$0.0052	$37,900.99		
Rural Rate Protection	kWh	7,288,652	$0.0010	$7,288.65	7,288,652	$0.0010	$7,288.65		
Debt Retirement Charge	kWh	7,256,000	$0.0070	$50,792.00	7,256,000	$0.0070	$50,792.00		
TOTAL BILL				**$566,491.60**			**$570,069.44**	**$3,577.84**	**0.6%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

Large **RPP: n/a**

11,709,000 kWh's
17,801 kW's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
Monthly Service Charge				$18,021.42			$25,756.94	$7,735.52	42.9%
Distribution	kW	17,801	$1.1431	$20,348.32	17,801	$1.6337	$29,081.49	$8,733.17	42.9%
Sub-Total (Distribution)				**$38,369.74**			**$54,838.43**	**$16,468.69**	**42.9%**
Deferral/Variance	kW	17,801			17,801	($0.8908)	($15,857.13)	($15,857.13)	
Electricity (Commodity)	kWh	11,761,691	$0.0545	$641,012.13	11,761,691	$0.0545	$641,012.13		
Transmission - Network	kW	17,801	$2.0461	$36,422.63	17,801	$2.0461	$36,422.63		
Transmission - Connection	kW	17,801	$2.1296	$37,909.01	17,801	$2.1296	$37,909.01		
Wholesale Market Service	kWh	11,761,691	$0.0052	$61,160.79	11,761,691	$0.0052	$61,160.79		
Rural Rate Protection	kWh	11,761,691	$0.0010	$11,761.69	11,761,691	$0.0010	$11,761.69		
Debt Retirement Charge	kWh	11,709,000	$0.0070	$81,963.00	11,709,000	$0.0070	$81,963.00		
TOTAL BILL				**$908,598.99**			**$909,210.55**	**$611.56**	**0.1%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

Large **RPP: n/a**

4,446,000 kWh's
6,900 kW's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
Monthly Service Charge				$18,021.42			$25,756.94	$7,735.52	42.9%
Distribution	kW	6,900	$1.1431	$7,887.39	6,900	$1.6337	$11,272.53	$3,385.14	42.9%
Sub-Total (Distribution)				**$25,908.81**			**$37,029.47**	**$11,120.66**	**42.9%**
Deferral/Variance	kW	6,900			6,900	($0.8908)	($6,146.52)	($6,146.52)	
Electricity (Commodity)	kWh	4,466,007	$0.0545	$243,397.38	4,466,007	$0.0545	$243,397.38		
Transmission - Network	kW	6,900	$2.0461	$14,118.09	6,900	$2.0461	$14,118.09		
Transmission - Connection	kW	6,900	$2.1296	$14,694.24	6,900	$2.1296	$14,694.24		
Wholesale Market Service	kWh	4,466,007	$0.0052	$23,223.24	4,466,007	$0.0052	$23,223.24		
Rural Rate Protection	kWh	4,466,007	$0.0010	$4,466.01	4,466,007	$0.0010	$4,466.01		
Debt Retirement Charge	kWh	4,446,000	$0.0070	$31,122.00	4,446,000	$0.0070	$31,122.00		
TOTAL BILL				**$356,929.77**			**$361,903.91**	**$4,974.14**	**1.4%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

Large **RPP: n/a**

3,465,000 kWh's
6,000 kW's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
Monthly Service Charge				$18,021.42			$25,756.94	$7,735.52	42.9%
Distribution	kW	6,000	$1.1431	$6,858.60	6,000	$1.6337	$9,802.20	$2,943.60	42.9%
Sub-Total (Distribution)				**$24,880.02**			**$35,559.14**	**$10,679.12**	**42.9%**
Deferral/Variance	kW	6,000			6,000	($0.8908)	($5,344.80)	($5,344.80)	
Electricity (Commodity)	kWh	3,480,593	$0.0545	$189,692.29	3,480,593	$0.0545	$189,692.29		
Transmission - Network	kW	6,000	$2.0461	$12,276.60	6,000	$2.0461	$12,276.60		
Transmission - Connection	kW	6,000	$2.1296	$12,777.60	6,000	$2.1296	$12,777.60		
Wholesale Market Service	kWh	3,480,593	$0.0052	$18,099.08	3,480,593	$0.0052	$18,099.08		
Rural Rate Protection	kWh	3,480,593	$0.0010	$3,480.59	3,480,593	$0.0010	$3,480.59		
Debt Retirement Charge	kWh	3,465,000	$0.0070	$24,255.00	3,465,000	$0.0070	$24,255.00		
TOTAL BILL				**$285,461.18**			**$290,795.50**	**$5,334.32**	**1.9%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

