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

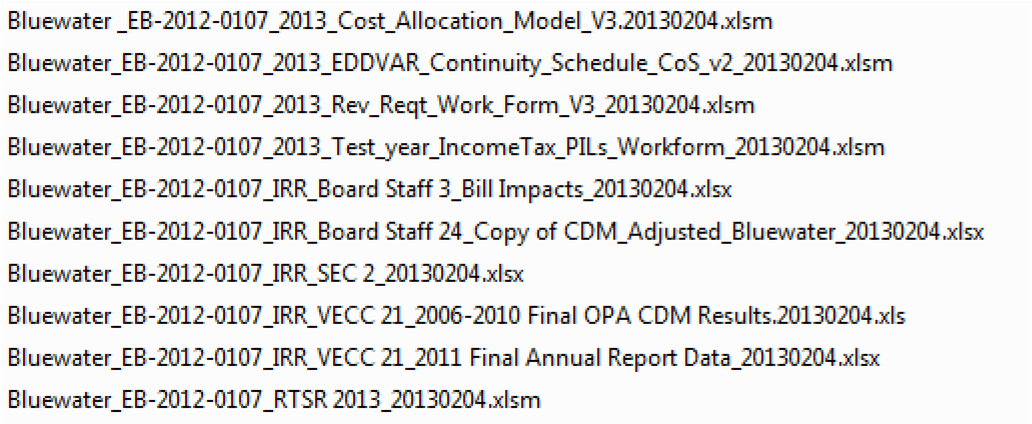
February 4, 2013

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

Re: Reply to Interrogatories EB-2012-0107

Dear Ms. Walli:

Bluewater Power Distribution Corporation hereby files its responses to interrogatories filed by the following parties: Board Staff, Energy Probe, VECC, School Energy Coalition, AMPCO. The following electronic versions of models and supporting files have been loaded to the Board's e-filing Services:



Bluewater _EB-2012-0107_2013_Cost_Allocation_Model_V3.20130204.xlsm
Bluewater_EB-2012-0107_2013_EDDVAR_Continuity_Schedule_CoS_v2_20130204.xlsm
Bluewater_EB-2012-0107_2013_Rev_Reqt_Work_Form_V3_20130204.xlsm
Bluewater_EB-2012-0107_2013_Test_year_IncomeTax_PILs_Workform_20130204.xlsm
Bluewater_EB-2012-0107_IRR_Board Staff 3_Bill Impacts_20130204.xlsx
Bluewater_EB-2012-0107_IRR_Board Staff 24_Copy of CDM_Adjusted_Bluewater_20130204.xlsx
Bluewater_EB-2012-0107_IRR_SEC 2_20130204.xlsx
Bluewater_EB-2012-0107_IRR_VECC 21_2006-2010 Final OPA CDM Results.20130204.xls
Bluewater_EB-2012-0107_IRR_VECC 21_2011 Final Annual Report Data_20130204.xlsx
Bluewater_EB-2012-0107_RTSR 2013_20130204.xlsm

This document is being filed pursuant to the Board's filing guidelines and through e-Filing Services.

Yours Truly,

L. Dugas

Leslie Dugas
Manager of Regulatory Affairs
Bluewater Power Distribution Corporation
Email: ldugas@bluewaterpower.com
Phone: 519-337-8201 Ext 2255

Bluewater Power Distribution Corporation

2013 COS Application

Response to Interrogatories

EB-2012-0107

Rates Effective: May 1, 2013

Date Filed: February 4, 2013

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

BLUEWATER
POWER
DISTRIBUTION CORPORATION

File Number: EB-2012-0107

Date Filed: February 4, 2013

BLUEWATER POWER DISTRIBUTION CORPORATION

Tab 1 of 11

Administration

Table of Contents

Title	Reference

Title **Reference**

File Number: EB-2012-0107

Date Filed: February 4, 2013

Tab 2 of 11

General Interrogatories

1.0-Staff-1 – Responses to Letters of Comment

Following publication of the Notice of Application, the Board received one letter of comment. Please confirm whether a reply was sent from the applicant to the author of the letter. If confirmed, please file that reply with the Board. Please ensure that the author's contact information except for the name is redacted. If not confirmed, please explain why a response was not sent and confirm if the applicant intends to respond.

The letter of comment speaks to issues that we interpreted as being beyond the control of the utility and, accordingly, we have not responded to the author directly. It was our interpretation of the letter of comment that the rate increases referred to were primarily increases in the commodity itself since the author states "I am not opposed to the rate increase of BWPower but wanted to make a few comments". The letter of comment continues to make reference to the debt of the former Ontario Hydro, and that is another matter beyond the control of management with Bluewater Power.

1.0-Staff-2 – Updated RRWF

Upon completing responses to all interrogatories from Board staff and intervenors, please provide an updated RRWF with any corrections or adjustments that the applicant wishes to make to the amounts in the previous version of the RRWF included in the middle column. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note.

Attachment 1 is the Revenue Requirement Workform (“RRWF”), which has been updated for all adjustments and corrections acknowledged by Bluewater Power through this Interrogatory process as requiring updating.

Attachment 2 to this Interrogatory response includes a table listing all such adjustments and corrections made as a result of these interrogatories.

We note that many of the interrogatories requested updates to reflect 2012 Actual data; although we have made best efforts to include updates for 2012, the values will not be final until reviewed by outside auditors. Accordingly, although the information has been provided in draft form in order to be responsive to interrogatories, the application has not been updated to reflect 2012 Actuals.

The adjustments and corrections noted above resulted in the following update to the revenue requirement in Table 1, and the revised rates in Table 2.

Table 1 – Updated Revenue Requirement

	2013 - Test Year Updated for IR Responses	2013 - Original Application
OM&A Expenses	13,449,974	13,302,742
Amortization Expense	5,151,966	5,011,623
Total Distribution Expenses	**18,601,940**	**18,314,365**
Regulated Return On Capital	4,065,294	4,056,060
PILs (with gross-up)	484,823	586,513
Service Revenue Requirement	**23,152,058**	**22,956,938**
Less: Revenue Offsets	1,070,249	1,080,249
Base Revenue Requirement	**22,081,809**	**21,876,689**
Add: Transformer ownership allowance	501,229	501,229
Add: Low Voltage		0
Total Gross Revenue Requirement	**22,583,038**	**22,377,918**

Table 2 – Updated Fixed and Variable Rates

Customer Class Name	Updated Fixed Rate	Original Application Fixed Rate	Updated Variable Rate	Original Application Variable Rate	Unit of Measure
Residential	$16.54	$16.39	$0.0225	$0.0223	kWh
General Service < 50 kW	$28.42	$28.16	$0.0199	$0.0197	kWh
General Service > 50 to 999 kW	$142.00	$142.00	$4.4827	$4.4311	kW
General Service 1000 to 4999 kW	$3,121.63	$3,121.63	$1.8557	$1.8052	kW
Large Use	$24,427.60	$24,427.60	$2.0552	$2.0412	kW
Unmetered Scattered Load	$13.48	$13.45	$0.0366	$0.0365	kWh
Sentinel Lighting	$4.11	$4.07	$27.1276	$26.8757	kW
Street Lighting	$2.57	$2.54	$19.8408	$19.6565	kW

Revenue Requirement Workform

Version 3.00

Utility Name	Bluewater Power Distribution Corp.
Service Territory	
Assigned EB Number	EB-2012-0107
Name and Title	Leslie Dugas, Manager of Regulatory Affairs
Phone Number	519-337-8201 Ext 2255
Email Address	ldugas@bluewaterpower.com

Revenue Requirement Workform

Notes:

(1) Pale green cells represent inputs
(2) Pale green boxes at the bottom of each page are for additional notes
(3) Pale yellow cells represent drop-down lists
(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Revenue Requirement Workform

Data Input (1)

		Initial Application	(2)	Adjustments		Interrogatory Responses	(6)	Adjustments		Per Board Decision	
1	**Rate Base**										
	Gross Fixed Assets (average)	$60,605,808	13	$ -		$ 60,605,808				$60,605,808	
	Accumulated Depreciation (average)	($7,153,078)	(5)	($79,454)		($7,232,532)	A			($7,232,532)	
	Allowance for Working Capital:										
	Controllable Expenses	$13,302,742		$147,232		$ 13,449,974	B			$13,449,974	
	Cost of Power	$89,374,845		($1,104,556)		$ 88,270,289	C			$88,270,289	
	Working Capital Rate (%)	13.00%	(9)			13.00%	(9)			13.00%	(9)
2	**Utility Income**										
	Operating Revenues:										
	Distribution Revenue at Current Rates	$18,420,657		$0		$18,420,657					
	Distribution Revenue at Proposed Rates	$21,876,690		$205,119		$22,081,809					
	Other Revenue:										
	Specific Service Charges	$571,199		$0		$571,199					
	Late Payment Charges	$232,694		$0		$232,694					
	Other Distribution Revenue	$180,257		$0		$180,257					
	Other Income and Deductions	$96,099		($10,000)		$86,099	D				
	Total Revenue Offsets	$1,080,249	(7)	($10,000)		$1,070,249					
	Operating Expenses:										
	OM+A Expenses	$13,078,828		$98,732	B	$ 13,177,560				$13,177,560	
	Depreciation/Amortization	$5,011,623	(10)	$140,343	A	$ 5,151,966				$5,151,966	
	Property taxes	$223,914		$48,500	B	$ 272,414				$272,414	
	Other expenses										
3	**Taxes/PILs**										
	Taxable Income:										
	Adjustments required to arrive at taxable income	($892,023)	(3)			($966,781)					
	Utility Income Taxes and Rates:										
	Income taxes (not grossed up)	$444,375	(12)			$368,312					
	Income taxes (grossed up)	$586,513				$485,305					
	Federal tax (%)	15.00%				15.00%					
	Provincial tax (%)	9.23%				9.11%					
	Income Tax Credits	$69,984	(14)			$125,231					
4	**Capitalization/Cost of Capital**										
	Capital Structure:										
	Long-term debt Capitalization Ratio (%)	56.0%				56.0%					
	Short-term debt Capitalization Ratio (%)	4.0%	(8)			4.0%	(8)				(8)
	Common Equity Capitalization Ratio (%)	40.0%				40.0%					
	Prefered Shares Capitalization Ratio (%)										
		100.0%				100.0%					
	Cost of Capital										
	Long-term debt Cost Rate (%)	4.18%				4.24%					
	Short-term debt Cost Rate (%)	2.08%				2.08%					
	Common Equity Cost Rate (%)	9.12%				9.12%					
	Prefered Shares Cost Rate (%)										
	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS ($)		(11)				(11)				(11)

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

(10) Depreciation Expense should include the adjustment resulting from the amortization of the deferred PP&E balance as shown on Appendix 2-EA or Appendix 2-EB of the Chapter 2 Appendices to the Filing Requirements.

(11) Adjustment should include the adjustment to the return on rate base associated with deferred PP&E balance as shown on Appendix 2-EA or Appendix 2-EB of the Chapter 2 Appendices to the Filing Requirements.

(12) See Exhibit 4, Tab 8, Schedule 1 for full explanation. The Income taxes (grossed up) value of $586,517 includes a one-time adjustment of $92,369.

(13) Increased gross fixed assets by the IFRS adjustment of $364,881

(11) Note: An adjustment to gross fixed assets of $364,881 was made in order to accommodate the IFRS rate base adjustment. The effect on regulated return on capital is is $22,153. The amount of $22,153 was not included in cell E67 because the adjustment was made to the gross fixed assets instead as this was determined to lead to a more accurate representation of the effect on deemed interest expense and deemed return on equty.

(14) This is not actually an income credit, but rather had to use this cell to adjust for the one-time PILs adjustment of $92,369 (grossed-up)

Reference from Sheet 3.Data_Input_Sheet	Item Reference from Attachment 2 (List of Adjustments)
A	7,8
B	5,6
C	1,2,3
D	4

Revenue Requirement Workform

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$60,605,808	$ -	$60,605,808	$ -	$60,605,808
2	Accumulated Depreciation (average)	(3)	($7,153,078)	($79,454)	($7,232,532)	$ -	($7,232,532)
3	Net Fixed Assets (average)	(3)	$53,452,730	($79,454)	$53,373,276	$ -	$53,373,276
4	Allowance for Working Capital	(1)	$13,348,086	($124,452)	$13,223,634	$ -	$13,223,634
5	**Total Rate Base**		$66,800,816	($203,906)	$66,596,910	$ -	$66,596,910

Allowance for Working Capital - Derivation

(1)

6	Controllable Expenses		$13,302,742	$147,232	$13,449,974	$ -	$13,449,974
7	Cost of Power		$89,374,845	($1,104,556)	$88,270,289	$ -	$88,270,289
8	Working Capital Base		$102,677,587	($957,324)	$101,720,263	$ -	$101,720,263
9	Working Capital Rate %	(2)	13.00%	0.00%	13.00%	0.00%	13.00%
10	Working Capital Allowance		$13,348,086	($124,452)	$13,223,634	$ -	$13,223,634

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. Default rate for 2013 cost of service applications is 13%.

(3) Average of opening and closing balances for the year.

Revenue Requirement Workform

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$21,876,690	$205,119	$22,081,809	$ -	$22,081,809
2	Other Revenue	(1)	$1,080,249	($10,000)	$1,070,249	$ -	$1,070,249
3	Total Operating Revenues		$22,956,939	$195,119	$23,152,058	$ -	$23,152,058
	Operating Expenses:						
4	OM+A Expenses		$13,078,828	$98,732	$13,177,560	$ -	$13,177,560
5	Depreciation/Amortization		$5,011,623	$140,343	$5,151,966	$ -	$5,151,966
6	Property taxes		$223,914	$48,500	$272,414	$ -	$272,414
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$18,314,365	$287,575	$18,601,940	$ -	$18,601,940
10	Deemed Interest Expense		$1,619,166	$16,672	$1,635,839	($21,615)	$1,614,224
11	Total Expenses (lines 9 to 10)		$19,933,531	$304,248	$20,237,779	($21,615)	$20,216,164
12	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS		$ -	$ -	$ -	$ -	$ -
13	**Utility income before income taxes**		$3,023,408	($109,128)	$2,914,279	$21,615	$2,935,894
14	Income taxes (grossed-up)		$586,513	($101,208)	$485,305	$ -	$485,305
15	**Utility net income**		$2,436,895	($7,920)	$2,428,974	$21,615	$2,450,589

Notes

Other Revenues / Revenue Offsets

		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
(1)	Specific Service Charges	$571,199	$ -	$571,199		$571,199
	Late Payment Charges	$232,694	$ -	$232,694		$232,694
	Other Distribution Revenue	$180,257	$ -	$180,257		$180,257
	Other Income and Deductions	$96,099	($10,000)	$86,099		$86,099
	Total Revenue Offsets	$1,080,249	($10,000)	$1,070,249	$ -	$1,070,249

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application	Interrogatory Responses	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$2,436,894	$2,429,455	$2,429,455
2	Adjustments required to arrive at taxable utility income	($892,023)	($966,781)	($892,023)
3	Taxable income	$1,544,871	$1,462,674	$1,537,432
	Calculation of Utility income Taxes			
4	Income taxes	$444,375	$368,312	$368,312
6	Total taxes	$444,375	$368,312	$368,312
7	Gross-up of Income Taxes	$142,138	$116,993	$116,993
8	Grossed-up Income Taxes	$586,513	$485,305	$485,305
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$586,513	$485,305	$485,305
10	Other tax Credits	$69,984	$125,231	$125,231
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	9.23%	9.11%	9.11%
13	Total tax rate (%)	24.23%	24.11%	24.11%

Notes

Revenue Requirement Workform

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$37,408,457	4.18%	$1,563,588
2	Short-term Debt	4.00%	$2,672,033	2.08%	$55,578
3	**Total Debt**	60.00%	$40,080,490	4.04%	$1,619,166
	Equity				
4	Common Equity	40.00%	$26,720,327	9.12%	$2,436,894
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$26,720,327	9.12%	$2,436,894
7	**Total**	100.00%	$66,800,816	6.07%	$4,056,060
		Interrogatory Responses			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$37,294,270	4.24%	$1,580,430
2	Short-term Debt	4.00%	$2,663,876	2.08%	$55,409
3	**Total Debt**	60.00%	$39,958,146	4.09%	$1,635,839
	Equity				
4	Common Equity	40.00%	$26,638,764	9.12%	$2,429,455
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$26,638,764	9.12%	$2,429,455
7	**Total**	100.00%	$66,596,910	6.10%	$4,065,294
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$37,294,270	4.18%	$1,558,815
9	Short-term Debt	4.00%	$2,663,876	2.08%	$55,409
10	**Total Debt**	60.00%	$39,958,146	4.04%	$1,614,224
	Equity				
11	Common Equity	40.00%	$26,638,764	9.12%	$2,429,455
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$26,638,764	9.12%	$2,429,455
14	**Total**	100.00%	$66,596,910	6.07%	$4,043,679

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application		Interrogatory Responses		Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$3,456,032		$3,805,952		$3,784,337
2	Distribution Revenue	$18,420,657	$18,420,658	$18,420,657	$18,275,857	$18,420,657	$18,297,472
3	Other Operating Revenue Offsets - net	$1,080,249	$1,080,249	$1,070,249	$1,070,249	$1,070,249	$1,070,249
4	**Total Revenue**	$19,500,906	$22,956,939	$19,490,906	$23,152,058	$19,490,906	$23,152,058
5	Operating Expenses	$18,314,365	$18,314,365	$18,601,940	$18,601,940	$18,601,940	$18,601,940
6	Deemed Interest Expense	$1,619,166	$1,619,166	$1,635,839	$1,635,839	$1,614,224	$1,614,224
7	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	$ - **(2)**	$ -	$ - **(2)**	$ -	$ - **(2)**	$ -
8	**Total Cost and Expenses**	$19,933,531	$19,933,531	$20,237,779	$20,237,779	$20,216,164	$20,216,164
9	**Utility Income Before Income Taxes**	($432,625)	$3,023,408	($746,873)	$2,914,279	($725,258)	$2,935,894
10	Tax Adjustments to Accounting Income per 2013 PILs model	($892,023)	($892,023)	($966,781)	($966,781)	($966,781)	($966,781)
11	**Taxable Income**	($1,324,648)	$2,131,385	($1,713,654)	$1,947,498	($1,692,039)	$1,969,113
12	Income Tax Rate	24.23%	24.23%	24.11%	24.11%	24.11%	24.11%
13	**Income Tax on Taxable Income**	($321,021)	$516,529	($413,113)	$469,486	($407,902)	$474,696
14	**Income Tax Credits**	$69,984	$69,984	$125,231	$125,231	$125,231	$125,231
15	**Utility Net Income**	($181,588)	$2,436,895	($458,991)	$2,428,974	($442,587)	$2,450,589
16	**Utility Rate Base**	$66,800,816	$66,800,816	$66,596,910	$66,596,910	$66,596,910	$66,596,910
17	Deemed Equity Portion of Rate Base	$26,720,327	$26,720,327	$26,638,764	$26,638,764	$26,638,764	$26,638,764
18	Income/(Equity Portion of Rate Base)	-0.68%	9.12%	-1.72%	9.12%	-1.66%	9.20%
19	Target Return - Equity on Rate Base	9.12%	9.12%	9.12%	9.12%	9.12%	9.12%
20	Deficiency/Sufficiency in Return on Equity	-9.80%	0.00%	-10.84%	0.00%	-10.78%	0.08%
21	Indicated Rate of Return	2.15%	6.07%	1.77%	6.10%	1.76%	6.10%
22	Requested Rate of Return on Rate Base	6.07%	6.07%	6.10%	6.10%	6.07%	6.07%
23	Deficiency/Sufficiency in Rate of Return	-3.92%	0.00%	-4.34%	0.00%	-4.31%	0.03%
24	Target Return on Equity	$2,436,894	$2,436,894	$2,429,455	$2,429,455	$2,429,455	$2,429,455
25	Revenue Deficiency/(Sufficiency)	$2,618,482	$1	$2,888,447	($481)	$2,872,043	$21,134
26	**Gross Revenue Deficiency/(Sufficiency)**	$3,456,032 **(1)**		$3,805,952 **(1)**		$3,784,337 **(1)**	

Notes:

(1)	Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)
(2)	Treated as an adjustment pre-tax to avoid an impact on taxes/PILs and hence on revenue sufficiency deficiency
(3)	

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application		Interrogatory Responses		Per Board Decision	
1	OM&A Expenses	$13,078,828		$13,177,560		$13,177,560	
2	Amortization/Depreciation	$5,011,623		$5,151,966		$5,151,966	
3	Property Taxes	$223,914		$272,414		$272,414	
5	Income Taxes (Grossed up)	$586,513		$485,305		$485,305	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$1,619,166		$1,635,839		$1,614,224	
	Return on Deemed Equity	$2,436,894		$2,429,455		$2,429,455	
	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	$ -		$ -		$ -	
8	**Service Revenue Requirement (before Revenues)**	$22,956,938		$23,152,539		$23,130,925	
9	Revenue Offsets	$1,080,249		$1,070,249		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$21,876,689		$22,082,290		$23,130,925	
11	Distribution revenue	$21,876,690		$22,081,809		$22,081,809	
12	Other revenue	$1,080,249		$1,070,249		$1,070,249	
13	**Total revenue**	$22,956,939		$23,152,058		$23,152,058	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$1	**(1)**	($481)	**(1)**	$21,134	**(1)**

Notes

(1) Line 11 - Line 8

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1.0 - Staff 2 - Table of Adjustments

List of Adjustments and Corrections - Board Staff #2, and VECC #1

Item #	Intervenor & Question #	Description	Area of Change (working capital, pils etc)
1	8.0 -Board 47	Updated LV rates to reflect actual Hydro One approved rates for Jan 1, 2013	LV rates, working capital, revenue requirement
2	8.0 - Board 45	Updated RTSR Rates to reflect Uniform Transmission Rates approved for Jan 1, 2013	RTSR rates, working capital, revenue requirement
3	2.0 - EP 13	Commodity Price updated to reflect most recent OEB report	working capital, revenue requirement
4	3.0-EP 16 and 5-EP-30c	Reduce 10,000 from account 4405	Revenue Offsets, revenue requirement
5	4.0 - EP-24	Increase property taxes in regard to new building addition	OM&A, revenue requirement
6	1.0 - EP-2	Change 2013 Employee Benefit Obligation expense amount to be CGAAP amount	OM&A, PILs, revenue requirement
7	2.0 -VECC-2	Depreciation increased for Account 1960	Depreciation, PILs, Return on RB, revenue requirement
8	4.0 - EP -27	Depreciation increased for 2013 relating to all four smart meter cost categories	Depreciation, PILs, Return on RB, revenue requirement
9	4.0 - EP #29c	Class 10 and 50 corrected re: computer equipment	PILs, revenue requirement
10	4.0 - EP #29d	Class 1 and Class 1 Enhanced on Sch 8 corrected for 2012 and 2013 re building addition	PILs, revenue requirement
11	4.0 -Staff-39	Tax credits corrected	PILs, revenue requirement
12	9.0 - Board -56	Separate LRAM claim into LRAM 2013 to only include persistence from 2006-2010 programs in 2011/12	revised rate riders for LRAM (2 year riders)
13	9.0 - Board-57	Separate LRAM claim into LRAMVA 2013 to only include results for 2011 programs	revised rate riders for LRAMVA (one year riders)
14	9.0 - Staff 51	Stranded Meter disposition rate riders - change them from the original proposed rates	revised rate riders
15	9.0 - Staff-54	Removed claim for Account 1508 Sub-account IFRS Transition Costs	revised rate riders
16	9.0 - Staff-49	Account 1572 Deferral Account disposition updated with 2012 actuals	revised rate riders
17	5.0 - EP-30 (c)	Adjusted LTD deemed interest rate as a result of removing $2.2 million debenture	deemed LTD Interet rate, revenue requirement
		Above changes changed rate base, revenue requirment, and PILs so cost allocation model was updated in order to provide revised rates and bill impacts	Cost Allocation, rates, bill impacts

1.0-Staff-3 – Updated Appendix 2-W, Bill Impacts

Upon completing all interrogatories from Board staff and intervenors, please provide an updated Appendix 2-W for all classes at the typical consumption / demand levels (i.e. 800 kWh for residential, 2,000 kWh for GS<50).

Updated bill impacts are provided in Attachment 1 to this response. A summary of the bill impacts is presented in Table 1 below. Please see response to 1-Staff-2 in regard to the specific changes that were incorporated into the revised bill impacts.

Table 1 – Updated Bill Impacts related to Interrogatory Responses

			Distribution Charges		Delivery Charges		Total Bill	
Customer Class Name	kWh	kW	$ change	% change	$ change	% change	$ change	% change
Residential	500		$3.17	12.5%	$2.85	9.0%	$3.18	3.9%
	800		$3.71	12.0%	$3.19	7.7%	$3.70	3.1%
	1,500		$4.97	11.3%	$4.00	6.3%	$4.90	2.3%
	2,000		$5.87	11.0%	$4.57	5.8%	$5.78	2.1%
General Service < 50 kW	1,000		$10.97	23.7%	$10.42	18.0%	$11.16	7.1%
	2,000		$12.57	20.0%	$11.47	13.3%	$12.78	4.5%
	5,000		$17.37	15.5%	$14.61	8.6%	$17.66	2.7%
	10,000		$25.37	13.1%	$19.85	6.4%	$25.81	2.0%
General Service > 50 to 999 kW	26,000	60	$12.17	3.4%	($2.30)	(0.4%)	$13.58	0.4%
	52,000	135	$27.38	4.4%	($5.18)	(0.4%)	$26.58	0.4%
	165,000	355	$71.99	5.1%	($13.63)	(0.5%)	$87.19	0.4%
	430,000	860	$174.41	5.4%	($33.02)	(0.5%)	$229.74	0.4%
General Service 1000 to 4999 kW	605,000	1,360	($649.54)	(13.2%)	($1,002.86)	(8.6%)	($658.25)	(0.9%)
	977,118	2,578	($1,231.25)	(18.8%)	($1,901.02)	(9.9%)	($1,349.24)	(1.1%)
	3,011,152	4,500	($2,149.20)	(23.5%)	($3,318.30)	(10.6%)	($1,574.70)	(0.5%)
Large Use	4,230,083	6,943	($5,946.68)	(17.3%)	($7,971.95)	(10.9%)	($7,144.17)	(1.41%)
	7,340,623	10,492	($8,986.40)	(22.7%)	($12,046.91)	(12.4%)	($10,580.06)	(1.2%)
	11,523,872	16,869	($14,448.30)	(29.6%)	($19,368.99)	(13.6%)	($17,073.96)	(1.3%)
Unmetered Scattered Load	100		($2.97)	(14.8%)	($3.03)	(14.3%)	($3.02)	(9.8%)
	1,200		($11.44)	(17.5%)	($12.10)	(15.2%)	($11.58)	(5.9%)
	7,000		($56.10)	(18.4%)	($60.73)	(15.7%)	($56.70)	(5.1%)
Sentinel Lighting	182	0.46	$2.38	17.3%	$2.30	14.9%	$2.43	7.5%
	63	0.18	$1.35	17.6%	$1.31	15.9%	$1.37	9.7%
Street Lighting	86	0.18	$0.91	17.2%	$0.87	14.8%	$0.93	6.7%
	749,249	1,613.00	$4,262.14	16.5%	$3,965.51	12.6%	$4,491.77	4.0%

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Updated Bill Impacts

EB-2012-0107

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04-Feb-13

Appendix 2-W
Bill Impacts

Customer Class: Residential

Consumption **500** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	$ Change	% Change
Monthly Service Charge	Monthly	$ 13.8000	1	$ 13.80	$ 16.5400	1	$ 16.54	$ 2.74	19.86%
Smart Meter Rate Adder	Monthly	$ 1.9400	1	$ 1.94	$ -	1	$ -	-$ 1.94	-100.00%
Rate Rider for Tax change	kWh	-$ 0.0005	500	-$ 0.25	$ -	500	$ -	$ 0.25	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kWh	$ 0.0188	500	$ 9.40	$ 0.0225	500	$ 11.25	$ 1.85	19.68%
Smart Meter Disposition Rider				$ -			$ -	$ -	
LRAM 2011	kW	$ 0.0004	500	$ 0.20	$ -	500	$ -	-$ 0.20	-100.00%
LRAM 2012	kW	$ 0.0002	500	$ 0.10	$ 0.0002	500	$ 0.10	$ -	
LRAM 2013 & LRAMVA 2013	kW	$ -	500	$ -	$ 0.0005	500	$ 0.25	$ 0.25	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ 1.4700	1	$ 1.47	$ 1.47	
Sub-Total A				$ 25.44			$ 29.86	**$ 4.42**	**17.37%**
Rate Rider for Deferral/Variance Account Disposition 2011	kW	$ 0.0012	500	$ 0.60	$ -	500	$ -	-$ 0.60	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kW	-$ 0.0017	500	-$ 0.85	-$ 0.0017	500	-$ 0.85	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kW	$ -	500	$ -	-$ 0.0013	500	-$ 0.65	-$ 0.65	
Low Voltage Service Charge	kWh	$ 0.0002	500	$ 0.10	$ 0.0002	500	$ 0.10	$ -	
Smart Meter Entity Charge		▨	▨	▨		500	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 25.29**			**$ 28.46**	**$ 3.17**	**12.53%**
RTSR - Network	kWh	$ 0.0068	518	$ 3.52	$ 0.0064	521	$ 3.33	-$ 0.19	-5.30%
RTSR - Line and Transformation Connection	kWh	$ 0.0057	518	$ 2.95	$ 0.0054	521	$ 2.81	-$ 0.14	-4.67%
Sub-Total C - Delivery (including Sub-Total B)				**$ 31.76**			**$ 34.61**	**$ 2.85**	**8.96%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	518	$ 2.69	$ 0.0052	521	$ 2.71	$ 0.02	0.62%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	518	$ 0.57	$ 0.0011	521	$ 0.57	$ 0.00	0.62%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	500	$ 3.50	$ 0.0070	500	$ 3.50	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	517.8	$ 38.32	$ 0.0740	521.027	$ 38.56	$ 0.24	0.62%
Energy - RPP - Tier 2	kWh	$ 0.0870		$ -	$ 0.0870		$ -	$ -	
TOU - Off Peak	kWh	$ 0.0630	331	$ 20.88	$ 0.0630	333	$ 21.01	$ 0.13	0.62%
TOU - Mid Peak	kWh	$ 0.0990	93	$ 9.23	$ 0.0990	94	$ 9.28	$ 0.06	0.62%
TOU - On Peak	kWh	$ 0.1180	93	$ 11.00	$ 0.1180	94	$ 11.07	$ 0.07	0.62%
Total Bill on RPP (before Taxes)				**$ 76.84**			**$ 79.95**	**$ 3.10**	**4.04%**
HST		13%		$ 9.99	13%		$ 10.39	$ 0.40	4.04%
Total Bill (including HST)				$ 86.83			$ 90.34	$ 3.51	4.04%
Ontario Clean Energy Benefit 1				-$ 8.68			-$ 9.03	-$ 0.35	4.03%
Total Bill on RPP (including OCEB)				**$ 78.15**			**$ 81.31**	**$ 3.16**	**4.04%**
Total Bill on TOU (before Taxes)				**$ 79.63**			**$ 82.75**	**$ 3.12**	**3.92%**
HST		13%		$ 10.35	13%		$ 10.76	$ 0.41	3.92%
Total Bill (including HST)				$ 89.98			$ 93.51	$ 3.53	3.92%
Ontario Clean Energy Benefit 1				-$ 9.00			-$ 9.35	-$ 0.35	3.89%
Total Bill on TOU (including OCEB)				**$ 80.98**			**$ 84.16**	**$ 3.18**	**3.92%**
Loss Factor (%)		3.56%			4.21%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: Residential

Consumption 800 **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	$ Change	% Change
Monthly Service Charge	Monthly	$ 13.8000	1	$ 13.80	$ 16.5400	1	$ 16.54	$ 2.74	19.86%
Smart Meter Rate Adder	Monthly	$ 1.9400	1	$ 1.94	$ -	1	$ -	-$ 1.94	-100.00%
Rate Rider for Tax change	kWh	-$ 0.0005	800	-$ 0.40	$ -	800	$ -	$ 0.40	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kWh	$ 0.0188	800	$ 15.04	$ 0.0225	800	$ 18.00	$ 2.96	19.68%
Smart Meter Disposition Rider				$ -	$ -		$ -	$ -	
LRAM 2011	kW	$ 0.0004	800	$ 0.32	$ -	800	$ -	-$ 0.32	-100.00%
LRAM 2012	kW	$ 0.0002	800	$ 0.16	$ 0.0002	800	$ 0.16	$ -	
LRAM 2013 & LRAMVA 2013	kW	$ -	800	$ -	$ 0.0005	800	$ 0.40	$ 0.40	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ 1.4700	1	$ 1.47	$ 1.47	
Sub-Total A				$ 31.11			$ 36.82	**$ 5.71**	**18.35%**
Rate Rider for Deferral/Variance Account Disposition 2011	kW	$ 0.0012	800	$ 0.96	$ -	800	$ -	-$ 0.96	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kW	-$ 0.0017	800	-$ 1.36	-$ 0.0017	800	-$ 1.36	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kW	$ -	800	$ -	-$ 0.0013	800	-$ 1.04	-$ 1.04	
Low Voltage Service Charge	kWh	$ 0.0002	800	$ 0.16	$ 0.0002	800	$ 0.16	$ -	
Smart Meter Entity Charge		▨	▨	▨		800	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 30.87**			**$ 34.58**	**$ 3.71**	**12.02%**
RTSR - Network	kWh	$ 0.0068	828	$ 5.63	$ 0.0064	834	$ 5.34	-$ 0.30	-5.30%
RTSR - Line and Transformation Connection	kWh	$ 0.0057	828	$ 4.72	$ 0.0054	834	$ 4.50	-$ 0.22	-4.67%
Sub-Total C - Delivery (including Sub-Total B)				**$ 41.23**			**$ 44.42**	**$ 3.19**	**7.74%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	828	$ 4.31	$ 0.0052	834	$ 4.33	$ 0.03	0.62%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	828	$ 0.91	$ 0.0011	834	$ 0.92	$ 0.01	0.62%
Standard Supply Service Charge			1	$ -	$ -	1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	600	$ 44.40	$ 0.0740	600	$ 44.40	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0870	228.48	$ 19.88	$ 0.0870	233.6433	$ 20.33	$ 0.45	2.26%
TOU - Off Peak	kWh	$ 0.0630	530	$ 33.40	$ 0.0630	534	$ 33.61	$ 0.21	0.62%
TOU - Mid Peak	kWh	$ 0.0990	149	$ 14.76	$ 0.0990	150	$ 14.86	$ 0.09	0.62%
TOU - On Peak	kWh	$ 0.1180	149	$ 17.60	$ 0.1180	150	$ 17.71	$ 0.11	0.62%
Total Bill on RPP (before Taxes)				**$ 116.32**			**$ 120.00**	**$ 3.67**	**3.16%**
HST		13%		$ 15.12	13%		$ 15.60	$ 0.48	3.16%
Total Bill (including HST)				$ 131.45			$ 135.60	$ 4.15	3.16%
Ontario Clean Energy Benefit 1				-$ 13.14			-$ 13.56	-$ 0.42	3.20%
Total Bill on RPP (including OCEB)				**$ 118.31**			**$ 122.04**	**$ 3.73**	**3.15%**
Total Bill on TOU (before Taxes)				**$ 117.81**			**$ 121.44**	**$ 3.63**	**3.08%**
HST		13%		$ 15.32	13%		$ 15.79	$ 0.47	3.08%
Total Bill (including HST)				$ 133.13			$ 137.23	$ 4.11	3.08%
Ontario Clean Energy Benefit 1				-$ 13.31			-$ 13.72	-$ 0.41	3.08%
Total Bill on TOU (including OCEB)				**$ 119.82**			**$ 123.51**	**$ 3.70**	**3.08%**
Loss Factor (%)		3.56%			4.21%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: Residential

Consumption 1500 **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	$ Change	% Change
Monthly Service Charge	Monthly	$ 13.8000	1	$ 13.80	$ 16.5400	1	$ 16.54	$ 2.74	19.86%
Smart Meter Rate Adder	Monthly	$ 1.9400	1	$ 1.94	$ -	1	$ -	-$ 1.94	-100.00%
Rate Rider for Tax change	kWh	-$ 0.0005	1500	-$ 0.75	$ -	1500	$ -	$ 0.75	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kWh	$ 0.0188	1500	$ 28.20	$ 0.0225	1500	$ 33.75	$ 5.55	19.68%
Smart Meter Disposition Rider				$ -	$ -		$ -	$ -	
LRAM 2011	kW	$ 0.0004	1500	$ 0.60	$ -	1500	$ -	-$ 0.60	-100.00%
LRAM 2012	kW	$ 0.0002	1500	$ 0.30	$ 0.0002	1500	$ 0.30	$ -	
LRAM 2013 & LRAMVA 2013	kW	$ -	1500	$ -	$ 0.0005	1500	$ 0.75	$ 0.75	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ 1.4700	1	$ 1.47	$ 1.47	
Sub-Total A				$ 44.34			$ 53.06	**$ 8.72**	**19.67%**
Rate Rider for Deferral/Variance Account Disposition 2011	kW	$ 0.0012	1500	$ 1.80	$ -	1500	$ -	-$ 1.80	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kW	-$ 0.0017	1500	-$ 2.55	-$ 0.0017	1500	-$ 2.55	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kW	$ -	1500	$ -	-$ 0.0013	1500	-$ 1.95	-$ 1.95	
Low Voltage Service Charge	kWh	$ 0.0002	1500	$ 0.30	$ 0.0002	1500	$ 0.30	$ -	
Smart Meter Entity Charge					$ -	1500	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 43.89**			**$ 48.86**	**$ 4.97**	**11.32%**
RTSR - Network	kWh	$ 0.0068	1553	$ 10.56	$ 0.0064	1563	$ 10.00	-$ 0.56	-5.30%
RTSR - Line and Transformation Connection	kWh	$ 0.0057	1553	$ 8.85	$ 0.0054	1563	$ 8.44	-$ 0.41	-4.67%
Sub-Total C - Delivery (including Sub-Total B)				**$ 63.31**			**$ 67.30**	**$ 4.00**	**6.31%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	1553	$ 8.08	$ 0.0052	1563	$ 8.13	$ 0.05	0.62%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	1553	$ 1.71	$ 0.0011	1563	$ 1.72	$ 0.01	0.62%
Standard Supply Service Charge			1	$ -	$ -	1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	1500	$ 10.50	$ 0.0070	1500	$ 10.50	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	600	$ 44.40	$ 0.0740	600	$ 44.40	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0870	953.4	$ 82.95	$ 0.0870	963.0811	$ 83.79	$ 0.84	1.02%
TOU - Off Peak	kWh	$ 0.0630	994	$ 62.63	$ 0.0630	1000	$ 63.02	$ 0.39	0.62%
TOU - Mid Peak	kWh	$ 0.0990	280	$ 27.68	$ 0.0990	281	$ 27.85	$ 0.17	0.62%
TOU - On Peak	kWh	$ 0.1180	280	$ 32.99	$ 0.1180	281	$ 33.20	$ 0.21	0.62%
Total Bill on RPP (before Taxes)				**$ 210.94**			**$ 215.84**	**$ 4.90**	**2.32%**
HST		13%		$ 27.42	13%		$ 28.06	$ 0.64	2.32%
Total Bill (including HST)				$ 238.36			$ 243.90	$ 5.54	2.32%
Ontario Clean Energy Benefit 1				-$ 23.84			-$ 24.39	-$ 0.55	2.31%
Total Bill on RPP (including OCEB)				**$ 214.52**			**$ 219.51**	**$ 4.99**	**2.32%**
Total Bill on TOU (before Taxes)				**$ 206.90**			**$ 211.73**	**$ 4.83**	**2.33%**
HST		13%		$ 26.90	13%		$ 27.52	$ 0.63	2.33%
Total Bill (including HST)				$ 233.80			$ 239.25	$ 5.45	2.33%
Ontario Clean Energy Benefit 1				-$ 23.38			-$ 23.93	-$ 0.55	2.35%
Total Bill on TOU (including OCEB)				**$ 210.42**			**$ 215.32**	**$ 4.90**	**2.33%**
Loss Factor (%)		3.56%			4.21%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

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GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: Residential

Consumption 2000 kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 13.8000	1	$ 13.80	$ 16.5400	1	$ 16.54	$ 2.74	19.86%
Smart Meter Rate Adder	Monthly	$ 1.9400	1	$ 1.94	$ -	1	$ -	-$ 1.94	-100.00%
Rate Rider for Tax change	kWh	-$ 0.0005	2000	-$ 1.00	$ -	2000	$ -	$ 1.00	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kWh	$ 0.0188	2000	$ 37.60	$ 0.0225	2000	$ 45.00	$ 7.40	19.68%
Smart Meter Disposition Rider				$ -	$ -		$ -	$ -	
LRAM 2011	kW	$ 0.0004	2000	$ 0.80	$ -	2000	$ -	-$ 0.80	-100.00%
LRAM 2012	kW	$ 0.0002	2000	$ 0.40	$ 0.0002	2000	$ 0.40	$ -	
LRAM 2013 & LRAMVA 2013	kW	$ -	2000	$ -	$ 0.0005	2000	$ 1.00	$ 1.00	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ 1.4700	1	$ 1.47	$ 1.47	
Sub-Total A				$ 53.79			$ 64.66	**$ 10.87**	**20.21%**
Rate Rider for Deferral/Variance Account Disposition 2011	kW	$ 0.0012	2000	$ 2.40	$ -	2000	$ -	-$ 2.40	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kW	-$ 0.0017	2000	-$ 3.40	-$ 0.0017	2000	-$ 3.40	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kW	$ -	2000	$ -	-$ 0.0013	2000	-$ 2.60	-$ 2.60	
Low Voltage Service Charge	kWh	$ 0.0002	2000	$ 0.40	$ 0.0002	2000	$ 0.40	$ -	
Smart Meter Entity Charge		▨	▨	▨		2000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 53.19**			**$ 59.06**	**$ 5.87**	**11.04%**
RTSR - Network	kWh	$ 0.0068	2071	$ 14.08	$ 0.0064	2084	$ 13.34	-$ 0.75	-5.30%
RTSR - Line and Transformation Connection	kWh	$ 0.0057	2071	$ 11.81	$ 0.0054	2084	$ 11.25	-$ 0.55	-4.67%
Sub-Total C - Delivery (including Sub-Total B)				**$ 79.08**			**$ 83.65**	**$ 4.57**	**5.78%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	2071	$ 10.77	$ 0.0052	2084	$ 10.84	$ 0.07	0.62%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	2071	$ 2.28	$ 0.0011	2084	$ 2.29	$ 0.01	0.62%
Standard Supply Service Charge			1	$ -	$ -	1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	600	$ 44.40	$ 0.0740	600	$ 44.40	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0870	1471.2	$ 127.99	$ 0.0870	1484.108	$ 129.12	$ 1.12	0.88%
TOU - Off Peak	kWh	$ 0.0630	1326	$ 83.51	$ 0.0630	1334	$ 84.03	$ 0.52	0.62%
TOU - Mid Peak	kWh	$ 0.0990	373	$ 36.91	$ 0.0990	375	$ 37.14	$ 0.23	0.62%
TOU - On Peak	kWh	$ 0.1180	373	$ 43.99	$ 0.1180	375	$ 44.27	$ 0.27	0.62%
Total Bill on RPP (before Taxes)				**$ 278.52**			**$ 284.30**	**$ 5.78**	**2.07%**
HST		13%		$ 36.21	13%		$ 36.96	$ 0.75	2.07%
Total Bill (including HST)				$ 314.73			$ 321.26	$ 6.53	2.07%
Ontario Clean Energy Benefit 1				-$ 31.47			-$ 32.13	-$ 0.66	2.10%
Total Bill on RPP (including OCEB)				**$ 283.26**			**$ 289.13**	**$ 5.87**	**2.07%**
Total Bill on TOU (before Taxes)				**$ 270.54**			**$ 276.22**	**$ 5.68**	**2.10%**
HST		13%		$ 35.17	13%		$ 35.91	$ 0.74	2.10%
Total Bill (including HST)				$ 305.71			$ 312.13	$ 6.42	2.10%
Ontario Clean Energy Benefit 1				-$ 30.57			-$ 31.21	-$ 0.64	2.09%
Total Bill on TOU (including OCEB)				**$ 275.14**			**$ 280.92**	**$ 5.78**	**2.10%**

	Current Board-Approved	Proposed
Loss Factor (%)	3.56%	4.21%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: General Service < 50 kW

Consumption 1000 kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	$ Change	% Change
Monthly Service Charge	Monthly	$ 23.7100	1	$ 23.71	$ 28.4200	1	$ 28.42	$ 4.71	19.87%
Smart Meter Rate Adder	Monthly	$ 5.9400	1	$ 5.94	$ 5.9400	1	$ 5.94	$ -	
Rate Rider for Tax change	kWh	-$ 0.0003	1000	-$ 0.30	$ -	1000	$ -	$ 0.30	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kWh	$ 0.0166	1000	$ 16.60	$ 0.0199	1000	$ 19.90	$ 3.30	19.88%
Smart Meter Disposition Rider				$ -			$ -	$ -	
LRAM 2011	kW	$ 0.0001	1000	$ 0.10	$ -	1000	$ -	-$ 0.10	-100.00%
LRAM 2012	kW	$ 0.0002	1000	$ 0.20	$ 0.0002	1000	$ 0.20	$ -	
LRAM 2013 & LRAMVA 2013	kW	$ -	1000	$ -	$ 0.0005	1000	$ 0.50	$ 0.50	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ 4.6600	1	$ 4.66	$ 4.66	
Sub-Total A				$ 46.50			$ 59.87	**$ 13.37**	**28.75%**
Rate Rider for Deferral/Variance Account Disposition 2011	kW	$ 0.0012	1000	$ 1.20	$ -	1000	$ -	-$ 1.20	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kW	-$ 0.0016	1000	-$ 1.60	-$ 0.0016	1000	-$ 1.60	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kW	$ -	1000	$ -	-$ 0.0012	1000	-$ 1.20	-$ 1.20	
Low Voltage Service Charge	kWh	$ 0.0002	1000	$ 0.20	$ 0.0002	1000	$ 0.20	$ -	
Smart Meter Entity Charge		▨	▨	▨		1000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 46.30**			**$ 57.27**	**$ 10.97**	**23.69%**
RTSR - Network	kWh	$ 0.0063	1036	$ 6.52	$ 0.0060	1042	$ 6.25	-$ 0.27	-4.17%
RTSR - Line and Transformation Connection	kWh	$ 0.0050	1036	$ 5.18	$ 0.0047	1042	$ 4.90	-$ 0.28	-5.41%
Sub-Total C - Delivery (including Sub-Total B)				**$ 58.00**			**$ 68.42**	**$ 10.42**	**17.96%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	1036	$ 5.39	$ 0.0052	1042	$ 5.42	$ 0.03	0.62%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	1036	$ 1.14	$ 0.0011	1042	$ 1.15	$ 0.01	0.62%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	1000	$ 7.00	$ 0.0070	1000	$ 7.00	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	750	$ 55.50	$ 0.0740	750	$ 55.50	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0870	285.6	$ 24.85	$ 0.0870	292.0541	$ 25.41	$ 0.56	2.26%
TOU - Off Peak	kWh	$ 0.0630	663	$ 41.76	$ 0.0630	667	$ 42.02	$ 0.26	0.62%
TOU - Mid Peak	kWh	$ 0.0990	186	$ 18.45	$ 0.0990	188	$ 18.57	$ 0.12	0.62%
TOU - On Peak	kWh	$ 0.1180	186	$ 22.00	$ 0.1180	188	$ 22.13	$ 0.14	0.62%
Total Bill on RPP (before Taxes)				**$ 151.87**			**$ 162.89**	**$ 11.02**	**7.26%**
HST		13%		$ 19.74	13%		$ 21.18	$ 1.43	7.26%
Total Bill (including HST)				$ 171.62			$ 184.07	$ 12.45	7.26%
Ontario Clean Energy Benefit 1				-$ 17.16			-$ 18.41	-$ 1.25	7.28%
Total Bill on RPP (including OCEB)				**$ 154.46**			**$ 165.66**	**$ 11.20**	**7.25%**
Total Bill on TOU (before Taxes)				**$ 153.73**			**$ 164.70**	**$ 10.97**	**7.14%**
HST		13%		$ 19.99	13%		$ 21.41	$ 1.43	7.14%
Total Bill (including HST)				$ 173.72			$ 186.11	$ 12.40	7.14%
Ontario Clean Energy Benefit 1				-$ 17.37			-$ 18.61	-$ 1.24	7.14%
Total Bill on TOU (including OCEB)				**$ 156.35**			**$ 167.50**	**$ 11.16**	**7.14%**
Loss Factor (%)		3.56%			4.21%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: General Service < 50 kW