Unmetered Scattered

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
500		Non-res.	$14.79	77.9%	$14.09	25.0%
1,000		Non-res.	$19.79	78.0%	$18.34	17.9%
5,000		Non-res.	$59.79	78.1%	$52.48	10.7%
15,000		Non-res.	$159.79	78.1%	$137.83	9.4%
950,000		Non-res.	$9,509.79	78.1%	$8,118.81	8.8%

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

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Unmetered Scattered Load **RPP: Non-res.**

500 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				$12.58			$22.37	$9.79	77.8%
Distribution	kWh	500	$0.0128	$6.40	500	$0.0228	$11.40	$5.00	78.1%
Sub-Total (Distribution)				**$18.98**			**$33.77**	**$14.79**	**77.9%**
Deferral/Variance	kWh	500			500	($0.0008)	($0.40)	($0.40)	
Electricity (Commodity)	kWh	522	RPP-Non-res.	$26.12	518	RPP-Non-res.	$25.89	($0.23)	(0.9%)
Transmission - Network	kWh	522	$0.0043	$2.25	518	$0.0043	$2.23	($0.02)	(0.9%)
Transmission - Connection	kWh	522	$0.0043	$2.25	518	$0.0043	$2.23	($0.02)	(0.9%)
Wholesale Market Service	kWh	522	$0.0052	$2.72	518	$0.0052	$2.69	($0.03)	(1.1%)
Rural Rate Protection	kWh	522	$0.0010	$0.52	518	$0.0010	$0.52		
Debt Retirement Charge	kWh	500	$0.0070	$3.50	500	$0.0070	$3.50		
TOTAL BILL				**$56.34**			**$70.43**	**$14.09**	**25.0%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

Unmetered Scattered Load **RPP: Non-res.**

1,000 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				$12.58			$22.37	$9.79	77.8%
Distribution	kWh	1,000	$0.0128	$12.80	1,000	$0.0228	$22.80	$10.00	78.1%
Sub-Total (Distribution)				**$25.38**			**$45.17**	**$19.79**	**78.0%**
Deferral/Variance	kWh	1,000			1,000	($0.0008)	($0.80)	($0.80)	
Electricity (Commodity)	kWh	1,045	RPP-Non-res.	$54.88	1,036	RPP-Non-res.	$54.35	($0.53)	(1.0%)
Transmission - Network	kWh	1,045	$0.0043	$4.49	1,036	$0.0043	$4.45	($0.04)	(0.9%)
Transmission - Connection	kWh	1,045	$0.0043	$4.49	1,036	$0.0043	$4.45	($0.04)	(0.9%)
Wholesale Market Service	kWh	1,045	$0.0052	$5.43	1,036	$0.0052	$5.39	($0.04)	(0.7%)
Rural Rate Protection	kWh	1,045	$0.0010	$1.04	1,036	$0.0010	$1.04		
Debt Retirement Charge	kWh	1,000	$0.0070	$7.00	1,000	$0.0070	$7.00		
TOTAL BILL				**$102.71**			**$121.05**	**$18.34**	**17.9%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

Unmetered Scattered Load **RPP: Non-res.**

5,000 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				$12.58			$22.37	$9.79	77.8%
Distribution	kWh	5,000	$0.0128	$64.00	5,000	$0.0228	$114.00	$50.00	78.1%
Sub-Total (Distribution)				**$76.58**			**$136.37**	**$59.79**	**78.1%**
Deferral/Variance	kWh	5,000			5,000	($0.0008)	($4.00)	($4.00)	
Electricity (Commodity)	kWh	5,223	RPP-Non-res.	$301.41	5,178	RPP-Non-res.	$298.75	($2.66)	(0.9%)
Transmission - Network	kWh	5,223	$0.0043	$22.46	5,178	$0.0043	$22.27	($0.19)	(0.8%)
Transmission - Connection	kWh	5,223	$0.0043	$22.46	5,178	$0.0043	$22.27	($0.19)	(0.8%)
Wholesale Market Service	kWh	5,223	$0.0052	$27.16	5,178	$0.0052	$26.93	($0.23)	(0.8%)
Rural Rate Protection	kWh	5,223	$0.0010	$5.22	5,178	$0.0010	$5.18	($0.04)	(0.8%)
Debt Retirement Charge	kWh	5,000	$0.0070	$35.00	5,000	$0.0070	$35.00		
TOTAL BILL				**$490.29**			**$542.77**	**$52.48**	**10.7%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

Unmetered Scattered Load **RPP: Non-res.**

15,000 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				$12.58			$22.37	$9.79	77.8%
Distribution	kWh	15,000	$0.0128	$192.00	15,000	$0.0228	$342.00	$150.00	78.1%
Sub-Total (Distribution)				**$204.58**			**$364.37**	**$159.79**	**78.1%**
Deferral/Variance	kWh	15,000			15,000	($0.0008)	($12.00)	($12.00)	
Electricity (Commodity)	kWh	15,669	RPP-Non-res.	$917.72	15,534	RPP-Non-res.	$909.76	($7.96)	(0.9%)
Transmission - Network	kWh	15,669	$0.0043	$67.38	15,534	$0.0043	$66.80	($0.58)	(0.9%)
Transmission - Connection	kWh	15,669	$0.0043	$67.38	15,534	$0.0043	$66.80	($0.58)	(0.9%)
Wholesale Market Service	kWh	15,669	$0.0052	$81.48	15,534	$0.0052	$80.78	($0.70)	(0.9%)
Rural Rate Protection	kWh	15,669	$0.0010	$15.67	15,534	$0.0010	$15.53	($0.14)	(0.9%)
Debt Retirement Charge	kWh	15,000	$0.0070	$105.00	15,000	$0.0070	$105.00		
TOTAL BILL				**$1,459.21**			**$1,597.04**	**$137.83**	**9.4%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

Sentinel Lighting

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
176	0.46	Non-res.	$2.89	71.7%	$2.63	15.6%
318	0.45	Non-res.	$2.86	71.7%	$2.53	9.7%
63	0.21	Non-res.	$2.03	71.8%	$1.92	25.5%
48	0.13	Non-res.	$1.75	71.8%	$1.68	28.3%

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

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Sentinel Lighting **RPP: Non-res.**

176 kWh's
0 kW's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				$1.81			$3.11	$1.30	71.8%
Distribution	kW	0	$4.8230	$2.22	0	$8.2803	$3.81	$1.59	71.7%
Sub-Total (Distribution)				**$4.03**			**$6.92**	**$2.89**	**71.7%**
Deferral/Variance	kW	0			0	($0.3737)	($0.17)	($0.17)	
Electricity (Commodity)	kWh	184	RPP-Non-res.	$9.19	182	RPP-Non-res.	$9.11	($0.08)	(0.9%)
Transmission - Network	kW	0	$1.3188	$0.61	0	$1.3188	$0.61		
Transmission - Connection	kW	0	$1.3407	$0.62	0	$1.3407	$0.62		
Wholesale Market Service	kWh	184	$0.0052	$0.96	182	$0.0052	$0.95	($0.01)	(1.0%)
Rural Rate Protection	kWh	184	$0.0010	$0.18	182	$0.0010	$0.18		
Debt Retirement Charge	kWh	176	$0.0070	$1.23	176	$0.0070	$1.23		
TOTAL BILL				**$16.82**			**$19.45**	**$2.63**	**15.6%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

Sentinel Lighting **RPP: Non-res.**

318 kWh's
0 kW's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT	
									%
Monthly Service Charge				$1.81			$3.11	$1.30	71.8%
Distribution	kW	0	$4.8230	$2.17	0	$8.2803	$3.73	$1.56	71.7%
Sub-Total (Distribution)				**$3.98**			**$6.84**	**$2.86**	**71.7%**
Deferral/Variance	kW	0			0	($0.3737)	($0.17)	($0.17)	
Electricity (Commodity)	kWh	332	RPP-Non-res.	$16.61	329	RPP-Non-res.	$16.47	($0.14)	(0.8%)
Transmission - Network	kW	0	$1.3188	$0.59	0	$1.3188	$0.59		
Transmission - Connection	kW	0	$1.3407	$0.60	0	$1.3407	$0.60		
Wholesale Market Service	kWh	332	$0.0052	$1.73	329	$0.0052	$1.71	($0.02)	(1.2%)
Rural Rate Protection	kWh	332	$0.0010	$0.33	329	$0.0010	$0.33		
Debt Retirement Charge	kWh	318	$0.0070	$2.23	318	$0.0070	$2.23		
TOTAL BILL				**$26.07**			**$28.60**	**$2.53**	**9.7%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