Consumption 2000 **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	$ Change	% Change
Monthly Service Charge	Monthly	$ 23.7100	1	$ 23.71	$ 28.4200	1	$ 28.42	$ 4.71	19.87%
Smart Meter Rate Adder	Monthly	$ 5.9400	1	$ 5.94	$ 5.9400	1	$ 5.94	$ -	
Rate Rider for Tax change	kWh	-$ 0.0003	2000	-$ 0.60	$ -	2000	$ -	$ 0.60	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kWh	$ 0.0166	2000	$ 33.20	$ 0.0199	2000	$ 39.80	$ 6.60	19.88%
Smart Meter Disposition Rider				$ -	$ -		$ -	$ -	
LRAM 2011	kW	$ 0.0001	2000	$ 0.20	$ -	2000	$ -	-$ 0.20	-100.00%
LRAM 2012	kW	$ 0.0002	2000	$ 0.40	$ 0.0002	2000	$ 0.40	$ -	
LRAM 2013 & LRAMVA 2013	kW	$ -	2000	$ -	$ 0.0005	2000	$ 1.00	$ 1.00	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ 4.6600	1	$ 4.66	$ 4.66	
Sub-Total A				$ 63.10			$ 80.47	**$ 17.37**	**27.53%**
Rate Rider for Deferral/Variance Account Disposition 2011	kW	$ 0.0012	2000	$ 2.40	$ -	2000	$ -	-$ 2.40	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kW	-$ 0.0016	2000	-$ 3.20	-$ 0.0016	2000	-$ 3.20	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kW	$ -	2000	$ -	-$ 0.0012	2000	-$ 2.40	-$ 2.40	
Low Voltage Service Charge	kWh	$ 0.0002	2000	$ 0.40	$ 0.0002	2000	$ 0.40	$ -	
Smart Meter Entity Charge						2000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 62.70**			**$ 75.27**	**$ 12.57**	**20.05%**
RTSR - Network	kWh	$ 0.0063	2071	$ 13.05	$ 0.0060	2084	$ 12.50	-$ 0.54	-4.17%
RTSR - Line and Transformation Connection	kWh	$ 0.0050	2071	$ 10.36	$ 0.0047	2084	$ 9.80	-$ 0.56	-5.41%
Sub-Total C - Delivery (including Sub-Total B)				**$ 86.10**			**$ 97.57**	**$ 11.47**	**13.32%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	2071	$ 10.77	$ 0.0052	2084	$ 10.84	$ 0.07	0.62%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	2071	$ 2.28	$ 0.0011	2084	$ 2.29	$ 0.01	0.62%
Standard Supply Service Charge			1	$ -	$ -	1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	750	$ 55.50	$ 0.0740	750	$ 55.50	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0870	1321.2	$ 114.94	$ 0.0870	1334.108	$ 116.07	$ 1.12	0.98%
TOU - Off Peak	kWh	$ 0.0630	1326	$ 83.51	$ 0.0630	1334	$ 84.03	$ 0.52	0.62%
TOU - Mid Peak	kWh	$ 0.0990	373	$ 36.91	$ 0.0990	375	$ 37.14	$ 0.23	0.62%
TOU - On Peak	kWh	$ 0.1180	373	$ 43.99	$ 0.1180	375	$ 44.27	$ 0.27	0.62%
Total Bill on RPP (before Taxes)				**$ 283.60**			**$ 296.27**	**$ 12.67**	**4.47%**
HST		13%		$ 36.87	13%		$ 38.51	$ 1.65	4.47%
Total Bill (including HST)				$ 320.47			$ 334.78	$ 14.32	4.47%
Ontario Clean Energy Benefit 1				-$ 32.05			-$ 33.48	-$ 1.43	4.46%
Total Bill on RPP (including OCEB)				**$ 288.42**			**$ 301.30**	**$ 12.89**	**4.47%**
Total Bill on TOU (before Taxes)				**$ 277.56**			**$ 290.14**	**$ 12.57**	**4.53%**
HST		13%		$ 36.08	13%		$ 37.72	$ 1.63	4.53%
Total Bill (including HST)				$ 313.65			$ 327.85	$ 14.21	4.53%
Ontario Clean Energy Benefit 1				-$ 31.36			-$ 32.79	-$ 1.43	4.56%
Total Bill on TOU (including OCEB)				**$ 282.29**			**$ 295.06**	**$ 12.78**	**4.53%**

Loss Factor (%) 3.56% 4.21%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: General Service < 50 kW

Consumption 5000 **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	$ Change	% Change
Monthly Service Charge	Monthly	$ 23.7100	1	$ 23.71	$ 28.4200	1	$ 28.42	$ 4.71	19.87%
Smart Meter Rate Adder	Monthly	$ 5.9400	1	$ 5.94	$ 5.9400	1	$ 5.94	$ -	
Rate Rider for Tax change	kWh	-$ 0.0003	5000	-$ 1.50	$ -	5000	$ -	$ 1.50	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kWh	$ 0.0166	5000	$ 83.00	$ 0.0199	5000	$ 99.50	$ 16.50	19.88%
Smart Meter Disposition Rider				$ -	$ -		$ -	$ -	
LRAM 2011	kW	$ 0.0001	5000	$ 0.50	$ -	5000	$ -	-$ 0.50	-100.00%
LRAM 2012	kW	$ 0.0002	5000	$ 1.00	$ 0.0002	5000	$ 1.00	$ -	
LRAM 2013 & LRAMVA 2013	kW	$ -	5000	$ -	$ 0.0005	5000	$ 2.50	$ 2.50	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ 4.6600	1	$ 4.66	$ 4.66	
Sub-Total A				$ 112.90			$ 142.27	**$ 29.37**	**26.01%**
Rate Rider for Deferral/Variance Account Disposition 2011	kW	$ 0.0012	5000	$ 6.00	$ -	5000	$ -	-$ 6.00	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kW	-$ 0.0016	5000	-$ 8.00	-$ 0.0016	5000	-$ 8.00	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kW	$ -	5000	$ -	-$ 0.0012	5000	-$ 6.00	-$ 6.00	
Low Voltage Service Charge	kWh	$ 0.0002	5000	$ 1.00	$ 0.0002	5000	$ 1.00	$ -	
Smart Meter Entity Charge						5000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 111.90**			**$ 129.27**	**$ 17.37**	**15.52%**
RTSR - Network	kWh	$ 0.0063	5178	$ 32.62	$ 0.0060	5210	$ 31.26	-$ 1.36	-4.17%
RTSR - Line and Transformation Connection	kWh	$ 0.0050	5178	$ 25.89	$ 0.0047	5210	$ 24.49	-$ 1.40	-5.41%
Sub-Total C - Delivery (including Sub-Total B)				**$ 170.41**			**$ 185.02**	**$ 14.61**	**8.57%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	5178	$ 26.93	$ 0.0052	5210	$ 27.09	$ 0.17	0.62%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	5178	$ 5.70	$ 0.0011	5210	$ 5.73	$ 0.04	0.62%
Standard Supply Service Charge			1	$ -	$ -	1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	5000	$ 35.00	$ 0.0070	5000	$ 35.00	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	750	$ 55.50	$ 0.0740	750	$ 55.50	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0870	4428	$ 385.24	$ 0.0870	4460.27	$ 388.04	$ 2.81	0.73%
TOU - Off Peak	kWh	$ 0.0630	3314	$ 208.78	$ 0.0630	3335	$ 210.08	$ 1.30	0.62%
TOU - Mid Peak	kWh	$ 0.0990	932	$ 92.27	$ 0.0990	938	$ 92.85	$ 0.58	0.62%
TOU - On Peak	kWh	$ 0.1180	932	$ 109.98	$ 0.1180	938	$ 110.67	$ 0.69	0.62%
Total Bill on RPP (before Taxes)				**$ 678.77**			**$ 696.39**	**$ 17.62**	**2.60%**
HST		13%		$ 88.24	13%		$ 90.53	$ 2.29	2.60%
Total Bill (including HST)				$ 767.01			$ 786.92	$ 19.91	2.60%
Ontario Clean Energy Benefit 1				-$ 76.70			-$ 78.69	-$ 1.99	2.59%
Total Bill on RPP (including OCEB)				**$ 690.31**			**$ 708.23**	**$ 17.92**	**2.60%**
Total Bill on TOU (before Taxes)				**$ 649.06**			**$ 666.44**	**$ 17.37**	**2.68%**
HST		13%		$ 84.38	13%		$ 86.64	$ 2.26	2.68%
Total Bill (including HST)				$ 733.44			$ 753.07	$ 19.63	2.68%
Ontario Clean Energy Benefit 1				-$ 73.34			-$ 75.31	-$ 1.97	2.69%
Total Bill on TOU (including OCEB)				**$ 660.10**			**$ 677.76**	**$ 17.66**	**2.68%**
Loss Factor (%)		3.56%			4.21%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: General Service < 50 kW

Consumption 10000 **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	$ Change	% Change
Monthly Service Charge	Monthly	$ 23.7100	1	$ 23.71	$ 28.4200	1	$ 28.42	$ 4.71	19.87%
Smart Meter Rate Adder	Monthly	$ 5.9400	1	$ 5.94	$ 5.9400	1	$ 5.94	$ -	
Rate Rider for Tax change	kWh	-$ 0.0003	10000	-$ 3.00	$ -	10000	$ -	$ 3.00	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kWh	$ 0.0166	10000	$ 166.00	$ 0.0199	10000	$ 199.00	$ 33.00	19.88%
Smart Meter Disposition Rider				$ -	$ -		$ -	$ -	
LRAM 2011	kW	$ 0.0001	10000	$ 1.00	$ -	10000	$ -	-$ 1.00	-100.00%
LRAM 2012	kW	$ 0.0002	10000	$ 2.00	$ 0.0002	10000	$ 2.00	$ -	
LRAM 2013 & LRAMVA 2013	kW	$ -	10000	$ -	$ 0.0005	10000	$ 5.00	$ 5.00	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ 4.6600	1	$ 4.66	$ 4.66	
Sub-Total A				$ 195.90			$ 245.27	**$ 49.37**	**25.20%**
Rate Rider for Deferral/Variance Account Disposition 2011	kW	$ 0.0012	10000	$ 12.00	$ -	10000	$ -	-$ 12.00	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kW	-$ 0.0016	10000	-$ 16.00	-$ 0.0016	10000	-$ 16.00	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kW	$ -	10000	$ -	-$ 0.0012	10000	-$ 12.00	-$ 12.00	
Low Voltage Service Charge	kWh	$ 0.0002	10000	$ 2.00	$ 0.0002	10000	$ 2.00	$ -	
Smart Meter Entity Charge						10000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 193.90**			**$ 219.27**	**$ 25.37**	**13.08%**
RTSR - Network	kWh	$ 0.0063	10356	$ 65.24	$ 0.0060	10421	$ 62.52	-$ 2.72	-4.17%
RTSR - Line and Transformation Connection	kWh	$ 0.0050	10356	$ 51.78	$ 0.0047	10421	$ 48.98	-$ 2.80	-5.41%
Sub-Total C - Delivery (including Sub-Total B)				**$ 310.92**			**$ 330.77**	**$ 19.85**	**6.38%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	10356	$ 53.85	$ 0.0052	10421	$ 54.19	$ 0.34	0.62%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	10356	$ 11.39	$ 0.0011	10421	$ 11.46	$ 0.07	0.62%
Standard Supply Service Charge			1	$ -	$ -	1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	10000	$ 70.00	$ 0.0070	10000	$ 70.00	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	750	$ 55.50	$ 0.0740	750	$ 55.50	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0870	9606	$ 835.72	$ 0.0870	9670.541	$ 841.34	$ 5.62	0.67%
TOU - Off Peak	kWh	$ 0.0630	6628	$ 417.55	$ 0.0630	6669	$ 420.16	$ 2.60	0.62%
TOU - Mid Peak	kWh	$ 0.0990	1864	$ 184.54	$ 0.0990	1876	$ 185.69	$ 1.15	0.62%
TOU - On Peak	kWh	$ 0.1180	1864	$ 219.96	$ 0.1180	1876	$ 221.33	$ 1.37	0.62%
Total Bill on RPP (before Taxes)				**$ 1,337.39**			**$ 1,363.26**	**$ 25.87**	**1.93%**
HST		13%		$ 173.86	13%		$ 177.22	$ 3.36	1.93%
Total Bill (including HST)				$ 1,511.25			$ 1,540.48	$ 29.23	1.93%
Ontario Clean Energy Benefit 1				-$ 151.12			-$ 154.05	-$ 2.93	1.94%
Total Bill on RPP (including OCEB)				**$ 1,360.13**			**$ 1,386.43**	**$ 26.30**	**1.93%**
Total Bill on TOU (before Taxes)				**$ 1,268.22**			**$ 1,293.60**	**$ 25.38**	**2.00%**
HST		13%		$ 164.87	13%		$ 168.17	$ 3.30	2.00%
Total Bill (including HST)				$ 1,433.09			$ 1,461.77	$ 28.68	2.00%
Ontario Clean Energy Benefit 1				-$ 143.31			-$ 146.18	-$ 2.87	2.00%
Total Bill on TOU (including OCEB)				**$ 1,289.78**			**$ 1,315.59**	**$ 25.81**	**2.00%**
Loss Factor (%)		3.56%			4.21%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: General Service > 50 to 999 kW

Consumption 26000 kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	$ Change	% Change
Monthly Service Charge	Monthly	$ 142.0000	1	$ 142.00	$ 142.0000	1	$ 142.00	$ -	
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for Tax change	kW	-$ 0.0614	60	-$ 3.68	$ -	60	$ -	$ 3.68	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kW	$ 3.5617	60	$ 213.70	$ 4.4827	60	$ 268.96	$ 55.26	25.86%
Smart Meter Disposition Rider				$ -			$ -	$ -	
LRAM 2011	kW	$ -	60	$ -	$ -	60	$ -	$ -	
LRAM 2012	kW	$ 0.0149	60	$ 0.89	$ 0.0149	60	$ 0.89	$ -	
LRAM 2013 & LRAMVA 2013	kW	$ -	60	$ -	$ 0.0880	60	$ 5.28	$ 5.28	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A				$ 353.16			$ 417.39	**$ 64.22**	**18.19%**
Rate Rider for Deferral/Variance Account Disposition 2011	kW	$ 0.4186	60	$ 25.12	$ -	60	$ -	-$ 25.12	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kW	-$ 0.4464	60	-$ 26.78	-$ 0.4464	60	-$ 26.78	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kW	$ -	60	$ -	-$ 0.4518	60	-$ 27.11	-$ 27.11	
Low Voltage Service Charge	kW	$ 0.0722	60	$ 4.33	$ 0.0750	60	$ 4.50	$ 0.17	3.88%
Smart Meter Entity Charge						26000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 355.83**			**$ 367.99**	**$ 12.17**	**3.42%**
RTSR - Network	kW	$ 2.5648	60	$ 153.89	$ 2.4271	60	$ 145.63	-$ 8.26	-5.37%
RTSR - Line and Transformation Connection	kW	$ 1.9998	60	$ 119.99	$ 1.8963	60	$ 113.78	-$ 6.21	-5.18%
Sub-Total C - Delivery (including Sub-Total B)				**$ 629.70**			**$ 627.40**	**-$ 2.30**	**-0.37%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	26926	$ 140.01	$ 0.0052	27093	$ 140.89	$ 0.87	0.62%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	26926	$ 29.62	$ 0.0011	27093	$ 29.80	$ 0.18	0.62%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	26000	$ 182.00	$ 0.0070	26000	$ 182.00	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	750	$ 55.50	$ 0.0740	750	$ 55.50	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0870	26176	$ 2,277.28	$ 0.0870	26343	$ 2,291.88	$ 14.60	0.64%
TOU - Off Peak	kWh	$ 0.0630	17232	$ 1,085.64	$ 0.0630	17340	$ 1,092.41	$ 6.77	0.62%
TOU - Mid Peak	kWh	$ 0.0990	4847	$ 479.81	$ 0.0990	4877	$ 482.80	$ 2.99	0.62%
TOU - On Peak	kWh	$ 0.1180	4847	$ 571.90	$ 0.1180	4877	$ 575.46	$ 3.56	0.62%
Total Bill on RPP (before Taxes)				**$ 3,314.11**			**$ 3,327.46**	**$ 13.35**	**0.40%**
HST		13%		$ 430.83	13%		$ 432.57	$ 1.74	0.40%
Total Bill (including HST)				$ 3,744.94			$ 3,760.03	$ 15.09	0.40%
Ontario Clean Energy Benefit 1				-$ 374.49			-$ 376.00	-$ 1.51	0.40%
Total Bill on RPP (including OCEB)				**$ 3,370.45**			**$ 3,384.03**	**$ 13.58**	**0.40%**
Total Bill on TOU (before Taxes)				**$ 3,118.69**			**$ 3,130.76**	**$ 12.07**	**0.39%**
HST		13%		$ 405.43	13%		$ 407.00	$ 1.57	0.39%
Total Bill (including HST)				$ 3,524.12			$ 3,537.76	$ 13.64	0.39%
Ontario Clean Energy Benefit 1				-$ 352.41			-$ 353.78	-$ 1.37	0.39%
Total Bill on TOU (including OCEB)				**$ 3,171.71**			**$ 3,183.98**	**$ 12.27**	**0.39%**
Loss Factor (%)		3.56%			4.21%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: General Service > 50 to 999 kW

Consumption 52000 kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	$ Change	% Change
Monthly Service Charge	Monthly	$ 142.0000	1	$ 142.00	$ 142.0000	1	$ 142.00	$ -	
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for Tax change	kW	-$ 0.0614	135	-$ 8.29	$ -	135	$ -	$ 8.29	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kW	$ 3.5617	135	$ 480.83	$ 4.4827	135	$ 605.16	$ 124.34	25.86%
Smart Meter Disposition Rider				$ -	$ -		$ -	$ -	
LRAM 2011	kW	$ -	135	$ -	$ -	135	$ -	$ -	
LRAM 2012	kW	$ 0.0149	135	$ 2.01	$ 0.0149	135	$ 2.01	$ -	
LRAM 2013 & LRAMVA 2013	kW	$ -	135	$ -	$ 0.0880	135	$ 11.88	$ 11.88	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A				$ 616.80			$ 761.31	**$ 144.50**	**23.43%**
Rate Rider for Deferral/Variance Account Disposition 2011	kW	$ 0.4186	135	$ 56.51	$ -	135	$ -	-$ 56.51	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kW	-$ 0.4464	135	-$ 60.26	-$ 0.4464	135	-$ 60.26	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kW	$ -	135	$ -	-$ 0.4518	135	-$ 60.99	-$ 60.99	
Low Voltage Service Charge	kW	$ 0.0722	135	$ 9.75	$ 0.0750	135	$ 10.13	$ 0.38	3.88%
Smart Meter Entity Charge					$ -	52000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 622.80**			**$ 650.17**	**$ 27.38**	**4.40%**
RTSR - Network	kW	$ 2.5648	135	$ 346.25	$ 2.4271	135	$ 327.66	-$ 18.59	-5.37%
RTSR - Line and Transformation Connection	kW	$ 1.9998	135	$ 269.97	$ 1.8963	135	$ 256.00	-$ 13.97	-5.18%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,239.02**			**$ 1,233.83**	**-$ 5.18**	**-0.42%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	53851	$ 280.03	$ 0.0052	54187	$ 281.77	$ 1.75	0.62%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	53851	$ 59.24	$ 0.0011	54187	$ 59.61	$ 0.37	0.62%
Standard Supply Service Charge			1	$ -	$ -	1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	52000	$ 364.00	$ 0.0070	52000	$ 364.00	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	750	$ 55.50	$ 0.0740	750	$ 55.50	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0870	53101	$ 4,619.80	$ 0.0870	53437	$ 4,649.00	$ 29.20	0.63%
TOU - Off Peak	kWh	$ 0.0630	34465	$ 2,171.28	$ 0.0630	34680	$ 2,184.81	$ 13.53	0.62%
TOU - Mid Peak	kWh	$ 0.0990	9693	$ 959.63	$ 0.0990	9754	$ 965.61	$ 5.98	0.62%
TOU - On Peak	kWh	$ 0.1180	9693	$ 1,143.80	$ 0.1180	9754	$ 1,150.93	$ 7.13	0.62%
Total Bill on RPP (before Taxes)				**$ 6,617.58**			**$ 6,643.71**	**$ 26.13**	**0.39%**
HST		13%		$ 860.29	13%		$ 863.68	$ 3.40	0.39%
Total Bill (including HST)				$ 7,477.87			$ 7,507.40	$ 29.53	0.39%
Ontario Clean Energy Benefit 1				-$ 747.79			-$ 750.74	-$ 2.95	0.39%
Total Bill on RPP (including OCEB)				**$ 6,730.08**			**$ 6,756.66**	**$ 26.58**	**0.39%**
Total Bill on TOU (before Taxes)				**$ 6,216.99**			**$ 6,240.56**	**$ 23.57**	**0.38%**
HST		13%		$ 808.21	13%		$ 811.27	$ 3.06	0.38%
Total Bill (including HST)				$ 7,025.20			$ 7,051.83	$ 26.64	0.38%
Ontario Clean Energy Benefit 1				-$ 702.52			-$ 705.18	-$ 2.66	0.38%
Total Bill on TOU (including OCEB)				**$ 6,322.68**			**$ 6,346.65**	**$ 23.98**	**0.38%**

Loss Factor (%) 3.56% 4.21%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: General Service > 50 to 999 kW

Consumption **165000** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	$ Change	% Change
Monthly Service Charge	Monthly	$ 142.0000	1	$ 142.00	$ 142.0000	1	$ 142.00	$ -	
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for Tax change	kW	-$ 0.0614	355	-$ 21.80	$ -	355	$ -	$ 21.80	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kW	$ 3.5617	355	$ 1,264.40	$ 4.4827	355	$ 1,591.36	$ 326.96	25.86%
Smart Meter Disposition Rider				$ -	$ -		$ -	$ -	
LRAM 2011	kW	$ -	355	$ -	$ -	355	$ -	$ -	
LRAM 2012	kW	$ 0.0149	355	$ 5.29	$ 0.0149	355	$ 5.29	$ -	
LRAM 2013 & LRAMVA 2013	kW	$ -	355	$ -	$ 0.0880	355	$ 31.24	$ 31.24	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A				$ 1,390.15			$ 1,770.14	**$ 379.99**	**27.33%**
Rate Rider for Deferral/Variance Account Disposition 2011	kW	$ 0.4186	355	$ 148.60	$ -	355	$ -	-$ 148.60	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kW	-$ 0.4464	355	-$ 158.47	-$ 0.4464	355	-$ 158.47	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kW	$ -	355	$ -	-$ 0.4518	355	-$ 160.39	-$ 160.39	
Low Voltage Service Charge	kW	$ 0.0722	355	$ 25.63	$ 0.0750	355	$ 26.63	$ 0.99	3.88%
Smart Meter Entity Charge		▨	▨	▨		165000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 1,405.91**			**$ 1,477.90**	**$ 71.99**	**5.12%**
RTSR - Network	kW	$ 2.5648	355	$ 910.50	$ 2.4271	355	$ 861.62	-$ 48.88	-5.37%
RTSR - Line and Transformation Connection	kW	$ 1.9998	355	$ 709.93	$ 1.8963	355	$ 673.19	-$ 36.74	-5.18%
Sub-Total C - Delivery (including Sub-Total B)				**$ 3,026.34**			**$ 3,012.71**	**-$ 13.63**	**-0.45%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	170874	$ 888.54	$ 0.0052	171939	$ 894.08	$ 5.54	0.62%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	170874	$ 187.96	$ 0.0011	171939	$ 189.13	$ 1.17	0.62%
Standard Supply Service Charge			1	$ -	$ -	1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	165000	$ 1,155.00	$ 0.0070	165000	$ 1,155.00	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	750	$ 55.50	$ 0.0740	750	$ 55.50	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0870	170124	$ 14,800.79	$ 0.0870	171189	$ 14,893.44	$ 92.65	0.63%
TOU - Off Peak	kWh	$ 0.0630	109359	$ 6,889.64	$ 0.0630	110041	$ 6,932.58	$ 42.94	0.62%
TOU - Mid Peak	kWh	$ 0.0990	30757	$ 3,044.97	$ 0.0990	30949	$ 3,063.95	$ 18.98	0.62%
TOU - On Peak	kWh	$ 0.1180	30757	$ 3,629.36	$ 0.1180	30949	$ 3,651.98	$ 22.62	0.62%
Total Bill on RPP (before Taxes)				**$ 20,114.14**			**$ 20,199.86**	**$ 85.73**	**0.43%**
HST		13%		$ 2,614.84	13%		$ 2,625.98	$ 11.14	0.43%
Total Bill (including HST)				$ 22,728.97			$ 22,825.84	$ 96.87	0.43%
Ontario Clean Energy Benefit 1				-$ 2,272.90			-$ 2,282.58	-$ 9.68	0.43%
Total Bill on RPP (including OCEB)				**$ 20,456.07**			**$ 20,543.26**	**$ 87.19**	**0.43%**
Total Bill on TOU (before Taxes)				**$ 18,821.83**			**$ 18,899.44**	**$ 77.61**	**0.41%**
HST		13%		$ 2,446.84	13%		$ 2,456.93	$ 10.09	0.41%
Total Bill (including HST)				$ 21,268.66			$ 21,356.36	$ 87.70	0.41%
Ontario Clean Energy Benefit 1				-$ 2,126.87			-$ 2,135.64	-$ 8.77	0.41%
Total Bill on TOU (including OCEB)				**$ 19,141.79**			**$ 19,220.72**	**$ 78.93**	**0.41%**

Loss Factor (%) 3.56% 4.21%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: General Service > 50 to 999 kW

Consumption 430000 **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 142.0000	1	$ 142.00	$ 142.0000	1	$ 142.00	$ -	
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for Tax change	kW	-$ 0.0614	860	-$ 52.80	$ -	860	$ -	$ 52.80	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kW	$ 3.5617	860	$ 3,063.06	$ 4.4827	860	$ 3,855.12	$ 792.06	25.86%
Smart Meter Disposition Rider				$ -	$ -		$ -	$ -	
LRAM 2011	kW	$ -	860	$ -	$ -	860	$ -	$ -	
LRAM 2012	kW	$ 0.0149	860	$ 12.81	$ 0.0149	860	$ 12.81	$ -	
LRAM 2013 & LRAMVA 2013	kW	$ -	860	$ -	$ 0.0880	860	$ 75.68	$ 75.68	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A				$ 3,165.32			$ 4,085.87	**$ 920.54**	**29.08%**
Rate Rider for Deferral/Variance Account Disposition 2011	kW	$ 0.4186	860	$ 360.00	$ -	860	$ -	-$ 360.00	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kW	-$ 0.4464	860	-$ 383.90	-$ 0.4464	860	-$ 383.90	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kW	$ -	860	$ -	-$ 0.4518	860	-$ 388.55	-$ 388.55	
Low Voltage Service Charge	kW	$ 0.0722	860	$ 62.09	$ 0.0750	860	$ 64.50	$ 2.41	3.88%
Smart Meter Entity Charge		▨	▨	▨		430000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 3,203.51**			**$ 3,377.91**	**$ 174.41**	**5.44%**
RTSR - Network	kW	$ 2.5648	860	$ 2,205.73	$ 2.4271	860	$ 2,087.31	-$ 118.42	-5.37%
RTSR - Line and Transformation Connection	kW	$ 1.9998	860	$ 1,719.83	$ 1.8963	860	$ 1,630.82	-$ 89.01	-5.18%
Sub-Total C - Delivery (including Sub-Total B)				**$ 7,129.06**			**$ 7,096.04**	**-$ 33.02**	**-0.46%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	445308	$ 2,315.60	$ 0.0052	448083	$ 2,330.03	$ 14.43	0.62%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	445308	$ 489.84	$ 0.0011	448083	$ 492.89	$ 3.05	0.62%
Standard Supply Service Charge			1	$ -	$ -	1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	430000	$ 3,010.00	$ 0.0070	430000	$ 3,010.00	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	750	$ 55.50	$ 0.0740	750	$ 55.50	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0870	444558	$ 38,676.55	$ 0.0870	447333	$ 38,917.99	$ 241.45	0.62%
TOU - Off Peak	kWh	$ 0.0630	284997	$ 17,954.82	$ 0.0630	286773	$ 18,066.72	$ 111.90	0.62%
TOU - Mid Peak	kWh	$ 0.0990	80155	$ 7,935.39	$ 0.0990	80655	$ 7,984.84	$ 49.45	0.62%
TOU - On Peak	kWh	$ 0.1180	80155	$ 9,458.34	$ 0.1180	80655	$ 9,517.29	$ 58.95	0.62%
Total Bill on RPP (before Taxes)				**$ 51,676.55**			**$ 51,902.46**	**$ 225.91**	**0.44%**
HST		13%		$ 6,717.95	13%		$ 6,747.32	$ 29.37	0.44%
Total Bill (including HST)				$ 58,394.50			$ 58,649.77	$ 255.27	0.44%
Ontario Clean Energy Benefit 1				-$ 5,839.45			-$ 5,864.98	-$ 25.53	0.44%
Total Bill on RPP (including OCEB)				**$ 52,555.05**			**$ 52,784.79**	**$ 229.74**	**0.44%**
Total Bill on TOU (before Taxes)				**$ 48,293.05**			**$ 48,497.81**	**$ 204.76**	**0.42%**
HST		13%		$ 6,278.10	13%		$ 6,304.72	$ 26.62	0.42%
Total Bill (including HST)				$ 54,571.15			$ 54,802.53	$ 231.38	0.42%
Ontario Clean Energy Benefit 1				-$ 5,457.11			-$ 5,480.25	-$ 23.14	0.42%
Total Bill on TOU (including OCEB)				**$ 49,114.04**			**$ 49,322.28**	**$ 208.24**	**0.42%**
Loss Factor (%)		3.56%			4.21%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: General Service 1000 to 4999 kW

Consumption **605000** **kWh**

	Charge Unit	Current Board-Approved **Rate ($)**	**Volume**	**Charge ($)**	Proposed **Rate ($)**	**Volume**	**Charge ($)**	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 3,121.6300	1	$ 3,121.63	$ 3,121.6300	1	$ 3,121.63	$ -	
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for Tax change	kW	-$ 0.0363	1360	-$ 49.37	$ -	1360	$ -	$ 49.37	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kW	$ 1.2790	1360	$ 1,739.44	$ 1.8557	1360	$ 2,523.75	$ 784.31	45.09%
Smart Meter Disposition Rider				$ -			$ -	$ -	
LRAM 2011	kW	$ -	1360	$ -	$ -	1360	$ -	$ -	
LRAM 2012	kW	$ -	1360	$ -	$ -	1360	$ -	$ -	
LRAM 2013 & LRAMVA 2013	kW	$ -	1360	$ -	$ -	1360	$ -	$ -	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A				$ 4,811.95			$ 5,645.63	**$ 833.68**	**17.33%**
Rate Rider for Deferral/Variance Account Disposition 2011	kW	$ 0.5237	1360	$ 712.23	$ -	1360	$ -	-$ 712.23	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kW	-$ 0.5105	1360	-$ 694.28	-$ 0.5105	1360	-$ 694.28	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kW	$ -	1360	$ -	-$ 0.5699	1360	-$ 775.06	-$ 775.06	
Low Voltage Service Charge	kW	$ 0.0792	1360	$ 107.71	$ 0.0822	1360	$ 111.79	$ 4.08	3.79%
Smart Meter Entity Charge		▨	▨	▨		605000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 4,937.62**			**$ 4,288.08**	**-$ 649.54**	**-13.15%**
RTSR - Network	kW	$ 2.7241	1360	$ 3,704.78	$ 2.5778	1360	$ 3,505.81	-$ 198.97	-5.37%
RTSR - Line and Transformation Connection	kW	$ 2.1923	1360	$ 2,981.53	$ 2.0788	1360	$ 2,827.17	-$ 154.36	-5.18%
Sub-Total C - Delivery (including Sub-Total B)				**$ 11,623.92**			**$ 10,621.06**	**-$ 1,002.86**	**-8.63%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	620307	$ 3,225.59	$ 0.0052	624118	$ 3,245.41	$ 19.82	0.61%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	620307	$ 682.34	$ 0.0011	624118	$ 686.53	$ 4.19	0.61%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	605000	$ 4,235.00	$ 0.0070	605000	$ 4,235.00	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	750	$ 55.50	$ 0.0740	750	$ 55.50	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0870	619557	$ 53,901.42	$ 0.0870	623368	$ 54,233.02	$ 331.60	0.62%
TOU - Off Peak	kWh	$ 0.0630	396996	$ 25,010.76	$ 0.0630	399436	$ 25,164.44	$ 153.68	0.61%
TOU - Mid Peak	kWh	$ 0.0990	111655	$ 11,053.86	$ 0.0990	112341	$ 11,121.78	$ 67.92	0.61%
TOU - On Peak	kWh	$ 0.1180	111655	$ 13,175.31	$ 0.1180	112341	$ 13,256.27	$ 80.96	0.61%
Total Bill on RPP (before Taxes)				**$ 73,723.77**			**$ 73,076.52**	**-$ 647.25**	**-0.88%**
HST		13%		$ 9,584.09	13%		$ 9,499.95	-$ 84.14	-0.88%
Total Bill (including HST)				$ 83,307.86			$ 82,576.46	-$ 731.39	-0.88%
Ontario Clean Energy Benefit 1				-$ 8,330.79			-$ 8,257.65	$ 73.14	-0.88%
Total Bill on RPP (including OCEB)				**$ 74,977.07**			**$ 74,318.81**	**-$ 658.25**	**-0.88%**
Total Bill on TOU (before Taxes)				**$ 69,006.78**			**$ 68,330.49**	**-$ 676.29**	**-0.98%**
HST		13%		$ 8,970.88	13%		$ 8,882.96	-$ 87.92	-0.98%
Total Bill (including HST)				$ 77,977.66			$ 77,213.45	-$ 764.21	-0.98%
Ontario Clean Energy Benefit 1				-$ 7,797.77			-$ 7,721.34	$ 76.43	-0.98%
Total Bill on TOU (including OCEB)				**$ 70,179.89**			**$ 69,492.11**	**-$ 687.78**	**-0.98%**
Loss Factor (%)		2.53%			3.16%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: General Service 1000 to 4999 kW

Consumption 977118 **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	$ Change	% Change
Monthly Service Charge	Monthly	$ 3,121.6300	1	$ 3,121.63	$ 3,121.6300	1	$ 3,121.63	$ -	
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for Tax change	kW	-$ 0.0363	2578	-$ 93.58	$ -	2578	$ -	$ 93.58	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kW	$ 1.2790	2578	$ 3,297.26	$ 1.8557	2578	$ 4,783.99	$ 1,486.73	45.09%
Smart Meter Disposition Rider				$ -	$ -		$ -	$ -	
LRAM 2011	kW	$ -	2578	$ -	$ -	2578	$ -	$ -	
LRAM 2012	kW	$ -	2578	$ -	$ -	2578	$ -	$ -	
LRAM 2013 & LRAMVA 2013	kW	$ -	2578	$ -	$ -	2578	$ -	$ -	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A				$ 6,325.56			$ 7,905.87	**$ 1,580.31**	**24.98%**
Rate Rider for Deferral/Variance Account Disposition 2011	kW	$ 0.5237	2578	$ 1,350.10	$ -	2578	$ -	-$ 1,350.10	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kW	-$ 0.5105	2578	-$ 1,316.07	-$ 0.5105	2578	-$ 1,316.07	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kW	$ -	2578	$ -	-$ 0.5699	2578	-$ 1,469.20	-$ 1,469.20	
Low Voltage Service Charge	kW	$ 0.0792	2578	$ 204.18	$ 0.0822	2578	$ 211.91	$ 7.73	3.79%
Smart Meter Entity Charge						977118	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 6,563.77**			**$ 5,332.52**	**-$ 1,231.25**	**-18.76%**
RTSR - Network	kW	$ 2.7241	2578	$ 7,022.73	$ 2.5778	2578	$ 6,645.57	-$ 377.16	-5.37%
RTSR - Line and Transformation Connection	kW	$ 2.1923	2578	$ 5,651.75	$ 2.0788	2578	$ 5,359.15	-$ 292.60	-5.18%
Sub-Total C - Delivery (including Sub-Total B)				**$ 19,238.25**			**$ 17,337.23**	**-$ 1,901.02**	**-9.88%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	1001839	$ 5,209.56	$ 0.0052	1007995	$ 5,241.57	$ 32.01	0.61%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	1001839	$ 1,102.02	$ 0.0011	1007995	$ 1,108.79	$ 6.77	0.61%
Standard Supply Service Charge			1	$ -	$ -	1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	977118	$ 6,839.83	$ 0.0070	977118	$ 6,839.83	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	750	$ 55.50	$ 0.0740	750	$ 55.50	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0870	1001089	$ 87,094.75	$ 0.0870	1007245	$ 87,630.31	$ 535.56	0.61%
TOU - Off Peak	kWh	$ 0.0630	641177	$ 40,394.15	$ 0.0630	645117	$ 40,642.36	$ 248.20	0.61%
TOU - Mid Peak	kWh	$ 0.0990	180331	$ 17,852.77	$ 0.0990	181439	$ 17,962.47	$ 109.70	0.61%
TOU - On Peak	kWh	$ 0.1180	180331	$ 21,279.06	$ 0.1180	181439	$ 21,409.81	$ 130.75	0.61%
Total Bill on RPP (before Taxes)				**$ 119,539.91**			**$ 118,213.23**	**-$ 1,326.68**	**-1.11%**
HST		13%		$ 15,540.19	13%		$ 15,367.72	-$ 172.47	-1.11%
Total Bill (including HST)				$ 135,080.10			$ 133,580.95	-$ 1,499.15	-1.11%
Ontario Clean Energy Benefit 1				-$ 13,508.01			-$ 13,358.10	$ 149.91	-1.11%
Total Bill on RPP (including OCEB)				**$ 121,572.09**			**$ 120,222.85**	**-$ 1,349.24**	**-1.11%**
Total Bill on TOU (before Taxes)				**$ 111,915.65**			**$ 110,542.06**	**-$ 1,373.58**	**-1.23%**
HST		13%		$ 14,549.03	13%		$ 14,370.47	-$ 178.57	-1.23%
Total Bill (including HST)				$ 126,464.68			$ 124,912.53	-$ 1,552.15	-1.23%
Ontario Clean Energy Benefit 1				-$ 12,646.47			-$ 12,491.25	$ 155.22	-1.23%
Total Bill on TOU (including OCEB)				**$ 113,818.21**			**$ 112,421.28**	**-$ 1,396.93**	**-1.23%**

Loss Factor (%) 2.53% 3.16%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: General Service 1000 to 4999 kW

Consumption 3011152 kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	$ Change	% Change
Monthly Service Charge	Monthly	$ 3,121.6300	1	$ 3,121.63	$ 3,121.6300	1	$ 3,121.63	$ -	
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for Tax change	kW	-$ 0.0363	4500	-$ 163.35	$ -	4500	$ -	$ 163.35	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kW	$ 1.2790	4500	$ 5,755.50	$ 1.8557	4500	$ 8,350.65	$ 2,595.15	45.09%
Smart Meter Disposition Rider				$ -	$ -		$ -	$ -	
LRAM 2011	kW	$ -	4500	$ -	$ -	4500	$ -	$ -	
LRAM 2012	kW	$ -	4500	$ -	$ -	4500	$ -	$ -	
LRAM 2013	kW	$ -	4500	$ -	$ -	4500	$ -	$ -	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A				$ 8,714.03			$ 11,472.53	**$ 2,758.50**	**31.66%**
Rate Rider for Deferral/Variance Account Disposition 2011	kW	$ 0.5237	4500	$ 2,356.65	$ -	4500	$ -	-$ 2,356.65	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kW	-$ 0.5105	4500	-$ 2,297.25	-$ 0.5105	4500	-$ 2,297.25	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kW	$ -	4500	$ -	-$ 0.5699	4500	-$ 2,564.55	-$ 2,564.55	
Low Voltage Service Charge	kW	$ 0.0792	4500	$ 356.40	$ 0.0822	4500	$ 369.90	$ 13.50	3.79%
Smart Meter Entity Charge						3011152	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 9,129.83**			**$ 6,980.63**	**-$ 2,149.20**	**-23.54%**
RTSR - Network	kW	$ 2.7241	4500	$ 12,258.45	$ 2.5778	4500	$ 11,600.10	-$ 658.35	-5.37%
RTSR - Line and Transformation Connection	kW	$ 2.1923	4500	$ 9,865.35	$ 2.0788	4500	$ 9,354.60	-$ 510.75	-5.18%
Sub-Total C - Delivery (including Sub-Total B)				**$ 31,253.63**			**$ 27,935.33**	**-$ 3,318.30**	**-10.62%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	3087334	$ 16,054.14	$ 0.0052	3106304	$ 16,152.78	$ 98.65	0.61%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	3087334	$ 3,396.07	$ 0.0011	3106304	$ 3,416.93	$ 20.87	0.61%
Standard Supply Service Charge			1	$ -	$ -	1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	3011152	$ 21,078.06	$ 0.0070	3011152	$ 21,078.06	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	750	$ 55.50	$ 0.0740	750	$ 55.50	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0870	3086584	$ 268,532.82	$ 0.0870	3105554	$ 270,183.23	$ 1,650.41	0.61%
TOU - Off Peak	kWh	$ 0.0630	1975894	$ 124,481.31	$ 0.0630	1988035	$ 125,246.19	$ 764.88	0.61%
TOU - Mid Peak	kWh	$ 0.0990	555720	$ 55,016.29	$ 0.0990	559135	$ 55,354.34	$ 338.05	0.61%
TOU - On Peak	kWh	$ 0.1180	555720	$ 65,574.98	$ 0.1180	559135	$ 65,977.91	$ 402.93	0.61%
Total Bill on RPP (before Taxes)				**$ 340,370.22**			**$ 338,821.84**	**-$ 1,548.37**	**-0.45%**
HST		13%		$ 44,248.13	13%		$ 44,046.84	-$ 201.29	-0.45%
Total Bill (including HST)				$ 384,618.35			$ 382,868.68	-$ 1,749.66	-0.45%
Ontario Clean Energy Benefit 1				-$ 38,461.83			-$ 38,286.87	$ 174.96	-0.45%
Total Bill on RPP (including OCEB)				**$ 346,156.52**			**$ 344,581.81**	**-$ 1,574.70**	**-0.45%**
Total Bill on TOU (before Taxes)				**$ 316,854.48**			**$ 315,161.56**	**-$ 1,692.93**	**-0.53%**
HST		13%		$ 41,191.08	13%		$ 40,971.00	-$ 220.08	-0.53%
Total Bill (including HST)				$ 358,045.57			$ 356,132.56	-$ 1,913.01	-0.53%
Ontario Clean Energy Benefit 1				-$ 35,804.56			-$ 35,613.26	$ 191.30	-0.53%
Total Bill on TOU (including OCEB)				**$ 322,241.01**			**$ 320,519.30**	**-$ 1,721.71**	**-0.53%**

Loss Factor (%) 2.53% 3.16%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: Large Use

Consumption 4230083 **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 24,427.6000	1	$ 24,427.60	$ 24,427.6000	1	$ 24,427.60	$ -	
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for Tax change	kW	-$ 0.0470	6943	-$ 326.32	$ -	6943	$ -	$ 326.32	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kW	$ 1.4610	6943	$ 10,143.72	$ 2.0552	6943	$ 14,269.25	$ 4,125.53	40.67%
Smart Meter Disposition Rider				$ -			$ -	$ -	
LRAM 2011	kW	$ -	6943	$ -	$ -	6943	$ -	$ -	
LRAM 2012	kW	$ -	6943	$ -	$ -	6943	$ -	$ -	
LRAM 2013	kW	$ -	6943	$ -	$ -	6943	$ -	$ -	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A				$ 34,245.25			$ 38,697.10	**$ 4,451.85**	**13.00%**
Rate Rider for Deferral/Variance Account Disposition 2011	kW	$ 0.6579	6943	$ 4,567.80	$ -	6943	$ -	-$ 4,567.80	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kW	-$ 0.7177	6943	-$ 4,982.99	-$ 0.7177	6943	-$ 4,982.99	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kW	$ -	6943	$ -	-$ 0.8433	6943	-$ 5,855.03	-$ 5,855.03	
Low Voltage Service Charge	kW	$ 0.0905	6943	$ 628.34	$ 0.0940	6943	$ 652.64	$ 24.30	3.87%
Smart Meter Entity Charge						4230083	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 34,458.40**			**$ 28,511.72**	**-$ 5,946.68**	**-17.26%**
RTSR - Network	kW	$ 3.0162	6943	$ 20,941.48	$ 2.8543	6943	$ 19,817.40	-$ 1,124.07	-5.37%
RTSR - Line and Transformation Connection	kW	$ 2.5070	6943	$ 17,406.10	$ 2.3772	6943	$ 16,504.90	-$ 901.20	-5.18%
Sub-Total C - Delivery (including Sub-Total B)				**$ 72,805.98**			**$ 64,834.03**	**-$ 7,971.95**	**-10.95%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	4249118	$ 22,095.42	$ 0.0052	4259271	$ 22,148.21	$ 52.79	0.24%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	4249118	$ 4,674.03	$ 0.0011	4259271	$ 4,685.20	$ 11.17	0.24%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	4230083	$ 29,610.58	$ 0.0070	4230083	$ 29,610.58	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	750	$ 55.50	$ 0.0740	750	$ 55.50	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0870	4248368	$ 369,608.05	$ 0.0870	4258521	$ 370,491.29	$ 883.24	0.24%
TOU - Off Peak	kWh	$ 0.0630	2719436	$ 171,324.45	$ 0.0630	2725933	$ 171,733.79	$ 409.34	0.24%
TOU - Mid Peak	kWh	$ 0.0990	764841	$ 75,719.29	$ 0.0990	766669	$ 75,900.20	$ 180.91	0.24%
TOU - On Peak	kWh	$ 0.1180	764841	$ 90,251.27	$ 0.1180	766669	$ 90,466.91	$ 215.63	0.24%
Total Bill on RPP (before Taxes)				**$ 498,849.55**			**$ 491,824.80**	**-$ 7,024.75**	**-1.41%**
HST		13%		$ 64,850.44	13%		$ 63,937.22	-$ 913.22	-1.41%
Total Bill (including HST)				$ 563,700.00			$ 555,762.03	-$ 7,937.97	-1.41%
Ontario Clean Energy Benefit 1				-$ 56,370.00			-$ 55,576.20	$ 793.80	-1.41%
Total Bill on RPP (including OCEB)				**$ 507,330.00**			**$ 500,185.83**	**-$ 7,144.17**	**-1.41%**
Total Bill on TOU (before Taxes)				**$ 466,481.02**			**$ 459,378.91**	**-$ 7,102.11**	**-1.52%**
HST		13%		$ 60,642.53	13%		$ 59,719.26	-$ 923.27	-1.52%
Total Bill (including HST)				$ 527,123.56			$ 519,098.17	-$ 8,025.39	-1.52%
Ontario Clean Energy Benefit 1				-$ 52,712.36			-$ 51,909.82	$ 802.54	-1.52%
Total Bill on TOU (including OCEB)				**$ 474,411.20**			**$ 467,188.35**	**-$ 7,222.85**	**-1.52%**

Loss Factor (%) 0.4500% 0.6900%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: Large Use