Sentinel Lighting **RPP: Non-res.**

63 kWh's
0 kW's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT	%
Monthly Service Charge				$1.81			$3.11	$1.30	71.8%
Distribution	kW	0	$4.8230	$1.01	0	$8.2803	$1.74	$0.73	71.7%
Sub-Total (Distribution)				**$2.82**			**$4.85**	**$2.03**	**71.8%**
Deferral/Variance	kW	0			0	($0.3737)	($0.08)	($0.08)	
Electricity (Commodity)	kWh	66	RPP-Non-res.	$3.29	65	RPP-Non-res.	$3.26	($0.03)	(0.9%)
Transmission - Network	kW	0	$1.3188	$0.28	0	$1.3188	$0.28		
Transmission - Connection	kW	0	$1.3407	$0.28	0	$1.3407	$0.28		
Wholesale Market Service	kWh	66	$0.0052	$0.34	65	$0.0052	$0.34		
Rural Rate Protection	kWh	66	$0.0010	$0.07	65	$0.0010	$0.07		
Debt Retirement Charge	kWh	63	$0.0070	$0.44	63	$0.0070	$0.44		
TOTAL BILL				**$7.52**			**$9.44**	**$1.92**	**25.5%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

Sentinel Lighting **RPP: Non-res.**

48 kWh's
0 kW's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT	
									%
Monthly Service Charge				$1.81			$3.11	$1.30	71.8%
Distribution	kW	0	$4.8230	$0.63	0	$8.2803	$1.08	$0.45	71.7%
Sub-Total (Distribution)				**$2.44**			**$4.19**	**$1.75**	**71.8%**
Deferral/Variance	kW	0			0	($0.3737)	($0.05)	($0.05)	
Electricity (Commodity)	kWh	50	RPP-Non-res.	$2.51	50	RPP-Non-res.	$2.49	($0.02)	(0.8%)
Transmission - Network	kW	0	$1.3188	$0.17	0	$1.3188	$0.17		
Transmission - Connection	kW	0	$1.3407	$0.17	0	$1.3407	$0.17		
Wholesale Market Service	kWh	50	$0.0052	$0.26	50	$0.0052	$0.26		
Rural Rate Protection	kWh	50	$0.0010	$0.05	50	$0.0010	$0.05		
Debt Retirement Charge	kWh	48	$0.0070	$0.34	48	$0.0070	$0.34		
TOTAL BILL				**$5.94**			**$7.62**	**$1.68**	**28.3%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

Enter example volumes in kWh's (and kW's if applicable) for each customer class

Street Lighting

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
99	0.21	Non-res.	$1.56	72.2%	$1.44	15.6%
81	0.18	Non-res.	$1.48	72.2%	$1.38	17.5%
83	0.18	Non-res.	$1.48	72.2%	$1.38	17.2%
102	0.22	Non-res.	$1.58	72.2%	$1.46	15.5%
81	0.18	Non-res.	$1.48	72.2%	$1.38	17.5%
65	0.14	Non-res.	$1.37	72.2%	$1.30	19.9%
92	0.20	Non-res.	$1.53	72.2%	$1.41	16.2%

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

Enter example volumes in kWh's (and kW's if applicable) for each customer class

`

Street Lighting **RPP: Non-res.**

99 kWh's
0 kW's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT	CHANGE IMPACT %
Monthly Service Charge				$1.37			$2.36	$0.99	72.3%
Distribution	kW	0	$3.7378	$0.78	0	$6.4356	$1.35	$0.57	72.2%
Sub-Total (Distribution)				**$2.15**			**$3.71**	**$1.56**	**72.2%**
Deferral/Variance	kW	0			0	($0.3256)	($0.07)	($0.07)	
Electricity (Commodity)	kWh	103	RPP-Non-res.	$5.17	103	RPP-Non-res.	$5.13	($0.04)	(0.8%)
Transmission - Network	kW	0	$1.3122	$0.28	0	$1.3122	$0.28		
Transmission - Connection	kW	0	$1.3133	$0.28	0	$1.3133	$0.28		
Wholesale Market Service	kWh	103	$0.0052	$0.54	103	$0.0052	$0.53	($0.01)	(1.9%)
Rural Rate Protection	kWh	103	$0.0010	$0.10	103	$0.0010	$0.10		
Debt Retirement Charge	kWh	99	$0.0070	$0.69	99	$0.0070	$0.69		
TOTAL BILL				**$9.21**			**$10.65**	**$1.44**	**15.6%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

Enter example volumes in kWh's (and kW's if applicable) for each customer class

Street Lighting **RPP: Non-res.**

81 kWh's
0 kW's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT	
									%
Monthly Service Charge				$1.37			$2.36	$0.99	72.3%
Distribution	kW	0	$3.7378	$0.67	0	$6.4356	$1.16	$0.49	72.2%
Sub-Total (Distribution)				**$2.04**			**$3.52**	**$1.48**	**72.2%**
Deferral/Variance	kW	0			0	($0.3256)	($0.06)	($0.06)	
Electricity (Commodity)	kWh	85	RPP-Non-res.	$4.23	84	RPP-Non-res.	$4.19	($0.04)	(0.9%)
Transmission - Network	kW	0	$1.3122	$0.24	0	$1.3122	$0.24		
Transmission - Connection	kW	0	$1.3133	$0.24	0	$1.3133	$0.24		
Wholesale Market Service	kWh	85	$0.0052	$0.44	84	$0.0052	$0.44		
Rural Rate Protection	kWh	85	$0.0010	$0.08	84	$0.0010	$0.08		
Debt Retirement Charge	kWh	81	$0.0070	$0.57	81	$0.0070	$0.57		
TOTAL BILL				**$7.84**			**$9.22**	**$1.38**	**17.5%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

Enter example volumes in kWh's (and kW's if applicable) for each customer class

Street Lighting **RPP: Non-res.**

83 kWh's
0 kW's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT	CHANGE IMPACT %
Monthly Service Charge				$1.37			$2.36	$0.99	72.3%
Distribution	kW	0	$3.7378	$0.67	0	$6.4356	$1.16	$0.49	72.2%
Sub-Total (Distribution)				**$2.04**			**$3.52**	**$1.48**	**72.2%**
Deferral/Variance	kW	0			0	($0.3256)	($0.06)	($0.06)	
Electricity (Commodity)	kWh	87	RPP-Non-res.	$4.34	86	RPP-Non-res.	$4.30	($0.04)	(0.9%)
Transmission - Network	kW	0	$1.3122	$0.24	0	$1.3122	$0.24		
Transmission - Connection	kW	0	$1.3133	$0.24	0	$1.3133	$0.24		
Wholesale Market Service	kWh	87	$0.0052	$0.45	86	$0.0052	$0.45		
Rural Rate Protection	kWh	87	$0.0010	$0.09	86	$0.0010	$0.09		
Debt Retirement Charge	kWh	83	$0.0070	$0.58	83	$0.0070	$0.58		
TOTAL BILL				**$7.98**			**$9.36**	**$1.38**	**17.2%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

Enter example volumes in kWh's (and kW's if applicable) for each customer class

Street Lighting **RPP: Non-res.**

102 kWh's
0 kW's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT	
									%
Monthly Service Charge				$1.37			$2.36	$0.99	72.3%
Distribution	kW	0	$3.7378	$0.82	0	$6.4356	$1.42	$0.59	72.2%
Sub-Total (Distribution)				**$2.19**			**$3.78**	**$1.58**	**72.2%**
Deferral/Variance	kW	0			0	($0.3256)	($0.07)	($0.07)	
Electricity (Commodity)	kWh	107	RPP-Non-res.	$5.33	106	RPP-Non-res.	$5.28	($0.05)	(0.9%)
Transmission - Network	kW	0	$1.3122	$0.29	0	$1.3122	$0.29		
Transmission - Connection	kW	0	$1.3133	$0.29	0	$1.3133	$0.29		
Wholesale Market Service	kWh	107	$0.0052	$0.55	106	$0.0052	$0.55		
Rural Rate Protection	kWh	107	$0.0010	$0.11	106	$0.0010	$0.11		
Debt Retirement Charge	kWh	102	$0.0070	$0.71	102	$0.0070	$0.71		
TOTAL BILL				**$9.47**			**$10.94**	**$1.46**	**15.5%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