Consumption 7340623 kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	$ Change	% Change
Monthly Service Charge	Monthly	$ 24,427.6000	1	$ 24,427.60	$ 24,427.6000	1	$ 24,427.60	$ -	
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for Tax change	kW	-$ 0.0470	10492	-$ 493.12	$ -	10492	$ -	$ 493.12	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kW	$ 1.4610	10492	$ 15,328.81	$ 2.0552	10492	$ 21,563.16	$ 6,234.35	40.67%
Smart Meter Disposition Rider				$ -	$ -		$ -	$ -	
LRAM 2011	kW	$ -	10492	$ -	$ -	10492	$ -	$ -	
LRAM 2012	kW	$ -	10492	$ -	$ -	10492	$ -	$ -	
LRAM 2013	kW	$ -	10492	$ -	$ -	10492	$ -	$ -	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A				$ 39,263.54			$ 45,991.01	**$ 6,727.47**	**17.13%**
Rate Rider for Deferral/Variance Account Disposition 2011	kW	$ 0.6579	10492	$ 6,902.69	$ -	10492	$ -	-$ 6,902.69	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kW	-$ 0.7177	10492	-$ 7,530.11	-$ 0.7177	10492	-$ 7,530.11	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kW	$ -	10492	$ -	-$ 0.8433	10492	-$ 8,847.90	-$ 8,847.90	
Low Voltage Service Charge	kW	$ 0.0905	10492	$ 949.53	$ 0.0940	10492	$ 986.25	$ 36.72	3.87%
Smart Meter Entity Charge						7340623	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 39,585.64**			**$ 30,599.24**	**-$ 8,986.40**	**-22.70%**
RTSR - Network	kW	$ 3.0162	10492	$ 31,645.97	$ 2.8543	10492	$ 29,947.32	-$ 1,698.65	-5.37%
RTSR - Line and Transformation Connection	kW	$ 2.5070	10492	$ 26,303.44	$ 2.3772	10492	$ 24,941.58	-$ 1,361.86	-5.18%
Sub-Total C - Delivery (including Sub-Total B)				**$ 97,535.06**			**$ 85,488.14**	**-$ 12,046.91**	**-12.35%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	7373656	$ 38,343.01	$ 0.0052	7391273	$ 38,434.62	$ 91.61	0.24%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	7373656	$ 8,111.02	$ 0.0011	7391273	$ 8,130.40	$ 19.38	0.24%
Standard Supply Service Charge			1	$ -	$ -	1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	7340623	$ 51,384.36	$ 0.0070	7340623	$ 51,384.36	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	750	$ 55.50	$ 0.0740	750	$ 55.50	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0870	7372906	$ 641,442.80	$ 0.0870	7390523	$ 642,975.53	$ 1,532.72	0.24%
TOU - Off Peak	kWh	$ 0.0630	4719140	$ 297,305.80	$ 0.0630	4730415	$ 298,016.14	$ 710.34	0.24%
TOU - Mid Peak	kWh	$ 0.0990	1327258	$ 131,398.55	$ 0.0990	1330429	$ 131,712.49	$ 313.94	0.24%
TOU - On Peak	kWh	$ 0.1180	1327258	$ 156,616.45	$ 0.1180	1330429	$ 156,990.64	$ 374.20	0.24%
Total Bill on RPP (before Taxes)				**$ 836,871.75**			**$ 826,468.55**	**-$ 10,403.20**	**-1.24%**
HST		13%		$ 108,793.33	13%		$ 107,440.91	-$ 1,352.42	-1.24%
Total Bill (including HST)				$ 945,665.08			$ 933,909.46	-$ 11,755.62	-1.24%
Ontario Clean Energy Benefit 1				-$ 94,566.51			-$ 93,390.95	$ 1,175.56	-1.24%
Total Bill on RPP (including OCEB)				**$ 851,098.57**			**$ 840,518.51**	**-$ 10,580.06**	**-1.24%**
Total Bill on TOU (before Taxes)				**$ 780,694.25**			**$ 770,156.80**	**-$ 10,537.45**	**-1.35%**
HST		13%		$ 101,490.25	13%		$ 100,120.38	-$ 1,369.87	-1.35%
Total Bill (including HST)				$ 882,184.50			$ 870,277.18	-$ 11,907.32	-1.35%
Ontario Clean Energy Benefit 1				-$ 88,218.45			-$ 87,027.72	$ 1,190.73	-1.35%
Total Bill on TOU (including OCEB)				**$ 793,966.05**			**$ 783,249.46**	**-$ 10,716.59**	**-1.35%**

Loss Factor (%) 0.4500% 0.6900%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Tab:
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Appendix 2-W
Bill Impacts

Customer Class: Large Use

Consumption **11523872** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	$ Change	% Change
Monthly Service Charge	Monthly	$ 24,427.6000	1	$ 24,427.60	$ 24,427.6000	1	$ 24,427.60	$ -	
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for Tax change	kW	-$ 0.0470	16869	-$ 792.84	$ -	16869	$ -	$ 792.84	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kW	$ 1.4610	16869	$ 24,645.61	$ 2.0552	16869	$ 34,669.17	$ 10,023.56	40.67%
Smart Meter Disposition Rider				$ -	$ -		$ -	$ -	
LRAM 2011	kW	$ -	16869	$ -	$ -	16869	$ -	$ -	
LRAM 2012	kW	$ -	16869	$ -	$ -	16869	$ -	$ -	
LRAM 2013	kW	$ -	16869	$ -	$ -	16869	$ -	$ -	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A				$ 48,280.62			$ 59,097.02	**$ 10,816.40**	**22.40%**
Rate Rider for Deferral/Variance Account Disposition 2011	kW	$ 0.6579	16869	$ 11,098.12	$ -	16869	$ -	-$ 11,098.12	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kW	-$ 0.7177	16869	-$ 12,106.88	-$ 0.7177	16869	-$ 12,106.88	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kW	$ -	16869	$ -	-$ 0.8433	16869	-$ 14,225.63	-$ 14,225.63	
Low Voltage Service Charge	kW	$ 0.0905	16869	$ 1,526.64	$ 0.0940	16869	$ 1,585.69	$ 59.04	3.87%
Smart Meter Entity Charge						11523872	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 48,798.49**			**$ 34,350.20**	**-$ 14,448.30**	**-29.61%**
RTSR - Network	kW	$ 3.0162	16869	$ 50,880.28	$ 2.8543	16869	$ 48,149.19	-$ 2,731.09	-5.37%
RTSR - Line and Transformation Connection	kW	$ 2.5070	16869	$ 42,290.58	$ 2.3772	16869	$ 40,100.99	-$ 2,189.60	-5.18%
Sub-Total C - Delivery (including Sub-Total B)				**$ 141,969.36**			**$ 122,600.37**	**-$ 19,368.99**	**-13.64%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	11575729	$ 60,193.79	$ 0.0052	11603387	$ 60,337.61	$ 143.82	0.24%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	11575729	$ 12,733.30	$ 0.0011	11603387	$ 12,763.73	$ 30.42	0.24%
Standard Supply Service Charge			1	$ -	$ -	1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	11523872	$ 80,667.10	$ 0.0070	11523872	$ 80,667.10	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	750	$ 55.50	$ 0.0740	750	$ 55.50	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0870	11574979	$ 1,007,023.21	$ 0.0870	11602637	$ 1,009,429.39	$ 2,406.18	0.24%
TOU - Off Peak	kWh	$ 0.0630	7408467	$ 466,733.41	$ 0.0630	7426167	$ 467,848.55	$ 1,115.14	0.24%
TOU - Mid Peak	kWh	$ 0.0990	2083631	$ 206,279.50	$ 0.0990	2088610	$ 206,772.35	$ 492.85	0.24%
TOU - On Peak	kWh	$ 0.1180	2083631	$ 245,868.49	$ 0.1180	2088610	$ 246,455.93	$ 587.44	0.24%
Total Bill on RPP (before Taxes)				**$ 1,302,642.26**			**$ 1,285,853.70**	**-$ 16,788.56**	**-1.29%**
HST		13%		$ 169,343.49	13%		$ 167,160.98	-$ 2,182.51	-1.29%
Total Bill (including HST)				$ 1,471,985.76			$ 1,453,014.69	-$ 18,971.07	-1.29%
Ontario Clean Energy Benefit 1				-$ 147,198.58			-$ 145,301.47	$ 1,897.11	-1.29%
Total Bill on RPP (including OCEB)				**$ 1,324,787.18**			**$ 1,307,713.22**	**-$ 17,073.96**	**-1.29%**
Total Bill on TOU (before Taxes)				**$ 1,214,444.96**			**$ 1,197,445.65**	**-$ 16,999.31**	**-1.40%**
HST		13%		$ 157,877.84	13%		$ 155,667.93	-$ 2,209.91	-1.40%
Total Bill (including HST)				$ 1,372,322.80			$ 1,353,113.58	-$ 19,209.22	-1.40%
Ontario Clean Energy Benefit 1				-$ 137,232.28			-$ 135,311.36	$ 1,920.92	-1.40%
Total Bill on TOU (including OCEB)				**$ 1,235,090.52**			**$ 1,217,802.22**	**-$ 17,288.30**	**-1.40%**

Loss Factor (%) 0.4500% 0.6900%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: Unmetered Scattered Load

Consumption 100 **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	$ Change	% Change
Monthly Service Charge	Monthly	$ 15.6800	1	$ 15.68	$ 13.4800	1	$ 13.48	-$ 2.20	-14.03%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for Tax change	kW	-$ 0.0008	100	-$ 0.08	$ -		$ -	$ 0.08	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kWh	$ 0.0426	100	$ 4.26	$ 0.0366	100	$ 3.66	-$ 0.60	-14.08%
Smart Meter Disposition Rider				$ -			$ -	$ -	
LRAM 2011	kW	$ -	100	$ -	$ -	100	$ -	$ -	
LRAM 2012	kW	$ -	100	$ -	$ -	100	$ -	$ -	
LRAM 2013	kW	$ -	100	$ -	$ -	100	$ -	$ -	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A				$ 20.11			$ 17.39	**-$ 2.72**	**-13.53%**
Rate Rider for Deferral/Variance Account Disposition 2011	kWh	$ 0.0012	100	$ 0.12	$ -	100	$ -	-$ 0.12	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kWh	-$ 0.0020	100	-$ 0.20	-$ 0.0020	100	-$ 0.20	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kWh	$ -	100	$ -	-$ 0.0013	100	-$ 0.13	-$ 0.13	
Low Voltage Service Charge	kWh	$ 0.0002	100	$ 0.02	$ 0.0002	100	$ 0.02	$ -	
Smart Meter Entity Charge						100	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 20.05**			**$ 17.08**	**-$ 2.97**	**-14.81%**
RTSR - Network	kWh	$ 0.0063	104	$ 0.65	$ 0.0060	104	$ 0.63	-$ 0.03	-4.17%
RTSR - Line and Transformation Connection	kWh	$ 0.0050	104	$ 0.52	$ 0.0047	104	$ 0.49	-$ 0.03	-5.41%
Sub-Total C - Delivery (including Sub-Total B)				**$ 21.22**			**$ 18.19**	**-$ 3.03**	**-14.26%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	104	$ 0.54	$ 0.0052	104	$ 0.54	$ 0.00	0.62%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	104	$ 0.11	$ 0.0011	104	$ 0.11	$ 0.00	0.62%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	100	$ 0.70	$ 0.0070	100	$ 0.70	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	104	$ 7.66	$ 0.0740	104	$ 7.71	$ 0.05	0.62%
Energy - RPP - Tier 2	kWh	$ 0.0870		$ -	$ 0.0870		$ -	$ -	
TOU - Off Peak	kWh	$ 0.0630	66	$ 4.18	$ 0.0630	67	$ 4.20	$ 0.03	0.62%
TOU - Mid Peak	kWh	$ 0.0990	19	$ 1.85	$ 0.0990	19	$ 1.86	$ 0.01	0.62%
TOU - On Peak	kWh	$ 0.1180	19	$ 2.20	$ 0.1180	19	$ 2.21	$ 0.01	0.62%
Total Bill on RPP (before Taxes)				**$ 30.24**			**$ 27.26**	**-$ 2.97**	**-9.83%**
HST		13%		$ 3.93	13%		$ 3.54	-$ 0.39	-9.83%
Total Bill (including HST)				$ 34.17			$ 30.81	-$ 3.36	-9.83%
Ontario Clean Energy Benefit 1				-$ 3.42			-$ 3.08	$ 0.34	-9.94%
Total Bill on RPP (including OCEB)				**$ 30.75**			**$ 27.73**	**-$ 3.02**	**-9.82%**
Total Bill on TOU (before Taxes)				**$ 30.79**			**$ 27.82**	**-$ 2.97**	**-9.64%**
HST		13%		$ 4.00	13%		$ 3.62	-$ 0.39	-9.64%
Total Bill (including HST)				$ 34.80			$ 31.44	-$ 3.36	-9.64%
Ontario Clean Energy Benefit 1				-$ 3.48			-$ 3.14	$ 0.34	-9.77%
Total Bill on TOU (including OCEB)				**$ 31.32**			**$ 28.30**	**-$ 3.02**	**-9.63%**
Loss Factor (%)		3.56%			4.21%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: Unmetered Scattered Load

Consumption 1200 **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	$ Change	% Change
Monthly Service Charge	Monthly	$ 15.6800	1	$ 15.68	$ 13.4800	1	$ 13.48	-$ 2.20	-14.03%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for Tax change	kWh	-$ 0.0008	1200	-$ 0.96	$ -	1200	$ -	$ 0.96	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kWh	$ 0.0426	1200	$ 51.12	$ 0.0366	1200	$ 43.92	-$ 7.20	-14.08%
Smart Meter Disposition Rider				$ -	$ -		$ -	$ -	
LRAM 2011	kW	$ -	1200	$ -	$ -	1200	$ -	$ -	
LRAM 2012	kW	$ -	1200	$ -	$ -	1200	$ -	$ -	
LRAM 2013	kW	$ -	1200	$ -	$ -	1200	$ -	$ -	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A				$ 66.09			$ 57.65	**-$ 8.44**	**-12.77%**
Rate Rider for Deferral/Variance Account Disposition 2011	kWh	$ 0.0012	1200	$ 1.44	$ -	1200	$ -	-$ 1.44	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kWh	-$ 0.0020	1200	-$ 2.40	-$ 0.0020	1200	-$ 2.40	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kWh	$ -	1200	$ -	-$ 0.0013	1200	-$ 1.56	-$ 1.56	
Low Voltage Service Charge	kWh	$ 0.0002	1200	$ 0.24	$ 0.0002	1200	$ 0.24	$ -	
Smart Meter Entity Charge		▨	▨	▨		1200	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 65.37**			**$ 53.93**	**-$ 11.44**	**-17.50%**
RTSR - Network	kWh	$ 0.0063	1243	$ 7.83	$ 0.0060	1250	$ 7.50	-$ 0.33	-4.17%
RTSR - Line and Transformation Connection	kWh	$ 0.0050	1243	$ 6.21	$ 0.0047	1250	$ 5.88	-$ 0.34	-5.41%
Sub-Total C - Delivery (including Sub-Total B)				**$ 79.41**			**$ 67.31**	**-$ 12.10**	**-15.24%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	1243	$ 6.46	$ 0.0052	1250	$ 6.50	$ 0.04	0.62%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	1243	$ 1.37	$ 0.0011	1250	$ 1.38	$ 0.01	0.62%
Standard Supply Service Charge			1	$ -	$ -	1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	1200	$ 8.40	$ 0.0070	1200	$ 8.40	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	750	$ 55.50	$ 0.0740	750	$ 55.50	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0870	493	$ 42.87	$ 0.0870	500	$ 43.54	$ 0.67	1.57%
TOU - Off Peak	kWh	$ 0.0630	795	$ 50.11	$ 0.0630	800	$ 50.42	$ 0.31	0.62%
TOU - Mid Peak	kWh	$ 0.0990	224	$ 22.15	$ 0.0990	225	$ 22.28	$ 0.14	0.62%
TOU - On Peak	kWh	$ 0.1180	224	$ 26.40	$ 0.1180	225	$ 26.56	$ 0.16	0.62%
Total Bill on RPP (before Taxes)				**$ 194.01**			**$ 182.63**	**-$ 11.38**	**-5.87%**
HST		13%		$ 25.22	13%		$ 23.74	-$ 1.48	-5.87%
Total Bill (including HST)				$ 219.23			$ 206.37	-$ 12.86	-5.87%
Ontario Clean Energy Benefit 1				-$ 21.92			-$ 20.64	$ 1.28	-5.84%
Total Bill on RPP (including OCEB)				**$ 197.31**			**$ 185.73**	**-$ 11.58**	**-5.87%**
Total Bill on TOU (before Taxes)				**$ 194.29**			**$ 182.85**	**-$ 11.44**	**-5.89%**
HST		13%		$ 25.26	13%		$ 23.77	-$ 1.49	-5.89%
Total Bill (including HST)				$ 219.55			$ 206.62	-$ 12.93	-5.89%
Ontario Clean Energy Benefit 1				-$ 21.95			-$ 20.66	$ 1.29	-5.88%
Total Bill on TOU (including OCEB)				**$ 197.60**			**$ 185.96**	**-$ 11.64**	**-5.89%**
Loss Factor (%)		3.56%			4.21%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: Unmetered Scattered Load

Consumption **7000** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	$ Change	% Change
Monthly Service Charge	Monthly	$ 15.6800	1	$ 15.68	$ 13.4800	1	$ 13.48	-$ 2.20	-14.03%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for Tax change	kWh	-$ 0.0008	7000	-$ 5.60	$ -	7000	$ -	$ 5.60	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kWh	$ 0.0426	7000	$ 298.20	$ 0.0366	7000	$ 256.20	-$ 42.00	-14.08%
Smart Meter Disposition Rider				$ -	$ -		$ -	$ -	
LRAM 2011	kW	$ -	7000	$ -	$ -	7000	$ -	$ -	
LRAM 2012	kW	$ -	7000	$ -	$ -	7000	$ -	$ -	
LRAM 2013	kW	$ -	7000	$ -	$ -	7000	$ -	$ -	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A				$ 308.53			$ 269.93	**-$ 38.60**	**-12.51%**
Rate Rider for Deferral/Variance Account Disposition 2011	kWh	$ 0.0012	7000	$ 8.40	$ -	7000	$ -	-$ 8.40	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kWh	-$ 0.0020	7000	-$ 14.00	-$ 0.0020	7000	-$ 14.00	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kWh	$ -	7000	$ -	-$ 0.0013	7000	-$ 9.10	-$ 9.10	
Low Voltage Service Charge	kWh	$ 0.0002	7000	$ 1.40	$ 0.0002	7000	$ 1.40	$ -	
Smart Meter Entity Charge		▨	▨	▨		7000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 304.33**			**$ 248.23**	**-$ 56.10**	**-18.43%**
RTSR - Network	kWh	$ 0.0063	7249	$ 45.67	$ 0.0060	7294	$ 43.77	-$ 1.90	-4.17%
RTSR - Line and Transformation Connection	kWh	$ 0.0050	7249	$ 36.25	$ 0.0047	7294	$ 34.28	-$ 1.96	-5.41%
Sub-Total C - Delivery (including Sub-Total B)				**$ 386.25**			**$ 326.28**	**-$ 59.97**	**-15.53%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	7249	$ 37.70	$ 0.0052	7294	$ 37.93	$ 0.23	0.62%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	7249	$ 7.97	$ 0.0011	7294	$ 8.02	$ 0.05	0.62%
Standard Supply Service Charge			1	$ -	$ -	1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	7000	$ 49.00	$ 0.0070	7000	$ 49.00	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	750	$ 55.50	$ 0.0740	750	$ 55.50	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0870	6499	$ 565.43	$ 0.0870	6544	$ 569.36	$ 3.93	0.70%
TOU - Off Peak	kWh	$ 0.0630	4639	$ 292.29	$ 0.0630	4668	$ 294.11	$ 1.82	0.62%
TOU - Mid Peak	kWh	$ 0.0990	1305	$ 129.18	$ 0.0990	1313	$ 129.99	$ 0.81	0.62%
TOU - On Peak	kWh	$ 0.1180	1305	$ 153.97	$ 0.1180	1313	$ 154.93	$ 0.96	0.62%
Total Bill on RPP (before Taxes)				**$ 1,101.85**			**$ 1,046.10**	**-$ 55.75**	**-5.06%**
HST		13%		$ 143.24	13%		$ 135.99	-$ 7.25	-5.06%
Total Bill (including HST)				$ 1,245.09			$ 1,182.09	-$ 63.00	-5.06%
Ontario Clean Energy Benefit 1				-$ 124.51			-$ 118.21	$ 6.30	-5.06%
Total Bill on RPP (including OCEB)				**$ 1,120.58**			**$ 1,063.88**	**-$ 56.70**	**-5.06%**
Total Bill on TOU (before Taxes)				**$ 1,056.36**			**$ 1,000.26**	**-$ 56.10**	**-5.31%**
HST		13%		$ 137.33	13%		$ 130.03	-$ 7.29	-5.31%
Total Bill (including HST)				$ 1,193.68			$ 1,130.30	-$ 63.39	-5.31%
Ontario Clean Energy Benefit 1				-$ 119.37			-$ 113.03	$ 6.34	-5.31%
Total Bill on TOU (including OCEB)				**$ 1,074.31**			**$ 1,017.27**	**-$ 57.05**	**-5.31%**

Loss Factor (%) 3.56% 4.21%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: Sentinel Lighting

Consumption **182** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	$ Change	% Change
Monthly Service Charge	Monthly	$ 3.4300	1	$ 3.43	$ 4.1100	1	$ 4.11	$ 0.68	19.83%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for Tax change	kW	-$ 0.3944	0.46	-$ 0.18	$ -	0.46	$ -	$ 0.18	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kW	$ 22.6299	0.46	$ 10.41	$ 27.1276	0.46	$ 12.48	$ 2.07	19.88%
Smart Meter Disposition Rider				$ -			$ -	$ -	
LRAM 2011	kW	$ -	0.46	$ -	$ -	0.46	$ -	$ -	
LRAM 2012	kW	$ -	0.46	$ -	$ -	0.46	$ -	$ -	
LRAM 2013	kW	$ -	0.46	$ -	$ -	0.46	$ -	$ -	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A				$ 13.91			$ 16.84	**$ 2.93**	**21.07%**
Rate Rider for Deferral/Variance Account Disposition 2011	kW	$ 0.4944	0.46	$ 0.23	$ -	0.46	$ -	-$ 0.23	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kW	-$ 0.8027	0.46	-$ 0.37	-$ 0.8027	0.46	-$ 0.37	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kW	$ -	0.46	$ -	-$ 0.6421	0.46	-$ 0.30	-$ 0.30	
Low Voltage Service Charge	kW	$ 0.0570	0.46	$ 0.03	$ 0.0002	0.46	$ 0.00	-$ 0.03	-99.65%
Smart Meter Entity Charge							$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 13.79**			**$ 16.17**	**$ 2.38**	**17.27%**
RTSR - Network	kW	$ 1.9441	0.46	$ 0.89	$ 1.8397	0.46	$ 0.85	-$ 0.05	-5.37%
RTSR - Line and Transformation Connection	kW	$ 1.5783	0.46	$ 0.73	$ 1.4966	0.46	$ 0.69	-$ 0.04	-5.18%
Sub-Total C - Delivery (including Sub-Total B)				**$ 15.41**			**$ 17.71**	**$ 2.30**	**14.90%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	188	$ 0.98	$ 0.0052	190	$ 0.99	$ 0.01	0.62%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	188	$ 0.21	$ 0.0011	190	$ 0.21	$ 0.00	0.62%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	182	$ 1.27	$ 0.0070	182	$ 1.27	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	188	$ 13.95	$ 0.0740	190	$ 14.03	$ 0.09	0.62%
Energy - RPP - Tier 2	kWh	$ 0.0870		$ -	$ 0.0870		$ -	$ -	
TOU - Off Peak	kWh	$ 0.0630	121	$ 7.60	$ 0.0630	121	$ 7.65	$ 0.05	0.62%
TOU - Mid Peak	kWh	$ 0.0990	34	$ 3.36	$ 0.0990	34	$ 3.38	$ 0.02	0.62%
TOU - On Peak	kWh	$ 0.1180	34	$ 4.00	$ 0.1180	34	$ 4.03	$ 0.02	0.62%
Total Bill on RPP (before Taxes)				**$ 31.82**			**$ 34.21**	**$ 2.39**	**7.51%**
HST		13%		$ 4.14	13%		$ 4.45	$ 0.31	7.51%
Total Bill (including HST)				$ 35.96			$ 38.66	$ 2.70	7.51%
Ontario Clean Energy Benefit 1				-$ 3.60			-$ 3.87	-$ 0.27	7.50%
Total Bill on RPP (including OCEB)				**$ 32.36**			**$ 34.79**	**$ 2.43**	**7.51%**
Total Bill on TOU (before Taxes)				**$ 32.84**			**$ 35.23**	**$ 2.40**	**7.30%**
HST		13%		$ 4.27	13%		$ 4.58	$ 0.31	7.30%
Total Bill (including HST)				$ 37.10			$ 39.81	$ 2.71	7.30%
Ontario Clean Energy Benefit 1				-$ 3.71			-$ 3.98	-$ 0.27	7.28%
Total Bill on TOU (including OCEB)				**$ 33.39**			**$ 35.83**	**$ 2.44**	**7.30%**

Loss Factor (%) 3.56% 4.21%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: Sentinel Lighting

Consumption 63 **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	$ Change	% Change
Monthly Service Charge	Monthly	$ 3.4300	1	$ 3.43	$ 4.1100	1	$ 4.11	$ 0.68	19.83%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for Tax change	kW	-$ 0.3944	0.18	-$ 0.07	$ -	0.18	$ -	$ 0.07	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kW	$ 22.6299	0.18	$ 4.07	$ 27.1276	0.18	$ 4.88	$ 0.81	19.88%
Smart Meter Disposition Rider				$ -	$ -		$ -	$ -	
LRAM 2011	kW	$ -	0.18	$ -	$ -	0.18	$ -	$ -	
LRAM 2012	kW	$ -	0.18	$ -	$ -	0.18	$ -	$ -	
LRAM 2013	kW	$ -	0.18	$ -	$ -	0.18	$ -	$ -	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A				$ 7.68			$ 9.24	**$ 1.56**	**20.31%**
Rate Rider for Deferral/Variance Account Disposition 2011	kW	$ 0.4944	0.18	$ 0.09	$ -	0.18	$ -	-$ 0.09	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kW	-$ 0.8027	0.18	-$ 0.14	-$ 0.8027	0.18	-$ 0.14	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kW	$ -	0.18	$ -	-$ 0.6421	0.18	-$ 0.12	-$ 0.12	
Low Voltage Service Charge	kW	$ 0.0570	0.18	$ 0.01	$ 0.0002	0.18	$ 0.00	-$ 0.01	-99.65%
Smart Meter Entity Charge					$ -		$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 7.64**			**$ 8.98**	**$ 1.35**	**17.62%**
RTSR - Network	kW	$ 1.9441	0.18	$ 0.35	$ 1.8397	0.18	$ 0.33	-$ 0.02	-5.37%
RTSR - Line and Transformation Connection	kW	$ 1.5783	0.18	$ 0.28	$ 1.4966	0.18	$ 0.27	-$ 0.01	-5.18%
Sub-Total C - Delivery (including Sub-Total B)				**$ 8.27**			**$ 9.58**	**$ 1.31**	**15.87%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	65	$ 0.34	$ 0.0052	66	$ 0.34	$ 0.00	0.62%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	65	$ 0.07	$ 0.0011	66	$ 0.07	$ 0.00	0.62%
Standard Supply Service Charge			1	$ -	$ -	1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	63	$ 0.44	$ 0.0070	63	$ 0.44	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	65	$ 4.83	$ 0.0740	66	$ 4.86	$ 0.03	0.62%
Energy - RPP - Tier 2	kWh	$ 0.0870		$ -	$ 0.0870		$ -	$ -	
TOU - Off Peak	kWh	$ 0.0630	42	$ 2.63	$ 0.0630	42	$ 2.65	$ 0.02	0.62%
TOU - Mid Peak	kWh	$ 0.0990	12	$ 1.16	$ 0.0990	12	$ 1.17	$ 0.01	0.62%
TOU - On Peak	kWh	$ 0.1180	12	$ 1.39	$ 0.1180	12	$ 1.39	$ 0.01	0.62%
Total Bill on RPP (before Taxes)				**$ 13.95**			**$ 15.30**	**$ 1.34**	**9.64%**
HST		13%		$ 1.81	13%		$ 1.99	$ 0.17	9.64%
Total Bill (including HST)				$ 15.76			$ 17.28	$ 1.52	9.64%
Ontario Clean Energy Benefit 1				-$ 1.58			-$ 1.73	-$ 0.15	9.49%
Total Bill on RPP (including OCEB)				**$ 14.18**			**$ 15.55**	**$ 1.37**	**9.66%**
Total Bill on TOU (before Taxes)				**$ 14.30**			**$ 15.65**	**$ 1.35**	**9.42%**
HST		13%		$ 1.86	13%		$ 2.03	$ 0.18	9.42%
Total Bill (including HST)				$ 16.16			$ 17.68	$ 1.52	9.42%
Ontario Clean Energy Benefit 1				-$ 1.62			-$ 1.77	-$ 0.15	9.26%
Total Bill on TOU (including OCEB)				**$ 14.54**			**$ 15.91**	**$ 1.37**	**9.44%**
Loss Factor (%)		3.56%			4.21%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: Street Lighting

Consumption 86 **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	$ Change	% Change
Monthly Service Charge	Monthly	$ 2.1400	1	$ 2.14	$ 2.5700	1	$ 2.57	$ 0.43	20.09%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for Tax change	kW	-$ 0.3152	0.18	-$ 0.06	$ -	0.18	$ -	$ 0.06	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kW	$ 16.5512	0.18	$ 2.98	$ 19.8408	0.18	$ 3.57	$ 0.59	19.88%
Smart Meter Disposition Rider				$ -			$ -	$ -	
LRAM 2011	kW	$ -	0.18	$ -	$ -	0.18	$ -	$ -	
LRAM 2012	kW	$ -	0.18	$ -	$ -	0.18	$ -	$ -	
LRAM 2013	kW	$ -	0.18	$ -	$ -	0.18	$ -	$ -	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A				$ 5.31			$ 6.39	**$ 1.08**	**20.31%**
Rate Rider for Deferral/Variance Account Disposition 2011	kW	$ 0.4212	0.18	$ 0.08	$ -	0.18	$ -	-$ 0.08	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kW	-$ 0.6964	0.18	-$ 0.13	-$ 0.6964	0.18	-$ 0.13	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kW	$ -	0.18	$ -	-$ 0.5437	0.18	-$ 0.10	-$ 0.10	
Low Voltage Service Charge	kW	$ 0.0558	0.18	$ 0.01	$ 0.0580	0.18	$ 0.01	$ 0.00	3.94%
Smart Meter Entity Charge		▨	▨	▨			$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 5.27**			**$ 6.18**	**$ 0.91**	**17.17%**
RTSR - Network	kW	$ 1.9342	0.18	$ 0.35	$ 1.8304	0.18	$ 0.33	-$ 0.02	-5.37%
RTSR - Line and Transformation Connection	kW	$ 1.5461	0.18	$ 0.28	$ 1.4660	0.18	$ 0.26	-$ 0.01	-5.18%
Sub-Total C - Delivery (including Sub-Total B)				**$ 5.90**			**$ 6.77**	**$ 0.87**	**14.79%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	89	$ 0.46	$ 0.0052	90	$ 0.47	$ 0.00	0.62%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	89	$ 0.10	$ 0.0011	90	$ 0.10	$ 0.00	0.62%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	86	$ 0.60	$ 0.0070	86	$ 0.60	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	89	$ 6.59	$ 0.0740	90	$ 6.63	$ 0.04	0.62%
Energy - RPP - Tier 2	kWh	$ 0.0870		$ -	$ 0.0870		$ -	$ -	
TOU - Off Peak	kWh	$ 0.0630	57	$ 3.59	$ 0.0630	57	$ 3.61	$ 0.02	0.62%
TOU - Mid Peak	kWh	$ 0.0990	16	$ 1.59	$ 0.0990	16	$ 1.60	$ 0.01	0.62%
TOU - On Peak	kWh	$ 0.1180	16	$ 1.89	$ 0.1180	16	$ 1.90	$ 0.01	0.62%
Total Bill on RPP (before Taxes)				**$ 13.65**			**$ 14.57**	**$ 0.92**	**6.72%**
HST		13%		$ 1.77	13%		$ 1.89	$ 0.12	6.72%
Total Bill (including HST)				$ 15.43			$ 16.46	$ 1.04	6.72%
Ontario Clean Energy Benefit 1				-$ 1.54			-$ 1.65	-$ 0.11	7.14%
Total Bill on RPP (including OCEB)				**$ 13.89**			**$ 14.81**	**$ 0.93**	**6.67%**
Total Bill on TOU (before Taxes)				**$ 14.13**			**$ 15.05**	**$ 0.92**	**6.51%**
HST		13%		$ 1.84	13%		$ 1.96	$ 0.12	6.51%
Total Bill (including HST)				$ 15.97			$ 17.01	$ 1.04	6.51%
Ontario Clean Energy Benefit 1				-$ 1.60			-$ 1.70	-$ 0.10	6.25%
Total Bill on TOU (including OCEB)				**$ 14.37**			**$ 15.31**	**$ 0.94**	**6.54%**

Loss Factor (%) 3.56% 4.21%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: Street Lighting

Consumption **749249** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	$ Change	% Change
Monthly Service Charge	Monthly	$ 2.1400	1	$ 2.14	$ 2.5700	1	$ 2.57	$ 0.43	20.09%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for Tax change	kW	-$ 0.3152	1613	-$ 508.42	$ -	1613	$ -	$ 508.42	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kW	$ 16.5512	1613	$ 26,697.09	$ 19.8408	1613	$ 32,003.21	$ 5,306.12	19.88%
Smart Meter Disposition Rider				$ -	$ -		$ -	$ -	
LRAM 2011	kW	$ -	1613	$ -	$ -	1613	$ -	$ -	
LRAM 2012	kW	$ -	1613	$ -	$ -	1613	$ -	$ -	
LRAM 2013	kW	$ -	1613	$ -	$ -	1613	$ -	$ -	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A				$ 26,191.06			$ 32,006.03	**$ 5,814.97**	**22.20%**
Rate Rider for Deferral/Variance Account Disposition 2011	kW	$ 0.4212	1613	$ 679.40	$ -	1613	$ -	-$ 679.40	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kW	-$ 0.6964	1613	-$ 1,123.29	-$ 0.6964	1613	-$ 1,123.29	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kW	$ -	1613	$ -	-$ 0.5437	1613	-$ 876.99	-$ 876.99	
Low Voltage Service Charge	kW	$ 0.0558	1613	$ 90.01	$ 0.0580	1613	$ 93.55	$ 3.55	3.94%
Smart Meter Entity Charge		▨	▨	▨		749249	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 25,837.17**			**$ 30,099.30**	**$ 4,262.14**	**16.50%**
RTSR - Network	kW	$ 1.9342	1613	$ 3,119.86	$ 1.8304	1613	$ 2,952.44	-$ 167.43	-5.37%
RTSR - Line and Transformation Connection	kW	$ 1.5461	1613	$ 2,493.86	$ 1.4660	1613	$ 2,364.66	-$ 129.20	-5.18%
Sub-Total C - Delivery (including Sub-Total B)				**$ 31,450.89**			**$ 35,416.40**	**$ 3,965.51**	**12.61%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	775922	$ 4,034.80	$ 0.0052	780758	$ 4,059.94	$ 25.15	0.62%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	775922	$ 853.51	$ 0.0011	780758	$ 858.83	$ 5.32	0.62%
Standard Supply Service Charge			1	$ -	$ -	1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	749249	$ 5,244.74	$ 0.0070	749249	$ 5,244.74	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	750	$ 55.50	$ 0.0740	750	$ 55.50	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0870	775172	$ 67,439.99	$ 0.0870	780008	$ 67,860.69	$ 420.71	0.62%
TOU - Off Peak	kWh	$ 0.0630	496590	$ 31,285.19	$ 0.0630	499685	$ 31,480.16	$ 194.98	0.62%
TOU - Mid Peak	kWh	$ 0.0990	139666	$ 13,826.93	$ 0.0990	140536	$ 13,913.11	$ 86.17	0.62%
TOU - On Peak	kWh	$ 0.1180	139666	$ 16,480.59	$ 0.1180	140536	$ 16,583.30	$ 102.71	0.62%
Total Bill on RPP (before Taxes)				**$ 109,079.43**			**$ 113,496.11**	**$ 4,416.68**	**4.05%**
HST		13%		$ 14,180.33	13%		$ 14,754.49	$ 574.17	4.05%
Total Bill (including HST)				$ 123,259.76			$ 128,250.60	$ 4,990.85	4.05%
Ontario Clean Energy Benefit 1				-$ 12,325.98			-$ 12,825.06	-$ 499.08	4.05%
Total Bill on RPP (including OCEB)				**$ 110,933.78**			**$ 115,425.54**	**$ 4,491.77**	**4.05%**
Total Bill on TOU (before Taxes)				**$ 103,176.65**			**$ 107,556.48**	**$ 4,379.83**	**4.24%**
HST		13%		$ 13,412.96	13%		$ 13,982.34	$ 569.38	4.24%
Total Bill (including HST)				$ 116,589.62			$ 121,538.82	$ 4,949.21	4.24%
Ontario Clean Energy Benefit 1				-$ 11,658.96			-$ 12,153.88	-$ 494.92	4.24%
Total Bill on TOU (including OCEB)				**$ 104,930.66**			**$ 109,384.94**	**$ 4,454.29**	**4.24%**
Loss Factor (%)		3.56%			4.21%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: Wholesale Market Participants GS > 50

Consumption **500000** **kWh** 800 kw

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	$ Change	% Change
Monthly Service Charge	Monthly	$ 142.0000	1	$ 142.00	$ 142.0000	1	$ 142.00	$ -	
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for Tax change	kW	-$ 0.0614	800	-$ 49.12	$ -	800	$ -	$ 49.12	-100.00%
Standard Supply Service Charge	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate		$ 3.5617	800	$ 2,849.36	$ 4.4827	800	$ 3,586.16	$ 736.80	25.86%
Smart Meter Disposition Rider				$ -			$ -	$ -	
LRAM 2011	kW	$ -	800	$ -	$ -	800	$ -	$ -	
LRAM 2012	kW	$ 0.0149	800	$ 11.92	$ 0.0149	800	$ 11.92	$ -	
LRAM 2013	kW	$ -	800	$ -	$ 0.0076	800	$ 6.08	$ 6.08	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A				$ 2,954.16			$ 3,746.16	**$ 792.00**	**26.81%**
Rate Rider for Deferral/Variance Account Disposition 2013 - GEN WMP	kW	$ -	800	$ -	-$ 0.2431	800	-$ 194.48	-$ 194.48	
Low Voltage Service Charge	kWh	$ 0.0722	800	$ 57.76	$ 0.0750	800	$ 60.00	$ 2.24	3.88%
Smart Meter Entity Charge		▨	▨	▨			$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 3,011.92**			**$ 3,611.68**	**$ 599.76**	**19.91%**
RTSR - Network	kWh	$ 2.5648	800	$ 2,051.84	$ 2.4271	800	$ 1,941.68	-$ 110.16	-5.37%
RTSR - Line and Transformation Connection	kWh	$ 1.9998	800	$ 1,599.84	$ 1.8963	800	$ 1,517.04	-$ 82.80	-5.18%
Sub-Total C - Delivery (including Sub-Total B)				**$ 6,663.60**			**$ 7,070.40**	**$ 406.80**	**6.10%**
Wholesale Market Service Charge (WMSC)	kWh	$ -	517800	$ -	$ -	521027	$ -	$ -	
Rural and Remote Rate Protection (RRRP)	kWh	$ -	517800	$ -	$ -	521027	$ -	$ -	
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	500000	$ 3,500.00	$ 0.0070	500000	$ 3,500.00	$ -	
Energy - RPP - Tier 1	kWh	$ -	750	$ -	$ -	750	$ -	$ -	
Energy - RPP - Tier 2	kWh	$ -	517050	$ -	$ -	520277	$ -	$ -	
TOU - Off Peak	kWh	$ -	331392	$ -	$ -	333457	$ -	$ -	
TOU - Mid Peak	kWh	$ -	93204	$ -	$ -	93785	$ -	$ -	
TOU - On Peak	kWh	$ -	93204	$ -	$ -	93785	$ -	$ -	
Total Bill on RPP (before Taxes)				**$ 10,163.60**			**$ 10,570.40**	**$ 406.80**	**4.00%**
HST		13%		$ 1,321.27	13%		$ 1,374.15	$ 52.88	4.00%
Total Bill (including HST)				$ 11,484.87			$ 11,944.55	$ 459.68	4.00%
Ontario Clean Energy Benefit 1				-$ 1,148.49			-$ 1,194.46	-$ 45.97	4.00%
Total Bill on RPP (including OCEB)				**$ 10,336.38**			**$ 10,750.09**	**$ 413.71**	**4.00%**
Total Bill on TOU (before Taxes)				**$ 10,163.60**			**$ 10,570.40**	**$ 406.80**	**4.00%**
HST		13%		$ 1,321.27	13%		$ 1,374.15	$ 52.88	4.00%
Total Bill (including HST)				$ 11,484.87			$ 11,944.55	$ 459.68	4.00%
Ontario Clean Energy Benefit 1				-$ 1,148.49			-$ 1,194.46	-$ 45.97	4.00%
Total Bill on TOU (including OCEB)				**$ 10,336.38**			**$ 10,750.09**	**$ 413.71**	**4.00%**
Loss Factor (%)		3.56%			4.21%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: Wholesale Market Participants LU

Consumption 11523872 **kWh** 16869 kw

		Current Board-Approved				Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**		**Rate ($)**	**Volume**	**Charge ($)**	$ Change	% Change
Monthly Service Charge	Monthly	$ 24,427.6000	1	$ 24,427.60		$ 24,427.6000	1	$ 24,427.60	$ -	
Smart Meter Rate Adder	Monthly	$ -	1	$ -		$ -	1	$ -	$ -	
Rate Rider for Tax change	kWh	-$ 0.0470	16869	-$ 792.84		$ -	16869	$ -	$ 792.84	-100.00%
Standard Supply Service Charge	Monthly	$ -	1	$ -		$ -	1	$ -	$ -	
Distribution Volumetric Rate		$ 1.4610	16869	$ 24,645.61		$ 2.0552	16869	$ 34,669.17	$ 10,023.56	40.67%
Smart Meter Disposition Rider				$ -				$ -	$ -	
LRAM 2011	kW	$ -	16869	$ -		$ -	16869	$ -	$ -	
LRAM 2012	kW	$ -	16869	$ -		$ -	16869	$ -	$ -	
LRAM 2013	kW	$ -	16869	$ -		$ -	16869	$ -	$ -	
Stranded Meters Recovery	Monthly	$ -	1	$ -		$ -	1	$ -	$ -	
Sub-Total A				$ 48,280.37				$ 59,096.77	**$ 10,816.40**	**22.40%**
Rate Rider for Deferral/Variance Account disposition 2011- ONLY TO Large WMP	kW	-$ 0.0530	16869	-$ 894.06		$ -	16869	$ -	$ 894.06	-100.00%
Rate Rider for Deferral/Variance Account disposition 2012 - ONLY TO Large WMP	kW	-$ 0.1377	16869	-$ 2,322.86		-$ 0.1377	16869	-$ 2,322.86	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 - Large WMP	kW	$ -	16869	$ -		-$ 0.3269	16869	-$ 5,514.48	-$ 5,514.48	
Low Voltage Service Charge	kWh	$ 0.0905	16869	$ 1,526.64		$ 0.0940	16869	$ 1,585.69	$ 59.04	3.87%
Smart Meter Entity Charge		▨	▨	▨				$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 46,590.09**				**$ 52,845.12**	**$ 6,255.03**	**13.43%**
RTSR - Network	kWh	$ 3.0162	16869	$ 50,880.28		$ 2.8543	16869	$ 48,149.19	-$ 2,731.09	-5.37%
RTSR - Line and Transformation Connection	kWh	$ 2.5070	16869	$ 42,290.58		$ 2.3772	16869	$ 40,100.99	-$ 2,189.60	-5.18%
Sub-Total C - Delivery (including Sub-Total B)				**$ 139,760.95**				**$ 141,095.29**	**$ 1,334.34**	**0.95%**
Wholesale Market Service Charge (WMSC)	kWh	$ -	11575729	$ -		$ -	11603387	$ -	$ -	
Rural and Remote Rate Protection (RRRP)	kWh	$ -	11575729	$ -		$ -	11603387	$ -	$ -	
Standard Supply Service Charge			1	$ -			1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	11523872	$ 80,667.10		$ 0.0070	11523872	$ 80,667.10	$ -	
Energy - RPP - Tier 1	kWh	$ -	750	$ -		$ -	750	$ -	$ -	
Energy - RPP - Tier 2	kWh	$ -	11574979	$ -		$ -	11602637	$ -	$ -	
TOU - Off Peak	kWh	$ -	7408467	$ -		$ -	7426167	$ -	$ -	
TOU - Mid Peak	kWh	$ -	2083631	$ -		$ -	2088610	$ -	$ -	
TOU - On Peak	kWh	$ -	2083631	$ -		$ -	2088610	$ -	$ -	
Total Bill on RPP (before Taxes)				**$ 220,428.06**				**$ 221,762.39**	**$ 1,334.34**	**0.61%**
HST		13%		$ 28,655.65		13%		$ 28,829.11	$ 173.46	0.61%
Total Bill (including HST)				$ 249,083.70				$ 250,591.51	$ 1,507.80	0.61%
Ontario Clean Energy Benefit 1				-$ 24,908.37				-$ 25,059.15	-$ 150.78	0.61%
Total Bill on RPP (including OCEB)				**$ 224,175.33**				**$ 225,532.36**	**$ 1,357.02**	**0.61%**
Total Bill on TOU (before Taxes)				**$ 220,428.06**				**$ 221,762.39**	**$ 1,334.34**	**0.61%**
HST		13%		$ 28,655.65		13%		$ 28,829.11	$ 173.46	0.61%
Total Bill (including HST)				$ 249,083.70				$ 250,591.51	$ 1,507.80	0.61%
Ontario Clean Energy Benefit 1				-$ 24,908.37				-$ 25,059.15	-$ 150.78	0.61%
Total Bill on TOU (including OCEB)				**$ 224,175.33**				**$ 225,532.36**	**$ 1,357.02**	**0.61%**
Loss Factor (%)		0.4500%				0.6900%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

1.0 - VECC 1 - Adjustment Tracking Sheet

Reference: Exhibits All

a) Please provide a tracking sheet (table) showing all adjustments arising from the interrogatories (include Reference IR #.; Item description; area of change, i.e. return on capital/rate base/working capital allowance/amortization/PILS/OM&A/ etc.).

Please see response to 1-Staff 2.

BLUEWATER POWER DISTRIBUTION CORPORATION

File Number: EB-2012-0107

Date Filed: February 4, 2013

Tab 3 of 11

Exhibit 1 - Administration

1.0 EP 1 - Board of Directors Costs

Ref: Exhibit 1, Tab 1, Attachment 1

Please confirm that no costs associate with the Board of Directors of any of the affiliates shown in Attachment 1, including the parent holding company, have been recovered in the revenue requirement of the regulated distribution company. If this cannot be confirmed, please provide the amount included associated with each affiliate.

Confirmed. The costs associated with the Board of Directors for the affiliates are incurred by Bluewater Power Distribution Corporation at first instance and then allocated to the affiliates. The practice of allocating Board of Director costs has been implemented in the 2013 Test Year for the first time as a necessary adjustment identified during the review undertaken during the preparation of the Transfer Pricing Study. This issue is discussed under the heading of Corporate Cost Allocation (Exhibit 4-5-1) in the pre-filed evidence where it states (at page 15):

> *“There are no costs shown for 2011 Actual or 2009 Board Approved because no Board of Director costs were allocated to affiliates in those years. The Transfer Pricing Study undertaken in 2012 identified the lack of allocation of these costs as a deficiency in Bluewater Power’s transfer pricing methodology. Accordingly, for the 2013 Test Year, Board of Director costs (being annual fees, meeting fees and Director and Officer Liability expenses) are allocated to affiliates.”*

1.0 - EP 2 - MIFRS Adoption

Ref: Exhibit 1, Tab 2, Schedule 1

Please confirm that Bluewater Power has adopted MIFRS as of January 1, 2013 and that it has not delayed the adoption of IFRS until January 1, 2014, which is now an option for the company.

The audit committee of the Bluewater Power board of directors made the decision in November 2012 to take the additional one year deferral of IFRS. Therefore, Bluewater Power will be adopting IFRS as of January 1, 2014 (with 2013 as the comparative year).

The 2013 Test Year will remain on an MIFRS basis, even though the 2013 reporting year will be based on CGAAP, and we offer the following clarifying points to assist the Board to understand how this approach can be consistent:

1) Although Bluewater Power will be under CGAAP for 2012, we have made the decision to make the following changes under CGAAP effective January 1, 2013:
    - Indirect overhead will no longer be capitalized (same as MIFRS)
    - The useful lives of capital assets for depreciation purposes will be changed to the same basis as filed in the 2013 Test Year (same as MIFRS)
    - The useful lives for the amortization of contributed capital will be changed to the same basis as filed in the 2013 Test Year (same as MIFRS)

2) With the adjustments noted in (1) above, no changes are made to Account 1575 and therefore no changes are made to the related ratebase and depreciation adjustments in the 2013 Test Year.

3) The 2013 test year OM&A includes $478,667 relating to the employee future benefit obligation expense calculated on an IFRS basis (see Exh 4-4-1 Attachment 8). This amount is calculated after assuming the unamortized actuarial gains/losses (under CGAAP) have been charged to equity per the transitional adjustment required upon conversion from CGAAP to IFRS. As per the response to 4-Staff-35, this transitional adjustment will not occur until Bluewater Power adopts IFRS. Therefore, Bluewater Power has adjusted the expense amount in the 2013 Test Year OM&A to the 2013 CGAAP amount as per an updated actuarial report received in late 2012. This revised employee future benefit obligation expense amount is $577,399 which includes the continued amortization of the unrecognized actuarial loss under CGAAP. The updated actuarial report can be found in Attachment 1 of this interrogatory response. Bluewater Power has incorporated this OM&A change into the revised revenue requirement and the RRWF and the bill impacts presented in the response to interrogatories.

In summary of the first two points, all material impacts of the transition to MIFRS for rate-making purposes have not been changed as a result of the decision to delay adoption of IFRS.

With respect to the third point, which increases OM&A for the 2013 Test Year, Bluewater Power will request a deferral account in a later proceeding that will hold customers and the utility whole. The deferral account will not only address the one-time transitional adjustment, but will also address the variance between the annual CGAAP expense amounts embedded in rates and the resulting actual IFRS expense amounts recorded after adoption of IFRS.

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Attachment 1 of 1

1.0 - EP 2 - Updated Actuarial Report

11/9/2012

Bluewater Power Distribution Corporation
ESTIMATED BENEFIT EXPENSE (CICA 3461)
FINAL

	Calendar Year 2012	Projected** Calendar Year 2013
Discount Rate - January 1	4.50%	4.25%
Discount Rate - December 31	4.25%	4.25%
Withdrawal Rate	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*

A. Determination of Benefit Expense

	Calendar Year 2012	Projected** Calendar Year 2013
Current Service Cost	278,479	309,474
Interest on Benefits	437,802	450,685
Expected Interest on Assets	-	-
Past Service Cost/(Gain)	-	-
Transitional Obligation/(Asset)	-	-
Actuarial (Gain)/Loss	94,870	126,571
Benefit Expense	811,150	886,730

B. Reconciliation of Prepaid Benefit Asset (Liability)

	Calendar Year 2012	Projected** Calendar Year 2013
Accrued Benefit Obligation (ABO) as at December 31	10,449,533	10,900,361
Assets as at December 31	-	-
Unfunded ABO	(10,449,533)	(10,900,361)
Unrecognized Loss/(Gain)	2,437,235	2,310,664
Unrecognized Past Service Cost/(Gain)	-	-
Unrecognized Transition	-	-
Prepaid Benefit Asset (Liability)	(8,012,298)	(8,589,697)
Prepaid Benefit/(Liability) as at January 1	(7,507,737)	(8,012,298)
Transfer of Liability to Bluewater Power Services Corporation	5,100	-
Benefit Income/(Expense)	(811,150)	(886,730)
Contributions/Benefit Payments by the Employer	301,489	309,331
Prepaid Benefit Asset (Liability)	(8,012,298)	(8,589,697)

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

**For informational purposes only. Significant changes in 2013 such as re-negotiated benefits, increased benefit costs, changes to best estimate assumptions, or significant benefit swings may require revised projections/a full actuarial review.

11/9/2012

Bluewater Power Distribution Corporation
ESTIMATED BENEFIT EXPENSE (CICA 3461)
FINAL

	Calendar Year 2012	Projected** Calendar Year 2013
Discount Rate - January 1	4.50%	4.25%
Discount Rate - December 31	4.25%	4.25%
Withdrawal Rate	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*

C. Calculation of Component Items

	Calendar Year 2012	Projected** Calendar Year 2013
Calculation of the Service Cost		
- Current Service Cost	278,479	309,474
Interest on Benefits		
- ABO at January 1	9,601,194	10,449,533
- Current Service Cost	278,479	309,474
- Benefit Payments	(150,744)	(154,665)
- Accrued Benefits	9,728,929	10,604,342
- Interest	437,802	450,685
Expected Interest on Assets		
- Assets at January 1	-	-
- Funding	150,744	154,665
- Benefit Payments	(150,744)	(154,665)
- Expected Assets	-	-
- Interest	-	-
Expected ABO as at December 31		
- ABO at January 1	9,601,194	10,449,533
- Current Service Cost	278,479	309,474
- Interest on Benefits	437,802	450,685
- Benefit Payments	(301,489)	(309,331)
- Expected ABO at December 31	10,015,986	10,900,361
Expected Assets as at December 31		
- Assets at January 1	-	-
- Funding	301,489	309,331
- Interest on Assets	-	-
- Benefit Payments	(301,489)	(309,331)
- Expected Assets at December 31	-	-

**For informational purposes only. Significant changes in 2013 such as re-negotiated benefits, increased benefit costs, changes to best estimate assumptions, or significant benefit swings may require revised projections/a full actuarial review.

11/9/2012

Bluewater Power Distribution Corporation
ESTIMATED BENEFIT EXPENSE (CICA 3461)
FINAL

	Calendar Year 2012	Projected** Calendar Year 2013
Discount Rate - January 1	4.50%	4.25%
Discount Rate - December 31	4.25%	4.25%
Withdrawal Rate	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*

D. Actuarial (Gain)/Loss

	Calendar Year 2012	Calendar Year 2013
(Gain)/Loss on ABO as at January 1		
- Prepaid Benefit/(Liability)	7,507,737	8,012,298
- Transfer of Liability to Bluewater Power Services	(5,100)	-
- Unamortized (Gain)/Loss From Prior Year	2,098,558	2,437,235
- Expected ABO	9,601,194	10,449,533
- Actual ABO	9,601,194	10,449,533
- (Gain)/Loss on ABO	-	-
(Gain)/Loss on assets as at January 1		
- Expected Assets	-	-
- Actual Assets	-	-
- (Gain)/Loss on Assets	-	-
Total (Gain)/Loss as at January 1	2,098,558	2,437,235
10% of ABO as at January 1	960,119	1,044,953
Total (Gain)/Loss in Excess of 10%	1,138,438	1,392,282
Expected Average Remaining Service Life (Years)	12	11
Minimum Amortization for Current Year	94,870	126,571
Actual Amortization for Current Year	94,870	126,571
(Gain)/Loss on ABO at December 31 due to change in discount rate assumption		
- Expected ABO - December 31	10,015,986	10,900,361
- Actual ABO - December 31	10,449,533	10,900,361
- (Gain)/Loss on ABO at December 31	433,547	-
Unamortized (Gain)/Loss at December 31	2,437,235	2,310,664

**For informational purposes only. Significant changes in 2013 such as re-negotiated benefits, increased benefit costs, changes to best estimate assumptions, or significant benefit swings may require revised projections/a full actuarial review.

1.0 - EP 3 - Smart Meter Decision Adjustments

Ref: Exhibit 1, Tab 2, Schedule 1, pages 9 - 10

Are any adjustments required to the application as a result of the EB-2012-0263 Decision received in October 2012? If yes, please provide a description of the changes required and a table that shows the impact on the revenue requirement, broken down into each of the components of the change.

Bluewater Power's smart meter application EB-2012-0263 was approved with the OEB's Decision and Order dated October 18, 2012. This decision approved Bluewater Power's smart meter capital expenditures in their entirety. This decision resulted in some minor OM&A items that were disallowed, and consequently the smart meter model was updated to reflect the changes.

As a result of the OEB's Decision and Order for EB-2012-0263, there is nothing to update in the 2013 COS rate application.

See also 9-Staff-54 and 2-VECC-11.

1.0 - EP 5 - Trend Forecast for Other Revenue

Ref: Exhibit 1, Tab 2, Schedule 3, page 2

What 3 years were utilized in the development of the trend forecast for the 2013 test year?

Bluewater Power reviewed the last three historical years 2009, 2010 and 2011.

1.0 - EP 6 - Revenue Requirement, LV

Ref: Exhibit 1, Tab 2, Schedule 5 &
Exhibit 1, Tab 2, Schedule 6

a) Please reconcile the total gross revenue requirement of $22,377,919 shown in Table 1 of Schedule 6 with the Total Revenue of $22,956,939 shown in Table 1 of Schedule 5. What is the difference related to?

Table 1 of Schedule 5 indicates ‘Total Revenue’ of $22,956,938. This is the same value shown as the ‘Service Revenue Requirement’ in Table 1 of Schedule 6. This amount represents the regulated revenue required to operate the business including the regulated return for 2013.

Table 1, Schedule 6 shows the ‘Service Revenue Requirement’ of $22,956,938, from which the amount of $1,080,249 is subtracted representing the revenue from other sources such as specific service charges and billable work. The result is the ‘Base Revenue Requirement’ of $21,876,690, which is the amount recovered through base distribution rates (fixed and variable rates). Finally, an amount of $501,229 is added to the Base Revenue Requirement to account for the amount that Bluewater Power will pay out to customers that own their own transformer leading to a ‘Total Gross Revenue Requirement’ of $22,377,919 which matches the ‘Total Revenue’ in Table 1 of Schedule 6.

b) Please explain why there is no Low Voltage revenue shown in Table 1 in Schedule 6 for the 2013 test year when there was revenue in this line item in the 2009 Board Approved column.

In 2009, the amount of revenue required in order to recover the low voltage costs was recovered as part of the Gross Revenue Requirement and included in base rates. Conversely, in the 2013 rate application, the revenue required to cover the low voltage costs is treated as a pass-through item similar to the RTSR rates, and is treated as a separate rate rider. Therefore for the 2013 Test Year, Table 1 in Ex. 1-2-6 does not include low voltage in the revenue required to be collected through base rates as it is treated as a rate rider.

1.0 - SEC 1 - Schools by rate class

SEC - 1 [General] Please confirm that there are 43 schools in the Applicant's service area. Please provide a breakdown of the rate classes of those schools between GS<50 and GS>50.

Bluewater Power has 38 publicly funded schools within its service territory, broken down as follows:

- 7 in the GS<50 rate class
- 31 in the GS>50 rate class

1.0 - SEC 2 - Yearbook Data questions

[General] With respect to the table attached to these interrogatories and marked "Bluewater Timeline Data":

a. Please confirm that the data in the table correctly transposes the data from the 2008 through 2011 Electricity Yearbooks relative to the Applicant, or performs correct calculations on that data. If any of the data is incorrect, please provide the correct information. A live copy of the Excel spreadsheet has been provided for assistance in responding.

Please see Attachment 1 for the table reviewed and completed by Bluewater Power ("SEC Schedule"). The majority of the data in the table correctly transposed the data from the OEB Yearbook. The items highlighted in orange have been amended by Bluewater Power to either correct the data, or to present the data as referenced elsewhere in our application in an effort to provide more meaningful and consistent data. An electronic copy of the file has also been provided.

b. Please complete the columns for 2012 and 2013 with actuals or forecasts for each of the line items, calculated on the same basis as the past data.

Please see Attachment 1.

c. Please reconcile the figures (from "Statistics by Customer Class" in the Yearbooks) for Distribution Revenues by class with the total distribution revenues (from the Income Statements for each year) and with the Application. Please provide a consistent set of data that shows distribution revenue by class for each of the four years, plus 2012 and 2013, and reconciles that data with the RRR reporting and the income statement.

The data in Attachment 1 provides Distribution Revenue in a consistent manner from 2008 to 2013 in accordance with the OEB's grouping of accounts. It should be noted that the OEB defines 'Power and Distribution Revenue' to include accounts 4006-4245. The effect of this grouping is that certain 'other revenue' such as retail revenue, rent from electric property, late payment charges, miscellaneous service revenue and other electric revenue is considered as 'Power and Distribution Revenue'. A breakdown of the Distribution Revenue presented in Attachment 1 is provided in Table 1 below. There is a variance amount that has to do with the difference in the grouping of accounts between Bluewater Power and the OEB accounts. The offsetting variance is in the cost of power group of accounts, which nets to a zero impact to distribution revenue.

Bluewater Power reports 'Total Revenue from Distribution' on the financial statements as the amount of revenue realized from only the fixed and variable rates, therefore there is a variance between what is reported on the financial statements, and what is reported in the OEB yearbook as Power and Distribution Revenue. A full reconciliation of the Yearbook data, Financial Statements, Bluewater Power's application, and the SEC schedule is provided at Attachment 2.

Table 1 – Reconciliation of Distribution Revenue

OEB Source	Revenue from Services - Distribution	Account	2013	2012	2011	2010	2009	2008
Trial Balance	Distribution Service Revenue	4080	- 21,876,690	- 18,410,482	- 18,642,816	- 18,527,871	- 16,741,128	- 15,579,328
Trial Balance	Retail Services Revenue	4082	-	- 39,362	- 48,541	- 56,983	- 60,838	- 60,238
Trial Balance	Service Transaction Requests (STR) Revenues	4084	-	- 1,548	- 3,805	- 3,756	- 1,746	- 2,063
	SSS Admin	4086	- 90,395	- 97,854	-	-	-	-
			- 21,967,085	- 18,549,246	- 18,695,162	- 18,588,610	- 16,803,712	- 15,641,629
	Other Operating Revenues							
Trial Balance	Rent from Electric Property	4210	- 274,745	- 287,735	- 279,577	- 313,529	- 307,829	- 138,625
Trial Balance	Other Electric Revenues	4220	-	- 105,948	- 112,751	- 113,172	- 117,610	- 56,250
Trial Balance	Late Payment Charges	4225	- 232,694	- 255,934	- 244,953	- 230,017	- 285,586	- 261,939
Trial Balance	Miscellaneous Service Revenue	4235	- 157,724	- 173,990	- 174,751	- 209,404	- 1,105,751	- 326,957
			- 665,163	- 823,607	- 812,032	- 866,122	- 1,816,776	- 783,771
	Total Calculated		- 22,632,248	- 19,372,853	- 19,507,194	- 19,454,732	- 18,620,488	- 16,425,400
	Per SEC schedule and OEB Yearbook				- 19,507,000	- 19,468,000	- 18,850,000	- 16,505,000
	Variance due to grouping of accounts				- 194	13,268	229,512	79,600

d. Please provide any reasons known to the Applicant to explain the unusual pattern of Average Peak Demand over the past four years.

Bluewater Power has revised the 'SEC Comparison Table' to include revised Average Peak Demand data. We have verified with the OEB, that the calculation of the Average Peak Demand is the average of the hourly peaks whereas Bluewater Power had calculated the average on a different basis in the prior RRR reports. The restated average peak demands are as follows.

	2008	2009	2010	2011
Average Peak Demand	113,933	104,358	110,044	107,251

The peak occurred in 2008, at which point we had 5 large use customers. Since 2008 we have lost 2 large use customers, and we have seen a general decline in demand due to the economic decline experience globally, but particularly impacting manufacturing. In 2010, we experienced a very hot summer which contributed to the higher peak seen in that year.

e. Please explain why actual losses experienced in 2010 were outside of the pattern of all other years.

Please refer to OEB Appendix 2-R found in the evidence at Exhibit 8, Tab 3, Schedule 6, Attachment 1 for a more precise calculation of the loss factor. The 'SEC Schedule' provided in this interrogatory contains the data as filed in 2.1.5 of the Annual OEB RRR filings which is a modified version of the more detailed analysis that is performed at rebasing. However, for the purposes of a discussion of losses, it is most appropriate to rely on the current data in our application related to line losses.

Please see response to Board Staff # 48 for a discussion on overall losses.

f. Please explain the large increase in PP&E from 2009 to 2010. If the primary reason for that increase was information technology projects, please provide details of those projects or provide evidence references in the Application.

Refer to the response to AMPCO #3, specifically tables 3b and 4b.

g. Please explain the large increase in Operations spending from 2008 to 2009, and the large increase in G&A spending from 2010 to 2011.

Operations from 2008 to 2009

The 2008 and 2009 actuals were both lower than the 2008 Bridge Year and 2009 Test Year presented in the 2009 rebasing application (EB-2008-0221) by approximately $1.2M. Accordingly, we will refer Table 4.2.3.2 (reproduced below) to provide a response. The detailed variance explanation can be found at pages 2-4 in Ex.4-3-2 of EB-2008-0221. By way of summary, the capitalization policy was revised for 2009 to move away from a burdened labour rate (which removed cost from operational groups) to an overhead capitalization rate (which removed costs from G&A). The variance in Salary (new supervisor, new project administrator, and two positions with full year vs. half year of costs) and Labour (reorganization of staff, one new line technician, and two positions with full year vs. half year of costs) are also explained.

Table 4.2.3.2 (from EB-2008-0221)
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

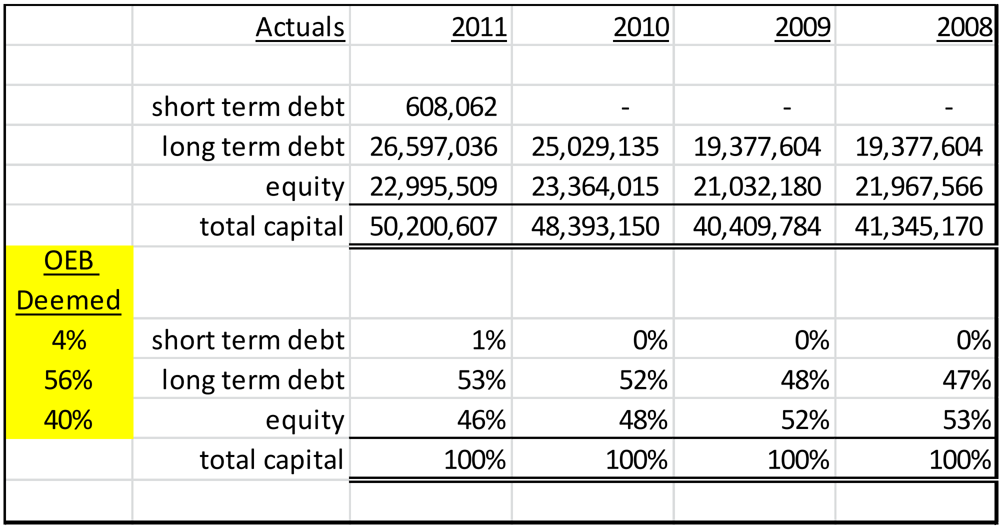
G&A spending from 2010 to 2011

The detailed variance explanations are found at Ex.4-3-1 page 13, under the heading ‘2010 Actuals to 2011 Actuals’. By way of summary, we can comment on Account 5605 Executive Salaries and Expenses and Account 5615 General Administrative Salaries and Expenses. The increase to Account 5605 relates primarily to an executive position which was vacant in 2010. The increase to Account 5615 relates primarily to the difference in Payroll Accrual for 2010 vs. 2011 which impacts this account for the entire corporation. The remaining increase in Account 5615 relates to an assistant which was added in 2011 associated with the addition of a new executive position. Finally, we note that the increase in cost in Account 5615 also relates to the decrease in direct allocation of labour to capital and billable projects in 2011 versus 2010.

h. Please advise whether the decrease in actual equity thickness from 2008 to 2011 (37.4% to 30.9%) was part of a plan to increase actual leveraging over time. If that was the case, please provide the planning and/or approval document related to the leveraging plan. If it was not part of a plan, please advise the reasons for the decrease in equity thickness over those four years. In either case, please advise whether the Applicant plans to bring equity thickness up to the Board-approved level of 40%, and if so on what schedule and by what means.

In this question, the ‘equity thickness’ of 30.9% in 2011 was calculated by taking Total Equity as a percentage of Total Assets; the question then asks us to compare this percentage to the 40% deemed equity level set by the OEB. However, the OEB deemed capital structure dictates Short and Long Term Debt plus Equity. Bluewater Power considers Short and Long Term Debt to be different than Short and Long Term Liabilities. For example, regular trade payables and accruals are not considered to be debt. Therefore a realistic comparison cannot be made between the ‘equity thickness’ as calculated and the OEB deemed capital structure.

Bluewater Power regularly compares its actual results to the OEB deemed capital structure, and where debt is not forecast as required to finance growth then equity is adjusted through dividends. That in mind, the chart below demonstrates that Bluewater Power is moving towards the OEB deemed capital structure as it was revised from 50% debt to 60% debt.



	Actuals	2011	2010	2009	2008
	short term debt	608,062	-	-	-
	long term debt	26,597,036	25,029,135	19,377,604	19,377,604
	equity	22,995,509	23,364,015	21,032,180	21,967,566
	total capital	50,200,607	48,393,150	40,409,784	41,345,170
OEB Deemed					
4%	short term debt	1%	0%	0%	0%
56%	long term debt	53%	52%	48%	47%
40%	equity	46%	48%	52%	53%
	total capital	100%	100%	100%	100%

i. Please reconcile the amount of $26.720 million of shareholders’ equity in the RRR filing for 2011 with the amount of $22.996 of shareholders equity in Ex. 1/3/1, Attachment 1.

The RRR filing for 2011 had $22.996 million for shareholders’ equity which agrees to the amount in the 2011 audited financial statements found at Exh 1-3-1, Attachment 1.

File Number:EB-2012-0107

Tab: 3
Schedule: 7

Date Filed:February 4, 2013

SEC 2 - Bluewater Power Data in the SEC Schedule

Bluewater Timeline Data

Comparator	2008	2009	2010	2011	2012 Actual (CGAAP)	2012 Basis	2013 (MIFRS)	Notes
Customers (METERED)	35,952	35,323	35,688	35,772	35,808	Actual	36,119	
Residential	31,626	31,420	31,750	31,841	31,896	Actual	32,122	
GS<50	3,906	3,505	3,511	3,495	3,480	Actual	3,544	Removed the number of USL customers that were included in GS<50 for 2008 for equal comparison
GS>50 (includes Intermediate)	416	395	424	433	429	Actual	450	
Large User	4	3	3	3	3	Actual	3	
Percentage Increase		-1.75%	1.03%	0.24%	0.10%	Calculation	0.87%	
Volumes Sold (kwh) (millions)	1,092	1,005	1,043	1,025	1,013	Actual	991	2012 is per EP 14, combination of actual where available and remaining fcst, 2013 is per application
Total Losses (DLF)	2.87%	3.87%	3.28%	4.45%	Not available		Not available	The losses have been revised to reflect the rate application Appendix 2-R
Average Peak Demand	113,933	104,358	110,044	107,251	Not available		Not available	These have been revised based on a defintion clarificiation with the OEB of 'Average Peak Demand'
DX Revenues (000s omitted)	$16,505	$18,850	$19,468	$19,507	$19,373	Draft Actual	$22,632	this includes SSS admin, retail revenue and other revenue items (Accounts 4080-4086, 4210-4235)
Residential	$8,150	$9,158	$10,031	$10,032	$10,047	Draft Actual	$12,026	
GS<50	$2,605	$2,800	$2,972	$2,822	$2,727	Draft Actual	$3,118	
GS>50 and Large	$4,538	$4,441	$4,822	$4,737	$4,819	Draft Actual	$5,763	
Other	$1,212	$2,451	$1,643	$1,916	$1,780		$969	this is the revenue from rate classes not listed above, plus the other revenue per the OEB groupings.
Property, Plant & Equipment (000s omitted)	$38,952	$38,819	$42,523	$42,915	$51,963	Draft Actual	$53,751	2012 & 2013 used ending NBV for year
PP&E per Customer	$1,083.44	$1,098.97	$1,191.52	$1,199.68	$1,451.17	Calculation	$1,488.16	
Percentage Increase		1.43%	8.42%	0.68%	20.96%	Calculation	2.55%	
Capital Additions/Depreciation	123.7%	135.3%	206.8%	126.6%	202.9%	Draft Actual	126.9%	
OM&A (000s omitted)	$9,108	$10,441	$10,490	$11,712	$11,461	Draft Actual	$13,303	
Operations	$2,085	$3,254	$3,136	$3,177	$3,067	Draft Actual	$3,467	
Maintenance	$169	$162	$176	$157	$852	Draft Actual	$143	
Administration	$6,854	$6,729	$6,943	$7,729	$7,358	Draft Actual	$9,469	
Other	$0	$296	$235	$649	$184	Draft Actual	$224	2011 - includes one time PILs adjustment of $428,796, other years is property tax
OM&A per Customer	$253.34	$295.59	$293.94	$327.41	$320.07	Calculation	$368.30	
Actual Shareholders' Equity (000s omitted)	$21,968	$21,032	$23,364	$22,995	$22,828	Per original filing	$23,792	
Equity Thickness'	37.4%	32.6%	30.7%	30.9%	30.4%	Per original filing	31.3%	
LTD & Aff. Debt (000s omitted)	$19,378	$19,378	$25,029	$27,205	$25,870	Draft Actual	$25,241	Note 1 and 2 for 2009 and 2011.
Net Income (000s omitted)	$1,912	$2,819	$3,498	$2,297	$2,432	Per original filing	$1,764	
Financial ROE	8.70%	13.40%	14.97%	9.99%	10.70%	Per original filing	7.40%	
Interest Cost (000s omitted)	$1,395	$1,472	$1,571	$1,732	$1,870	Draft Actual	$1,134	
PILs (000s omitted)	$1,065	$1,293	$906	$525	$141	Per original filing	$494	
Total Cost of Capital	$4,372	$5,584	$5,975	$4,554	$4,443	Calculation	$3,392	

Changes Made

1 For 2009 the LTD is 19,377,604. The value of 1,874,957 in the yearbook as 'Inter-company' is not debt. Per note 14 of the Audited Statements, this represents billed amounts for water billing not yet remitted to municipal shareholders.

2 For 2011, the LTD debt number has been corrected to correspond to what is indicated in the 2011 yearbook which is LTD of 19,377,604 plus Inter-Company LTD and advances of 7827494

2011												
Source		Account	RRR Data	Yearbook Data	Financial Statements	Application	Application Reference	SEC Schedule	Notes			
	Revenue from Services - Distribution											
Trial Balance	Distribution Service Revenue	4080	- 18,642,816		18,307,805				- 335,011	variance		
Trial Balance	Retail Services Revenue	4082	- 48,541						93,861	SSS Admin		
Trial Balance	Service Transaction Requests (STR) Revenu	4084	- 3,805						- 241,150	LRAM		
			- 18,695,162									
	Other Operating Revenues											
Trial Balance	Rent from Electric Property	4210	- 279,577									
Trial Balance	Other Electric Revenues	4220	- 112,751									
Trial Balance	Late Payment Charges	4225	- 244,953									
Trial Balance	Miscellaneous Service Revenue	4235	- 174,751									
			- 812,032									
	Total		- 19,507,194									
Trial Balance	Residential Energy Sales	4006	- 19,599,670									
Trial Balance	Energy Sales to Large Users	4020	- 4,308,559									
Trial Balance	Streetlight	4025	- 257,751									
Trial Balance	Sentinel	4030	- 38,612									
Trial Balance	General Energy Sales	4035	- 20,509,566									
Trial Balance	Revenue Adjustment	4050	569,130									
Trial Balance	Billed WMS	4062	- 6,099,260									
Trial Balance	Billed NW	4066	- 5,682,064									
Trial Balance	Billed Connection	4068	- 4,831,345									
			- 60,757,697		60,757,697							
Trial Balance	Power Purchased	4705	44,764,887									
Trial Balance	Charges WMS	4708	3,535,211									
Trial Balance	Cost of power adjustments	4710	1,484,516									
Trial Balance	Charges NW	4714	5,301,643									
Trial Balance	charges CN	4716	4,716,434									
Trial Balance	Rural Rate Assistance	4730	955,006									
			60,757,697		60,757,697							
	Power and Distribution Revenue		- 80,264,891	80,264,953	79,065,502							
	Cost of Power and related costs		60,757,697	60,757,697	60,757,697							
	Total Revenue from Distribution		- 19,507,194	19,507,256	18,307,805							
2.1.5	Residential		10,032,358	10,032,358		10,032,358		10,032				
2.1.5	GS<50		2,822,474	2,822,474		2,822,474		2,822				
2.1.5	GS>50 (yearbook aggregates GS>50, Intermediate and Large)		3,447,255	4,737,379		2,752,119		4,737	2.1.5 aggregates GS>50 and Intermediate into one GS>50 class			
	Intermediate					695,136						
	Large		1,290,124			1,290,125						
2.1.5	Streetlight		544,686	🟥		544,686			The yearbook does not present revenue for streetlight and sentinel			
2.1.5	Sentinel		43,478	🟥		43,478			even though it is provided in 2.1.5 data			
2.1.5	USL		127,429	127,429		127,429						
			18,307,804	17,719,640		18,307,805	3/1/5/2					
	Classified as Other for SEC schedule							1,916				
	Total Dist Revenue on SEC Schedule							19,507				

2010												
Source		Account	RRR Data	Yearbook Data (electronic data)	Financial Statements	Application	Application Reference	SEC Schedule	variances			
	Revenue from Services - Distribution											
Trial Balance	Distribution Service Revenue	4080	- 18,527,871		18,450,776				- 77,095			
Trial Balance	Retail Services Revenue	4082	- 56,983						90,530	SSS Admin		
Trial Balance	Service Transaction Requests (STR) Revenu	4084	- 3,756						13,435	variance due to account grouping		
			- 18,588,610									
	Other Operating Revenues											
Trial Balance	Rent from Electric Property	4210	- 313,529									
Trial Balance	Other Electric Revenues	4220	- 113,172									
Trial Balance	Late Payment Charges	4225	- 230,017									
Trial Balance	Miscellaneous Service Revenue	4235	- 209,404									
			- 866,122									
	Total		- 19,454,732									
Trial Balance	Residential Energy Sales	4006	- 19,726,387									
Trial Balance	Energy Sales to Large Users	4020	- 5,138,928									
Trial Balance	Streetlight	4025	- 297,661									
Trial Balance	Sentinel	4030	- 37,250									
Trial Balance	General Energy Sales	4035	- 20,822,402									
Trial Balance	Revenue Adjustment	4050	- 1,067,986									
Trial Balance	Billed WMS	4062	- 6,179,030									
Trial Balance	Billed NW	4066	- 5,278,832									
Trial Balance	Billed Connection	4068	- 4,788,270									
			- 63,336,746		63,323,310				- 13,436			
Trial Balance	Power Purchased	4705	46,646,401									
Trial Balance	Charges WMS	4708	3,911,352									
Trial Balance	Cost of power adjustments	4710	1,642,950									
Trial Balance	Charges NW	4714	5,335,078									
Trial Balance	charges CN	4716	4,732,567									
Trial Balance	Rural Rate Assistance	4730	1,054,963									
			63,323,311		63,323,311							
	Power and Distribution Revenue		- 82,791,478	82,791,478	81,774,086							
	Cost of Power and related costs		63,323,311	63,323,311	63,323,311							
	Total Revenue from Distribution		- 19,468,167	19,468,167	18,450,775							
2.1.5	Residential		10,031,282	10,031,282		10,031,282		10,031				
2.1.5	GS<50		2,972,249	2,972,249		2,972,249		2,972				
2.1.5	GS>50 (yearbook aggregates GS>50, Intermediate and Large)		2,735,517	4,822,049		2,735,517		4,822				
	Intermediate		815,189			815,189						
	Large		1,271,343			1,271,343						
2.1.5	Streetlight		465,903	🟥		465,903						
2.1.5	Sentinel		38,682	🟥		38,682						
2.1.5	USL		120,612	120,612		120,612						
			18,450,777	17,946,192		18,450,777	3/1/5/2					
	Classified as Other for SEC schedule							1,643				
	Total Dist Revenue on SEC Schedule							19,468				

2009 Actual

Source		Account	RRR Data	Yearbook Data	Financial Statements	Application	Application Reference	SEC Schedule	variance			
	Revenue from Services - Distribution											
Trial Balance	Distribution Service Revenue	4080	- 16,741,128		16,881,501				140,373			
Trial Balance	Retail Services Revenue	4082	- 60,838						89,114	SSS Admin		
Trial Balance	Service Transaction Requests (STR) Revenu	4084	- 1,746						229,487	variance due to account grouping		
			- 16,803,712									
	Other Operating Revenues											
Trial Balance	Rent from Electric Property	4210	- 307,829									
Trial Balance	Other Electric Revenues	4220	- 117,610									
Trial Balance	Late Payment Charges	4225	- 285,586									
Trial Balance	Miscellaneous Service Revenue	4235	- 1,105,751									
			- 1,816,776									
	Total		- 18,620,488									
Trial Balance	Residential Energy Sales	4006	- 16,673,090									
Trial Balance	Energy Sales to Large Users	4020	- 4,259,156									
Trial Balance	Streetlight	4025	- 334,728									
Trial Balance	Sentinel	4030	- 35,473									
Trial Balance	General Energy Sales	4035	- 19,817,083									
Trial Balance	Revenue Adjustment	4050	2,072,687									
Trial Balance	Billed WMS	4062	- 5,871,872									
Trial Balance	Billed NW	4066	- 4,582,688									
Trial Balance	Billed Connection	4068	- 4,507,168									
			- 54,008,571		53,779,083				- 229,488			
Trial Balance	Power Purchased	4705	41,596,698									
Trial Balance	Charges WMS	4708	4,575,002									
Trial Balance	Cost of power adjustments	4710	- 2,371,042									
Trial Balance	Charges NW	4714	4,672,460									
Trial Balance	charges CN	4716	4,311,876									
Trial Balance	Rural Rate Assistance	4730	994,090									
			53,779,084		53,779,083							
	Power and Distribution Revenue		- 72,629,059	72,629,059	70,660,584							
	Cost of Power and related costs		53,779,084	53,779,084	53,779,083							
	Total Revenue from Distribution		- 18,849,975	18,849,975	16,881,501							
2.1.5	Residential		9,157,764	9,157,764		9,157,764		9,158				
2.1.5	GS<50		2,800,099	2,800,099		2,800,099		2,800				
2.1.5	GS>50 (yearbook aggregates GS>50, Intermediate and Large)		3,353,661	4,441,480		2,541,703		4,441				
	Intermediate					811,958						
	Large		1,087,819			1,087,819						
2.1.5	Streetlight		360,409	🟥		360,409						
2.1.5	Sentinel		27,528	🟥		27,528						
2.1.5	USL		94,221	94,221		94,221						
			16,881,501	16,493,564		16,881,501	3/1/5/2					
	Classified as Other for SEC schedule							2,451				
	Total Dist Revenue on SEC Schedule							18,850				

2008												
Source		Account	RRR Data	Yearbook Data	Financial Statements	Application	Application Reference	SEC Schedule	variance			
	Revenue from Services - Distribution											
Trial Balance	Distribution Service Revenue	4080	- 15,579,328		15,570,034				- 9,294			
Trial Balance	Retail Services Revenue	4082	- 60,238						88,602	SSS Admin		
Trial Balance	Service Transaction Requests (STR) Revenu	4084	- 2,063						79,308	Variance due to account grouping		
			- 15,641,629									
	Other Operating Revenues											
Trial Balance	Rent from Electric Property	4210	- 138,625									
Trial Balance	Other Electric Revenues	4220	- 56,250									
Trial Balance	Late Payment Charges	4225	- 261,939									
Trial Balance	Miscellaneous Service Revenue	4235	- 326,957									
			- 783,771									
	Total		- 16,425,400									
Trial Balance	Residential Energy Sales	4006	- 17,823,451									
Trial Balance	Energy Sales to Large Users	4020	- 9,056,995									
Trial Balance	Streetlight	4025	- 536,995									
Trial Balance	Sentinel	4030	- 31,104									
Trial Balance	General Energy Sales	4035	- 25,078,166									
Trial Balance	Revenue Adjustment	4050	- 503,838									
Trial Balance	Billed WMS	4062	- 6,237,766									
Trial Balance	Billed NW	4066	- 5,018,070									
Trial Balance	Billed Connection	4068	- 4,765,584									
			- 69,051,969		68,972,660				- 79,309			
Trial Balance	Power Purchased	4705	51,551,794									
Trial Balance	Charges WMS	4708	4,781,862									
Trial Balance	Cost of power adjustments	4710	2,832,580									
Trial Balance	Charges NW	4714	4,455,859									
Trial Balance	charges CN	4716	4,436,253									
Trial Balance	Rural Rate Assistance	4730	914,313									
			68,972,661		68,972,660							
	Power and Distribution Revenue		- 85,477,369	85,477,369	84,542,694							
	Cost of Power and related costs		68,972,661	68,972,661	68,972,660							
	Total Revenue from Distribution		- 16,504,708	16,504,708	15,570,034							
2.1.5	Residential		8,150,103	8,150,103		not filed		8,150				
2.1.5	GS<50		2,605,427	2,605,427		not filed		2,605				
2.1.5	GS>50 (yearbook aggregates GS>50, Intermediate and Large)		3,342,074	4,538,019		not filed		4,538				
	Intermediate					not filed						
	Large		1,195,945	1,195,945		not filed						
2.1.5	Streetlight		257,248	🟥		not filed						
2.1.5	Sentinel		19,237	🟥		not filed						
2.1.5	USL			🟥		not filed						
			15,570,034	16,489,494		-	3/1/5/2					
	Classified as Other for SEC schedule							1,212				
	Total Dist Revenue on SEC Schedule							16,505				

1.0 - SEC 3 - Comparison Data

[General] Please confirm that the following table correctly sets out the 2011 Yearbook data, and calculations from it, for the Applicant and the other named LDCs.

Comparisons of Distributor Data - Bluewater Power

	OM&A/ Cust 2011	***Rank***	***Net Fixed Ass/Cust.***	***Rank***	***CapAdds/ Depr.***	***Rank***
E.L.K.	$217.48	**6**	$688	**1**	57%	**15**
Wasaga	$183.71	**1**	$727	**2**	102%	**14**
Chatham-Kent	$268.60	**12**	$1,540	**12**	141%	**11**
Peterborough	$212.07	**5**	$1,400	**10**	181%	**7**
Festival	$203.79	**2**	$1,717	**14**	145%	**9**
Welland	$244.88	**9**	$1,035	**4**	142%	**10**
Kingston	$242.86	**8**	$1,135	**5**	288%	**2**
Westario	$209.58	**4**	$1,425	**11**	215%	**4**
COLLUS	$259.70	**11**	$865	**3**	197%	**5**
St. Thomas	$231.19	**7**	$1,163	**6**	147%	**8**
Essex	$205.78	**3**	$1,391	**9**	237%	**3**
Woodstock	$259.27	**10**	$1,673	**13**	297%	**1**
Niagara Peninsula	$275.74	**13**	$1,976	**15**	138%	**12**
Bluewater	$327.42	**15**	$1,200	**7**	127%	**13**
Erie Thames	$321.43	14	$1,300	8	191%	6
Averages	$244.23		$1,282		174%	
Bluewater/Average	134%		94%		73%	

With respect to the information in the table:

a. Please explain the primary reasons, if known, why the Applicant's OM&A per customer in 2011 is so much higher than that of its peers.

Bluewater Power confirms that the table presented in the question correctly sets out the 2011 Yearbook data, and calculations from it.

Bluewater Power notes, however, that ranking of distributors on the basis of any single ratio, including OM&A per customer, is not a meaningful indicator of either productivity or the reasonableness of the level of costs incurred by the distributor. That is the reason that the OEB has in the past utilized econometric methods for developing its cohort rankings. That approach takes into account some of the most significant factors that result in inherent cost differences across distributors.

Furthermore, the Renewed Regulatory Framework for Electricity Distributors ("RRFE") process addresses the concern, which is recognized by the OEB, that its existing OM&A based measures are incomplete comparators of operational efficiency. The RRFE work to date clearly demonstrates that the OEB recognizes that the Balanced Scorecard measures and improved approach to benchmarking will provide performance measures that are more meaningful than those that have been relied upon to date.

Bluewater Power therefore rejects the implication of the question that its ranking within a group of 15 LDCs is an indicator or productivity that has any relevance to the reasonableness of the proposed revenue requirement and rates.

Some of the reasons that Bluewater Power has comparatively high OM&A costs as reported in the Statistical Yearbook can be demonstrated through a more complete analysis of the statistics that are available in the 2011 Yearbook. Bluewater Power cautions, however, that while the information provided below should assist in appreciating why Bluewater Power's OM&A as reported in the Statistical Yearbook is high within the group of 15, this additional ratios cannot be considered to be a thorough analysis of relative productivity.

First, it is important to recognize that Bluewater Power's O&M per customer value of $327.42 is overstated given a one-time PILS anomaly. An amount of $428,796 related to a one-time PILS adjustment was booked to account 6310 and hence included in the O&M per customer calculation. If we eliminate this one-time non-O&M adjustment, then result is an O&M of $315.43 per customer.

Among the many factors that affect a distributor's costs are: kwhrs sold, percentage of rural customers, total service area, other revenue and capitalized labour. These cost factors can vary dramatically among utilities within a peer group. The following chart displays these other relevant calculations from the peer group as noted above from the 2011 Statistical Yearbook. Key conclusions from this additional analysis are as follows:

(i) Bluewater Power has the third largest service area of the group and thus would expect a higher cost per customer to service. Accounting for this fact, the calculation of O&M per square kilometer of service area puts Bluewater Power at 68% below the peer group average at $56,138 per square kilometer. Bluewater Power ranks 13/15 in its number of customers per square kilometer service area. Our value of 178 customers/km^2 is 51% lower than the average of our peer group. As such, a lower customer density would be expected to result in a higher cost of service.

(ii) Bluewater Power has the third largest number of kilometers of line and as such would expect a higher cost per customer to service. Bluewater Power's 777 kilometers of line is 54% higher than the average of the peer group, and it follows that our ratio of 46 customers/km of line is 20% lower than the average of our peer group. On a cost per kilometer of line basis, Bluewater Power ranks approximately the middle of the group at $14,524 of O&M per kilometer of line.

(iii) Bluewater Power has the second largest kwhrs sold within the peer group. Our value of 1,051,399,006 kwhrs is 82% higher than the average of the peer group. As such, we would expect higher costs given this level of throughput. If we calculate a cost per kwhr, Bluewater Power again falls in the middle of the group with an average cost per kwhr of $.0107 sold.

(iv) Bluewater Power ranks third in its percentage of rural customers at 73%. The majority of our comparator utilities have a rural customer percentage of 0% indicated. Again, the higher rural service territory would intuitively result in a higher cost per customer.

(v) The results reported in the OEB Yearbook also reveal that Bluewater Power ranks below average in both net fixed assets per customer and capital spending per customer. This is relevant to the discussion at hand because it suggests that Bluewater Power capitalizes a lower portion of its total O&M. Supporting this notion is the fact that Bluewater Power’s lower value of Plant, Property and Equipment (PPE) per customer is comparable to our higher value of O&M per customer. That is, Bluewater Power is $82 per customer lower in PPE and $83 higher in O&M per customer than our peer averages. As such, in order to carry out a comparison of O&M per customer, the Board would need to see a comparison of Bluewater Power’s capitalization policy with that of its peers. For the purposes of this Interrogatory, we can simply suggest that the lower capital spending for Bluewater Power may be driven by a lower capitalization rate compared to its peers which contributes to higher O&M cost per customer.

In summary, the above analysis supports the following conclusions:

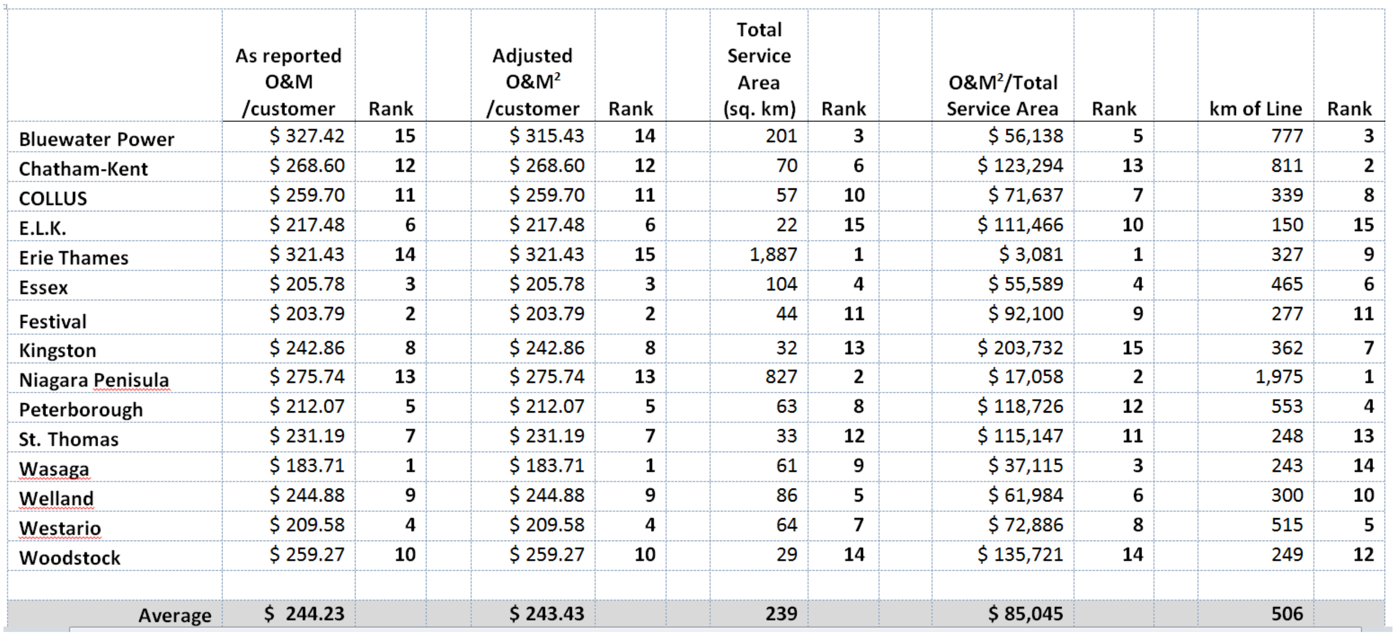
(i) O&M per customer is not a comprehensive indicator of performance in isolation of other factors. Benchmarking can only be meaningful with a thorough analysis of other factors that affect costs per customer. The OEB recognizes the importance of ensuring that benchmarking accurately accounts for the circumstances of a distributor; in fact, benchmarking and performance measure is the subject of an ongoing OEB consultation (EB-2010-0379). It is not possible in the context of an IR response to address the complexity of issues involved, but the response provided above addresses those factors that Bluewater Power submits contribute to its O&M per customer.

(ii) In general, we suggest that Bluewater Power's unique circumstances discussed above would support O&M per customer higher than average when compared to its peers.

(iii) Moreover, other measures/ratios of efficiency highlighted above would place Bluewater Power at or even below an average level for its peer group (the back-up for the Comparative Analysis are included in the tables that follow).