Enter example volumes in kWh's (and kW's if applicable) for each customer class

Street Lighting **RPP: Non-res.**

81 kWh's
0 kW's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT	
									%
Monthly Service Charge				$1.37			$2.36	$0.99	72.3%
Distribution	kW	0	$3.7378	$0.67	0	$6.4356	$1.16	$0.49	72.2%
Sub-Total (Distribution)				**$2.04**			**$3.52**	**$1.48**	**72.2%**
Deferral/Variance	kW	0			0	($0.3256)	($0.06)	($0.06)	
Electricity (Commodity)	kWh	85	RPP-Non-res.	$4.23	84	RPP-Non-res.	$4.19	($0.04)	(0.9%)
Transmission - Network	kW	0	$1.3122	$0.24	0	$1.3122	$0.24		
Transmission - Connection	kW	0	$1.3133	$0.24	0	$1.3133	$0.24		
Wholesale Market Service	kWh	85	$0.0052	$0.44	84	$0.0052	$0.44		
Rural Rate Protection	kWh	85	$0.0010	$0.08	84	$0.0010	$0.08		
Debt Retirement Charge	kWh	81	$0.0070	$0.57	81	$0.0070	$0.57		
TOTAL BILL				**$7.84**			**$9.22**	**$1.38**	**17.5%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

Enter example volumes in kWh's (and kW's if applicable) for each customer class

Street Lighting **RPP: Non-res.**

65 kWh's
0 kW's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT	
									%
Monthly Service Charge				$1.37			$2.36	$0.99	72.3%
Distribution	kW	0	$3.7378	$0.52	0	$6.4356	$0.90	$0.38	72.2%
Sub-Total (Distribution)				**$1.89**			**$3.26**	**$1.37**	**72.2%**
Deferral/Variance	kW	0			0	($0.3256)	($0.05)	($0.05)	
Electricity (Commodity)	kWh	68	RPP-Non-res.	$3.39	67	RPP-Non-res.	$3.37	($0.02)	(0.6%)
Transmission - Network	kW	0	$1.3122	$0.18	0	$1.3122	$0.18		
Transmission - Connection	kW	0	$1.3133	$0.18	0	$1.3133	$0.18		
Wholesale Market Service	kWh	68	$0.0052	$0.35	67	$0.0052	$0.35		
Rural Rate Protection	kWh	68	$0.0010	$0.07	67	$0.0010	$0.07		
Debt Retirement Charge	kWh	65	$0.0070	$0.46	65	$0.0070	$0.46		
TOTAL BILL				**$6.52**			**$7.82**	**$1.30**	**19.9%**

Bluewater Power Distribution Corporation (EB-2002-0517)

2009 EDR Application (ED-2008-0221)

F8 Customer Bill Impact Analysis

##

Enter example volumes in kWh's (and kW's if applicable) for each customer class

Street Lighting **RPP: Non-res.**

92 kWh's
0 kW's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				$1.37			$2.36	$0.99	72.3%
Distribution	kW	0	$3.7378	$0.75	0	$6.4356	$1.29	$0.54	72.2%
Sub-Total (Distribution)				**$2.12**			**$3.65**	**$1.53**	**72.2%**
Deferral/Variance	kW	0			0	($0.3256)	($0.07)	($0.07)	
Electricity (Commodity)	kWh	96	RPP-Non-res.	$4.81	95	RPP-Non-res.	$4.76	($0.05)	(1.0%)
Transmission - Network	kW	0	$1.3122	$0.26	0	$1.3122	$0.26		
Transmission - Connection	kW	0	$1.3133	$0.26	0	$1.3133	$0.26		
Wholesale Market Service	kWh	96	$0.0052	$0.50	95	$0.0052	$0.50		
Rural Rate Protection	kWh	96	$0.0010	$0.10	95	$0.0010	$0.10		
Debt Retirement Charge	kWh	92	$0.0070	$0.64	92	$0.0070	$0.64		
TOTAL BILL				**$8.69**			**$10.10**	**$1.41**	**16.2%**

Rate Impacts for Residential and General Service < 50 kW with Sub-total for 'Delivery' Line Items