Bluewater Power

Comparative Analysis[1]



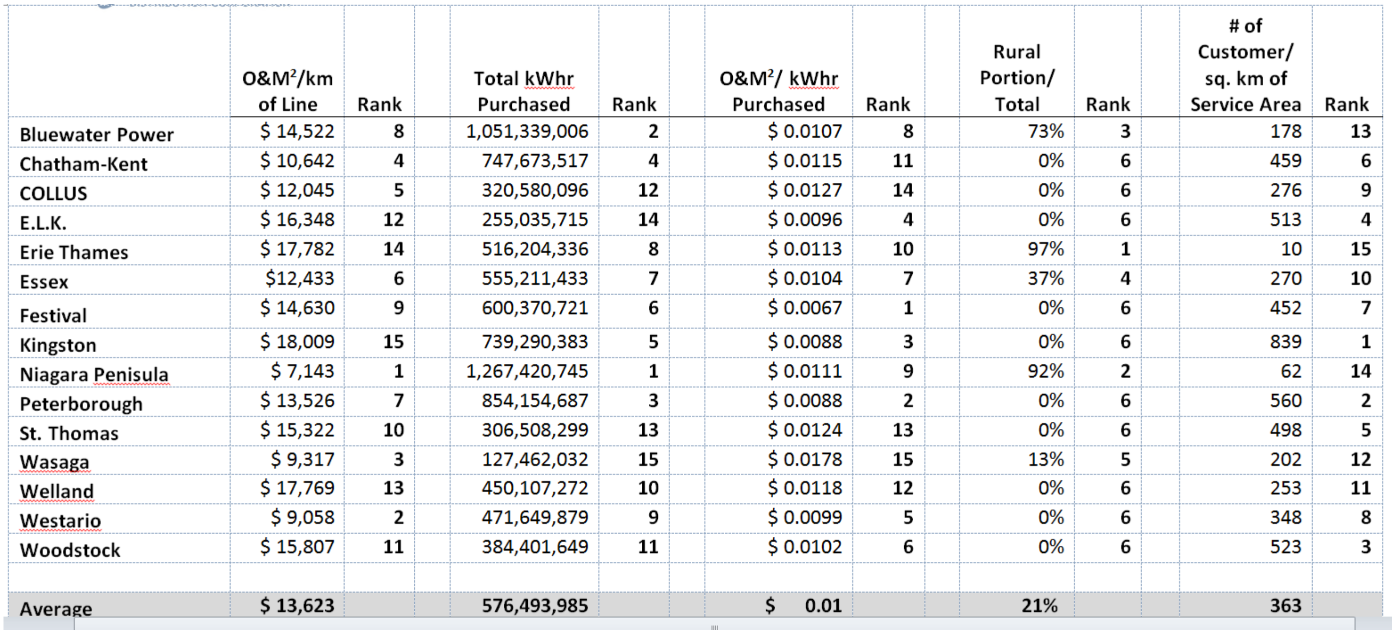
	As reported O&M /customer	Rank	Adjusted O&M[2] /customer	Rank	Total Service Area (sq. km)	Rank	O&M[2]/Total Service Area	Rank	km of Line	Rank
Bluewater Power	$ 327.42	15	$ 315.43	14	201	3	$ 56,138	5	777	3
Chatham-Kent	$ 268.60	12	$ 268.60	12	70	6	$ 123,294	13	811	2
COLLUS	$ 259.70	11	$ 259.70	11	57	10	$ 71,637	7	339	8
E.L.K.	$ 217.48	6	$ 217.48	6	22	15	$ 111,466	10	150	15
Erie Thames	$ 321.43	14	$ 321.43	15	1,887	1	$ 3,081	1	327	9
Essex	$ 205.78	3	$ 205.78	3	104	4	$ 55,589	4	465	6
Festival	$ 203.79	2	$ 203.79	2	44	11	$ 92,100	9	277	11
Kingston	$ 242.86	8	$ 242.86	8	32	13	$ 203,732	15	362	7
Niagara Penisula	$ 275.74	13	$ 275.74	13	827	2	$ 17,058	2	1,975	1
Peterborough	$ 212.07	5	$ 212.07	5	63	8	$ 118,726	12	553	4
St. Thomas	$ 231.19	7	$ 231.19	7	33	12	$ 115,147	11	248	13
Wasaga	$ 183.71	1	$ 183.71	1	61	9	$ 37,115	3	243	14
Welland	$ 244.88	9	$ 244.88	9	86	5	$ 61,984	6	300	10
Westario	$ 209.58	4	$ 209.58	4	64	7	$ 72,886	8	515	5
Woodstock	$ 259.27	10	$ 259.27	10	29	14	$ 135,721	14	249	12
Average	**$ 244.23**		**$ 243.43**		**239**		**$ 85,045**		**506**	

[1] Data collected from 2011 Yearbook for Electricity Distributors, published by the Ontario Energy Board on September 13, 2012.
[2] Adjusted O&M is based on removal of one-time PILs adjustment costs of $428,796 incurred to Bluewater Power in 2011.

Bluewater Power

Comparative Analysis[1]

(continued)



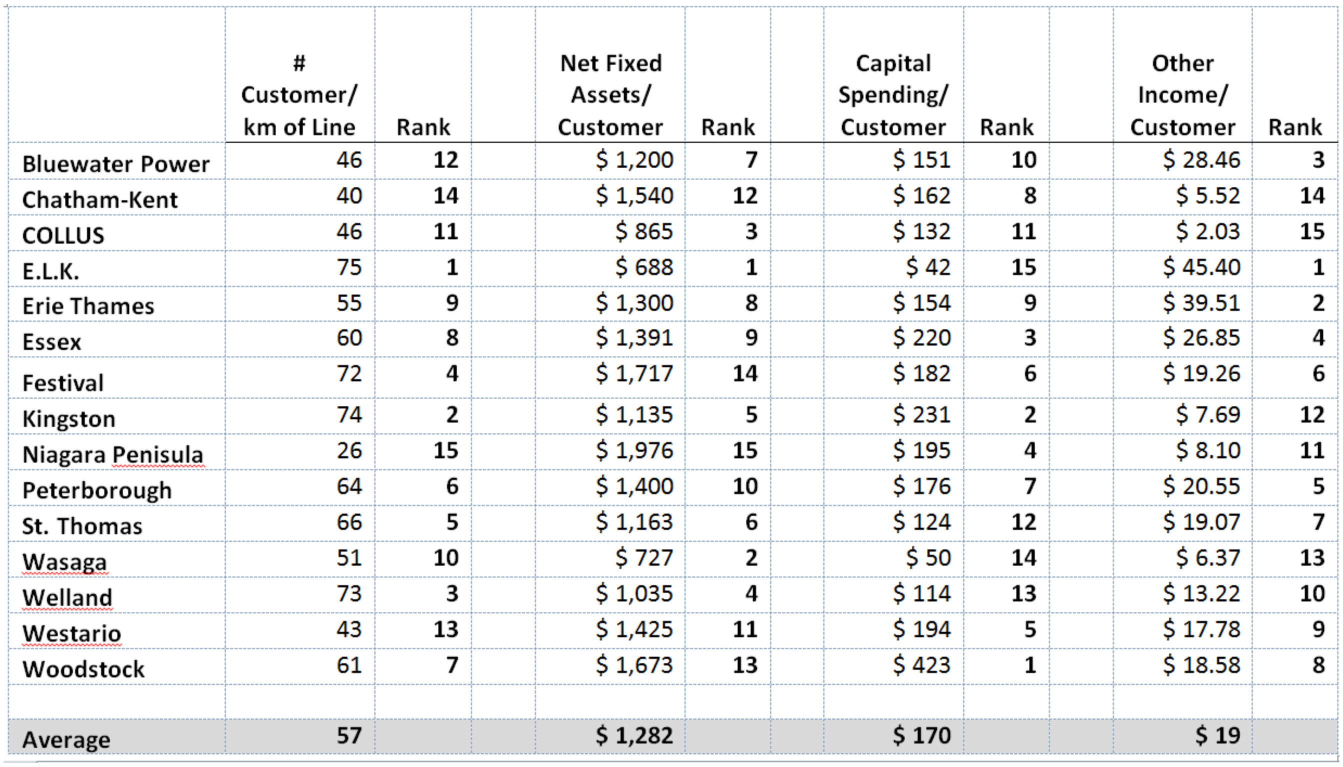
	O&M²/km of Line	Rank	Total kWhr Purchased	Rank	O&M²/ kWhr Purchased	Rank	Rural Portion/ Total	Rank	# of Customer/ sq. km of Service Area	Rank
Bluewater Power	$ 14,522	8	1,051,339,006	2	$ 0.0107	8	73%	3	178	13
Chatham-Kent	$ 10,642	4	747,673,517	4	$ 0.0115	11	0%	6	459	6
COLLUS	$ 12,045	5	320,580,096	12	$ 0.0127	14	0%	6	276	9
E.L.K.	$ 16,348	12	255,035,715	14	$ 0.0096	4	0%	6	513	4
Erie Thames	$ 17,782	14	516,204,336	8	$ 0.0113	10	97%	1	10	15
Essex	$12,433	6	555,211,433	7	$ 0.0104	7	37%	4	270	10
Festival	$ 14,630	9	600,370,721	6	$ 0.0067	1	0%	6	452	7
Kingston	$ 18,009	15	739,290,383	5	$ 0.0088	3	0%	6	839	1
Niagara Penisula	$ 7,143	1	1,267,420,745	1	$ 0.0111	9	92%	2	62	14
Peterborough	$ 13,526	7	854,154,687	3	$ 0.0088	2	0%	6	560	2
St. Thomas	$ 15,322	10	306,508,299	13	$ 0.0124	13	0%	6	498	5
Wasaga	$ 9,317	3	127,462,032	15	$ 0.0178	15	13%	5	202	12
Welland	$ 17,769	13	450,107,272	10	$ 0.0118	12	0%	6	253	11
Westario	$ 9,058	2	471,649,879	9	$ 0.0099	5	0%	6	348	8
Woodstock	$ 15,807	11	384,401,649	11	$ 0.0102	6	0%	6	523	3
Average	$ 13,623		576,493,985		$ 0.01		21%		363	

[2] Adjusted O&M is based on removal of one-time PILs adjustment costs of $428,796 incurred to Bluewater Power in 2011.

Bluewater Power

Comparative Analysis[1]

(continued)



	# Customer/ km of Line	Rank		Net Fixed Assets/ Customer	Rank		Capital Spending/ Customer	Rank		Other Income/ Customer	Rank
Bluewater Power	46	**12**		$ 1,200	**7**		$ 151	**10**		$ 28.46	**3**
Chatham-Kent	40	**14**		$ 1,540	**12**		$ 162	**8**		$ 5.52	**14**
COLLUS	46	**11**		$ 865	**3**		$ 132	**11**		$ 2.03	**15**
E.L.K.	75	**1**		$ 688	**1**		$ 42	**15**		$ 45.40	**1**
Erie Thames	55	**9**		$ 1,300	**8**		$ 154	**9**		$ 39.51	**2**
Essex	60	**8**		$ 1,391	**9**		$ 220	**3**		$ 26.85	**4**
Festival	72	**4**		$ 1,717	**14**		$ 182	**6**		$ 19.26	**6**
Kingston	74	**2**		$ 1,135	**5**		$ 231	**2**		$ 7.69	**12**
Niagara Penisula	26	**15**		$ 1,976	**15**		$ 195	**4**		$ 8.10	**11**
Peterborough	64	**6**		$ 1,400	**10**		$ 176	**7**		$ 20.55	**5**
St. Thomas	66	**5**		$ 1,163	**6**		$ 124	**12**		$ 19.07	**7**
Wasaga	51	**10**		$ 727	**2**		$ 50	**14**		$ 6.37	**13**
Welland	73	**3**		$ 1,035	**4**		$ 114	**13**		$ 13.22	**10**
Westario	43	**13**		$ 1,425	**11**		$ 194	**5**		$ 17.78	**9**
Woodstock	61	**7**		$ 1,673	**13**		$ 423	**1**		$ 18.58	**8**
Average	**57**			**$ 1,282**			**$ 170**			**$ 19**	

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[2] Adjusted O&M is based on removal of one-time PILs adjustment costs of $428,796 incurred to Bluewater Power in 2011.

b. Please advise whether the Applicant has a strategy to bring OM&A per customer in line with the levels of its peers in the future, and if so describe that strategy.

For the reasons set out above, Bluewater Power does not accept the premise of the question that OM&A per customer, without accounting for the unique circumstances of a distributor, ought to be a goal on which to develop a strategy. As noted in the response above, there are measurement ratios (OM&A/kilometer of service area, OM&A/kilometer of line, and OM&A/kwhr sold) which demonstrate Bluewater Power to be at and even below the average level of its peer group. In addition, any effort to compare distributors that does not include capital spending, including capitalization policies, is inadequate. That in mind, Bluewater Power will answer the question to say that the utility's Asset Management Plan and its Human Resources Strategy both focus on providing reliable service at an efficient price.

c. Please advise why, with an existing PP&E per customer of only $1,200, the capital additions (as a percentage of depreciation) of the Applicant are well below the average of the peer group and the average of the industry (about 243% weighted average, and 185% simple average).

An answer to this question would require Bluewater Power to understand and comment upon the capital additions of other utilities in our peer group. As noted in answer to (a) and (b) above, the lower PP&E per customer and capital additions as a percentage of depreciation may relate to Bluewater Power's capitalization rate being lower than our peers. We can say that our Asset Management Plan (Ex. 2-4-3, Attachment 3) contains a measured and sustainable plan for our capital infrastructure and that our capitalization rate (Ex. 2-2-2) is supported by the evidence. In other words, we are satisfied that our customers will receive reliable service into the future at a reasonable price, but we cannot compare that response to the plans of our peers.

1.0 - SEC 4 - Financial Statements

[1/1/10] Please provide the most recent financial statements (audited, if audits were carried out) for each of:

a. Bluewater Power Services Corporation.

b. Electek Power Services Inc.

c. Bluewater Power Generation Corporation.

d. Bluewater Power Renewable Energy Inc.

e. Bluewater Power Corporation (consolidated and unconsolidated).

Bluewater Power denies this request on the basis of relevance. Many of the business activities that Bluewater Power's affiliates are engaged in are unrelated to the distribution business. Bluewater Power believes that the non-distribution related activities of its affiliates are beyond the scope of this proceeding. For affiliate activities related to the distribution business, in order to assist the Board and intervenors, Bluewater Power filed a *Study of Affiliate Service Costs and Cost Allocation* at Exhibit 4, Tab 5, Schedule 1, Attachment 2.

1.0 - SEC 5 - Shareholder Agreement and Corporate Strategic Plan

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Please provide, with respect to the Applicant and its parent company:

a. Any current Shareholders' Agreement or Direction, and any previous Shareholders' Agreement or Direction dated after 2000.

b. The current Corporate Strategic Plan and/or Business Plan.

a. Shareholders' Agreement:

Attachment 1 includes the current Shareholders' Agreement, along with a Shareholders' resolutions passed in the year 2006 to amend certain terms and conditions contained therein.

Attachment 1 : Shareholder Agreement
Shareholders Resolution #1
Shareholders Resolution #2

b. Business Plan:

The Business Plan for Bluewater Power in a given year is contained in its annual budget passed in November of the preceding year, both O&M and Capital. The assumptions and processes that are described in Ex.1-2-3 apply to the annual budget process as well as the assumption in this Rebasing Application. As a regulated distribution company, Bluewater Power's business objects are heavily dependent on two things, its physical assets and its people. The development of plans regarding both capital planning and people planning is therefore critical to Bluewater Power. The second step in the achievement of those objectives is ongoing monitoring, which is critical to effective business planning.

The Capital Plan is described in detail in Exhibit 2, which contains a description of the Asset Management Planning Process undertaken by Bluewater Power. Included in that description are the two external reviews, which concluded that our processes in place to assess the condition of our distribution assets were within the ‘expected’ to ‘leading’ range in all areas (Ex. 2- 4-2, Attachment 1) and then facilitated and documented the evolution of the Asset Management Plan (Ex.2- 4- 2, Attachment 2). With respect to the Information Technology assets of Bluewater Power, the answer to OEB Staff IR #14 describes the process undertaken to assess and manage those critical assets. The plan for all assets, including operations and information technology, are contained in the Asset Management Plan included with the pre-filed evidence as Ex.2- 4- 3, Attachment 3.

As discussed in the schedule entitled “Staffing and Compensation Levels” (Ex. 4- 4-1), employee compensation represents approximately 75% of the total O&M recoverable through distribution rates. It is critical to business planning that the utility manage its staff to meet the evolving challenges of the electricity industry in Ontario in a sustainable manner. That process is described in the Human Resources Strategy included as Ex.4- 4-1, Attachment 1.

Finally, business planning is not complete without ongoing monitoring. Bluewater Power management undertakes monthly reviews of performance versus budget, and quarterly updates are provided to the Board of Directors. This process permits Bluewater Power to ensure its business objectives are achieved in the face of the changing demands of the electricity sector in Ontario.

File Number:EB-2012-0107

Tab: 3
Schedule: 10

Date Filed:February 4, 2013

Attachment 1 of 1

SEC 5 - Shareholders' Agreement

SHAREHOLDERS' AGREEMENT

BETWEEN:

The Corporation of the Village of Alvinston

- and -

The Corporation of the Village of Oil Springs

- and -

The Corporation of the Town of Petrolia

- and -

The Corporation of the Village of Point Edward

- and -

The Corporation of the Township of Warwick

- and -

The Corporation of the City of Sarnia

- and -

Alvinston Electricity Holdings Inc.

- and -

Oil Springs Electricity Holdings Inc.

- and -

Petrolia Electricity Holdings Inc.

- and -

Point Edward Electricity Holdings Inc.

- and -

Warwick Electricity Holdings Inc.

- and -

Sarnia Power Corporation

- and -

Bluewater Power Corporation

- and -

Bluewater Power Distribution Corporation

- and -

Sarnia Hydro Energy Services Corporation

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SHAREHOLDERS' AGREEMENT

THIS AGREEMENT made as of the 1st day of November, 2000

BETWEEN:

The Corporation of the Village of Alvinston
(hereinafter called "**Alvinston**")

- and -

The Corporation of the Village of Oil Springs
(hereinafter called "**Oil Springs**")

- and -

The Corporation of the Town of Petrolia
(hereinafter called "**Petrolia**")

- and -

The Corporation of the Village of Point Edward
(hereinafter called "**Point Edward**")

- and -

The Corporation of the Township of Warwick
(hereinafter called "**Warwick**")

(Alvinston, Oil Springs, Petrolia, Point Edward and Warwick are hereinafter called the "**Municipal Shareholders**")

- and -

The Corporation of the City of Sarnia
(hereinafter called the "**City Shareholder**")

(the Municipal Shareholders and the City Shareholder are hereinafter called the "**Council Shareholders**")

\- and -

Alvinston Electricity Holdings Inc.
(hereinafter called "**Alvinston Holdco**")

\- and -

Oil Springs Electricity Holdings Inc.
(hereinafter called "**Oil Springs Holdco**")

\- and -

Petrolia Electricity Holdings Inc.
(hereinafter called "**Petrolia Holdco**")

\- and -

Point Edward Electricity Holdings Inc.
(hereinafter called "**Point Edward Holdco**")

\- and -

Warwick Electricity Holdings Inc.
(hereinafter called "**Warwick Holdco**")

(Alvinston Holdco, Oil Springs Holdco, Petrolia Holdco, Point Edward Holdco and Warwick Holdco are hereinafter called the "**Specified Shareholders**")

- and -

Sarnia Power Corporation
(hereinafter called the "**Sarnia Shareholder**")

(the Specified Shareholders and the Sarnia Shareholder are hereinafter called the "**Shareholders**")

- and -

Bluewater Power Corporation
(hereinafter called the "**Corporation**")

- and -

Bluewater Power Distribution Corporation
(hereinafter called "**BPDC**")

- and -

Sarnia Hydro Energy Services Corporation
(hereinafter called "**SHESC**")

RECITALS:

1. The authorized capital of the Corporation consists of an unlimited number of Shares;

2. The issued capital of the Corporation consists of ten thousand (10,000) Shares;

3. SPC, Oil Springs Holdco, Petrolia Holdco, Point Edward Holdco, Warwick Holdco and Alvinston Holdco are the sole registered and beneficial shareholders of the Corporation holding the following numbers of Shares, respectively:

Shareholder	Shares	Percentage of Total
SPC	8,562	85.62%
Oil Springs Holdco	41	0.41%

Petrolia Holdco	758	7.58%
Point Edward Holdco	329	3.29%
Warwick Holdco	230	2.30%
Alvinston Holdco	80	0.80%

4. The Shareholders and Council Shareholders desire to enter into an agreement providing for certain arrangements for the ongoing operation and control of the Corporation and providing for certain restrictions on, and arrangements respecting, dealings with shares of the Corporation and Holdco Shares which are issued and outstanding from time to time;

NOW THEREFORE THIS AGREEMENT WITNESSES that in consideration of the mutual covenants herein contained, the parties hereto agree as follows:

ARTICLE 1
DEFINITIONS AND INTERPRETATION

1.1 Definitions.

In this Agreement, unless there is something in the subject matter or context inconsistent therewith,

(a) **"Act"** means the *Business Corporations Act* (Ontario), and unless otherwise indicated, means such Act as amended and re-enacted from time to time;

(b) **"Affiliate"** of a particular body corporate means another body corporate which is affiliated with the particular body corporate and for such purposes one body shall be deemed to be affiliated with another body corporate if, but only if, one of them is the Subsidiary of the other or both of them are Subsidiaries of the same body corporate or each of them is Controlled by the same person, and if two bodies corporate are affiliated with the same body corporate at the same time, they are deemed to be affiliated with each other at that time;

(c) **"Agreement"** means this Agreement including all schedules and exhibits to this Agreement and includes any and every agreement made at any time (whether past, present or future) which amends or supplements or restates any agreement which is, or is included in, this Agreement;

(d) **"Articles of Incorporation"** of, or in relation to, a corporation means at any time such original or restated articles of incorporation, articles of amendment, articles of amalgamation, articles of continuance, articles of reorganization, articles of arrangement, articles of dissolution, articles of revival, letters patent, supplementary letters patent and any other instrument of a substantially similar nature to any of the foregoing, as are in effect at the time for or in relation to the corporation;

(e) **"Arm's Length"** has the meaning attributed thereto in the *Income Tax Act* (Canada);

(f) **"Auditor"** means the auditor designated pursuant to section 4.2;

(g) **"BPDC"** means a corporation to be incorporated under the laws of the Province of Ontario and which is a wholly-owned subsidiary of the Corporation;

(h) **"Board"** means the Board of Directors of the Corporation;

(i) **"Business Day"** means any day, other than a day that is a Saturday, a Sunday, a statutory holiday in Ontario or a day on which banks generally are not open to the public for business in the city, town or township that is the principal place of business of the Corporation;

(j) **"Businesses"** has the meaning ascribed thereto in section 2.1;

(k) **"City Shareholder"** has the meaning set out in the recitals hereto;

(l) **"Control"** in relation to a body corporate means control of the body corporate and for purposes of this Agreement a person has, or two or more persons have, control of a body corporate, and a body corporate is "Controlled" by a person or by two or more persons, if:

  (i) securities of the body corporate to which are attached more than fifty per cent (50%) of the votes that may be cast to elect directors of the body corporate are held, other than by way of security only, by or for the benefit of that person or by or for the benefit of those persons, and

  (ii) the votes attached to those securities are sufficient, if exercised, to elect a majority of the directors of the body corporate;

(m) **"Corporation"** has the meaning set out in the recitals hereto;

(n) **"Council"** means the city, township or village council of a Council Shareholder;

(o) **"Council Shareholders"** has the meaning set out in the introduction hereto (the Municipal Shareholders and the City Shareholders are the Council Shareholders);

(p) **"Electricity Act"** means the *Electricity Act, 1998*;

(q) **"Fair Market Value"** has the meaning set out in Schedule 6.9(a);

(r) **"GAAP"** means Canadian generally accepted accounting principles;

(s) **"Holdco Share"** means a share of any class in the capital of a corporation where such shares are owned by a Council Shareholder and where such corporation owns, directly or indirectly, any Shares in the Corporation;

(t) "*Income Tax Act*" means the *Income Tax Act* of Canada as amended and re-enacted from time to time;

(u) **"Insolvency Event"** has the meaning ascribed thereto in section 6.9(a);

(v) **"Insolvent Shareholder"** has the meaning ascribed thereto in section 6.9(a);

(w) **"Merger Agreement"** means an agreement between the parties dated as of October 30, 2000;

(x) **"Municipal Shareholders"** has the meaning set out in the introduction hereto (Alvinston, Oil Springs, Petrolia, Point Edward and Warwick are the Municipal Shareholders);

(y) **"Net Book Value"** means the consolidated net book value of the assets of the Corporation and its Subsidiaries based on the latest audited financial statements for the Corporation;

(z) **"OEB"** means the Ontario Energy Board;

(aa) **"OEB Act"** means the *Ontario Energy Board Act, 1998*;

(bb) **"Party"** means a party to this Agreement including any person that becomes bound by this Agreement as provided herein;

(cc) **"person"** means and includes any individual, corporation, body corporate, partnership, firm, joint venture, syndicate, association, trust, trustee, government, governmental agency or board or commission or authority or other form of entity or organization;

(dd) **"Prime Rate"** means, for and in relation to any particular day in a calendar month, the variable rate of interest, expressed as a rate per annum, equal to the rate of interest determined by the principal bank of the Corporation (hereinafter in this section referred to as the "Bank") as, or commonly known as, its prime rate of interest effective for the first day in such calendar month for Canadian dollar loans made by the Bank in Canada from time to time, being a variable per annum reference rate of interest adjusted automatically upon change by the Bank;

(ee) **"Promissory Note"** means a promissory note due and payable on its terms bearing interest at a rate of 7.25% or as may be revised, calculated and payable quarterly;

(ff) **"Related Shareholder"** of a person means at any time a Shareholder that is then, or at any earlier time was an Affiliate of such person;

(gg) "SHESC" means a corporation incorporated under the laws of the Province of Ontario which is a wholly-owned subsidiary of the Corporation;

(hh) **"Share"** means a share of any class in the capital of the Corporation;

(ii) **"Shareholder"** means at any time a person that is a party to this Agreement that is bound by this Agreement at the time and holds one or more Shares at the time or a person that becomes bound by this Agreement at any time and is bound by this Agreement at the time and holds one or more Shares at the time, and, for greater certainty, does not include a Council Shareholder;

(jj) **"Shareholder Special Approval"** means, with respect to any matter, the approval of such matter by the Sarnia Shareholder and a minimum of one of the Specified Shareholders, acting reasonably and with a view to the best interests of the Corporation and/or a Subsidiary by:

(i) a resolution passed at a duly constituted meeting of the Shareholders by the favourable vote of the Sarnia Shareholder plus a minimum of one of the Specified Shareholders; or

(ii) one or more instruments in writing which shall have been signed by the Sarnia Shareholder plus a minimum of one of the Specified Shareholders,

and any Shareholder Special Approval given by resolution as aforesaid shall become effective on the day on which such resolution is duly passed and any Shareholder Special Approval given by one or more instruments in writing as aforesaid shall become effective on the effective date shown in such one or more instruments. For purposes of this definition of Shareholder Special Approval, "acting reasonably and with a view to the best interests of the Corporation" means that in determining whether to give approval to a matter each Shareholder will consider whether a proposed course of action may be reasonably anticipated to result in profits for the Corporation and/or a Subsidiary to the benefit of all Shareholders having regard to the general principles annuciated in Section 2.3.

(kk) "**Share Proportion**" of a Shareholder (determined in relation to one or more particular Shareholders) as at any time means, with respect to a class of shares, the number obtained when the number of shares of a given class held by that Shareholder as at such time is divided by the total number of shares of the same class held by all Shareholders as at such time;

(ll) "**Specified Shareholders**" has the meaning set out in the recitals hereto (Alvinston Holdco, Oil springs Holdco, Petrolia Holdco, Point Edward Holdco and Warwick Holdco are the Specified Shareholders);

(mm) "**Subsidiary**" of a particular corporation (including, without limitation, a city, town, township or village) means a body corporate that is:

(i) Controlled by:

(A) the particular corporation,

(B) the particular corporation and one or more bodies corporate each of which is Controlled by the particular corporation, or

(C) two or more bodies corporate each of which is Controlled by the particular corporation, or

(ii) a Subsidiary of a body corporate that is a Subsidiary of the particular corporation;

(nn) **"Transfer By-law"** means the Transfer By-laws passed by the Council of each of the Council Shareholders in respect of the incorporation of the Corporation, BPDC and SHESC and the transfer by the Council and such Council Shareholders of employees, assets, liabilities, rights and obligations by such Council Shareholders to the Corporation and/or its Subsidiaries.

1.2 Interpretation.

In this Agreement, unless there is something in the subject matter or context inconsistent therewith,

(a) (i) words in the singular include the plural and such words shall be construed as if the plural had been used,

(ii) words in the plural include the singular and such words shall be construed as if the singular had been used,

(iii) words importing the masculine gender or the feminine gender include the feminine gender, the masculine gender and the neuter and shall be construed as if the corresponding word importing the feminine gender, the masculine gender or the neuter had been used, and

(iv) words importing the neuter include the masculine gender and the feminine gender and shall be construed as if the corresponding word importing the masculine gender or the feminine gender had been used, where the context or a party hereto so requires, and the rest of the sentence shall be construed as if the grammatical and terminological changes thereby rendered necessary had been made;

(b) "this Agreement", "hereto", "herein", "hereby", "hereunder", "hereof" and similar expressions refer to this Agreement and not to any particular Article, section, paragraph, subparagraph, clause, subclause or other portion of this Agreement;

(c) a reference to any one or more parties to this Agreement shall be deemed to include a reference to the respective heirs, executors, administrators, legal representatives, successors and permitted assigns of each such Party;

(d) unless otherwise specifically provided, all references herein to dollar amounts are in Canadian funds;

(e) unless otherwise specifically provided, each reference herein, which is to a time or contemplates a time refers to Ontario time; and

(f) unless the Shareholders otherwise agree in writing, in applying this Agreement in relation to any transaction, occurrence, event or matter, each term and each expression defined in this Agreement shall be construed and applied using the meaning in effect for such term or expression as at the time immediately before the time of such transaction, occurrence, event or matter.

1.3 Schedules.

The following are the Schedules attached hereto and incorporated by reference and deemed to be a part hereof:

Schedule 6.9(a) - Determination of Fair Market Value

1.4 Unanimous Shareholder Agreement.

Each of the parties hereby acknowledges and agrees that this Agreement is intended to operate and be construed as a unanimous shareholder agreement with respect to the Corporation and it Subsidiaries within the meaning of the Act.

ARTICLE 2
BUSINESS OF THE CORPORATION

2.1 Business of the Corporation.

The Parties acknowledge that the businesses (the "Businesses") which they intend that the Corporation and/or the Subsidiaries carry on are the following, namely:

(a) the business of distributing electricity; and

(b) the business of holding shares in corporations that distribute electricity and/or engage in distribution activities including: meter reading services; billing and collection services; tree trimming services for the purpose of line maintenance; repair and maintenance for the distribution lines and facilities; construction of distribution lines and facilities; general administrative support services; telecommunications services for electricity distribution (e.g. SCADA); street lights and traffic lights services; and other services that satisfy the general principles established by the OEB from time to time in its interpretation of section 71 of the OEB Act;

and each Party agrees that none of them shall be affiliated with any person that carries on any of the Businesses other than the Corporation or its Subsidiaries nor may they carry on, directly or indirectly, any of the Businesses other than through the Corporation or its Subsidiaries.

2.2 Rates and Quality of Service.

The Corporation shall, subject to OEB guidelines and approvals, eliminate differences in rates and maintain quality of service attributable to location within the service area, at minimum, at the level prescribed by the OEB in its applicable regulations, rules and policies.

2.3 Investment and Expenditure by the Corporation.

The Corporation or its Subsidiaries shall operate, with a view over time, to ensuring fair and equitable treatment of Shareholders, in proportion to their shares, with respect to expenditures, investments or opportunities for investment related to the Businesses of the Corporation or its Subsidiaries.

ARTICLE 3

CONTRIBUTIONS OF THE SHAREHOLDERS

3.1 Credit Facilities.

Each Shareholder shall cooperate with the Corporation to facilitate the establishment by the Corporation of such credit facilities as the directors of the Corporation from time to time determine to be necessary or desirable for the conduct of the business of the Corporation and/or any Subsidiary of the Corporation.

3.2 Shareholders Inter-Creditor Agreement.

Where two or more Shareholders and/or Council Shareholders are joint creditors on a Promissory Note or other similar debt instrument or where a Shareholder and/or Council Shareholder holds a Promissory Note which is one of several Promissory Notes which has been issued by the Corporation and/or the Subsidiaries to all of the Shareholders and/or Council Shareholders, each Promissory Note shall rank equally vis-à-vis each other Promissory Note of the same class, as to the payment of principal and interest in respect of such obligations, provided that the Sarnia Shareholder and/or City Shareholder may request and the other Shareholders and/or Council Shareholders shall agree to subordinate the Corporation and/or Subsidiaries' obligation to pay principal and interest to them in favour of a third party creditor.

ARTICLE 4

OPERATION AND CONTROL OF THE CORPORATION AND SUBSIDIARIES

4.1 Operation and Control.

The Parties hereto shall cause such meetings of directors and Shareholders of the Corporation to be held, votes to be cast, resolutions to be passed, by-laws to be passed, documents to be executed and all things and acts to be done to ensure the following continuing arrangements with respect to the operation and control of the Corporation:

(1) The Board of the Corporation shall be composed of seven (7) members. The Specified Shareholders as a group shall be entitled, from time to time, by notice to the Corporation and the other Shareholders, to designate one (1) nominee for election or appointment to the Board of the Corporation. The Sarnia Shareholder shall be entitled, from time to time, by notice to the Corporation and the other Shareholders, to designate six (6) nominees for election or appointment to the

Board of the Corporation. The Corporation and the Shareholders shall act diligently and promptly to take such actions as are necessary in order that, at any time, the Board of the Corporation includes the then latest nominee designated by the Specified Shareholders and the then latest nominee of the Sarnia Shareholder in accordance with this paragraph for election or appointment to the Board of the Corporation except for any such nominee as is not ready, willing or able to serve as a director of the Corporation.

(2) A quorum for a meeting of the directors of the Corporation shall be comprised of four (4) of the seven (7) of the directors of the Corporation.

(3) Except as otherwise provided herein, any resolution of the directors of the Corporation shall only be validly passed and effective if at a duly constituted meeting of the directors of the Corporation such resolution receives the affirmative vote of at least a majority of the directors participating in the meeting.

(4) No person shall have a second or casting vote in any circumstances at any meeting of the directors of the Corporation or at any meeting of the Shareholders of the Corporation.

(5) All written contracts made, and all cheques and negotiable instruments made or issued, by the Corporation shall be signed by such one or more directors or officers of the Corporation as are from time to time designated or authorized to do so by the by-laws of the Corporation or by a resolution duly passed by the directors of the Corporation.

(6) Each of the following shall require Shareholder Special Approval:

(a) any change in the number of directors of the Corporation;

(b) changing the name of the Corporation or a Subsidiary; adding, changing or removing any restriction on the business of the Corporation or a Subsidiary; creating new classes of shares; or in any other manner amending its articles of incorporation or making, amending or repealing any by-law;

(c) amalgamating with any other corporation(s) other than amalgamations which may, under the OBCA, be approved by a resolution of directors;

(d) taking or instituting proceedings for any winding up, arrangement, or dissolution of the Corporation or a Subsidiary;

(e) applying to continue as a corporation under the laws of another jurisdiction;

(f) issuing, or entering into any agreement to issue, any shares of any class, or any securities convertible into any shares of any class, of the Corporation or a Subsidiary;

(g) redeeming or purchasing any of its outstanding shares;

(h) selling and/or purchasing any plant, property or other assets valued in excess of twenty percent (20%) of Net Book Value of the Corporation and its Subsidiaries, provided that where the Corporation or any Subsidiary proposes to acquire another distribution utility valued below the threshold stated above, it shall first be required to provide notice to the Shareholders on a confidential basis; and

(i) entering into any transaction or arrangement which would result in the Corporation or a Subsidiary issuing debt or borrowing on an unsecured basis representing more than sixty-five percent (65%) of the total initial capitalization of the Corporation or a Subsidiary.

(7) December 31st in each calendar year shall be the end of a financial year of the Corporation and its Subsidiaries and shall also be the end of a taxation year for which an applicable return shall be filed pursuant to the relevant taxation legislation.

(8) The Board may establish compensation for members of the Board and the Chair in amounts sufficient to attract candidates with necessary qualifications and consistent with industry norms and standards for comparable businesses. The compensation paid to members of the Board will be disclosed publicly at the time of any change and at the end of the fiscal year of the Corporation.

(9) Meetings of the Board of the Corporation may be called by any director of the Corporation and shall be held in Sarnia, Ontario or such location determined by the directors from time to time and at least one meeting of the directors of the Corporation shall be held in 2000.

(10) Meetings of the Shareholders of the Corporation may be called by any director of the Corporation and shall be held in Sarnia, Ontario or such other location determined by the Shareholders from time to time.

4.2 Auditor.

The auditor of the Corporation and its Subsidiaries shall be Kime Mills Dunlop, London, Ontario, unless and until otherwise agreed as provided herein.

4.3 Books of Account.

Proper books of account shall be kept by the Corporation and its Subsidiaries and entries shall be made therein of all such matters, terms, transactions and things as are usually written, recorded or entered in books of account kept by corporations engaged in an enterprise of a similar nature. The books of account for the Corporation shall be kept at the principal place of business of the Corporation.

4.4 Budgets.

In the case of the initial budget and for each and every subsequent financial year of the Corporation, the Corporation shall prepare a budget showing, among other things, in a reasonable degree of detail the anticipated revenues, expenditures and cash flow of the Corporation and its Subsidiaries for such financial year of the Corporation and its Subsidiaries. The budget for any particular financial year of the Corporation and its Subsidiaries shall be prepared and delivered to the Board:

(a) in the case of the first budget, by December 1, 2000, and

(b) in the case of any other financial year commencing with the financial year 2001-2002, at least thirty (30) days prior to the beginning of such financial year.

The Board shall meet to review and discuss the budget for a financial year with a view to agreeing upon a final budget for such financial year.

4.5 Reporting Requirements.

(1) The Board may from time to time report to the Shareholders on major business developments or materially significant or materially adverse results as the Board, in its discretion, considers appropriate. Such reports may be received and considered by the Council Shareholders at an in camera meeting of Council.

(2) The Board shall report quarterly to the Shareholders in writing on a confidential basis providing details of interim financial statements, budgets, capitalization and reserves.

4.6 Periodic Financial Statements.

For each quarter the Corporation shall prepare a financial statement which shall include, on a consolidated basis, statements of income, retained earnings and changes in financial position for the month and a balance sheet as at the end of the month and such statement shall be prepared in accordance with GAAP, but need not reflect accruals and adjustments ordinarily made only as at the end of a financial year. The financial statement prepared for such quarter shall be delivered on a confidential basis to each Shareholder within twenty-one (21) days following the end of such quarter.

4.7 Application of Sections 4.1 to 4.6 to Subsidiaries.

Unless the Shareholders otherwise agree in writing and except as provided herein, the provisions of sections 4.1 to 4.6, inclusive, shall apply to each and every Subsidiary of the

Corporation; provided that in applying the provisions of such sections to any particular Subsidiary all references to the Corporation in such sections shall be read as a reference to the particular Subsidiary.

ARTICLE 5

SARNIA HYDRO ENERGY SERVICES CORPORATION AND BLUEWATER POWER DISTRIBUTION CORPORATION

5.1 Subsidiaries.

BPDC and SHESC shall carry on the businesses set out under Article 2.1.

5.2 Directors.

(a) The initial directors of SHESC shall be determined by the directors of the Corporation.

(b) The initial directors of BPDC shall be determined by the directors of the Corporation.

(c) the board of directors of each of SHESC and BPDC shall be composed of seven (7) directors, none of whom shall be members of Council or a Mayor.

5.3 Ownership of Shares.

Subject to Sections 4.1(6)(h) and 6.3, all of the issued and outstanding shares in the capital of SHESC and BPDC shall be owned beneficially and held of record by the Corporation as contemplated in the Transfer By-laws and Merger Agreement.

ARTICLE 6

TRANSFER AND DISPOSITION OF SHARES AND ASSETS

6.1 Restriction on Transfer.

No Shares of the Corporation or any interest therein shall be sold, exchanged, transferred, disposed of, encumbered, pledged, mortgaged, hypothecated and/or given, directly or indirectly, and no agreement or commitment shall be made to do any of the same except in each case pursuant to the applicable provisions of this Agreement and any attempt to do so without such consent or not pursuant to such provisions shall be void and, because the Parties hereto acknowledge the inadequacy of money damages in such circumstances, shall be subject to specific performance and injunctive relief at the instance of the other Parties hereto.

6.2 Transfer of Holdco Shares.

The Parties agree that the provisions of Article 6 shall apply, with the necessary modifications, to a transfer of any Holdco Share by Municipal Shareholder.

6.3 One Year Share Transfer Restriction.

For one (1) year from the date of this Agreement, the directors of the Corporation may seek out a third party to invest in ten percent (10%) or less of the Corporation and/or the

Subsidiaries and to become a party to this Agreement and upon receiving Special Shareholder Approval the Shareholders shall either sell their pro rata portion of ten percent (10%) or less of their Shares in the Corporation to the third party or approve the equivalent issue of shares from the treasury of the Corporation to the third party.

6.4 Shareholder Consent and Tax Exempt Status of the Corporation.

The Shareholders may vote the Shares owned by them to approve, as required by this Agreement or the Articles, any partial transfer of Shares which is permitted by this Agreement, provided, however, that where the transfer of any Share would, in the opinion of the Sarnia Shareholder, cause the Corporation to lose its exemption from liability for tax under subsection 149 of the *Income Tax Act*, the transfer of share(s) must be approved by the Sarnia Shareholder.

6.5 Permitted Transfers.

(a) Notwithstanding section 6.1 all or, with the consent of the Board expressed by resolution, part of the Shares of a Shareholder may be transferred to an Affiliate of such Shareholder and Article 7 shall apply, *mutatis mutandis*, to such transfer.

(b) Notwithstanding section 6.1, all or, with the consent of the Board expressed by resolution, part of the Shares of a Specified Shareholder may be offered for sale to the Corporation, at any time when the Corporation is not in default of a major obligation or insolvent, upon notice to the Corporation and the Corporation shall purchase such Shares at Fair Market Value provided that the Corporation may pay the purchase price to the Specified Shareholder over three (3) years in equal annual instalments bearing interest at the prime rate of the Corporation's primary bank.

6.6 Right of First Refusal.

Subject to the provisions of sections 6.4, 6.8 and 6.9, commencing one (1) year from the execution of this Agreement, if any Shareholder (hereinafter in this section 6.6 called the "Offeror") wishes to sell (other than pursuant to section 6.5) all, or with the consent of the Board expressed by resolution, part of the Shares owned by it and any Affiliate to a Person with whom it deals at Arm's Length in a bona fide transaction, the Offeror shall give notice (hereinafter in this section 6.6 called the "Selling Notice") to the other holders of Shares (hereinafter in this section 6.6 called collectively the "Offerees" and individually an "Offeree") of its intention to do so. Such Selling Notice shall set forth the number and class of the Shares (hereinafter in this section 6.6 called the "Offered Shares") which the Offeror wishes to sell and have annexed thereto a true copy of the offer, agreement or similar document (the "Offer") containing the terms and conditions pursuant to which the Offeror wishes to sell the Offered Shares to the prospective purchaser, the price per share at which the Offeror is prepared to sell the Offered Shares (which shall be the same as set forth in the Offer) and any other terms and conditions, provided that such must not be contrary to the provisions of Article 7 of this Agreement, and the proposed date of sale (hereafter called the "Sale Date"), which shall not be less than thirty (30) days nor more than sixty (60) days after the date on which the Selling Notice is given to the Offerees. In such event, unless all the Shareholders otherwise agree, the following provisions of this section 6.6 shall govern such purchase and sale:

(a) the Selling Notice shall be deemed to be an offer, irrevocable within the time hereinafter specified for acceptance, by the Offeror to sell the Offered Shares to the Offerees;

(b) within thirty (30) days after receipt of the Selling Notice (the "Acceptance Period"), each Offeree may give to the Offeror a notice of acceptance which shall set forth the number of Offered Shares which such Offeree is willing to purchase from the Offeror;

(c) if the Offerees accepting the offer collectively are prepared to purchase all the Offered Shares, then they shall be entitled to purchase the Offered Shares as nearly as may be in proportion to the number of Shares of the Corporation then held by them respectively, provided that, if any such Offeree claims less than its respective proportion, the difference in unclaimed Offered Shares shall be used to satisfy the claims of those who claim in excess of their proportions and if the claims in excess are more than sufficient to exhaust such unclaimed Offered Shares, the unclaimed Offered Shares shall be divided *pro rata* among the Offerees desiring to purchase excess shares in proportion to their holdings of Shares of the Corporation immediately prior to the delivery of the Selling Notice, but no Offeree shall be bound to purchase any Offered Shares in excess of the number which it agreed to purchase in its notice of acceptance;

(d) if none of the Offerees accepts the offer or the Offerees accepting the offer collectively are not prepared to purchase all of the Offered Shares, then, subject to Section 6.4 and Section 2.1, the Offeror may sell all of the Offered Shares to any other person within sixty (60) days after the Sale Date at a price per security not less than and on terms and conditions not more favourable to such person than the price per security and the terms and conditions set forth in the Selling Notice. In the event that the Offeror does not sell the Offered Shares to such person within such sixty (60) day period, then the provisions of this Agreement shall once again apply and so on from time to time;

(e) if the Offered Shares shall not be capable, without division into fractions, of being offered to or being divided among such Offerees in the proportions above mentioned, the same shall be offered to or divided among such Offerees as nearly as may be in the proportions hereinbefore mentioned and any balance shall be offered to or divided among such Offerees or some of them in such manner as may be determined by the board of directors of the Corporation;

(f) provided that, where a Specified Shareholder is an Offeror and such Offeror gives a Selling Notice to the Offerees, a Shareholder that is not a Specified Shareholder may give to the Offeror a Notice of Acceptance:

(i) only within 30 days of the termination of the Acceptance Period provided that no Specified Shareholder has delivered a notice of acceptance during the acceptance period and subsections (a) to (e) shall apply *mutatis mutandis*; or

(ii) in priority over any other person if the Offerees accepting the offer collectively are not prepared to purchase all of the Offered Shares.

6.7 Piggyback Rights.

Where, after compliance with the provisions of section 6.6, any Shareholder wishes and is entitled to sell all but not less than all of the Shares held by it and each of its Affiliates to a third party, then any such sale, notwithstanding the provisions of section 6.6, shall be permitted only if such third party makes an offer in writing irrevocable for forty-five (45) days to all other Shareholders holding Shares to purchase such Shares held by such Shareholders or their Affiliates at the same price and upon the same terms and conditions.

6.8 Draw Along.

If, (i) an offer is made by a third party to purchase all outstanding Shares held by Shareholders holding more than eighty percent (80%) of the outstanding Shares; or (ii) an amalgamation, merger, plan of arrangement, or other reorganization of the Corporation, for greater certainty, excluding a municipal amalgamation or other restructuring, is proposed by a third party or an offer is made by a third party to purchase all or substantially all of the assets of the Corporation (collectively a "Reorganization"), all Shareholders are required to sell their Shares to the Offeror or approve such Reorganization, as the case may be.

6.9 Insolvency of Shareholder.

(a) If any Shareholder makes an assignment for the benefit of creditors or a proposal under the *Bankruptcy and Insolvency Act* (Canada) or a similar filing or proposal under any other bankruptcy or insolvency legislation or is declared bankrupt or becomes insolvent, or any trustee, receiver, receiver and manager, liquidator or other officer with similar powers is appointed for such member or for all or any material part of his property (such member being hereinafter referred to as the "Insolvent Shareholder" and any such assignment, proposal, filing, declaration or insolvency or the appointment of any trustee, receiver or receiver and manager, liquidator or other officer with similar powers being hereinafter referred to as an "Insolvency Event"), the other Shareholders (the "Solvent Shareholders") shall be deemed to be entitled, effective immediately prior to the Insolvency Event, to purchase all or any part of the Shares held by the Insolvent Shareholder for a cash purchase price equal to the Fair Market Value of the Shares as determined in accordance with Schedule 6.9(a). Solvent Shareholders shall have ninety (90) days from the date of the final determination of Fair Market Value of the Shares pursuant to Schedule 6.9(a) to deliver to the Insolvent Shareholder (with a copy to the Corporation) a notice in writing setting out therein their respective intentions to purchase, effective immediately prior to the Insolvency Event, all but not less than all of the Shares owned by the Insolvent Shareholders *pro rata*, based on their respective holdings of Shares.

(b) If the said Shares shall not be capable, without division into fractions, of being divided among such Solvent Shareholders in the proportions above mentioned, the same shall be divided among such Solvent Shareholders as nearly as may be in the proportions hereinbefore mentioned and any balance shall be divided among such Solvent Shareholders or some of them in such manner as may be determined by the board of directors of the Corporation.

(c) Subject to the provisions of the Act, if within ninety (90) days of the final determination of the Fair Market Value of the Shares pursuant to Schedule 6.9(a) a notice in writing shall not have been given to the Insolvent Shareholder (with a copy to the Corporation) by all or any of the Solvent Shareholders setting out therein the intention of such Solvent Shareholder or Shareholders to purchase, effective immediately prior to the Insolvency Event, all of the Shares owned by the Insolvent Shareholder, then the Corporation shall have the right to redeem and repurchase such portion of the Shares as shall not be the subject of a purchase and sale transaction with the Solvent Shareholder, effective immediately prior to the Insolvency Event, for a cash price equal to the value of the Shares as calculated by reference to the shareholders' equity of the Corporation as shown on the Corporation's most recent financial statements prior to the Insolvency Event prepared in accordance with this Agreement.

(d) Any transaction of purchase and sale pursuant to this section 6.9 shall be completed in accordance with the provisions of Article 7 hereof but with effect and deemed completion as of the time immediately prior to the occurrence of an Insolvency Event.