RPP: Summer

Residential			2008 BILL			2009 BILL			CHANGE IMPACT	
1,000 kWh's	Metric	Volume	Rate	Charge	Volume	Rate	Charge	$	%
Monthly Service Charge				$13.90			$ 18.50	$4.60	33.1%
Distribution	kWh	1,000	$0.0117	$11.70	1,000	$ 0.0150	$ 15.00	$3.30	28.2%
Deferral/Variance Dispositions	kWh	1,000			1,000	($0.0009)	($0.90)	($0.90)	
Electricity (Commodity)	kWh	1,045	RPP-Summer	$56.23	1,036	RPP-Summer	$55.70	($0.53)	(0.9%)
Transmission - Network	kWh	1,045	$0.0047	$4.91	1,036	$0.0047	$4.87	($0.04)	(0.8%)
Transmission - Connection	kWh	1,045	$0.0048	$5.01	1,036	$0.0048	$4.97	($0.04)	(0.8%)
Wholesale Market Service	kWh	1,045	$0.0052	$5.43	1,036	$0.0052	$5.39	($0.04)	(0.7%)
Rural Rate Protection	kWh	1,045	$0.0010	$1.04	1,036	$0.0010	$1.04		
Debt Retirement Charge	kWh	1,000	$0.0070	$7.00	1,000	$0.0070	$7.00		
Sub-Total (Delivery)				$35.52			$42.44	$6.92	19.5%
TOTAL BILL				**$105.22**			**$111.57**	**$6.35**	**6.0%**

RPP: Winter

Residential			2008 BILL			2009 BILL			CHANGE IMPACT	
1,000 kWh's	Metric	Volume	Rate	Charge	Volume	Rate	Charge	$	%
Monthly Service Charge				$13.90		$ -	$ 18.50	$4.60	33.1%
Distribution	kWh	1,000	$0.0117	$11.70	1,000	$ 0.0150	$ 15.00	$3.30	28.2%
Deferral/Variance Dispositions	kWh	1,000			1,000	($0.0009)	($0.90)	($0.90)	
Electricity (Commodity)	kWh	1,045	RPP-Winter	$52.63	1,036	RPP-Winter	$52.10	($0.53)	(1.0%)
Transmission - Network	kWh	1,045	$0.0047	$4.91	1,036	$0.0047	$4.87	($0.04)	(0.8%)
Transmission - Connection	kWh	1,045	$0.0048	$5.01	1,036	$0.0048	$4.97	($0.04)	(0.8%)
Wholesale Market Service	kWh	1,045	$0.0052	$5.43	1,036	$0.0052	$5.39	($0.04)	(0.7%)
Rural Rate Protection	kWh	1,045	$0.0010	$1.04	1,036	$0.0010	$1.04		
Debt Retirement Charge	kWh	1,000	$0.0070	$7.00	1,000	$0.0070	$7.00		
Sub-Total (Delivery)				$35.52			$42.44	$6.92	19.5%
TOTAL BILL				**$101.62**			**$107.97**	**$6.35**	**6.2%**

RPP: Non-res.

General Service <50 kW		**2008 BILL**			**2009 BILL**			**CHANGE IMPACT**	
2,000 kWh's	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$25.42		$ -	$ 32.52	$7.10	27.9%
Distribution	kWh	2,000	$0.0128	$25.60	2,000	$ 0.0160	$ 32.00	$6.40	25.0%
Deferral/Variance Dispositions	kWh	2,000			2,000	($0.0011)	($2.20)	($2.20)	
Electricity (Commodity)	kWh	2,089	RPP-Non-res.	$116.51	2,071	RPP-Non-res.	$115.45	($1.06)	(0.9%)
Transmission - Network	kWh	2,089	$0.0043	$8.98	2,071	$0.0043	$8.91	($0.07)	(0.8%)
Transmission - Connection	kWh	2,089	$0.0043	$8.98	2,071	$0.0043	$8.91	($0.07)	(0.8%)
Wholesale Market Service	kWh	2,089	$0.0052	$10.86	2,071	$0.0052	$10.77	($0.09)	(0.8%)
Rural Rate Protection	kWh	2,089	$0.0010	$2.09	2,071	$0.0010	$2.07	($0.02)	(1.0%)
Debt Retirement Charge	kWh	2,000	$0.0070	$14.00	2,000	$0.0070	$14.00		
Sub-Total (Delivery)				$68.98			$80.14	$11.16	16.2%
TOTAL BILL				**$212.44**			**$222.43**	**$9.99**	**4.7%**