6.10 Disposition of Assets.

Where BPDC proposes to sell more than fifty percent (50%) of BPDC's distribution assets located within the municipal boundary of a Specified Shareholder, the Specified Shareholder shall have the right of first refusal to purchase such assets at Fair Market Value plus fifty percent (50%) of any applicable tax payable on the proceeds of the sale by the Corporation, BPDC, the Shareholder or the municipality. The Specified Shareholder in whose municipal boundary the BPDC assets are located shall be entitled to receive written notice from BPDC of any proposed disposition of 50% of its distribution assets and shall have 60 days from the date of such notice to exercise its rights to purchase such assets, failing which the BPDC assets may be sold by BPDC.

ARTICLE 7
GENERAL SALE PROVISIONS

7.1 Sale Provisions.

Each Shareholder who hereafter sells any Shares pursuant to the provisions of this Agreement (such Shareholder being herein sometimes in this Article 7 called the "Seller") shall hereby be deemed to warrant to each other Shareholder or other person who purchases such Shares (such Purchasing Shareholder or other person being herein sometimes called the "Buyer") that, at the time of Closing of the transaction of purchase and sale in question, (a) the Seller shall have good and marketable title to such Shares, and (b) the Buyer will acquire such Shares free of any encumbrance of any kind, and in addition the Seller shall hereby be deemed to agree to indemnify and save the Buyer harmless against any loss suffered by the Buyer as a result of there being any encumbrance upon or any defect in the title of the Seller to such Shares.

7.2 Closing.

Each purchase and sale of Shares between Shareholders pursuant to this Agreement shall, unless otherwise expressly provided herein, be closed at the offices of the Corporation at 10:00 a.m. on the fifteenth (15th) day after the date of the last notice given (or deemed to be given) by the Buyer or the Seller, as the case may be, pursuant to the applicable sections of this Agreement or at such other time and/or on such other day as may be agreed upon by the Seller and the Buyer.

7.3 Conditions and Closing.

At the time of closing of any purchase of Shares of the Corporation as set forth in section 7.2, the Seller shall table:

(a) a certificate or certificates representing the Shares being sold by the Seller, duly endorsed by the Seller in blank for transfer and with the signature of the Seller guaranteed by a Canadian chartered bank and transfers of any Shares being sold in such form as the Buyer may reasonably require;

(b) in the case of a sale of Shares by a person which is not a natural person, such authorizing resolutions, orders and other instruments as the solicitors for the Buyer shall reasonably consider necessary to effect and evidence a valid transfer of such Shares; and

(c) evidence of the consent of the Shareholders to the purchase of Shares in question if such consent is required by this Agreement,

and each Buyer shall pay for such Shares by bank draft or certified cheque. If the Seller fails to comply with the requirements set out in this section, the Buyer shall, in addition to its other rights, including its right to specific performance, be entitled to rescind and shall have an action for damages.

7.4 Indebtedness of Seller to Corporation.

If, on the date of closing of any sale and purchase of Shares of the Corporation, the Seller is indebted to the Corporation in an amount recorded on the books of the Corporation and verified by the auditor of the Corporation, then unless otherwise agreed in writing between the Corporation and the Seller, each Buyer shall pay the purchase price payable therefor by it to the Corporation's solicitors, in trust, by tabling and delivering to the Corporation's solicitors, in trust, at the time of closing of such purchase and sale, the purchase price for such Shares. The Corporation's solicitor is hereby authorized by the Seller to apply the total purchase price proceeds to repayment of the indebtedness of the Seller to the Corporation. If such proceeds exceed such indebtedness, the Corporation's solicitors are hereby authorized by the Buyer to pay the excess over to the Seller at the time of closing of such purchase and sale. In the event that the Seller sells all of the Shares of the Corporation owned by it and the indebtedness of the Seller to the Corporation exceeds the proceeds of such sale, then the Seller shall at the time of closing of such purchase and sale pay the balance of such indebtedness to the Corporation to retire such indebtedness.

7.5 Indebtedness of Corporation to Seller.

If, on the date of closing of any sale and purchase of Shares of the Corporation, the Corporation is indebted to the Seller all of whose Shares are purchased by other Shareholders or other persons pursuant to Article 6, or if such Seller is the guarantor of any indebtedness of the Corporation, the Buyer or Buyers shall, at the time of closing, purchase such indebtedness at its face value or assume such guarantee in either case *pro rata* in accordance with the number of Shares purchased by it or them.

7.6 Agreement, Binding on Transferees.

No Shares of the Corporation shall be effectively issued, sold, assigned, transferred, disposed of or conveyed, whether pursuant to any provision of Article 6 or otherwise, by the Corporation or a Shareholder to any person other than a Shareholder, until the proposed transferee or purchaser executes and delivers to the parties hereto an agreement to the same effect as this Agreement and any further agreement with respect to the Corporation to which the Shareholders are then, or are then required to be, a party, and unless the proposed transferee or purchaser, on becoming a party to this Agreement, would be in compliance with the provisions of this Agreement. Upon the proposed transferee or purchaser so doing, such agreements shall enure to them as if all had executed and delivered the same agreements.

7.7 Continuing Obligations.

Any Shareholder who sells to a person, other than an Affiliate of the Shareholder, all of the Shares of the Corporation owned by it in accordance with the terms of this Agreement shall thereafter be released and discharged from the further performance of all of its covenants and obligations hereunder from and after the date of such sale and compliance by the transferee with section 7.6 except for any obligations under this Article 7 and any other obligations under this Agreement which expressly or impliedly are to survive any such sale.

7.8 Council Shareholders.

The Parties agree that the provisions of Article 7 shall apply, with the necessary modifications, to a transfer of any Holdco Share of a Municipal Shareholder.

ARTICLE 8
PRE-EMPTIVE RIGHT

8.1 Pre-Emptive Right.

Subject to subsection 4.1(6), if the Corporation wishes at any time hereafter to issue any Shares, the Corporation shall first offer them for purchase by the Shareholders by written notice given to each such Shareholder. Such notice shall be given within ten (10) days following approval by the Board of a proposal to issue Shares and shall set forth a description of the Shares to be offered, the proposed purchase price and the purchase date which shall be a date not earlier than thirty (30) days after the date of such notice. Upon receipt of such notice, each such Shareholder shall have the right to subscribe for and purchase at least a number of such Shares determined by multiplying the total number of Shares offered by a fraction the numerator of which shall be the number of Shares owned by such Shareholder at the date of such notice and the denominator of which shall be the total number of Shares outstanding as at the date of such notice. Such right shall be exercised by the Shareholder by giving notice of acceptance to the Corporation within ten (10) days after the receipt of the notice from the Corporation, which notice of acceptance shall set forth the number of Shares which such Shareholder is willing to purchase. In the event that the Shareholder does exercise such right, it shall subscribe, purchase and pay for such Shares on the purchase date set forth in the notice of the Corporation. If all the Shareholders do not subscribe for their respective proportions, the unsubscribed Shares shall be used to satisfy the subscriptions of such Shareholders for Shares in excess of their proportion and, if the subscriptions in excess are more than sufficient to exhaust such unsubscribed Shares, the unsubscribed Shares shall be divided *pro rata* among the Shareholders desiring Shares as nearly as may be in proportion to the number of Shares held by them respectively at the date of such notice, but no Shareholder shall be bound to take any such Shares in excess of the amount it desires.

8.2 Exchange of Shares.

If at any time any third party acquires, either directly or indirectly, an equity interest in an Affiliate of SHESC, BPDC or the Corporation, other than a corporation carrying on a business which is not a Business, and the Sarnia Shareholder retains an interest, either directly or indirectly, in such an Affiliate, then the Specified Shareholders shall collectively have the right to exchange their Shares in the Corporation for a number of securities of the same class and series of shares as those acquired by such third party, the fair market value of which is equal to the fair market value of such securities in the Corporation.

ARTICLE 9

LEGEND ON SHARE CERTIFICATES

9.1 Legend.

The certificates representing any Shares held by any Shareholder or Holdco Shares held by any Municipal Shareholder, with necessary modifications, shall have typed or otherwise written thereon the following legend:

> "The shares represented by this certificate are subject to the provisions of an agreement made as of the 1st day of November, 2000 among the Shareholders of the Corporation as of that date and the Corporation and such other persons as have or shall from time to time become bound by such agreement, as the same

may be amended, supplemented and restated from time to time and notice of the terms and conditions of such agreement is hereby given. Such agreement includes restrictions on the transfer of, and the right to transfer, shares in the capital of the Corporation including the shares represented by this certificate. Such shares may not be sold, assigned, transferred, donated, mortgaged, pledged, hypothecated, charged or otherwise encumbered or dealt with except in accordance with such agreement. A copy of such agreement, as amended, supplemented and restated from time to time may be examined at the principal place of business of the Corporation".

9.2 Corporation to Keep a Copy of the Agreement.

The Corporation shall keep a true copy of this Agreement at its principal place of business and on reasonable prior notice from any Party shall make the same available for examination by such Party during the Corporation's regular hours of business at such office.

ARTICLE 10

INDEMNIFICATION

10.1 Indemnity.

Each Shareholder hereby agrees to indemnify, hold harmless, reimburse and defend each and every other Shareholder (hereinafter in this section referred to as an "Indemnified Shareholder"), other than any Related Shareholder of the particular Shareholder, for, from and against any and all liability, loss, damage or expense (including, without limitation, reasonable legal fees and disbursements) and any claim thereof or therefor which:

(a) is asserted against, imposed on, or incurred or sustained by, any Indemnified Shareholder (regardless of the form or nature of such liability, damage, loss, expense or claim), and

(b) results from, arises out of or is connected with

   (i) the nonfulfillment or breach by any person (a "Designated Person") that is the particular Shareholder or any Related Shareholder of the particular Shareholder, of any covenant in or obligation under this Agreement, or

   (ii) the negligence or misconduct of (a) any Designated Person or (b) any shareholder, director, officer, employee or agent of any Designated Person or (c) any Affiliate (other than the Corporation or any Subsidiary of the Corporation) of a Designated Person.

ARTICLE 11
TERMINATION

11.1 Termination.

If on any day:

(a) any particular person (any such person being referred to as a "Terminated Party") that was a Shareholder at any earlier time, does not hold any Shares, and is not pursuant to this Agreement deemed to hold any Shares; and

(b) there is no Shareholder that is a Related Shareholder of the particular person then (unless and in any event until the particular person again becomes a Shareholder) after the expiration of such day:

(c) no further rights or obligations of the particular person shall arise or accrue under this Agreement other than in relation to any rights or obligations respecting or relating to the payment of any amount by or to the particular person pursuant to this Agreement; and

(d) this Agreement may be amended, terminated, replaced or superseded at any time by agreement of the Parties hereto, each of whom is not a Terminated Party at that time, it being understood that the same shall not affect the rights or obligations under this Agreement of any person who is then a Terminated Party.

11.2 Council Shareholders.

The Parties agree that the provisions of Article 11 shall apply, with the necessary modifications, to all Council Shareholders.

ARTICLE 12

CONFIDENTIALITY

12.1 Confidentiality.

Each of the Parties, Shareholders, Council Shareholders and their respective Affiliates shall keep in the strictest confidence and shall not disclose and not use, in any manner whatsoever in connection with or relating to, directly or indirectly, any business engaged in or participating in the Businesses or the operation, franchising, development or sale of products or services similar to those of the Corporation or its Subsidiaries, all non-public information pertaining to or concerning the Corporation and its Subsidiaries including, without limitation, budgets, forecasts, analyses, and financial results, costs, margins, wages and salaries, bids and other business activities, all supplier and customer lists, all non-public intellectual property including trade secrets, unfilled patents, trade-marks, technical expertise and know-how, documentation including standard terms and agreements and all other information not generally known outside the Corporation or its Subsidiaries except to persons through business dealings with the Corporation or its Subsidiaries. However, no Shareholder or Affiliate thereof shall be obliged to keep in confidence or shall incur any liability for disclosure of information which:

(a) was already in the public domain or comes into the public domain without any breach of this Agreement;

(b) is required to be disclosed pursuant to applicable law or court order; or

(c) is made to the legal representatives to such disclosing party, in which event such disclosing party shall, so far as reasonably possible, cause the recipient to comply with the terms hereof as if it were a party to this Agreement.

ARTICLE 13
GENERAL PROVISIONS

13.1 Further Acts.

The Parties hereto agree to do and to cause to be done all acts and things as directors and shareholders of the Corporation to effect compliance with or waiver of the restrictions on the transfer of shares contained in the Articles of Incorporation or by-laws of the Corporation to give effect to any transfer or intended transfer of Shares required or permitted to be made and recorded as a result of the application of the provisions of this Agreement in order that, notwithstanding such restrictions, the terms and conditions of this Agreement may be carried out.

13.2 Extended Application.

The Parties hereto agree that the provisions of this Agreement relating to Shares of a particular class (and series, if applicable) shall apply *mutatis mutandis*:

(a) to any shares or securities which result, either directly or indirectly, from the conversion, changing, reclassification, redivision, redesignation, subdivision or consolidation of Shares of such class (and series, if applicable);

(b) to any shares or securities in the capital of, or issued by, the Corporation which are received by any one or more Parties hereto as a stock dividend or distribution on or in respect of Shares of such class (and series, if applicable); and

(c) to any shares or securities in the capital of, or issued by, the Corporation or any successor or continuing body corporate to the Corporation which are received by any one or more Parties hereto (i) on a reorganization, amalgamation, consolidation or merger, statutory or otherwise and (ii) on or in respect of Shares of such class (and series, if applicable).

13.3 Assignment.

Subject to the restrictions to assignment contained herein, this Agreement shall enure to the benefit of and be binding upon the Parties hereto and their respective heirs, executors, administrators, personal representatives, successors and permitted assigns. Except as expressly permitted by this Agreement, the rights of any person under this Agreement shall not be assignable.

Any person (the "Assignor"), other than the Corporation, having rights under this Agreement shall be permitted to assign such rights to another person (the "Assignee") provided

(a) (i) the Assignor transfers all Shares owned by the Assignor to the Assignee and such transfer complies with this Agreement, and

(ii) the Assignor assigns all rights of the Assignor under this Agreement to the Assignee; and

(b) the Assignee is bound by this Agreement.

13.4 Notices.

The provisions of this section apply to any notice, offer or other communication (any such notice, offer or communication being referred to in this section as a "Notice") contemplated or provided for in this Agreement:

(1) Manner of Giving Notice. Any Notice required or permitted by this Agreement to be given or sent or delivered to, or received by, a person:

(a) shall be in writing;

(b) shall be addressed to such person at such person's Notice Address;

(c) shall be given to such person:

(i) by delivery, including delivery by courier, to such person,

(ii) by prepaid registered or certified mail, return receipt requested, mailed in Ontario in an envelope addressed to such person's Notice Address, or

(iii) by transmission by telecopier to such person at such person's Telecopier Number to the attention of such person's Telecopier Addressee; and

(d) shall, if being given to the Corporation, also be given to each Shareholder other than the Shareholder giving such Notice or any Related Shareholder of such Shareholder.

(2) Notices shall be given as follows:

If to Alvinston/Alvinston HoldCo, to:

Corporation of the Village of Alvinston
3236 River Street, P.O. Box 28
Alvinston, Ontario
N0N 1A0

Attention: Bob Alderman, Clerk
Fax: (519) 898-5653

If to Oil Springs/Oil Springs HoldCo, to:

Corporation of the Village of Oil Springs
P.O. Box 22
Oil Springs, Ontario
N0N 1P0

Attention: Marilyn Sanderson
Fax: (519) 834-2333

If to Petrolia/Petrolia HoldCo, to:

Corporation of the Town of Petrolia
411 Greenfield Street, P.O. Box 1270
Petrolia, Ontario
N0N 1R0

Attention: Terry Blackmore
Fax: (519) 882-3373

If to Point Edward/Point Edward HoldCo, to:

Corporation of the Village of Point Edward
36 St. Clair Street
Point Edward, Ontario
N7V 4G8

Attention: Joe Simon, Clerk Treasurer
Fax: (519) 337-5963

If to Warwick/Warwick HoldCo, to:

Corporation of the Township of Warwick
6332 Nauvoo Road, R.R. #8
Watford, Ontario
N0M 2S0

Attention: Donald Craig, Clerk-Administrator
Fax: (519) 849-6136

If to Sarnia, to:

Corporation of the City of Sarnia
255 North Christina Street
P.O. Box 3018
Sarnia, Ontario
N7T 7N2

Attention: Alex Palimaka, City Solicitor
Fax: (519) 332-8951

If to Sarnia Power Corporation, to:

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

Attention: President
Fax: (519) 344-6094

If to the Corporation, to:

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

Attention: Dave Simmons
Fax: (519) 344-6094

If to the BPDC, to:

855 Confederation Street
P.O. Box 2140
Sarnia, Ontario
N7T 7L6

Attention: Dave Simmons
Fax: (519) 344-6094

If to the SHESC, to:

855 Confederation Street
P.O. Box 2140
Sarnia, Ontario
N7T 7L6

Attention: Dave Simmons
Fax: (519) 344-6094

(3) Deemed Delivery. Any Notice given to a person as aforesaid:

(a) if given by delivery (other than by mail), shall be deemed to have been given, sent and delivered to, and received by, such person on the day on which it is so delivered;

(b) if given by mail, shall be deemed to have been given, sent and delivered to, and received by, such person on the day on which it is delivered as evidenced by a receipt, acknowledgement or other document issued by a postal authority; and

(c) if given by transmission by telecopier, shall be deemed to have been given, sent and delivered to, and received by, such person on the first Business Day after transmission.

13.5 Remedies Cumulative.

The rights and remedies of the Parties under this Agreement are cumulative and in addition to and not in substitution for any rights or remedies provided for in law.

13.6 Titles.

The titles to the Articles and certain other provisions hereof have been inserted for ease of reference only and shall not affect the construction or the interpretation of this Agreement.

13.7 Governing Law.

This Agreement shall be deemed to have been made in, and shall be governed by, and be construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable in such Province.

13.8 Counterparts.

This Agreement may be executed in several counterparts, each of which so executed shall be deemed to be an original, and such counterparts together shall constitute but one and the same instrument.

13.9 Entire Agreement.

This Agreement constitutes the entire agreement between the Parties hereto with respect to the subject matter of this Agreement. The Parties hereto acknowledge that there is no representation, warranty, agreement or understanding between them which has induced any of the Parties hereto to enter into this Agreement except as expressly stated herein.

13.10 Waiver.

Any Party which is entitled to any right or benefit under this Agreement may, and shall be entitled and have the right to, waive any term or condition relating to the application of this Agreement in relation to any matter or transaction provided that any such waiver shall only be effective if it is in writing signed by such Party and delivered to a Party to whom such waiver is directed. If a particular Party waives any term or condition relating to the application of this Agreement in relation to any matter or transaction as aforesaid, then in relation to the specific matter or transaction which is the subject matter of such waiver, each person that is then a Party or that subsequently becomes a Party shall be entitled to rely upon such waiver in the same manner and to the same extent as if such waiver had been directed and delivered to such person by the particular Party.

No failure on the part of any Party to exercise, and no delay by any Party in exercising, any right under this Agreement shall operate as a waiver of such right.

13.11 Time.

Time shall be of the essence in this Agreement.

13.12 Inconsistency with By-Laws.

In the event of any inconsistency between the provisions hereof and the by-laws of any of the Corporation, SHESC or BPDC, this Agreement shall prevail.

13.13 Independent Advice.

EACH OF THE PARTIES HERETO ACKNOWLEDGES AND CONFIRMS THAT IT HAS BEEN ADVISED TO AND HAS HAD AN OPPORTUNITY TO RETAIN COUNSEL AND RECEIVE INDEPENDENT LEGAL ADVICE WITH RESPECT TO THIS AGREEMENT.

IN WITNESS WHEREOF this Agreement has been executed by the Parties hereto.

SIGNED, SEALED AND DELIVERED)
in the presence of)**The Corporation of the Village of Alvinston**
)
)
) By: ______✓______c/s
) Name:
) Title:
)
) By: ____________
) Name:
) Title:
)
)
)**The Corporation of the Village of Oil Springs**
)
)
) By: ______✓______c/s
) Name:
) Title:
)
) By: ____________
) Name:
) Title:
)
)

)**The Corporation of the Town of Petrolia**
)
)
) By: ✓ c/s
) Name:
) Title:
)
) By:
) Name:
) Title:
)
)**The Corporation of the Village of**
)**Point Edward**
)
)
) By: ✓ c/s
) Name:
) Title:
)
) By:
) Name:
) Title:
)
)
)**The Corporation of the Township of Warwick**
)
)
) By: ✓ c/s
) Name:
) Title:
)
) By:
) Name:
) Title:
)
)

The Corporation of the City of Sarnia

By: ______________________ c/s
Name: Mike Bradley
Title: Mayor

By: ______________________
Name: Ann Tuplin
Title: Clerk

Alvinston Electricity Holdings Inc.

By: ___________________✓___ c/s
Name:
Title:

By: ______________________
Name:
Title:

Oil Springs Electricity Holdings Inc.

By: ___________________✓___ c/s
Name:
Title:

By: ______________________
Name:
Title:

Petrolia Electricity Holdings Inc.

By: ________✓________ c/s
Name:
Title:

By: ____________________
Name:
Title:

Point Edward Electricity Holdings Inc.

By: ________✓________ c/s
Name:
Title:

By: ____________________
Name:
Title:

Warwick Electricity Holdings Inc.

By: ________✓________ c/s
Name:
Title:

By: ____________________
Name:
Title:

Sarnia Power Corporation

By: c/s
Name: FIRMAN BENTLEY, CHAIR
Title:

By:
Name: DAVE SIMMONS
Title: INTERIM PRESIDENT

Bluewater Power Corporation

By: c/s
Name: FIRMAN BENTLEY
Title: CHAIR

By:
Name: DAVE SIMMONS
Title: INTERIM PRESIDENT

Bluewater Power Distribution Corporation

By: c/s
Name: FIRMAN BENTLEY
Title: CHAIR

By:
Name: DAVE SIMMONS
Title: INTERIM PRESIDENT

Sarnia Hydro Energy Services Corporation

By: c/s
Name: FIRMAN BENTLEY
Title: CHAIR

By: DL
Name: DAVE SIMMONS
Title: INTERIM PRESIDENT

IN WITNESS WHEREOF this Agreement has been executed by the Parties hereto.

SIGNED, SEALED AND DELIVERED
in the presence of

Corporation of the Village of Alvinston

By: R. Alderman c/s
Name:
Title: Clerk

By: Michelle
Name:
Title: Mayor

Corporation of the Village of Oil Springs

By: K L Hart c/s
Name:
Title: Mayor.

By:
Name:
Title: Clerk

Corporation of the Town of Petrolia

By: ~~c/s~~
Name: MAYOR
Title:

By:
Name:
Title: Admin-Clerk

Corporation of the Village of Point Edward

By: ______________________ c/s
Name:
Title: Mayor

By: J. A. Simon
Name: J. Simon
Title: Clerk Treasurer

Corporation of the Township of Warwick

By: ______________________ c/s
Name: MIKE PARKER
Title: MAYOR

By: ______________________
Name: Donald Craig
Title: Clerk. Treas

Alvinston Electricity Holdings Inc.

By: R. Alderman c/s
Name:
Title: Clerk

By: ______________________
Name:
Title: Mayor

Oil Springs Electricity Holdings Inc.

By: ______________________ c/s
Name:
Title: Mayor.

By: ______________________
Name:
Title: Clerk

Petrolia Electricity Holdings Inc.

By: ____________________ c/s
Name: MAYOR
Title:

By: ____________________
R Brad Langley
Name: Administrator/Clerk
Title:

Point Edward Electricity Holdings Inc.

By: ____________________ c/s
Name:
Title: Mayor

By: ____________________
Name: J. Simon
Title: Clerk Treasurer

Warwick Electricity Holdings Inc.

By: ____________________ c/s
Name: MAC PARKER
Title: MAYOR.

By: ____________________
Name: Donald Craig
Title: Director

SCHEDULE 6.9(a)

DETERMINATION OF FAIR MARKET VALUE

(a) For purposes of this Agreement where referenced, "Fair Market Value" means the price per Share, determined by an independent qualified business valuator (a "Valuator") pursuant to this schedule as of the relevant date, that would be received upon a sale of all of the issued and outstanding Shares in a single transaction determined in an open and unrestricted market between prudent parties, acting at arm's length and under no compulsion to act, and having reasonable knowledge of all relevant facts concerning the Corporation. In determining the Fair Market Value of the Shares, such Valuator shall be considered as an expert and shall not be construed as acting as an arbitrator within the meaning of the *Arbitration Act*, 1991 (Ontario).

(b) Such determination of the Fair Market Value of the Shares shall be made as if the Corporation were a "going concern" (except to the extent that market, financial, economic, business or other conditions shall dictate different criteria in the reasonable judgment of the Valuator) without any discount for a minority interest or any premium for control. The value of the Shares shall not be diminished because of the fact that the Shares are not publicly traded or the fact that the Insolvent Shareholder owns a minority interest in the Corporation.

(c) Within ten (10) days of the receipt of a notice under subsection 6.5(b) or 6.9(a), the Solvent Shareholders and the Insolvent Shareholder, or the relevant Shareholders under the section of this Agreement giving rise to a determination of Fair Market Value or under Subsection 6.5(b) (the "Relevant Shareholder") and the Corporation shall jointly appoint a Valuator. If the Shareholders and the Corporation are unable to jointly appoint a Valuator within the specified period, the Insolvent Shareholder or the Relevant Shareholder, on the one hand, and the Solvent Shareholders or the other Relevant Shareholders jointly, on the other, shall within ten (10) days of the expiry of such period each appoint a Valuator (the "Designated Valuators") and the two Designated Valuators so appointed shall, within ten (10) days of their appointment, jointly appoint a Valuator.

(d) The Shareholders shall instruct the Valuator to prepare and deliver to the Shareholders, as soon as practicable and in any event within a period of thirty (30) days of its appointment, a report setting forth the Valuator's estimate as to the Fair Market Value of the Shares of the Insolvent Shareholder immediately prior to the Insolvency Event or other event giving rise to a determination of Fair Market Value and the basis upon which such estimate has been calculated (the "Valuator's Report").

(e) The Valuator shall prepare the Valuator's Report having regard to the factors identified in clauses (a) and (b). The Valuator may also have regard to any representations that any Shareholder may wish to make. The Valuator's Report shall be conclusive and binding. The Fair Market Value so determined shall become the Fair Market Value of the Shares for purposes of the transactions contemplated in section 6.5(b) or 6.9.

(f) The costs and expenses of the Designated Valuators incurred in connection with the appointment of the Valuator and/or the Valuator in connection with the preparation of the Valuator's Report shall be paid by the Corporation.

(g) Capitalized terms used in this schedule and not defined shall have the meanings ascribed thereto in Article 6 of this Agreement.

(h) The provisions of this Schedule 6.9(a) shall apply, with the necessary modifications, to the determination of the Fair Market Value of a Holdco Share.

(i) The determination of the Fair Market Value of the assets under Section 6.10 shall be determined by an independent valuator selected by the Parties who shall value the assets as a "going concern" within the boundaries of the Muncipality as it stood at the execution of this Agreement (except to the extent that market, financial, economic, business or other conditions shall dictate different criteria in the reasonable judgement of the Valuator).

Shareholder Special Approval

WHEREAS Bluewater Power Distribution Corporation and its affiliates (collectively referred to as "Bluewater") are interested in pursuing opportunities in distributive generation;

AND WHEREAS the municipalities listed as signatories below, in their capacity as beneficial shareholders of Bluewater, are parties to a Shareholders' Agreement dated November 1, 2000 (the "Shareholders' Agreement");

AND WHEREAS subsection 4.1(6) requires Shareholder Special Approval in order for Bluewater to participate in certain activities such as generation of electricity to take place.

NOW THEREFORE, the municipal shareholders executing this Shareholder Special Approval hereby resolve as follows:

The Board of Directors for Bluewater, are hereby authorized to explore investment in Generation initiatives, and more specifically are authorized as follows:

(1) *That generation of electricity is added as a permitted activity;*

(2) *That the purchase of necessary plant and equipment is hereby authorized, provided that:*

  i. *notice of total spending by the Corporation on any generation project is provided in writing to the Municipal Council, in a format available to the public, prior to the submission of a proposal to the Province of Ontario, or the Ontario Power Authority, for the sale of electricity to be generated; and*

  ii. *the at-risk equity of all generation investments in total does not exceed 20% of Net Book Value of Consolidated Capital Assets (currently sitting at 20% of $36.8 M, or $7.4 M).*

(3) *That the Board of Directors are authorized to rename an existing corporate affiliate and/or establish a new corporate affiliate or limited partnership to be beneficially owned by the current municipal shareholders, all as required to carry out this investment in compliance with requirements of the Ontario Energy Board, or as required to realize a financial or other benefit.*

(4) *That any funds borrowed for generation projects that are unsecured, or secured by the generation project, are deemed to be outside of the borrowing restriction found in Section 4.1(6)(i) of the Shareholders' Agreement.*

THE FOREGOING RESOLUTION in writing is agreed to as required by subsection 4.1(6) of the Shareholders' Agreement.

DATED as of the 1st day of May, 2006.

THE CORPORATION OF THE CITY OF SARNIA

Mike Bradley, Mayor

Brian Knott, City Solicitor/Clerk

THE CORPORATION OF THE VILLAGE OF POINT EDWARD

Dick Kirkland, Mayor

Peggy Cramp

Peggy Cramp, C.A.O./Clerk-Treasurer

THE CORPORATION OF THE VILLAGE OF OIL SPRINGS

Gordon Perry, Mayor

Christine Poland, Clerk-Treasurer

THE CORPORATION OF THE TOWN OF PETROLIA

Brian McManaman

Brian McManaman, Mayor

Dela Horley, Clerk-Administrator

THE CORPORATION OF THE TOWNSHIIP OF BROOKE-ALVINSTON

Don McGugan

Don McGugan, Mayor

Cathy Case

Cathy Case, Clerk-Treasurer

THE CORPORATION OF THE TOWNSHIP OF WARWICK

Todd Case, Mayor

Don Bruder, Administrator-Treasurer

SCHEDULE "C"

Shareholder Resolution

WHEREAS Bluewater Power Distribution Corporation and its affiliates (collectively referred to as "Bluewater") are required to comply with the *Affiliate Relationship Code for Electricity and Transmission* ("ARC"), which requires one-third of the directors for a regulated distributor to be independent of any affiliate;

AND WHEREAS the municipalities listed as signatories below, in their capacity as beneficial shareholders of Bluewater, are parties to a Shareholders' Agreement dated November 1, 2000 (the "Shareholders' Agreement") requiring a minimum number of directors and establishing the quorum for each corporation

AND WHEREAS Bluewater is unable to comply with both the ARC and the Shareholders' Agreement, and has asked the shareholders to reduce the minimum number of directors and the quorum required for each corporation.

NOW THEREFORE, the municipal shareholders executing this Shareholder Resolution hereby resolve as follows:

---

(1) The shareholders hereby agree to amend Section 4.1(1) of the Shareholders' Agreement to read as follows:

> *"The Board of the Corporation shall be composed of a minimum of five (5) members in the case of Bluewater Power Distribution Corporation (BPDC) and three (3) in the case of all other corporations. The Specified Shareholders as a group shall be entitled, from time to time, by notice to the Corporation and the other Shareholders, to designate one (1) nominee for election or appointment to the Board of the Corporation. The Sarnia Shareholder shall be entitled, from time to time, by notice to the Corporation and the other Shareholders, to designate a maximum of six (6) nominees for election or appointment to the Board of the Corporation. The Corporation and the Shareholders shall act diligently and promptly to take such actions as are necessary in order that, at any time, the Board of the Corporation includes the then latest nominee designated by the Specified Shareholders and the then latest nominee of the Sarnia Shareholder in accordance with this paragraph for election or appointment to the Board of the Corporation except for any such nominee as is not ready, willing or able to serve as a director of the Corporation."*

(2) *The shareholders hereby agree to amend Section 4.1(2) of the Shareholders' Agreement as follows:*

> *"A quorum for a meeting of the directors of the Corporation shall be comprised of four (4) in the case of BPDC and three (3) in the case of all other corporations."*

(3) *The shareholders agree to execute such other documentation as may be required to bring into effect the intention of this shareholder resolution.*

THE FOREGOING RESOLUTION in writing is agreed to by the shareholders set-out below.

DATED as of the 1st day of July, 2006.

THE CORPORATION OF THE CITY OF SARNIA

Signed in counterpart
Mike Bradley, Mayor

Signed in Counterpart
Brian Knott, City Solicitor/Clerk

THE CORPORATION OF THE VILLAGE OF POINT EDWARD

Signed in counterpart
Dick Kirkland, Mayor

Signed in counterpart
Peggy Cramp, C.A.O./Clerk-Treasurer

THE CORPORATION OF THE VILLAGE OF OIL SPRINGS

Gordon Perry, Mayor

Christine Poland, Clerk-Treasurer

THE CORPORATION OF THE TOWN OF PETROLIA

Brian McManaman
Brian McManaman, Mayor

Dela Horley, Clerk-Administrator

THE CORPORATION OF THE TOWNSHIIP OF BROOKE-ALVINSTON

Don McGugan, Mayor

Cathy Case
Cathy Case, Clerk-Treasurer

THE CORPORATION OF THE TOWNSHIP OF WARWICK

Signed in Counterpart
Todd Case, Mayor

Signed in Counterpart
Don Bruder, Administrator-Treasurer

1.0 - SEC 8 - CGAAP vs MIFRS questions

[1/2/1, p. 7] Please provide a detailed reconciliation of the following estimates of the impact of moving from CGAAP to MIFRS:

a. 1/2/1, p. 7. $957,000 of overheads that would have been capitalized under CGAAP in 2013.

b. 2/2/1, p. 6. $956,578 of overheads expensed rather than capitalized.

c. 4/1/1, Attach. 1. $1,261,328 difference in OM&A in 2012 between CGAAP and MIFRS ("which is the overhead that is not capitalized under MIFRS" – 4/2/1, p. 1).

d. 4/2/2, p. 6. $602,000 of overheads no longer capitalized from 2011 to 2012.

The amount of $957,000 (item a) is the amount that would have been capitalized in 2013 had Bluewater Power stayed in CGAAP and is rounded up from the figure of $956,578 (item b).

The amount of $1,261,328 (item c) is the same calculation as above performed for the year 2012. The calculation shows the amount of overhead that was capitalized in 2012 under CGAAP but would not have been capitalized in 2012 under MIFRS.

The amount of $602,000 (item d) is a variance analysis between 2011 under CGAAP and 2012 on an MIFRS basis. The amount of capitalization in 2012 on an MIFRS basis is $nil, therefore the variance represents the amount that was capitalized in 2011 under Bluewater Power's Capitalization Policy at the time.

1.0 - SEC 10 - GS>50 increases

[1/2/1, p. 13] Please confirm that for a GS>50 customer with a load of 60 kW, the Applicant is proposing to keep the monthly charge at $142.00, but increase the volumetric charge from $3.5617/kW to $4.4311/kW, resulting in an increase in the charges from the Applicant of $52.16 per month, or 14.7%. Please reconcile this result with the figures in Table 9.

Bluewater Power confirms that the impact of keeping the monthly charge at $142 and changing only the variable rate results in a 14.7% increase from the current rate for a GS>50kW customer with a load of 60kW. This calculation, however, looks at only the fixed and variable charge.

When we look at the increase as a total bill impact and we include rate riders for a customer with a 60 kW monthly demand, the overall bill impact is an increase of $6.45 per month or 0.2%. The detailed bill impact which itemizes each proposed rate change and reconciles to (Ex.1/2/1) can be found in Ex. 8-4-3, Attachment 3, page 9, and is reproduced as the attachment to this interrogatory.

File Number:EB-2012-0107

Tab: 3
Schedule: 12

Date Filed:February 4, 2013

Attachment 1 of 1

SEC 10 - Bill Impact for GS>50

Appendix 2-W
Bill Impacts

Customer Class: General Service > 50 to 999 kW

Consumption **26000** **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 142.0000	1	$ 142.00	$ 142.0000	1	$ 142.00	$ -	
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for Tax change	kW	-$ 0.0614	60	-$ 3.68	$ -	60	$ -	$ 3.68	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kW	$ 3.5617	60	$ 213.70	$ 4.4311	60	$ 265.87	$ 52.16	24.41%
Smart Meter Disposition Rider				$ -			$ -	$ -	
LRAM 2011	kW	$ -	60	$ -	$ -	60	$ -	$ -	
LRAM 2012	kW	$ 0.0149	60	$ 0.89	$ 0.0149	60	$ 0.89	$ -	
LRAM 2013	kW	$ -	60	$ -	$ 0.0440	60	$ 2.64	$ 2.64	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A				$ 353.16			$ 411.65	**$ 58.49**	**16.56%**
Rate Rider for Deferral/Variance Account Disposition 2011	kW	$ 0.4186	60	$ 25.12	$ -	60	$ -	-$ 25.12	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kW	-$ 0.4464	60	-$ 26.78	-$ 0.4464	60	-$ 26.78	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kW	$ -	60	$ -	-$ 0.4374	60	-$ 26.24	-$ 26.24	
Low Voltage Service Charge	kW	$ 0.0722	60	$ 4.33	$ 0.0748	60	$ 4.49	$ 0.16	3.60%
Smart Meter Entity Charge		▨	▨	▨		26000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 355.83**			**$ 363.11**	**$ 7.28**	**2.05%**
RTSR - Network	kW	$ 2.5648	60	$ 153.89	$ 2.3589	60	$ 141.53	-$ 12.35	-8.03%
RTSR - Line and Transformation Connection	kW	$ 1.9998	60	$ 119.99	$ 1.9262	60	$ 115.57	-$ 4.42	-3.68%
Sub-Total C - Delivery (including Sub-Total B)				**$ 629.70**			**$ 620.22**	**-$ 9.49**	**-1.51%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	26926	$ 140.01	$ 0.0052	27093	$ 140.89	$ 0.87	0.62%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	26926	$ 29.62	$ 0.0011	27093	$ 29.80	$ 0.18	0.62%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	26000	$ 182.00	$ 0.0070	26000	$ 182.00	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0750	750	$ 56.25	$ 0.0750	750	$ 56.25	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0880	26176	$ 2,303.45	$ 0.0880	26343	$ 2,318.22	$ 14.77	0.64%
TOU - Off Peak	kWh	$ 0.0650	17232	$ 1,120.10	$ 0.0650	17340	$ 1,127.09	$ 6.98	0.62%
TOU - Mid Peak	kWh	$ 0.1000	4847	$ 484.66	$ 0.1000	4877	$ 487.68	$ 3.02	0.62%
TOU - On Peak	kWh	$ 0.1170	4847	$ 567.05	$ 0.1170	4877	$ 570.59	$ 3.53	0.62%
Total Bill on RPP (before Taxes)				**$ 3,341.04**			**$ 3,347.37**	**$ 6.34**	**0.19%**
HST		13%		$ 434.33	13%		$ 435.16	$ 0.82	0.19%
Total Bill (including HST)				$ 3,775.37			$ 3,782.53	$ 7.16	0.19%
Ontario Clean Energy Benefit 1				-$ 377.54			-$ 378.25	-$ 0.71	0.19%
Total Bill on RPP (including OCEB)				**$ 3,397.83**			**$ 3,404.28**	**$ 6.45**	**0.19%**
Total Bill on TOU (before Taxes)				**$ 3,153.15**			**$ 3,158.26**	**$ 5.11**	**0.16%**
HST		13%		$ 409.91	13%		$ 410.57	$ 0.66	0.16%
Total Bill (including HST)				$ 3,563.06			$ 3,568.83	$ 5.77	0.16%
Ontario Clean Energy Benefit 1				-$ 356.31			-$ 356.88	-$ 0.57	0.16%
Total Bill on TOU (including OCEB)				**$ 3,206.75**			**$ 3,211.95**	**$ 5.20**	**0.16%**

Loss Factor (%) 3.56% 4.21%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

1.0 - SEC 11 - Internal Payroll Budget

[1/2/3, p. 2] Please provide the separate internal payroll budget referred to.

The information requested by this interrogatory cannot be provided as it would reveal confidential and personal information. Moreover, the level of detail required by the OEB to make a determination as to the reasonableness and prudence of the costs claimed have been provided in the pre-filed evidence in Exhibit 4, Tab 4 and most particularly in Appendix 2-K entitled “Employee Costs”

1.0 - SEC 12 - Overall rate increase

[1/2/5, p. 2] Please confirm that the Applicant is proposing a weighted average rate increase in 2013 of 18.8% ($3,456,032/$18,420,658). Please confirm that, but for a decline in grossed-up PILS of $823,295, the weighted average rate increase from 2012 to 2013 would be 23.2%.

Bluewater Power confirms the calculation that the 2013 test year revenue deficiency of $3,456,032 as a percentage of the 2013 forecasted Distribution Revenue at current rates of $18,420,658 is 18.8%. However, we do not confirm that the calculation represents the 'weighted average' rate increase.

The 2009 board approved PILs is $1,409,808. The 2013 test year PILs amount is $586,513 as per Ex.4-8-1. The decrease indicated above as $823,295 is correct. Therefore, if this amount was added to the $3,456,032, it would result in a theoretical revenue deficiency of $4,279,327. Bluewater Power confirms that revised theoretical revenue deficiency as a percentage of the 2013 forecasted Distribution Revenue at current rates of $18,420,658 is 23.2%. However, we do not confirm that the calculation represents the 'weighted average rate increase from 2012 to 2013'.

1.0 - SEC 15 - Dividends

[1/3/1, Attach 1, p. 3 (unnumbered)] Please explain the substantial increase in dividends paid from 2010 to 2011.

Bluewater Power's dividend policy is based on one-third of after-tax net income subject to any extraordinary items. Based on this policy, the dividends declared in 2010 were $1,165,917 and in 2011 were $765,747. The reduction in 2011 is due to the decrease in net income.

Also in 2011, a special one-time dividend was declared of $1.9 million in order to reduce total equity in order to move towards the OEB deemed level of 40%. See also the response to SEC #2h.

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Tab 4 of 11

Exhibit 2 - Rate Base

2.0-Staff-4 – Renewed Regulatory Framework

Ref: Filing Requirements for Electricity Transmission and Distribution Applications, EB-2006-0170, June 28, 2012, pages 53-54
Ref: Exh 2-2-2 Appendix 2-EB - IFRS-CGAAP Transitional PP&E Amounts
Ref: Report of the Board – Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012, page 15

The *Filing Requirements for Electricity Transmission and Distribution Applications*, EB-2006-0170, June 28, 2012, state:

> **Account 1575 – IFRS-CGAAP Transitional PP&E Amounts**
> The applicant must propose a disposition period to “clear” the PP&E deferral account through a one-time adjustment to rate base to capture and remove the impact of the accounting policy changes as caused by the transition from CGAAP to MIFRS.

Appendix 2-EB states:

> Consistent with the 4 year normal rate cycle, the model is using a 4 year amortization period as a default selection to "clear" the PP&E deferral account through a one-time adjustment to rate base to capture and remove the impact of the accounting policy changes as caused by the transition from CGAAP to MIFRS.

The *Report of the Board – Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, states, “The Board has determined that the term for 4th Generation IR will be five years (rebasing plus 4 years).”

a) Bluewater Power's proposal with respect to the PP&E deferral account reflects a 4 year period, consistent with 3rd generation IRM. Has Bluewater Power considered the impact of this change to a five year term and how it will affect the proposal in the current application? If yes, please explain.

No, we have not considered the change to a five year term under 4th Generation IR. Our understanding is that distributors are not permitted to file 4th Generation IR applications until October 1, 2013. We note that *The Report of the Board – Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, dated October 18, 2012 states as follows (at page 69):

> *"Complete filing requirements (including Cost of Service Filing Requirements and Consolidated Capital Plan Filing Requirements) will be available for rebasing applications under 4th Generation IR for May 1, 2014 rates. In order to provide some additional time to prepare applications, these rebasing applications may be filed by October 1, 2013. When a distributor rebases using the 4th Generation filing requirements, the total term will be 5 years."*

Since the rules regarding 4th Generation IR are not finalized, it would not be appropriate to reflect a 5 year term in the recovery of deferral accounts.

b) Please update and file with the Board Appendix 2-EB, Appendix 2-CH (Depreciation and Amortization Expense), RRWF, and any other applicable evidence to reflect a five-year disposition period for the clearance of the PP&E deferral account to facilitate consideration of this option.

Bluewater Power's evidence was filed in compliance with the current Filing Guidelines. The potential to move from a four year to a five year term is clear, but that does not change the current Filing Guidline. In fact, the Report is very specific that until the Filing Guidelines are amended, applications cannot be filed under the 4th Generation IR.

Therefore, it would not be appropriate to provide the update requested by the Interrogatory. The work involved is significant and we respectfully submit that the probative value and relevance of the evidence requested is not sufficient.

2.0-Staff-5 - IFRS-CGAAP Transitional PP&E

Ref: Exh 2-2-2 Appendix 2-EB IFRS-CGAAP Transitional PP&E Amounts

The Board issued the decision for Bluewater Power's smart meter application (EB-2012-0263) on October 18, 2012. Please reconcile the stranded meter amount of $1,928,303 under MIFRS in Appendix 2-EB to USoA 1860 meters in 2012 MIFRS Fixed Asset Continuity Schedule in Appendix 2-B.

The NBV of stranded meters in Appendix 2-B '2012 MIFRS' is $1,957,885; this amount is comprised of a $2,113,444 adjustment to cost, less the $155,559 adjustment to accumulated depreciation. The MIFRS NBV of stranded meters in Appendix 2-EB is $1,928,303, which represents a variance of $29,582 from the amount in Appendix 2-B.

Upon further investigation of Appendix 2-B '2012 MIFRS', it has been determined that the full amount of contributed capital at the end of 2011 was not fully 'allocated' to Account 1860 at the beginning of 2012 for purposes of converting to MIFRS. This has resulted in the $2,113,444 cost adjustment figure being overstated by the variance amount, and conversely the $120,137 contributed capital adjustment figure being understated by the variance amount.

The variance of $29,582 can be traced as follows. The total contributed capital meant to be 'allocated' is $5,074,914, which is evident from Account 1995 'Contributions & Grants' (see row 51 in worksheet - $6,487,773 gross contributed capital less $1,412,859 accumulated amortization). The total amount that was actually 'allocated' was $5,045,332, which is the sum of Column F, specifically cells F24 through to F30.

The correction that is now required involves adding the $29,582 variance amount to the $120,137 contributed capital adjustment figure for Account 1860 'Meters' in Appendix 2-B for a correct adjustment amount of $149,719. This results in the total contributed capital of $5,074,914 being 'allocated' to the related capital assets. The correction then also involves subtracting the $29,582 variance amount from the $2,113,444 cost adjustment figure for Account 1860 'Meters' resulting in the correct adjustment amount of $2,083,862.

The revised cost adjustment amount for Account 1860 'Meters' is $2,083,862 and the accumulated amortization adjustment amount remains at $155,559. The NBV of the adjustment to Account 1860 'Meters' – being the stranded meter MIFRS NBV - is therefore $1,928,303 which agrees to the stranded meter NBV amount under MIFRS as presented in Appendix 2-EB.

The total net adjustments for Account 1860 does not change, nor does the total 2012 MIFRS NBV for all capital assets of $52,424,918 – which is found in both this appendix and in Appendix 2-EB.

2.0-Staff-6 - Asset Depreciation Study

Ref: Exh 2-2-4 Attachment 1

Ref: Asset Depreciation Study for the Ontario Energy Board (Kinectrics Inc. July 8, 2010)

Bluewater Power states that it is proposing useful lives for its assets that are within the ranges suggested as a guideline by the Kinectrics Report.

a) Under MIFRS, Bluewater Power proposes a 45 year useful life for fully dressed concrete poles. At Table F-1 of the Kinectrics Report, the useful life range for fully dressed concrete poles is listed as 50 to 80 years. Please explain Bluewater Power's proposal.

The number of concrete poles in Bluewater Power's territory is not material, so we have not componentized concrete poles separately. Concrete poles (as well as steel poles discussed next) will be grouped with the regular wood poles for amortization purposes. Accordingly, we did not address the issue of the useful life of fully dressed concrete poles since the rate would not be utilized in practice.

b) Similarly, Bluewater Power proposes a 45 year useful life for fully dressed steel poles. At Table F-1 of the Kinectrics Report, the useful life range for fully dressed steel poles is listed as 60 to 80 years. Please explain Bluewater Power's proposal.

Similar to the answer in part (a) above, Bluewater Power does not have any steel or composite poles in its distribution system and has no future plans to purchase any due to the cost involved.

2.0 - EP 10 - Kinetrics Report

Ref: Exhibit 2, Tab 2, Schedule 4, Attachment 1

Please add columns to the table to show the ranges as suggested as guidelines by the Kinectrics Report.

See response to 2-VECC-2.

2.0 - VECC 2 - Kinetrics Report

2-VECC-2.0 Reference: Exhibit 2, Tab 2, Schedule 4, Attachment 1

a) Please amend the Asset Components and Depreciation Rate Table to include the Kinectrics high, low and average life for each class

Please see the updated table in Attachment 1 of this interrogatory response.

b) Please provide an explanation for any asset class which falls outside of the Kinectrics recommended range.

Account 1830 – Concrete Poles

Please see response to 2-Staff-6a

Account 1830 – Steel Poles

Please see response to 2-Staff-6b

Account 1830 – Steel Poles

Please see response to 2-Staff-6b

Account 1960 – Misc Equip

This was an oversight and Bluewater Power has incorporated the changes necessary into the revised revenue requirement, into the RRWF and the bill impacts presented in the response to these interrogatories.

No additions have been made to this account for a number of years and none are forecast in the future. As per the pre-filed evidence, the annual amortization expense for this category for 2012 CGAAP is $5,689, and for 2012 and 2013 MIFRS are both $5,158. Upon investigation, and due to the age of this equipment, the estimated average remaining useful life has been determined to be 5 years from the end of 2011. The NBV at the end of 2011 (before conversion to MIFRS) is $72,207 per Ex.2-3-2 Appendix 2-B. Therefore, the 2012 and 2013 depreciation expense under MIFRS should be $14,441 ($72,207 / 5yrs) instead of $5,158.

File Number:EB-2012-0107

Tab: 4
Schedule: 5

Date Filed:February 4, 2013

Attachment 1 of 1

2.0 - VECC 2 - Kinetics Table

Asset Components and Depreciation Rates

OEB	CGAAP	MIFRS		CGAAP		MIFRS		Kenetrics		
Class	**Account**	**Account**	**Asset Component Description**	**Years**	**Rate**	**Years**	**Rate**	**Low**	**Aver**	**High**
1805	180500	180500	Land	NA	NA	NA	NA	NA	NA	NA
1806/1612	180600	161200	Land Rights/Easements (intangible asset under MIFRS)	25	4.0%	25	4.0%			
1820	182000	182001	Dist Stn Equip <50kV - Building	30	3.3%	50	2.0%	50		75
1820	182000	182002	Dist Stn Equip <50kV - Transformers	30	3.3%	45	2.2%	30	45	60
1820	182000	182003	Dist Stn Equip <50kV - Switch Gear	30	3.3%	40	2.5%	30	50	60
1820	182000	182004	Dist Stn Equip <50kV - Breakers	30	3.3%	45	2.2%	30	45	60
1820	182000	182005	Dist Stn Equip <50kV - Protection Control (Relays)	30	3.3%	20	5.0%	15	20	20
1820	182000	182006	Dist Stn Equip <50kV - Reclosures	30	3.3%	40	2.5%	25	40	55
1820	182000	182007	Dist Stn Equip <50kV - All Other Items Substation landscaping	30	3.3%	50	2.0%	**50**		75
1820	182000	182007	Dist Stn Equip <50kV - All Other Items Distribution Switches	30	3.3%	40	2.5%	**30**	40	60
1820	182000	182007	Dist Stn Equip <50kV - All Other Items Substation - Batteries	30	3.3%	10	10.0%	**10**	15	15
1820	182000	182007	Dist Stn Equip <50kV - All Other Items Substation - Parking lot	30	3.3%	30	3.3%	**25**	30	30
1830	183000	183001	Wood Poles (fully dressed)	25	4.0%	45	2.2%	35	45	75
1830	183000	183002	Concrete Poles (fully dressed)	25	4.0%	45	2.2%	50	60	80
1830	183000	183003	Steel Poles (fully dressed)	25	4.0%	45	2.2%	60	60	80
1830	183000	183004	Composite Poles (fully dressed)	25	4.0%	45	2.2%	60	60	80
1835	183500	183501	OH Conductors/Devices - Primary Conductor	25	4.0%	60	1.7%	50	60	75
1835	183500	183502	OH Conductors/Devices - Secondary Conductor	25	4.0%	60	1.7%	50	60	75
1835	183500	183503	OH Conductors/Devices - All Other Items	25	4.0%	40	2.5%	30	45	55
1840	184000	184001	UG Conduit	25	4.0%	50	2.0%	30	50	80
1840	184000	184002	Manholes and Vaults	25	4.0%	60	1.7%	40	60	80
1840	184000	184003	Underground Conduit - All Other Items	25	4.0%	50	2.0%	30	50	80
1845	184500	184501	UG Conductors/Devices - Primary Buried	25	4.0%	35	2.9%	25	30	35
1845	184500	184501	UG Conductors/Devices - Primary Buried in Duct	25	4.0%	40	2.5%	35	40	55
1845	184500	184502	UG Conductors/Devices - Secondary	25	4.0%	50	2.0%	35	40	60
1845	184500	184503	UG Conductors/Devices - All Other Items	25	4.0%	50	2.0%	35	40	60
1850	185000	185001	OH Transformers - 3 Phase Dressed (fully dressed)	25	4.0%	40	2.5%	30	40	60
1850	185000	185002	OH Transformers - Single Phase (fully dressed)	25	4.0%	40	2.5%	30	40	60
1850	185000	185003	OH Transformers - All Other Items	25	4.0%	40	2.5%	30	40	60
1850	185000	185004	UG Transformers - 3 Phase Padmount (fully dressed)	25	4.0%	40	2.5%	25	40	45
1850	185000	185005	UG Transformers - Single Phase Padmount (fully dressed)	25	4.0%	40	2.5%	25	40	45
1850	185000	185006	UG Transformers - All Other Items	25	4.0%	40	2.5%	25	40	45
1855	185500	185501	Services - Secondary	25	4.0%	25	4.0%	25	35	40
1855	185500	185502	Services - All Other Items	25	4.0%	25	4.0%	25	35	40
1860	186000	186001	Meters - Single Phase	25	4.0%	25	4.0%	25	30	35
1860	186000	186002	Meters - Poly Phase & Interval	25	4.0%	25	4.0%	25	30	35
1860	186000	186003	Meters - Smart	25	4.0%	15	6.7%	5	15	15
1860	186000	186004	Meters - All Other Items	25	4.0%	25	4.0%	25	30	35
1908	190800	190801	Building/Fixtures - Structure & Contents	60	1.7%	60	1.7%	50		75
1908	190800	190801	Building/Fixtures - HVAC	60	1.7%	30	3.3%	20		30
1908	190800	190802	Building/Fixtures - Asphalt Roof	60	1.7%	30	3.3%	20		30
1908	190800	190802	Building/Fixtures - Parking Lot	25	4.0%	25	4.0%	25		30
1908	190800	190802	Building/Fixtures - Fence	60	1.7%	30	3.3%	25		60
1915	191500	191500	Office Furniture & Equipment	10	10.0%	10	10.0%	5		10
1920	192000	192001	Computer H/W - PCs, Laptops, Printers, Servers, etc	5	20.0%	5	20.0%	3		5
1920	192000	192002	Computer H/W - UPS	5	20.0%	5	20.0%	3		5
1920	192000	192003	Computer H/W - Racks, Shelving, Wiring, etc	5	20.0%	5	20.0%	3		5
1611/1925	192500	161100	Computer S/W - All (intangible asset under MIFRS)	5	20.0%	5	20.0%	2		5
1930	193000	193001	Large Trucks	8	12.5%	10	10.0%	5		15
1930	193000	193002	Small Trucks and Vans	8	12.5%	8	12.5%	5		10
1930	193000	193003	Cars	8	12.5%	8	12.5%	5		10
1930	193000	193004	Other (trailers, forklift, riding mowers, etc)	8	12.5%	8	12.5%	5		20
1935	193500	193500	Stores Equipment	10	10.0%	10	10.0%	5		10
1940	194000	194000	Tools, Shop and Garage Equipment	10	10.0%	10	10.0%	5		10
1945	194500	194500	Measure and Testing Equipment	10	10.0%	10	10.0%	5		10
1955	195501	195501	Communication Equipment	10	10.0%	10	10.0%	5		10
1960	196000	196000	Miscellaneous Equipment	20	5.0%	20	5.0%	5		10
1970	197000	197000	Load Mgmt Controls - Customer Premises	10	10.0%	10	10.0%	5		10
1980	198000	198000	System Supervisory Equipment	25	4.0%	25	4.0%	15	20	30

2.0 - VECC 3 - Capital Contributions 2009 to 2013

2-VECC-3.0 Reference: Exhibit 2, Tab 2, Schedule 5 /Tab 4, Schedule 2, Attachment 1, p. 146.

a) Please provide the capital contributions for each of 2009 through 2013.

2009: $1,270,753

2010: $453,161

2011: $682,425

2012: $317,654 draft actual ($491,240 budget)

2013: $675,455 budget

b) Please explain the methodology for estimating 2013 capital contributions

Bluewater Power calculated the annual historical percentages of total contributed capital received in the year over the related total amount of capital costs. This was done for 2006 to 2011. Based on this, an average percentage was calculated.

Next, a forecast of the total capital costs was made for 2012 and 2013 based on the prior years' level of actual capital costs that had contributed capital associated with it.

The average percentage was then multiplied by the forecast level of capital costs for both 2012 and 2013.

2.0 - VECC 4 - CGAAP & MIFRS 2013 Capital and Capital Contribution

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2-VECC-4.0 Reference: Exhibit 2, Tab 4, Schedule 3, Attachment 1

a) Please show the adjustment to capital expenditures in 2013 for the difference in reporting under CGAAP and MIFRS.

Exh 2-4-3 Attachment 1 has been updated for the requested information and is found at the Attachment to this response. A column at the far right titled ‘2013 Difference’ quantifies the variance.

When updating this Attachment, it was found that the Subtotal (O) for the ‘Lines & Design’ category was not correct as it was missing Project UT1 due to an excel formula error. As a result, the grand total labelled as “TOTAL (O)” was also incorrect. The total capital spending for ‘Lines & Design’, and also the grand total for all projects at the bottom of the attachment, is correct. Therefore the updated Attachment 1 in response to this interrogatory also incorporates the correction for this error.

Please also refer to the response to AMPCO #3.

b) Please provide the capital contributions in 2013 as reported under Bluewater's prior capitalization policy and under the proposed (MIFRS) policy.

The 2013 test year amount for total capital contributions is $675,455. This amount is the same under both CGAAP and MIFRS. This amount is not broken down by capital project, or by capital account. See 2-VECC-3b for the methodology for estimating the 2013 amount.

Under CGAAP, this entire amount is recorded to Account 1995 'Contributions & Grants'. Under MIFRS, this entire amount is recorded to Account 2440 'Deferred Revenues'.

See also Exh 2-2-5 for a discussion regarding the Capital Contribution Policy.

File Number:EB-2012-0107

Tab: 4
Schedule: 7

Date Filed:February 4, 2013

Attachment 1 of 1

2.0 - VECC 4

Bluewater Power Distribution Corporation
Capital Expenditures Detail by Project - 2013 OEB filing

Project ID	Project Name	Ongoing (O) or Non-routine (N)	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 CGAAP	2012 MIFRS	2013 CGAAP	2013 MIFRS	2013 Diff
	Lines & Design										
UT1	Substation Building	O	106,970	32,659	61,927	79,448	117,214	103,000	102,420	90,000	(12,420)
UT2	27.6 Load Break Switch Replacement	N	48,940	42,169	29,602	49,073	68,280	60,000	-	-	-
UT3	Street Widening	O	53,274	20,195	17,045	-	22,760	20,000	22,760	20,000	(2,760)
UT4	27.6kV Neutral Program	N	146,820	45,326	19,024	55,316	170,700	150,000	170,700	150,000	(20,700)
UT5	27.6 Feeder - Petrolia	N	97,880	48,230	120,421	25,065	142,250	125,000	142,250	125,000	(17,250)
UT6	Alvinston/Oil Springs Capital Items	O	19,576	5,422	14,350	-	25,605	22,500	22,760	20,000	(2,760)
UT7	4KV Load Conversion	N	97,880	51,096	95,495	59,810	113,800	100,000	113,800	100,000	(13,800)
UT8	Pt Edward upgrades	O	48,940	46,828	1,938	25,133	56,900	50,000	28,450	25,000	(3,450)
UT9	Tools (Vehicle and others)	O	44,000	49,592	42,905	38,440	50,982	44,800	45,520	40,000	(5,520)
UT10	Vehicle Replacement - Lines	O	528,000	191,257	800,864	345,239	512,100	450,000	512,100	450,000	(62,100)
UT11	New Connections (OEB Requirements)	O	653,259	1,063,436	1,218,171	979,516	910,400	800,000	1,251,800	1,100,000	(151,800)
UT12	Transformers	O	163,485	173,858	283,795	63,943	170,700	150,000	170,700	150,000	(20,700)
UT13	Safety Related Projects	O	11,000	-	15,036	4,734	11,380	10,000	11,380	10,000	(1,380)
UT14	Cross Arm/Cap & Pin Insulator Replacement Program	O	97,880	126,755	63,019	53,183	142,250	125,000	136,560	120,000	(16,560)
UT15	Wood Pole Replacement Program	O	97,880	185,371	188,173	250,660	398,300	350,000	284,500	250,000	(34,500)
UT16	Watford	N	77,334	37,185	73,101	158,920	91,040	80,000	45,520	40,000	(5,520)
UT17	Load Balancing	N	47,425	13,641	-	10,277	187,770	165,000	28,450	25,000	(3,450)
UT18	Emergency System Improvement Fund	O	212,425	155,745	207,743	197,644	227,600	200,000	238,980	210,000	(28,980)
UT19	Service Centre	O	53,485	87,470	82,004	81,244	96,730	85,000	182,080	160,000	(22,080)
UT20	Overhead Line - Back Lot Rebuild	N	97,880	62,428	686	43,196	-	-	28,450	25,000	(3,450)
UT21	27.6 Kv Feeder Extensions	O	122,350	18,363	92,060	118,908	170,700	150,000	170,700	150,000	(20,700)
UT22	8 kv Load Conversion	O	73,410	62,708	19,792	96,349	113,800	100,000	113,800	100,000	(13,800)
UT23	Transformer Cover Replacements	O	24,470	2,359	9,570	6,401	45,520	40,000	-	-	-
UT24	Storm Restoration	O	146,820	261,923	90,277	180,819	170,700	150,000	204,840	180,000	(24,840)
UT25	Remote Load Break Switches	O	75,880	71,723	68,324	49,575	102,420	90,000	113,800	100,000	(13,800)
UT26	Primary Underground Cable Replacements	O	-	-	127,706	192,224	170,700	150,000	170,700	150,000	(20,700)
UT27	Remote Terminal Unit Upgrades	N	-	-	41,692	28,536	56,900	50,000	56,900	50,000	(6,900)
UT28	Asset Condition Assessment (feeder & substn)	O	163,485	4,504	54,507	83,586	62,590	55,000	85,350	75,000	(10,350)
UT29	Relay and Fuse Coordination	N	-	-	792	4,075	85,350	75,000	-	-	-
UT30	Fault Indicators - Overhead	N	-	-	-	6,834	6,828	6,000	6,828	6,000	(828)
UT31	Pad Mount Transformer Replacements	O	-	-	-	24,761	170,700	150,000	170,700	150,000	(20,700)
UT32	Data radio infrastructure upgrade	N	-	-	-	-	56,900	50,000	56,900	50,000	(6,900)
UT33	Animal Protection	N	103,940	98,379	44,200	-	5,690	5,000	5,690	5,000	(690)
UT34	27.6kV Lines Upgrades	N	97,880	29,617	10,902	23,061	-	-	170,700	150,000	(20,700)
UT35	Substation Transformer Replacements	N	126,137	54,447	123,077	39,778	-	-	187,770	165,000	(22,770)
UT36	Downtown Cable Replacement - Cromwell St. to	N	-	-	-	-	-	-	113,800	100,000	(13,800)
UT38	Control Room Upgrades	N	-	-	-	-	-	-	22,760	20,000	(2,760)
UT39	Operations Technology Systems Workflow	N	-	-	-	-	-	-	254,014	223,211	(30,803)
UT40	Guy Guard/Down Guy Replacement	O	-	-	-	-	-	-	28,450	25,000	(3,450)
UT41	Fault Indicators - Underground	N	18,970	4,063	-	-	-	-	-	-	-
UT42	Manhole Structure Re-builds	N	51,970	75,373	-	25,940	-	-	-	-	-
UT43	Geographical Information System (GIS)	N	160,189	78,420	-	-	-	-	-	-	-
UT44	SCADA Projects	N	-	-	43,466	3,125	-	-	-	-	-
UT45	Porcelain Arrester Replacement	N	-	-	16,167	11,655	-	-	-	-	-
UT46	5kV Protective Relay Replacement	N	81,940	72,723	73,171	279	-	-	-	-	-
		Subtotal (N)	**1,255,185**	**713,098**	**691,796**	**544,940**	**985,508**	**866,000**	**1,404,532**	**1,234,211**	**(170,321)**
		Subtotal (O)	**2,696,589**	**2,560,168**	**3,459,206**	**2,871,806**	**3,750,051**	**3,295,300**	**4,068,350**	**3,575,000**	**(493,350)**
	Total Lines & Design		**3,951,774**	**3,273,266**	**4,151,002**	**3,416,746**	**4,735,559**	**4,161,300**	**5,472,882**	**4,809,211**	**(663,671)**
	Metering										
M1	Single Phase 100 Amp Meter Replacement	O	96,706	11,805	74,283	16,320	22,760	20,000	22,760	20,000	(2,760)
M2	Poly Phase mechanical demand replacement	O	55,365	87,031	39,448	46,566	68,280	60,000	68,280	60,000	(8,280)
M3	New Meters	O	27,500	34,957	8,140	43,042	28,450	25,000	56,900	50,000	(6,900)
M4	Metering Equipment/Tools	O	6,600	-	1,134	786	2,276	2,000	2,276	2,000	(276)
M5	Meter Test Board	O	-	-	-	-	45,520	40,000	45,520	40,000	(5,520)
M6	Testing Equipment	O	-	-	-	31,169	2,737	2,405	-	-	-
M7	Trans Station Meter Upgrade - Modeland	N	525,074	426,930	34,113	3,146	-	-	-	-	-
M8	Smart Meter Remote Disconnect	N	-	-	-	324,158	-	-	-	-	-
		Subtotal (N)	**525,074**	**426,930**	**34,113**	**327,304**	**-**	**-**	**-**	**-**	**-**
		Subtotal (O)	**186,171**	**133,793**	**123,005**	**137,883**	**170,023**	**149,405**	**195,736**	**172,000**	**(23,736)**
	Total Metering		**711,245**	**560,723**	**157,118**	**465,187**	**170,023**	**149,405**	**195,736**	**172,000**	**(23,736)**

Bluewater Power Distribution Corporation
Capital Expenditures Detail by Project - 2013 OEB filing

Project ID	Project Name	Ongoing (O) or Non-routine (N)	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 CGAAP	2012 MIFRS	2013 CGAAP	2013 MIFRS	2013 Diff
	Information Technology Hardware										
IT1	Data Centre Lifecycle	O	265,379	257,729	179,708	249,478	306,006	268,898	343,560	301,898	(41,662)
IT2	Computer Infrastructure Lifecycle	O	118,777	99,404	131,550	98,699	159,137	139,839	167,123	146,857	(20,266)
			384,156	357,133	311,258	348,177	465,143	408,737	510,683	448,755	(61,928)
	Information Technology Software										
IT3	Corporate IT Security	O	48,462	40,221	71,369	34,373	146,636	128,854	140,485	123,449	(17,036)
IT4	IT Staff Capitalization	O	60,267	65,620	80,501	88,098	104,945	92,219	111,573	98,043	(13,530)
IT5	Legislated Business Application Upgrades	O	198,625	195,171	411,079	424,732	426,939	375,167	290,856	255,585	(35,271)
IT6	Software-Upgrades and Additions	O	107,036	100,972	92,328	180,278	134,526	118,213	161,020	141,494	(19,526)
IT7	IP Telephony and Messaging Upgrade	N	-	-	-	67,595	210,911	185,335	28,450	25,000	(3,450)
IT8	SCADA / ODS / OMS / GIS Integration	O	-	-	-	-	96,820	85,079	132,048	116,035	(16,013)
IT9	Disaster Recovery Plan Upgrade Phase III	N	-	-	-	-	149,529	131,396	198,131	174,105	(24,026)
IT10	SAP Customer Self Services and Electronic Billing	N	-	-	-	162,645	234,783	206,312	169,231	148,709	(20,522)
IT11	Fleet Management and Tracking	N	-	-	-	-	65,234	57,324	-	-	-
IT12	MV 90	N	-	-	-	-	40,251	35,370	-	-	-
IT13	System Upgrades	N	-	-	-	-	649,877	571,069	-	-	-
IT14	Document Management	N	15,018	79	-	-	-	-	104,422	91,759	(12,663)
IT15	Wireless network	N	-	-	-	-	-	-	68,712	60,380	(8,332)
IT16	SAP Upgrade	N	-	430,762	2,082,636	-	-	-	-	-	-
IT17	Disaster Recovery Plan Upgrade Phase II	N	-	-	-	136,315	-	-	-	-	-
IT18	Data Center Network Lifecycle Replacement	N	173,036	112,660	-	-	-	-	-	-	-
IT19	GIS Developments	N	-	-	6,985	-	-	-	-	-	-
IT20	Retail Settlement Automation	N	-	-	-	3,133	-	-	-	-	-
IT21	IFRS System Upgrade	N					618,943	543,886	-	-	-
			602,444	945,485	2,744,898	1,097,169	2,879,394	2,530,224	1,404,928	1,234,559	(170,369)
		Subtotal (N)	188,054	543,501	2,089,621	369,688	1,969,527	1,730,692	568,947	499,953	(68,994)
		Subtotal (O)	798,546	759,117	966,535	1,075,658	1,375,010	1,208,269	1,346,665	1,183,361	(163,304)
	Total Information Technology		**986,600**	**1,302,618**	**3,056,156**	**1,445,346**	**3,344,537**	**2,938,961**	**1,915,611**	**1,683,314**	**(232,297)**
	Other Projects										
O1	Building Renovations/Expansion	N	-	222,586	512,058	-	2,128,629	1,870,500	-	-	-
O2	UWO Project	N	-	-	-	29,956	-	-	-	-	-
O3	Furniture (Company wide)	O	2,202	10,160	19,428	20,151	11,380	10,000	11,380	10,000	(1,380)
O4	Meter-Reading Tools	N	-	-	3,889	146	2,276	2,000	-	-	-
O5	Misc Tools & Equipment	N	-	-	-	1,019	-	-	-	-	-
O6	CN Land Rights	N		-	-	-	-	-	292,694	257,200	(35,494)
O7	Building Petrolia	N	-	-	224,746	-	-	-	-	-	-
		Subtotal (N)	**-**	**222,586**	**740,693**	**31,121**	**2,130,905**	**1,872,500**	**292,694**	**257,200**	**(35,494)**
		Subtotal (O)	**2,202**	**10,160**	**19,428**	**20,151**	**11,380**	**10,000**	**11,380**	**10,000**	**(1,380)**
	Total Other Projects		**2,202**	**232,746**	**760,121**	**51,272**	**2,142,285**	**1,882,500**	**304,074**	**267,200**	**(36,874)**
		TOTAL (N)	**1,968,313**	**1,906,115**	**3,556,223**	**1,273,053**	**5,085,940**	**4,469,192**	**2,266,172**	**1,991,364**	**(274,808)**
		TOTAL (O)	**3,683,508**	**3,463,238**	**4,568,174**	**4,105,498**	**5,306,464**	**4,662,974**	**5,622,131**	**4,940,361**	**(681,770)**
			5,651,821	**5,369,353**	**8,124,397**	**5,378,551**	**10,392,404**	**9,132,166**	**7,888,303**	**6,931,725**	**(956,578)**

2.0-Staff-7 - Capital Schedule updated for 2012

Ref: Exh 2-4-3 Attachment 1

The attachment summarizes capital expenditure details by project. Please expand the table by one additional column and provide 2012 actual capital expenditures.

Bluewater Power has added one column with the heading “Actual 2012 MIFRS (Draft)” which provides the preliminary draft Capital Spending for 2012. See Attachment #1 to this Interrogatory.

We note that the results are preliminary and subject to the normal review through the audit process. We have not updated Revenue Requirement in 1-Staff-2 to reflect the impact of 2012 Actuals (draft) on Rate Base.

File Number:EB-2012-0107

Tab: 4
Schedule: 8

Date Filed:February 4, 2013

Attachment 1 of 1

2.0 - Board Staff 7 - 2012 Update for Capital

Bluewater Power Distribution Corporation
Capital Expenditures Detail by Project - 2013 OEB filing

Project ID	Project Name	Ongoing (O) or Non-routine (N)	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 CGAAP	2012 MIFRS	2012 Actual (DRAFT) MIFRS	2013 MIFRS
	Lines & Design									
UT1	Substation Building	O	106,970	32,659	61,927	79,448	117,214	103,000	33,649	90,000
UT2	27.6 Load Break Switch Replacement	N	48,940	42,169	29,602	49,073	68,280	60,000	50,722	-
UT3	Street Widening	O	53,274	20,195	17,045	-	22,760	20,000	-	20,000
UT4	27.6kV Neutral Program	N	146,820	45,326	19,024	55,316	170,700	150,000	37,755	150,000
UT5	27.6 Feeder - Petrolia	N	97,880	48,230	120,421	25,065	142,250	125,000	94,341	125,000
UT6	Alvinston/Oil Springs Capital Items	O	19,576	5,422	14,350	-	25,605	22,500	27,446	20,000
UT7	4KV Load Conversion	N	97,880	51,096	95,495	59,810	113,800	100,000	92,286	100,000
UT8	Pt Edward upgrades	O	48,940	46,828	1,938	25,133	56,900	50,000	40,717	25,000
UT9	Tools (Vehicle and others)	O	44,000	49,592	42,905	38,440	50,982	44,800	23,086	40,000
UT10	Vehicle Replacement - Lines	O	528,000	191,257	800,864	345,239	512,100	450,000	624,277	450,000
UT11	New Connections (OEB Requirements)	O	653,259	1,063,436	1,218,171	979,516	910,400	800,000	525,280	1,100,000
UT12	Transformers	O	163,485	173,858	283,795	63,943	170,700	150,000	314,264	150,000
UT13	Safety Related Projects	O	11,000	-	15,036	4,734	11,380	10,000	250	10,000
UT14	Cross Arm/Cap & Pin Insulator Replacement Program	O	97,880	126,755	63,019	53,183	142,250	125,000	151,832	120,000
UT15	Wood Pole Replacement Program	O	97,880	185,371	188,173	250,660	398,300	350,000	371,466	250,000
UT16	Watford	N	77,334	37,185	73,101	158,920	91,040	80,000	113,712	40,000
UT17	Load Balancing	N	47,425	13,641	-	10,277	187,770	165,000	-	25,000
UT18	Emergency System Improvement Fund	O	212,425	155,745	207,743	197,644	227,600	200,000	176,111	210,000
UT19	Service Centre	O	53,485	87,470	82,004	81,244	96,730	85,000	16,873	160,000
UT20	Overhead Line - Back Lot Rebuild	N	97,880	62,428	686	43,196	-	-	7,596	25,000
UT21	27.6 Kv Feeder Extensions	O	122,350	18,363	92,060	118,908	170,700	150,000	136,267	150,000
UT22	8 kv Load Conversion	O	73,410	62,708	19,792	96,349	113,800	100,000	59,164	100,000
UT23	Transformer Cover Replacements	O	24,470	2,359	9,570	6,401	45,520	40,000	5,826	-
UT24	Storm Restoration	O	146,820	261,923	90,277	180,819	170,700	150,000	366,941	180,000
UT25	Remote Load Break Switches	O	75,880	71,723	68,324	49,575	102,420	90,000	74,661	100,000
UT26	Primary Underground Cable Replacements	O	-	-	127,706	192,224	170,700	150,000	170,046	150,000
UT27	Remote Terminal Unit Upgrades	N	-	-	41,692	28,536	56,900	50,000	16,353	50,000
UT28	Asset Condition Assessment (feeder & substn)	O	163,485	4,504	54,507	83,586	62,590	55,000	32,385	75,000
UT29	Relay and Fuse Coordination	N	-	-	792	4,075	85,350	75,000	10,251	-
UT30	Fault Indicators - Overhead	N	-	-	-	6,834	6,828	6,000	-	6,000
UT31	Pad Mount Transformer Replacements	O	-	-	-	24,761	170,700	150,000	51,858	150,000
UT32	Data radio infrastructure upgrade	N	-	-	-	-	56,900	50,000	49,483	50,000
UT33	Animal Protection	N	103,940	98,379	44,200	-	5,690	5,000	10,143	5,000
UT34	27.6kV Lines Upgrades	N	97,880	29,617	10,902	23,061	-	-	6,977	150,000
UT35	Substation Transformer Replacements	N	126,137	54,447	123,077	39,778	-	-	-	165,000
UT36	Downtown Cable Replacement - Cromwell St. to Front St. -	N	-	-	-	-	-	-	-	100,000
UT38	Control Room Upgrades	N	-	-	-	-	-	-	-	20,000
UT39	Operations Technology Systems Workflow	N	-	-	-	-	-	-	-	223,211
UT40	Guy Guard/Down Guy Replacement	O	-	-	-	-	-	-	-	25,000
UT41	Fault Indicators - Underground	N	18,970	4,063	-	-	-	-	-	-
UT42	Manhole Structure Re-builds	N	51,970	75,373	-	25,940	-	-	-	-
UT43	Geographical Information System (GIS)	N	160,189	78,420	-	-	-	-	-	-
UT44	SCADA Projects	N	-	-	43,466	3,125	-	-	-	-
UT45	Porcelain Arrester Replacement	N	-	-	16,167	11,655	-	-	-	-
UT46	5kV Protective Relay Replacement	N	81,940	72,723	73,171	279	-	-	-	-
		Subtotal (N)	**1,255,185**	**713,098**	**691,796**	**544,940**	**985,508**	**866,000**	**489,619**	**1,234,211**
		Subtotal (O)	**2,696,589**	**2,560,168**	**3,459,206**	**2,871,806**	**3,750,051**	**3,295,300**	**3,202,399**	**3,575,000**
	Total Lines & Design		**3,951,774**	**3,273,266**	**4,151,002**	**3,416,746**	**4,735,559**	**4,161,300**	**3,692,018**	**4,809,211**
	Metering									
M1	Single Phase 100 Amp Meter Replacement	O	96,706	11,805	74,283	16,320	22,760	20,000	2,309	20,000
M2	Poly Phase mechanical demand replacement	O	55,365	87,031	39,448	46,566	68,280	60,000	57,473	60,000
M3	New Meters	O	27,500	34,957	8,140	43,042	28,450	25,000	7,182	50,000
M4	Metering Equipment/Tools	O	6,600	-	1,134	786	2,276	2,000	-	2,000
M5	Meter Test Board	O	-	-	-	-	45,520	40,000	41,574	40,000
M6	Testing Equipment	O	-	-	-	31,169	2,737	2,405	622	-
M7	Trans Station Meter Upgrade - Modeland	N	525,074	426,930	34,113	3,146	-	-	-	-
M8	Smart Meter Remote Disconnect	N	-	-	-	324,158	-	-	-	-
		Subtotal (N)	**525,074**	**426,930**	**34,113**	**327,304**	**-**	**-**	**-**	**-**
		Subtotal (O)	**186,171**	**133,793**	**123,005**	**137,883**	**170,023**	**149,405**	**109,160**	**172,000**
	Total Metering		**711,245**	**560,723**	**157,118**	**465,187**	**170,023**	**149,405**	**109,160**	**172,000**
	Information Technology Hardware									
IT1	Data Centre Lifecycle	O	265,379	257,729	179,708	249,478	306,006	268,898	247,567	301,898
IT2	Computer Infrastructure Lifecycle	O	118,777	99,404	131,550	98,699	159,137	139,839	170,157	146,857
			384,156	357,133	311,258	348,177	465,143	408,737	417,724	448,755
	Information Technology Software									
IT3	Corporate IT Security	O	48,462	40,221	71,369	34,373	146,636	128,854	133,210	123,449
IT4	IT Staff Capitalization	O	60,267	65,620	80,501	88,098	104,945	92,219	92,405	98,043
IT5	Legislated Business Application Upgrades	O	198,625	195,171	411,079	424,732	426,939	375,167	268,392	255,585
IT6	Software-Upgrades and Additions	O	107,036	100,972	92,328	180,278	134,526	118,213	89,344	141,494
IT7	IP Telephony and Messaging Upgrade	N	-	-	-	67,595	210,911	185,335	174,608	25,000
IT8	SCADA / ODS / OMS / GIS Integration	O	-	-	-	-	96,820	85,079	38,071	116,035
IT9	Disaster Recovery Plan Upgrade Phase III	N	-	-	-	-	149,529	131,396	85,093	174,105
IT10	SAP Customer Self Services and Electronic Billing	N	-	-	-	162,645	234,783	206,312	42,508	148,709
IT11	Fleet Management and Tracking	N	-	-	-	-	65,234	57,324	38,981	-
IT12	MV 90	N	-	-	-	-	40,251	35,370	2,973	-
IT13	System Upgrades	N	-	-	-	-	649,877	571,069	581,371	-
IT14	Document Management	N	15,018	79	-	-	-	-	-	91,759
IT15	Wireless network	N	-	-	-	-	-	-	-	60,380
IT16	SAP Upgrade	N	-	430,762	2,082,636	-	-	-	-	-
IT17	Disaster Recovery Plan Upgrade Phase II	N	-	-	-	136,315	-	-	-	-
IT18	Data Center Network Lifecycle Replacement	N	173,036	112,660	-	-	-	-	-	-
IT19	GIS Developments	N	-	-	6,985	-	-	-	-	-
IT20	Retail Settlement Automation	N	-	-	-	3,133	-	-	-	-
IT21	IFRS System Upgrade	N					618,943	543,886	542,886	-
			602,444	945,485	2,744,898	1,097,169	2,879,394	2,530,224	2,089,842	1,234,559
		Subtotal (N)	188,054	543,501	2,089,621	369,688	1,969,527	1,730,692	1,468,420	499,953
		Subtotal (O)	798,546	759,117	966,535	1,075,658	1,375,010	1,208,269	1,039,146	1,183,361
	Total Information Technology		**986,600**	**1,302,618**	**3,056,156**	**1,445,346**	**3,344,537**	**2,938,961**	**2,507,566**	**1,683,314**

Bluewater Power Distribution Corporation
Capital Expenditures Detail by Project - 2013 OEB filing

Project ID	Project Name	Ongoing (O) or Non-routine (N)	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 CGAAP	2012 MIFRS	2012 Actual (DRAFT) MIFRS	2013 MIFRS
	Other Projects									
O1	Building Renovations/Expansion	N	-	222,586	512,058	-	2,128,629	1,870,500	1,895,875	-
O2	UWO Project	N	-	-	-	29,956	-	-	471	-
O3	Furniture (Company wide)	O	2,202	10,160	19,428	20,151	11,380	10,000	2,857	10,000
O4	Meter-Reading Tools	N	-	-	3,889	146	2,276	2,000	-	-
O5	Misc Tools & Equipment	N	-	-	-	1,019	-	-	3,542	-
O6	CN Land Rights	N		-	-	-	-	-	-	257,200
O7	Building Petrolia	N	-	-	224,746	-	-	-	-	-
		Subtotal (N)	**-**	**222,586**	**740,693**	**31,121**	**2,130,905**	**1,872,500**	**1,899,888**	**257,200**
		Subtotal (O)	**2,202**	**10,160**	**19,428**	**20,151**	**11,380**	**10,000**	**2,857**	**10,000**
	Total Other Projects		**2,202**	**232,746**	**760,121**	**51,272**	**2,142,285**	**1,882,500**	**1,902,745**	**267,200**
		TOTAL (N)	**1,968,313**	**1,906,115**	**3,556,223**	**1,273,053**	**5,085,940**	**4,469,192**	**3,857,927**	**1,991,364**
		TOTAL (O)	**3,683,508**	**3,463,238**	**4,568,174**	**4,105,498**	**5,306,464**	**4,662,974**	**4,353,562**	**4,940,361**
			5,651,821	**5,369,353**	**8,124,397**	**5,378,551**	**10,392,404**	**9,132,166**	**8,211,489**	**6,931,725**

2.0 - EP 11 - Appendix 2-B Updated for 2012

Ref: Exhibit 2, Tab 3, Schedule 2, Attachment 2

a) Please provide updated schedules for 2012 in the format of Appendix 2-B as filed on both a CGAAP and MIFRS basis based on actual data for 2012. If actual data for all of 2012 is not yet available, please update the schedules based on the most recent year to date information available, along with an estimate for the remaining period in 2012. Please also indicate when actual information for 2012 will be available.

Please refer to Attachment #1 to this Interrogatory which provides the preliminary draft capital asset schedules for 2012 CGAAP, 2012 MIFRS and a 2012 MIFRS schedule which details the MIFRS Conversion and Smart/Stranded Meters.

b) For each account in 2009 through 2013 for which there is an associated contribution and grant, please show the gross additions to the account and the amount of the contribution & grant associated with the account. Please ensure that the contributions and grants add up to the totals shown in the schedules.

Please refer to the discussion at Ex. 2-2-5. Bluewater Power does not track contributed capital by asset account. The contributed capital budget for 2012 is $491,240 and for 2013 is $675,455. Under MIFRS, all contributed capital will be tracked/segregated according to the asset account to which it relates for amortization purposes only. For 2012, this has not been done due to Bluewater Power taking the additional one year deferral for IFRS conversion to January 1, 2014 (see Energy Probe #2 and 3-VECC-22a).

File Number:EB-2012-0107

Tab:	4
Schedule:	9

Date Filed:February 4, 2013

Attachment 1 of 1

2.0 - Energy Probe 11 - Appendix 2-B Updated for 2012

File Number:	
Exhibit:	2
Tab:	3
Schedule:	2
Attachment:	2
Date:	31-Jan-13

Appendix 2-B
Fixed Asset Continuity Schedule

Year **Preliminary 2012 CGAAP**

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Smart Meter and Stranded Meters**	**Closing Balance**	**Opening Balance**	**Additions**	**Smart Meter and Stranded Meters**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)		$ 9,500,884	$ 1,863,612	$ 3,537,240	$ 14,901,736	-$ 6,007,128	-$ 1,256,230	-$ 1,037,528	-$ 8,300,886	$ 6,600,850
CEC	1612	Land Rights (Formally known as Account 1906)		$ 283,160			$ 283,160	-$ 267,342	-$ 1,192		-$ 268,534	$ 14,626
N/A	1805	Land		$ 497,489			$ 497,489	$ -			$ -	$ 497,489
47	1808	Buildings		$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 6,455,582	$ 245,673		$ 6,701,255	-$ 3,215,427	-$ 165,649		-$ 3,381,076	$ 3,320,179
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 2,257,678	$ 1,121,251		$ 3,378,929	-$ 245,396	-$ 112,732		-$ 358,128	$ 3,020,801
47	1835	Overhead Conductors & Devices		$ 27,485,935	$ 566,567		$ 28,052,502	-$ 17,366,822	-$ 841,368		-$ 18,208,190	$ 9,844,312
47	1840	Underground Conduit		$ 1,150,356	$ 138,674		$ 1,289,030	-$ 105,793	-$ 48,788		-$ 154,581	$ 1,134,449
47	1845	Underground Conductors & Devices		$ 20,300,059	$ 774,196		$ 21,074,255	-$ 11,974,110	-$ 667,898		-$ 12,642,008	$ 8,432,247
47	1850	Line Transformers		$ 15,367,543	$ 880,808		$ 16,248,351	-$ 8,549,764	-$ 482,470		-$ 9,032,234	$ 7,216,117
47	1855	Services (Overhead & Underground)		$ 555,088	$ 33,004		$ 588,092	-$ 57,125	-$ 22,864		-$ 79,989	$ 508,103
47	1860	Meters		$ 7,862,812	$ 8,173	-$ 6,719,816	$ 1,151,169	-$ 4,840,300	-$ 204,360	$ 4,793,170	-$ 251,490	$ 899,679
8	1860	Meters (Smart Meters)		$ -		$ 4,661,948	$ 4,661,948	$ -		-$ 729,238	-$ 729,238	$ 3,932,710
N/A	1905	Land		$ -			$ -	$ -	$ -	$ -	$ -	$ -
1	1908	Buildings & Fixtures		$ 6,009,894	$ 2,121,549		$ 8,131,443	-$ 1,943,405	-$ 106,086		-$ 2,049,491	$ 6,081,952
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 876,633	$ 111,663		$ 988,296	-$ 691,137	-$ 38,024		-$ 729,161	$ 259,135
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ 5,099,380	$ 1,057,593	$ 330,711	$ 6,487,684	-$ 3,953,890	-$ 515,200	-$ 174,816	-$ 4,643,906	$ 1,843,778
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment		$ 4,341,254	$ 814,965		$ 5,156,219	-$ 2,815,922	-$ 366,067		-$ 3,181,989	$ 1,974,230
8	1935	Stores Equipment		$ 81,138			$ 81,138	-$ 71,284	-$ 4,790		-$ 76,074	$ 5,064
8	1940	Tools, Shop & Garage Equipment		$ 887,821	$ 30,303	$ 54,087	$ 972,211	-$ 653,757	-$ 40,667	-$ 12,692	-$ 707,116	$ 265,095
8	1945	Measurement & Testing Equipment		$ 313,080	$ 48,751		$ 361,831	-$ 223,931	-$ 14,332		-$ 238,263	$ 123,568
8	1950	Power Operated Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment		$ 252,975			$ 252,975	-$ 161,893	-$ 13,167		-$ 175,060	$ 77,915
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ 784,532			$ 784,532	-$ 712,325	-$ 5,689		-$ 718,014	$ 66,518
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment		$ 1,238,700			$ 1,238,700	-$ 794,694	-$ 40,294		-$ 834,988	$ 403,712
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants		-$ 6,487,773	-$ 317,654		-$ 6,805,427	$ 1,412,859	$ 265,864		$ 1,678,723	-$ 5,126,704
	1970	Load Management Controls - Customer Premises		$ 464,917			$ 464,917	-$ 464,917	$ -		-$ 464,917	$ -
	1990	Other Tangible Property (major spare parts)		$ 567,497			$ 567,497	$ -			$ -	$ 567,497
		Total		**$ 106,146,634**	**$ 9,499,128**	**$ 1,864,170**	**$ 117,509,932**	**-$ 63,703,503**	**-$ 4,682,003**	**$ 2,838,896**	**-$ 65,546,610**	**$ 51,963,322**

File Number:	
Exhibit:	2
Tab:	3
Schedule:	2
Attachment:	2
Date:	31-Jan-13

Appendix 2-B
Fixed Asset Continuity Schedule

Year Preliminary 2012 MIFRS

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance CGAAP**	**Additions**	**Conversion to MIFRS & Smart Meter**	**Closing Balance under MIFRS**	**Opening Balance CGAAP**	**Additions**	**Conversion to MIFRS & Smart Meter**	**Closing Balance under MIFRS**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)		$ 9,500,884	$ 1,637,620	-$ 2,877,159	$ 8,261,345	-$ 6,007,128	-$ 1,463,552	$ 5,376,871	-$ 2,093,809	$ 6,167,536
CEC	1612	Land Rights (Formally known as Account 1906)		$ 283,160		-$ 267,342	$ 15,818	-$ 267,342	-$ 1,217	$ 267,342	-$ 1,217	$ 14,601
N/A	1805	Land		$ 497,489		$ -	$ 497,489	$ -		$ -	$ -	$ 497,489
47	1808	Buildings		$ -		$ -	$ -	$ -		$ -	$ -	$ -
13	1810	Leasehold Improvements		$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 6,455,582	$ 215,898	-$ 3,215,427	$ 3,456,053	-$ 3,215,427	-$ 191,670	$ 3,215,427	-$ 191,670	$ 3,264,383
47	1825	Storage Battery Equipment		$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 2,257,678	$ 1,000,021	-$ 629,289	$ 2,628,410	-$ 245,396	-$ 49,376	$ 245,396	-$ 49,376	$ 2,579,034
47	1835	Overhead Conductors & Devices		$ 27,485,935	$ 512,320	-$ 18,694,500	$ 9,303,755	-$ 17,366,822	-$ 269,069	$ 17,366,822	-$ 269,069	$ 9,034,686
47	1840	Underground Conduit		$ 1,150,356	$ 123,316	-$ 352,303	$ 921,369	-$ 105,793	-$ 17,321	$ 105,793	-$ 17,321	$ 904,048
47	1845	Underground Conductors & Devices		$ 20,300,059	$ 687,694	-$ 13,609,036	$ 7,378,717	-$ 11,974,110	-$ 321,194	$ 11,974,110	-$ 321,194	$ 7,057,523
47	1850	Line Transformers		$ 15,367,543	$ 777,645	-$ 9,754,473	$ 6,390,715	-$ 8,549,764	-$ 196,731	$ 8,549,764	-$ 196,731	$ 6,193,984
47	1855	Services (Overhead & Underground)		$ 555,088	$ 29,380	-$ 184,605	$ 399,863	-$ 57,125	-$ 17,096	$ 57,125	-$ 17,096	$ 382,767
47	1860	Meters		$ 7,862,812	$ 7,182	-$ 7,073,881	$ 796,113	-$ 4,840,300	-$ 204,224	$ 4,995,859	-$ 48,665	$ 747,448
8	1860	Meters (Smart Meters)		$ -		$ 4,241,682	$ 4,241,682	$ -		-$ 308,972	-$ 308,972	$ 3,932,710
N/A	1905	Land		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures		$ 6,009,894	$ 1,860,046	-$ 1,943,405	$ 5,926,535	-$ 1,943,405	-$ 128,841	$ 1,943,405	-$ 128,841	$ 5,797,694
13	1910	Leasehold Improvements		$ -		$ -	$ -	$ -		$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 876,633	$ 102,672	-$ 691,137	$ 288,168	-$ 691,137	-$ 47,601	$ 691,137	-$ 47,601	$ 240,567
8	1915	Office Furniture & Equipment (5 years)		$ -		$ -	$ -	$ -		$ -	$ -	$ -
10	1920	Computer Equipment - Hardware		$ 5,099,380	$ 937,541	-$ 3,731,852	$ 2,305,069	-$ 3,953,890	-$ 473,868	$ 3,887,748	-$ 540,010	$ 1,765,059
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -		$ -	$ -	$ -		$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -		$ -	$ -	$ -		$ -	$ -	$ -
10	1930	Transportation Equipment		$ 4,341,254	$ 722,739	-$ 2,815,922	$ 2,248,071	-$ 2,815,922	-$ 278,618	$ 2,815,922	-$ 278,618	$ 1,969,453
8	1935	Stores Equipment		$ 81,138		-$ 71,284	$ 9,854	-$ 71,284	-$ 4,927	$ 71,284	-$ 4,927	$ 4,927
8	1940	Tools, Shop & Garage Equipment		$ 887,821	$ 26,628	-$ 606,953	$ 307,496	-$ 653,757	-$ 53,229	$ 648,348	-$ 58,638	$ 248,858
8	1945	Measurement & Testing Equipment		$ 313,080	$ 42,893	-$ 223,931	$ 132,042	-$ 223,931	-$ 19,070	$ 223,931	-$ 19,070	$ 112,972
8	1950	Power Operated Equipment		$ -		$ -	$ -	$ -		$ -	$ -	$ -
8	1955	Communications Equipment		$ 252,975		-$ 161,893	$ 91,082	-$ 161,893	-$ 16,526	$ 161,893	-$ 16,526	$ 74,556
8	1955	Communication Equipment (Smart Meters)		$ -		$ -	$ -	$ -		$ -	$ -	$ -
8	1960	Miscellaneous Equipment		$ 784,532		-$ 712,325	$ 72,207	-$ 712,325	-$ 5,158	$ 712,325	-$ 5,158	$ 67,049
47	1975	Load Management Controls Utility Premises		$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	1980	System Supervisor Equipment		$ 1,238,700		-$ 794,694	$ 444,006	-$ 794,694	-$ 38,354	$ 794,694	-$ 38,354	$ 405,652
47	1985	Miscellaneous Fixed Assets		$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	1995	Contributions & Grants		-$ 6,487,773	-$ 317,654	$ 6,487,773	-$ 317,654	$ 1,412,859	$ 3,863	-$ 1,412,859	$ 3,863	-$ 313,791
	1970	Load Management Controls - Customer Premises		$ 464,917		-$ 464,917	$ -	-$ 464,917	$ -	$ 464,917	$ -	$ -
	1990	Other Tangible Property (major spare parts)		$ 567,497		$ -	$ 567,497	$ -		$ -	$ -	$ 567,497
		Total		**$ 106,146,634**	**$ 8,365,941**	**-$ 58,146,873**	**$ 56,365,702**	**-$ 63,703,503**	**-$ 3,793,779**	**$ 62,848,282**	**-$ 4,649,000**	**$ 51,716,702**

File Number:	
Exhibit:	2
Tab:	3
Schedule:	2
Page:	2
Date:	31-Jan-13

Appendix 2-B

Fixed Asset Continuity Schedule 2012 MIFRS (with breakdown of MIFRS Conversion and Smart/Stranded Meters)

Year Preliminary 2012 MIFRS (Details)

				Cost Adjustment				**Accumulated Depreciation Adjustment**			
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**2011 Accumulated Depreciation**	**2011 Contributed Capital**	**Smart Meter and Stranded Meter**	**Conversion to MIFRS & Smart Meter**	**2011 Accumulated Depreciation**	**2011 Contributed Capital**	**Smart Meter and Stranded Meter**	**Conversion to MIFRS & Smart Meter**
12	1611	Computer Software (Formally known as Account 1925)		-$ 6,007,127	$ -	$ 3,129,969	-$ 2,877,159	$ 6,007,128		-$ 630,257	$ 5,376,871
CEC	1612	Land Rights (Formally known as Account 1906)		-$ 267,342	$ -	$ -	-$ 267,342	$ 267,342			$ 267,342
N/A	1805	Land					$ -	$ -			$ -
47	1808	Buildings					$ -	$ -			$ -
13	1810	Leasehold Improvements					$ -	$ -			$ -
47	1815	Transformer Station Equipment >50 kV					$ -	$ -			$ -
47	1820	Distribution Station Equipment <50 kV		-$ 3,215,427	$ 0	$ -	-$ 3,215,427	$ 3,215,427			$ 3,215,427
47	1825	Storage Battery Equipment					$ -	$ -			$ -
47	1830	Poles, Towers & Fixtures		-$ 245,396	-$ 383,893	$ -	-$ 629,289	$ 245,396			$ 245,396
47	1835	Overhead Conductors & Devices		-$ 17,366,822	-$ 1,327,678	$ -	-$ 18,694,500	$ 17,366,822			$ 17,366,822
47	1840	Underground Conduit		-$ 105,793	-$ 246,510	$ -	-$ 352,303	$ 105,793			$ 105,793
47	1845	Underground Conductors & Devices		-$ 11,974,110	-$ 1,634,926	$ -	-$ 13,609,036	$ 11,974,110			$ 11,974,110
47	1850	Line Transformers		-$ 8,549,765	-$ 1,204,709	$ -	-$ 9,754,473	$ 8,549,764			$ 8,549,764
47	1855	Services (Overhead & Underground)		-$ 57,125	-$ 127,480	$ -	-$ 184,605	$ 57,125			$ 57,125
47	1860	Meters		-$ 4,840,301	-$ 120,137	-$ 2,113,444	-$ 7,073,881	$ 4,840,300		$ 155,559	$ 4,995,859
8	1860	Meters (Smart Meters)				$ 4,241,682	$ 4,241,682	$ -		-$ 308,972	-$ 308,972
N/A	1905	Land					$ -	$ -			$ -
47	1908	Buildings & Fixtures		-$ 1,943,405	-$ 0	$ -	-$ 1,943,405	$ 1,943,405			$ 1,943,405
13	1910	Leasehold Improvements					$ -	$ -			$ -
8	1915	Office Furniture & Equipment (10 years)		-$ 691,137	$ -	$ -	-$ 691,137	$ 691,137			$ 691,137
8	1915	Office Furniture & Equipment (5 years)			$ -	$ -	$ -	$ -			$ -
10	1920	Computer Equipment - Hardware		-$ 3,953,890	$ -	$ 222,038	-$ 3,731,853	$ 3,953,890		-$ 66,142	$ 3,887,748
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)			$ -		$ -	$ -			$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)			$ -		$ -	$ -			$ -
10	1930	Transportation Equipment		-$ 2,815,922	$ -	$ -	-$ 2,815,922	$ 2,815,922			$ 2,815,922
8	1935	Stores Equipment		-$ 71,284	$ -	$ -	-$ 71,284	$ 71,284			$ 71,284
8	1940	Tools, Shop & Garage Equipment		-$ 653,757	$ -	$ 46,804	-$ 606,953	$ 653,757		-$ 5,409	$ 648,348
8	1945	Measurement & Testing Equipment		-$ 223,931	$ -	$ -	-$ 223,931	$ 223,931			$ 223,931
8	1950	Power Operated Equipment					$ -	$ -			$ -
8	1955	Communications Equipment		-$ 161,893	$ -	$ -	-$ 161,893	$ 161,893			$ 161,893
8	1955	Communication Equipment (Smart Meters)			$ -	$ -	$ -	$ -			$ -
8	1960	Miscellaneous Equipment		-$ 712,325	$ -	$ -	-$ 712,325	$ 712,325			$ 712,325
47	1975	Load Management Controls Utility Premises					$ -	$ -			$ -
47	1980	System Supervisor Equipment		-$ 794,694	$ -	$ -	-$ 794,694	$ 794,694			$ 794,694
47	1985	Miscellaneous Fixed Assets					$ -	$ -			$ -
47	1995	Contributions & Grants		$ -	$ 6,487,773	$ -	$ 6,487,773		-$ 1,412,859		-$ 1,412,859
	1970	Load Management Controls - Customer Premises		-$ 464,917			-$ 464,917	$ 464,917			$ 464,917
	1990	Other Tangible Property (major spare parts)		$ -		$ -	$ -	$ -		$ -	$ -
		Total		**-$ 65,116,363**	**$ 1,442,441**	**$ 5,527,048**	**-$ 58,146,873**	**$ 65,116,362**	**-$ 1,412,859**	**-$ 855,221**	**$ 62,848,282**

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The depreciation column (D) is not required as the relevant information will be provided in the following 2-C series of appendices.

2.0 - EP 12 - Capital Tables updated for 2012 & Building

Ref: Exhibit 2, Tab 4, Schedule 3

a) Please update Tables 1, 2 and 4 to reflect actual data for 2012. If actual data for all of 2012 is not yet available, please update the tables to reflect the most recent year to date data available for 2012, along with estimates for the remaining months of 2012.

The ‘Actual 2012’ figures in Tables 1, 3 and 4 are draft amounts.

Table 1

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 CGAAP	Actual 2012 CGAAP	Actual 2012 MIFRS	2012 MIFRS	2013 MIFRS
Operations	3,951,774	3,273,266	4,151,002	3,416,746	4,735,559	4,201,516	3,692,018	4,161,300	4,809,211
Metering	711,245	560,723	157,118	465,187	170,023	124,224	109,160	149,405	172,000
Information Technology	986,600	1,302,618	3,056,156	1,445,346	3,344,537	2,853,610	2,507,566	2,938,961	1,683,314
Other	2,202	232,746	760,121	51,272	2142,285	2,165,324	1,902,745	1,966,500	267,200
Total	5,651,821	5,369,353	8,124,397	5,378,551	10,392,464	9,344,674	8,211,489	9,216,166	6,931,725
Annual Variance		(282,468)	2,755,044	(2,745,846)	5,013,913	3,966,123	(1,133,185)	(1,271,831)	(2,284,441)

Table 3 – Ongoing Capital Spending by Department

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 CGAAP	Actual 2012 CGAAP	Actual 2012 MIFRS	2012 MIFRS	2013 MIFRS
Operations	2,696,589	2,560,168	3,459,206	2,871,806	3,750,051	3,644,330	3,202,399	3,295,300	4,068,350
Metering	186,171	133,793	123,005	137,883	170,023	124,224	109,160	149,405	172,000
Information Technology	798,546	759,117	966,535	1,075,658	1,375,010	1,182,548	1,039,146	1,208,269	1,183,361
Other	2,202	10,160	19,428	20,151	11,380	3,251	2,857	10,000	10,000
Total	3,683,508	3,463,238	4,568,174	4,105,498	5,306,464	4,954,354	4,353,562	4,662,974	4,940,361

Table 4 – Non-routine Investments

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 CGAAP	Actual 2012 CGAAP	Actual 2012 MIFRS	2012 MIFRS	2013 MIFRS
Operations	1,255,185	713,098	691,796	544,940	985,508	557,186	489,619	856,000	1,234,211
Metering	525,074	426,930	34,113	327,304	-	-	-	-	-
Information Technology	188,054	543,501	2,089,621	369,688	1,969,527	1,671,062	1,468,420	1,730,692	499,953
Other	-	222,586	740,693	31,121	2,130,905	2,162,073	1,899,888	1,872,500	257,200
Total	1,968,313	1,906,115	3,556,223	1,273,053	5,085,940	4,390,321	3,857,927	4,469,192	1,991,364

b) Please explain why the total expenditures shown in Table 1 for 2012 under CGAAP and MIFRS do not match the total figures shown in Attachment 1 in the line labelled "Total Spending per Exh. 2, Tab 4, Sch 3, Att 1", while they do for all other years.

Upon investigation, it has been determined that Table 1 was not updated prior to filing the rate application. During the preparation of the rate application, it was found that an amount for the new building furniture was duplicated and therefore corrected. Attachments 1,2,3 and 4 of Ex. 2-4-3 have correct figures (as does rate base), however Table 1 was not updated accordingly. Therefore, a corrected Table 1 is reproduced below and the totals now match. Table 1 is further updated as per part (a) above.

Table 1

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 CGAAP	2012 MIFRS	2013 MIFRS
Operations	3,951,774	3,273,266	4,151,002	3,416,746	4,735,559	4,161,300	4,809,211
Metering	711,245	560,723	157,118	465,187	170,023	149,405	172,000
I.T.	986,600	1,302,618	3,056,156	1,445,346	3,344,537	2,938,961	1,683,314
Other	2,202	232,746	760,121	51,272	2,142,285	1,882,500	267,200
Total	5,651,821	5,369,353	8,124,397	5,378,551	10,392,404	9,132,166	6,931,725
Annual Variance		(282,468)	2,755,044	(2,745,846)	5,013,853	(1,260,238)	(2,200,441)

c) What is the current status of Project ID O1 (Building Renovations/ Expansions) shown in Attachment 1? In particular, was the project completed by the end of 2012, and if so, please provide the actual costs associated with this project.

Project ID O1 was completed in December 2012. More specifically, Bluewater Power was granted occupancy on Dec 19th by the City of Sarnia for this building addition.

The actual CGAAP draft costs for this project, which includes 13.8% overhead, total $2,153,942 as at December 31, 2012. Bluewater Power believes it has accrued for all known costs still to be invoiced, however there is a possibility that some amounts may differ once actual invoices are received and processed in the first part of 2013.

2.0 - VECC 5 - 2012 CGAAP and MIFRS Update

Reference: Exhibit 2, Tab 4, Schedule 3, Attachment 2

a) Please update the 2012 CGAAP and MIFRS capital budget for year-end actuals.

Please see Attachment 1 to this interrogatory response for year-end draft actuals.

File Number:EB-2012-0107

Tab: 4
Schedule: 11

Date Filed:February 4, 2013

Attachment 1 of 1

2.0 - VECC 5 - 5 Year Capital Schedule updated for 2012

5 Year Historical, Bridge and Test Year Capital Spending

	2007 Actual	2008 Actual	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 CGAAP	Actual 2012 CGAAP (Draft)	Actual 2012 MIFRS (Draft)	2012 MIFRS	2013 MIFRS
Operations	3,385,683	3,761,889	3,951,774	3,273,266	4,151,002	3,416,746	4,735,559	4,201,516	3,692,018	4,161,300	4,809,211
Metering	521,844	130,276	711,245	560,723	157,118	465,187	170,023	124,224	109,160	149,405	172,000
Information Technology	776,909	852,765	986,600	1,302,618	3,056,156	1,445,346	3,344,537	2,853,610	2,507,566	2,938,961	1,683,314
Other	174,393	228,312	2,202	232,746	760,121	51,272	2,142,285	2,165,324	1,902,745	1,882,500	267,200
Total Spending per Exh 2, Tab 4, Sch 3, Att 1	4,858,829	4,973,242	5,651,821	5,369,353	8,124,397	5,378,551	10,392,404	9,344,674	8,211,489	9,132,166	6,931,725
Annual Variance		114,413	678,579	(282,468)	2,755,044	(2,745,846)	5,013,853	3,966,123	(1,133,185)	(1,260,239)	(2,200,441)
RECONCILE TO APPENDIX 2-B:											
Total spending per above	4,858,829	4,973,242	5,651,821	5,369,353	8,124,397	5,378,551	10,392,404	9,344,674	8,211,489	9,132,166	6,931,725
less: ending AUC	(143,036)	(557,143)	-	(981,909)	(352,445)	(472,126)	-	-	-	-	-
add: beginning AUC	32,795	143,036	-	557,143	981,909	352,445	472,126	472,126	472,126	472,126	-
less: contributed capital	(637,880)	(392,789)	(727,190)	(1,270,753)	(453,161)	(682,425)	(491,240)	(317,684)	(317,654)	(491,240)	(675,455)
less: major spare parts adjustment	-	622,174	-	(30,675)	(25,223)	1,221	(19)		(19)	(19)	-
Total per Fixed Asset Continuity Schedules in Appendix 2-B of Exh 2, Tab 3, Sch 1	4,110,708	4,788,520	4,924,631	3,643,159	8,275,477	4,577,666	10,373,271	9,499,116	8,365,942	9,113,033	6,256,270

2.0 - AMPCO 1 - Capital Spending Reconciliation

Interrogatory #1

Reference: Exhibit 2, Tab 4, Schedule 2, Page 1, Table 1

Preamble: Table 1 shows capital spending from 2012, the test year 2013 and 2014 and 2015.

a) The proposed capital spending for 2013 reconciles with Table 1 at Exhibit 2, Tab 4, Schedule 3, Page 3; the capital spending for 2012 does not. Please explain.

Table 1 from Ex. 2-4-2 page 1 is correct. See response to Energy Probe #12b.

2.0 - AMPCO 3 - Capital spending annual variance

Interrogatory #3

Reference: Exhibit 2, Tab 4, Schedule 3

a) Please provide a year-over-year variance analysis for the capital plan as shown in Table 3 Ongoing Capital Spending (Page 5) and Table 4 Non-routine Investments (Page 6) including reasons/drivers of variances.

It was discovered that the line labeled 'Operations' in Table 3 was incorrect due to an Excel formula error. Please refer to the response to 2-VECC-4. A revised Table 3 with the corrected figures is provided below.

Table 3 – Ongoing Capital Spending by Department

	2009 Board Approved	2009 Actuals	2010 Actuals	2011 Actuals	2012 GAAP	2012 MIFRS	2013 MIFRS
Operations	2,696,589	2,560,168	3,459,206	2,871,806	3,750,051	3,295,300	3,575,000
Metering	186,171	133,793	123,005	137,883	170,023	149,405	172,000
Information Technology	798,546	759,117	966,535	1,075,658	1,375,010	1,208,269	1,183,361
Other	2,202	10,160	19,428	20,151	11,380	10,000	10,000
TOTAL	3,683,508	3,463,238	4,568,174	4,105,498	5,306,464	4,662,974	4,940,361

Table 3a – Ongoing Capital Spending Variance by Department

	2009 Board Approved	2009 Board Approved vs. 2009 Actuals	2009 vs. 2010 Actuals	2010 vs. 2011 Actuals	2011 vs. 2012 GAAP	2012 GAAP vs. 2012 MIFRS	2013 MIFRS
Operations	2,696,589	(136,421)	899,038	(587,400)	878,245	(454,751)	279,700
Metering	186,171	(52,378)	(10,788)	(14,878)	32,140	(20,618)	22,595
Information Technology	798,546	(39,429)	207,418	109,123	299,352	(166,741)	(24,908)
Other	2,202	7,958	(9,268)	723	(8,771)	(1,380)	0
TOTAL	3,683,508	(220,270)	1,104,936	(462,676)	1,200,966	(643,490)	277,387

Set out below in Table 3b is the listing of Project ID Numbers and their respective annual variance amounts which drive the “Ongoing” annual variances in Table 3a. Detailed information of the projects and the historical costs can be found in Ex. 2-4-3, Attachment 3.

Table 3b – Ongoing Capital Spending Variance by Department by Project ID

	Project ID Number	2009 Board Approved vs. 2009 Actuals	2009 vs. 2010 Actuals	2010 vs. 2011 Actuals	2011 vs. 2012 GAAP	2012 GAAP vs. 2012 MIFRS	2013 MIFRS
Operations	UT10		609,607	(455,625)	166,861		
	UT11	(336,743)	154,735	(238,655)			300,000
	UT12	410,177	109,937	(219,852)	106,757		
	UT15				147,640		(100,000)
	UT21						
	UT24	(103,987)	(171,646)				
	UT26	115,103	127,706				
	UT28						
	UT31	(158,981)			145,939		
	Other Misc.	(61,990)	68,699	326,732	311,048	(454,751)	79,700
Metering	Other	52,378)	10,788)	(14,878)	32,140	(20,618)	22,595
Information Technology	IT3				112,263		
	IT5		215,908				(136,084)
	IT8				96,820		
	Other Misc.	(39,429)	(8,490)	109,123	90,269	(166,741)	111,176
Other	Other	7,958	(9,268)	723	(8,771)	(1,380)	0
TOTAL	3,683,508	220,270	1,104,936	(462,676)	1,200,966	(643,490)	277,387

Table 4a – Non-routine Investments Variance by Department

	2009 Board Approved	2009 Board Approved vs. 2009 Actuals	2009 vs. 2010 Actuals	2010 vs. 2011 Actuals	2011 vs. 2012 GAAP	2012 GAAP vs. 2012 MIFRS	2013 MIFRS
Operations	1,255,185	(542,087)	(21,302)	(146,856)	440,568	(119,508)	368,211
Metering	525,074	(98,144)	(392,817)	293,191			
Information Technology	188,054	355,447	1,546,120	(1,719,933)	1,599,839	(238,835)	(1,230,739)
Other	-	222,586	518,107	(709,572)	2,099,784	(258,405)	(1,615,300)
TOTAL	1,968,313	(62,198)	1,650,108	(2,283,170)	3,812,887	(616,748)	(2,477,828)

Set out below in Table 4b is the listing of Project ID Numbers and their respective annual variance amounts which drive the “Non-routine” annual variances in Table 4a. Detailed information of the projects and the historical costs can be found in Ex. 2-4-3, Attachment 3.

Table 4b – Non-routine Investments Variance by Department by Project ID

	Project ID Number	2009 Board Approved vs. 2009 Actuals	2009 vs. 2010 Actuals	2010 vs. 2011 Actuals	2011 vs. 2012 GAAP	2012 GAAP vs. 2012 MIFRS	2013 MIFRS
Operations	UT4	(101,494)			115,384		
	UT5			(95,356)	117,185		
	UT17				177,493		(140,000)
	UT34						150,000
	UT35						165,000
	UT36						100,000
	UT39						223,211
	Other Misc	(440,593)	(21,302)	(51,500)	30,506	(119,508)	(130,000)
Metering	M7	(98,144)	(392,817)	(30,967)	(3,146)	-	-
	M8			324,158	(324,158)		
Information Technology	IT7				143,316		(160,335)
	IT9				149,529		
	IT10			162,645			
	IT13				649,877		(571,069)
	IT16	430,762	1,651,874	(2,082,636)			
	IT17			136,315	(136,315)		
	IT18		(112,660)				
	IT21				618,943		(543,886)
	Other Misc	(75,315)	6,906	63,743	174,489	(238,835)	(20,375)
Other	O1	222,586	289,472	(512,058)	2,128,629		(1,870,500)
	O6						
	O7		224,746	(224,746)			257,200
			3,889	30,232	(28,845)	(258,405)	
							(2,000)
TOTAL	1,968,313	(62,198)	1,650,108	(2,283,170)	3,812,887	(616,748)	(2,477,828)

2.0-Staff-8 - Capital Project - vehicle replacement

Ref: Exh 2-4-3 Project UT10

Bluewater Power describes the capital expenditures for "vehicle replacement – lines" in document UT10.

a) For 2012, Bluewater Power proposes to replace 3 vans. The model vintage of the replaced vans range from 1999 to 2006. What are the criteria that Bluewater Power applies for replacement of vans?

Age of a vehicle is only one criteria considered. We perform a cost benefit analysis that considers the level of maintenance costs, significant forecast repairs, overall condition and mileage of vehicles. We can advise, for example, that the 2006 van replaced in 2012 had been driven 165,000 km and the engine needed to be replaced thus justifying replacement of the vehicle rather than incurring significant repair cost on a vehicle approaching a more normal retirement date.

b) The summary indicates that a 1998 GMC Truck will be replaced with a 2007 Dodge Pickup at a cost of $33,000. Please confirm whether the 1998 GMC truck will be replaced with a used truck or a new truck and confirm the cost.

In 2012, a 1998 GMC Truck was scrapped and replaced by a 2007 Dodge. The 2007 Dodge was transferred from an executive (VP, Strategic Planning) to be used by the fleet mechanic. Our pre-filed evidence should have stated that while the 2007 Dodge was replacing the 1998 GMC, the $33,000 was actually to purchase a new 2012 Ford Explorer for use by the VP, Strategic Planning.

c) In 2012 a pickup truck will be purchased for the Vice President of Operations at a cost of $33,000. Please summarize the rationale for this purchase

The VP, Operations position was vacant for approximately 8 months and the predecessor utilized a smaller vehicle (Ford Focus) which was his personal preference. That vehicle has become a floater vehicle for our fleet. The VP, Operations is on-call at all times and a vehicle has always been provided for the use of this key role to facilitate responses to calls. This vehicle also forms part of the compensation package for this senior executive role.

2.0 - VECC 8 - Transportation Equipment Spending in 2009

Reference: Exhibit 2, Tab 4, Schedule 3, Attachment 4;
Appendix 2-A

a) Please explain the reasons for the lower than average spending on Transportation Equipment (account 1930) in 2009.

Later in 2009, a $300,000 digger-derrick truck and a $40,000 ¾ ton pick-up truck were ordered in conjunction with the approved 2009 budget. However, due to lead times, these trucks were not delivered, and therefore not paid for, until 2010. Thus, 2009 is abnormally low and 2010 is abnormally high with respect to Account 1930.

2.0-Staff-9-Capital Project - Emergency Fund

Ref: Exh 2-4-3 Project UT18

Bluewater Power has established an Emergency System Improvement Fund to complete repairs that are unforeseen, but require attention in the budget year. The evidence states that the fund allows Bluewater Power senior management to provide more conservative and accurate capital budget figures.

a) Please provide a full justification explaining why the fund was created including how contingencies were dealt with before the fund was created, and why Bluewater Power management has adopted this approach.

The Emergency System Improvement Fund has existed in various forms since the year 2005. Its primary purpose when introduced was to account for unforeseen capital projects that required immediate attention, but that arise after the capital budget has been set for that particular year. The year 2004 was an unusual year with several unforeseen capital projects. It was felt following that year that the delays associated with waiting on Board approval were not acceptable in certain circumstances. Accordingly, a more flexible capital project was required. For the year 2005, the Board of Directors agreed to use this budget item to effectively delegate a portion of capital budget approval to the CEO within parameters and within an annual cap. That has continued and the history and the parameters around spending are included in the description of UT18 found in the Asset Management Plan.

Prior to the implementation of the Emergency System Improvement Fund, contingencies were dealt with by over-spending capital budgets or by seeking Board Approval above and beyond the capital budget for that calendar year. Although there continued to be capital spending beyond the capital budget in the years 2005 and 2006, the results for 2007 to 2012 demonstrate that the Emergency System Improvement Fund was able to capture unbudgeted spending such that the average spending outside of approved capital budgets was reduced to approximately $10,000 per year in total.

b) Please provide copies of any assessments that support the position that the fund allows Bluewater Power senior management to provide more conservative and accurate capital budget figures.

We have not previously created an assessment to support the position that the fund allows Bluewater Power to provide more conservative and accurate capital budgets. As stated above, the practice has been in place since the year 2005.

The theory behind the budget item is clear and puts the discretion in the hands of the CEO. Moreover, inherent in the approval of the Emergency System Improvement Fund each year, is a review by our Board of Directors of previous spending from this project budget. Accordingly, it is closely monitored to ensure the expenditures meet the intended purpose of the fund which is to respond to unanticipated circumstances.

2.0-Staff-10 - Capital Project SAP

<u>Ref: Exh 2-4-3 Project UT39</u>

Bluewater plans to spend $223,211 “on implementing upgrade improvements to SAP and connected Operations software to improve workflow efficiencies in Maintenance, Asset Management, Dispatch and Supply Chain.” The evidence also states that the scope of the project will be better defined in the second half of 2012.

a) Please provide copies of the documentation that better scopes this capital project. In the event that the documentation is not available, please summarize the scope of the project.

This project requires a third party consulting firm to help us at Bluewater Power to understand the gaps in the planning/scheduling processes in the Operations department. Beginning in December of 2012 we requested quotes to provide this consulting service from 3 companies. FMR – Focus Management Group, Value Tech Solutions and Leading Edge Group.

When the successful consulting firm is awarded, a multi-week process will begin. This process includes a 3-4 week assessment phase, a 1-2 week recommendation phase and an 8-12 week implementation phase. During the implementation phase we would need to address the required upgrade improvements required to SAP to allow Bluewater Power to fully implement the new streamlined process. The implementation phase would reasonably not take place until third quarter 2013.

b) What specific measures will Bluewater Power use to measure the improvements in workflow efficiencies?

The implementation phase above mentioned process will focus heavily on ensuring that all changes to the planning/scheduling/work execution implementation process are sustainable. It will require staff job description changes as well to ensure sustainability.

2.0-Staff-11 - Capital Project - Smart Grid

Ref: Exh 2-4-3 Project IT8

Ref: Exh 2-7-1

Bluewater Power is developing a strategy around Operations Technology Integration. The description states that "It is critical that Bluewater Power be positioned to make the most efficient use of the smart meter grid as it advances to better serve customers." The expenditures in 2012 ($85,079) and 2013 ($116,035) are for research and third party sources to develop strategy. Is the research described in capital project IT8 incremental to the $35,000 of annual smart grid research that Bluewater Power has identified in Exh 2-7-1?

The IT8 project is separate from the Smart Grid effort, which has been described as $35,000 directed toward annual research that is of benefit to Bluewater Power and the industry in general. The smart grid research identified in Ex. 2-7-1 relates more specifically to the Green Energy Act and the impact of generation technologies on utilities in Ontario.

The capital project described in IT8 for 2013 will include both strategic development and implementation of changes to technology primarily related to Smart Meters. The focus of this effort relates to optimizing business processes and extending current technology to better derive value from the Smart Meter assets.

2.0-Staff-12 - Capital Project - MyAccount

Ref: Exh 2-4-3 Project IT10

Ref: Exh 4-2-5

Bluewater Power has introduced MyAccount which offers customers various self-serve options. The services will be expanded to introduce options including e-billing. Bluewater Power forecasts expenditures of $206,312 in 2012 and $148,709 in 2013. Bluewater Power also plans to move towards monthly billing for all customers.

a) When will the e-billing option be available to Bluewater Power customers?

Bluewater Power is planning to have e-billing available for customers by the end of Q1, 2013.

b) As noted in ~~Exh 4-2-5~~ (4/3/1 page 20 of 21), $117,000 of additional postage related to monthly billing is forecast for 2013. Does the forecast for additional postage anticipate the impacts of e-billing?

No, the forecast amount for additional postage was determined solely on the number of additional bills required to provide monthly billing. We assumed that the operating cost of e-billing, whether through Canada Post or otherwise, were equivalent to the cost of postage. In any event, we can advise that we have forecasted an uptake for e-billing of approximately 10% of our customer base in 2013.

2.0-Staff-13 - Capital Project-IFRS Upgrade

The IT21 project, IFRS System Upgrade, was initiated in 2009 as part of a series of SAP upgrade projects. The forecast cost in 2012 is $543,886.

a) Please describe the scope of work for the IFRS System Upgrade project.

The scope of work for the IFRS System Upgrade project was created by Bluewater Power and Deloitte Consulting and is found in Attachment 1 to this interrogatory.

b) Bluewater Power indicates that this project was initiated in 2009. Are all of the costs for project IT21 incremental to the SAP upgrade project completed in 2010 at a cost of $2.5M?

Project IT21 was a stand-alone project initiated prior to the SAP upgrade project. The subject of the IFRS upgrade is separate from and therefore incremental to the $2.5M SAP upgrade project that followed.

Attachment 1 of 1

2.0 - Staff 13 - IFRS Attachment

Deloitte.

Bluewater Power
SAP IFRS Project

Blueprint

November, 2009

Document Sign-off

Role	Name	Signature	Date
Project Sponsor – Bluewater Power	Keith Broad		
Comments			
Deloitte Engagement Partner	Marcus Hill		
Comments			
Controller – Bluewater Power	Mark Hutson		
Comments			
Project Manager – Bluewater Power	Martine Vanderheide		
Comments			
Technical/Functional Lead - Bluewater Power	Tom Janes		
Comments			
Project Manager - Deloitte	Stuart Williams		
Comments			

Change Control

Version	Date	Summary of Changes
0.1	Nov 6, 2009	Draft
1.0	Nov 18, 2009	From Blueprint review session Executive summary updated Process & Package: Correction of Diagrams, addition of asset retirement diagram Capital v Expense – remove labor rate accounts, specify new settlement accounts for capitalization Security – Only to change FI related roles, Training – correction of number of key users from 10 to 8

Table of contents

Executive Summary

Goal

The scope of the project is to implement - within Bluewater Power SAP landscape - a solution that meets the IFRS compliant reporting requirements. This solution will use the new parallel ledgers functionality, and Business Objects (BO).

This Blueprint document identifies the requirements and changes required in the SAP system for Bluewater Power.

Process & Package

Process and package covers the SAP functional modules of ERP 6.0.

Listed below is a summary of the IFRS/CGAAP gap requirements from the workshops along with the solution that will be implemented within SAP. Within the section, each requirement is described in detail along with the SAP design that will fulfill the requirement.

Requirements from IFRS/CGAAP Gaps	SAP Solution
Dual Financial Reporting for IFRS and OEB. Therefore, 2 sets of books/ledger are required.	Two Ledgers, one for IFRS and one for CGAAP/OEB
IFRS requires that Income statements should be broken down by identifiable operating lines of business.	Use of Profit Center to identify operating line of business
Based on IFRS requirements, the first IFRS Opening Balances will be presented at NBV (NBV as its" Deemed Cost")	Classic GL YTD 2009 data will be migrated to both IFRS and CGAAP/OEB ledgers in order have the same beginning balances.
Regulatory Assets - there are differences in presentation of Regulatory assets between IFRS and OEB/CGAAP.	A reclassification journal will be created to adjust GL accounts which represent Regulatory Assets to IFRS.
Difference in Asset Lives for Deprecation between CGAAP/OEB and IFRS	Additional depreciation areas will be created to calculate and post different depreciation expense values
Component Accounting - IFRS requires more details on assets' records in PP&E.	New asset classes will be created. Transfer of assets from old to new classes.
Borrowing Costs must be capitalized under IFRS but not under OEB/CGAAP.	Manual financial posting to only one ledger (IFRS)
Asset impairments need to be reported differently in IFRS than in OEB/ CGAAP. There has never been any impairment yet.	Unique asset retirement transaction type for impairment to IFRS ledger only, will be defined. Will be reported on the SAP Asset continuity schedule.
Two asset classes (computer software and land rights) should be classified as intangible assets under IFRS, and not as PP&E as required by CGAAP	Will be controlled by Financial Statement versions that will be configured for specific ledger
Provision, Contingent Liabilities and Assets - Measurement of the provision in IFRS differs than those in CGAAP.	Financial posting to only one ledger
Employee Benefits- IFRS may require additional pension asset/liability in a contractual agreement to fund/share any surplus/deficit.	Financial posting to only one ledger
Major Spare Parts- some variation in treatment of cyclical and insurance spare parts between IFRS and OEB/CGAAP.	Financial posting to only one ledger
Customer Contributions - IFRS: If the service is a connection to	Will be controlled by Financial Statement versions that will be

Requirements from IFRS/CGAAP Gaps	SAP Solution
network only, revenue will be recognized at the connection date. Otherwise, revenue will be recognized over the useful life of the asset.	configured for a specific ledger.
Decommissioning- Differences in determining the decommissioning costs between IFRS and CGAAP.	New transaction type will be created for the capitalization of the decommissioning cost . Will be reported on the SAP Asset continuity schedule.
Capital v Expense-Certain costs cannot be capitalized under IFRS, such as O/H On labor, O/H on trucking etc.	SAP Costing Sheets on the PM work orders and Internal orders to calculate and post overhead, along with a Capitalization Key for settlement to separate the costs that cannot be capitalized.

Reporting

The financial statements (Balance Sheet and Income Statement) will now be executed from a different transaction code but are still structured using a financial statement version that is updated the using the existing process.

Two existing custom queries will need to be adjusted to be able to read the financial data from the appropriate ledger. This will require an ABAP developer.

Two new reports, the IFRS Change in Equity and SAP Ledger Reconciliation Report will be developed in the Business Objects environment.

Technology

A parallel landscape will be created so that all configuration and testing of the New GL will be kept separate from the existing Development and QA environment so that the Production environment can still be supported.

Upon the completion of the project, the existing Development and QA environment will be decommissioned as the new Development and QA environments will become the new SAP landscape for Bluewater Power.

The SAP Migration scenario proposed will be Scenario 2. This will be confirmed by SAP Migration Services.

Security and Controls

There are two main scenarios that will be encountered during the implementation of the functions to support IFRS.

- New transaction codes from the implementation of the New GL functions and Profit Center Accounting.
- Existing transactions codes that have been superseded by new transaction codes.

Transaction codes in both of these scenarios will be incorporated into existing security roles.

Training Approach

The Bluewater Power end-user training approach focuses on the following key objectives:

- Provide hands-on, scenario-based training to end-users in order to proficiently execute new or revised transactions and understand the rationale/context for these
- Involve end-users into User Acceptance Testing phase in order to increase their confidence and familiarity of the new transactions
- Ensure appropriateness and cost effectiveness of the training by concentrating on critical and essential training activities

Most of Bluewater Power end-users are familiar with the SAP system and many of them are power users. The conversion from CGAAP to IFRS will require specific training about the procedure and transaction changes required to be IFRS compliant.

Given the relatively small size of the impacted end-users (8) and their existing knowledge of SAP, training will be delivered to key users in the forms of:

- Classroom Training - 3-day traditional classroom training to provide hands-on business process and procedure exercises
- Key User Involvement in UAT – Participation of selected individuals in User Acceptance Testing (UAT) and Integration testing, including introduction to and instruction in the testing process and their roles in the process.

Deloitte consultants will deliver a 3-day class-room training session in the Final Preparation phase. The training sessions could be spread out over the one-week period to accommodate schedules. The project team will work closely with the business and schedule the training to allow for individual and business flexibility. In that week, all available end-users will attend the classroom training sessions, building their hands-on experience with the system.

If necessary, an additional discussion time (up to 2 days) could be set up in a week, ideally 3-6 weeks prior to Go-Live. End-users who miss the first week training or need a refresh discussion can have some questions-and-answers discussions with project team/consultants.

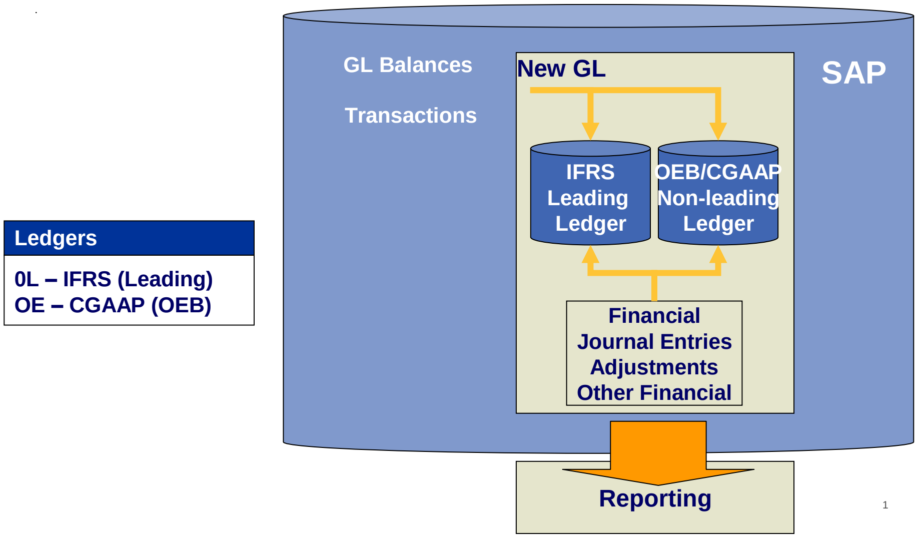
Process & Package

Dual Reporting

Requirement

The conversion from CGAAP to IFRS will have a significant impact on Bluewater Power, since it involves significant accounting policy changes that will require 2 sets of books/ledgers as follows: One book/ledger for IFRS and one for CGAAP/OEB. In SAP ERP 6.0 New General Ledger Accounting, several ledgers can be used simultaneously.

Bluewater Power Corporation (BWP)
Parallel Valuation in New GL
Solution Overview



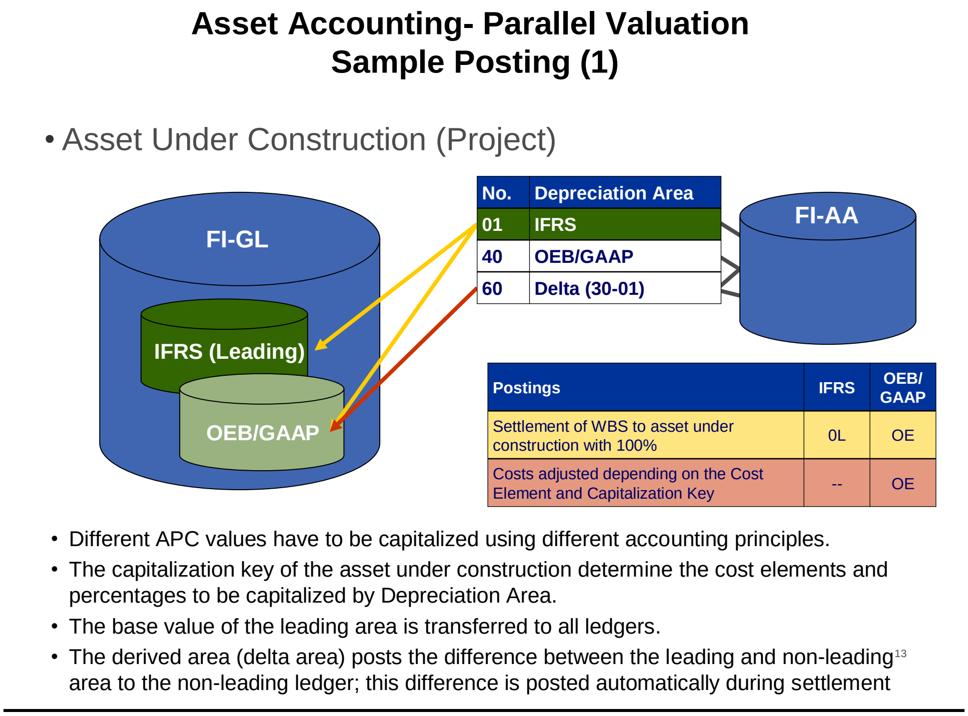
Design

General: To meet the need of Bluewater Power to report its financial statements in IFRS and in CGAAP/OEB, the parallel ledgers in New General Ledger Accounting will be activated. One ledger is for IFRS reporting and the other is for CGAAP/OEB reporting. The leading ledger 0L is the IFRS Ledger, since it will represent the accounting standards that will be the most commonly used, and non-leading ledger OE is the CGAAP/OEB. As both ledgers will operate on the same fiscal year, comparative analysis of the 2 ledgers will be possible.

Data concept: All financial documents without valuation differences are posted to all ledgers. Differences between leading and non leading ledger will result from valuation postings either generated through the flow of financial transaction such as capitalization of assets cost and depreciation, or through manual postings to a specific ledger such as provisions.

Asset Accounting (FI-AA) Integration with New GL parallel ledgers: In the current configuration of the Asset Accounting module, only one depreciation area (01) is used. Under the new design, two more depreciation areas will be added to all existing and future asset records as the depreciation area will need to be assigned to the specific SAP ledger.
Depreciation area 01 is always posted to the leading ledger 0L. Depreciation areas 40 and Depreciation area 60 (Delta 40-01) will be assigned to non-leading ledger OE.

Acquisition and Production Cost (APC) entries are posted, at first, to all ledgers (0L & OE) based on depreciation area 01 values, in real time. During period end processing, the delta values between depreciation area 01 and depreciation area 40 (depreciation area 60) will be posted to ledger OE. All depreciation areas must use the same GL accounts. See the below example:



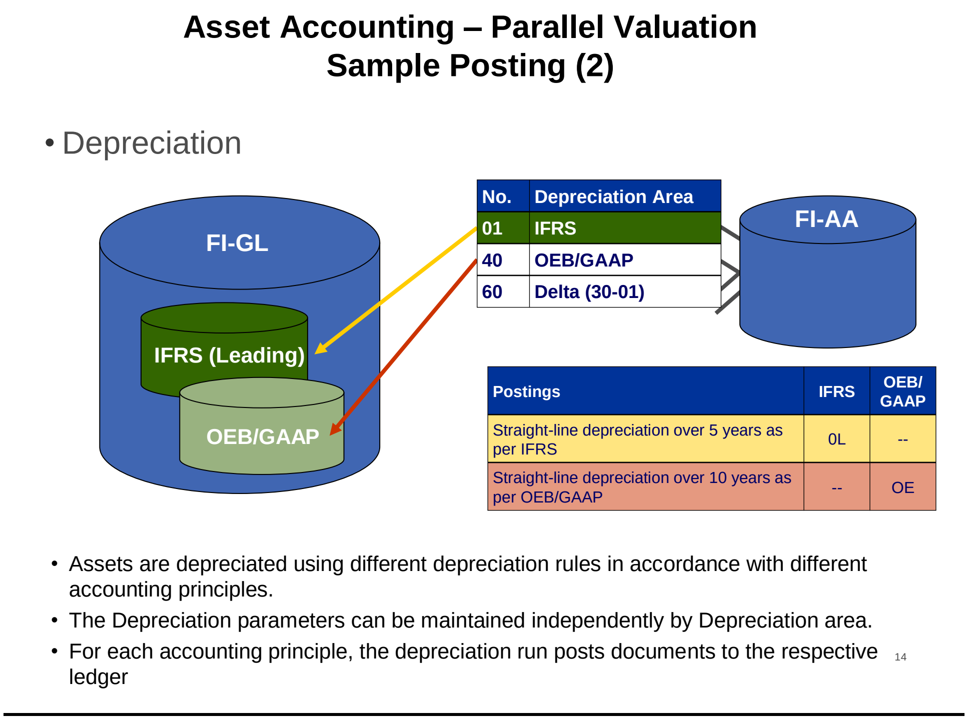
Asset Accounting- Parallel Valuation
Sample Posting (1)

- Asset Under Construction (Project)

No.	Depreciation Area
01	IFRS
40	OEB/GAAP
60	Delta (30-01)

Postings	IFRS	OEB/ GAAP
Settlement of WBS to asset under construction with 100%	0L	OE
Costs adjusted depending on the Cost Element and Capitalization Key	--	OE

- Different APC values have to be capitalized using different accounting principles.
- The capitalization key of the asset under construction determine the cost elements and percentages to be capitalized by Depreciation Area.
- The base value of the leading area is transferred to all ledgers.
- The derived area (delta area) posts the difference between the leading and non-leading area to the non-leading ledger; this difference is posted automatically during settlement



Asset Accounting – Parallel Valuation
Sample Posting (2)

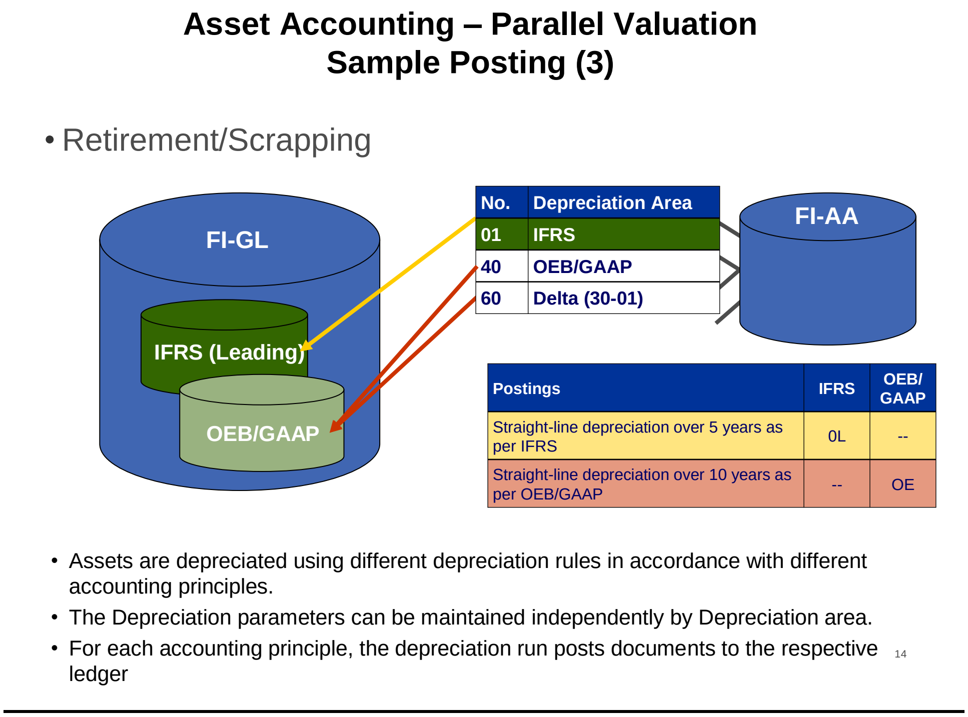
- Depreciation

No.	Depreciation Area
01	IFRS
40	OEB/GAAP
60	Delta (30-01)

Postings	IFRS	OEB/ GAAP
Straight-line depreciation over 5 years as per IFRS	0L	--
Straight-line depreciation over 10 years as per OEB/GAAP	--	OE

- Assets are depreciated using different depreciation rules in accordance with different accounting principles.
- The Depreciation parameters can be maintained independently by Depreciation area.
- For each accounting principle, the depreciation run posts documents to the respective ledger

When performing a depreciation run, GL-AA reconciliation accounts will be updated in 0L and in OE. Since depreciation areas are different, different depreciation values will be posted to the same GL account, but to different ledgers.



Asset Accounting – Parallel Valuation
Sample Posting (3)

- Retirement/Scrapping

No.	Depreciation Area
01	IFRS
40	OEB/GAAP
60	Delta (30-01)

Postings	IFRS	OEB/ GAAP
Straight-line depreciation over 5 years as per IFRS	0L	--
Straight-line depreciation over 10 years as per OEB/GAAP	--	OE

- Assets are depreciated using different depreciation rules in accordance with different accounting principles.
- The Depreciation parameters can be maintained independently by Depreciation area.
- For each accounting principle, the depreciation run posts documents to the respective ledger

Controlling (CO) Integration with New GL parallel ledgers: Only the leading ledger 0L (IFRS) is integrated with CO. Only values from the leading ledger are sent to CO. Postings that are made exclusively to the non-leading ledger (using the transaction codes FB01L and/or FB50L) are not transferred to Controlling with the standard settings.

6.

Other valuations: in order to post different valuations to specific ledgers using a manual journal entry (Transaction codes FB01L, FB50L), the user will manually select the ledger to which the entry should post to in the ledger group field. If the ledger group field is blank, the entry will post to all ledgers. Examples of the types of entries that would require ledger specific postings would be unbilled revenues and borrowing costs.

Line of Business

Requirement

IFRS 8 specifies a company should report financial and descriptive information about its operating line of businesses (segments). Bluewater Power needs to breakdown the Profit & Loss statements – for every company in the group- by line of business/segment only. In SAP ERP 6.0 New General Ledger Accounting, a profit center will be used as line of business for Profit & Loss reporting.

Design

Prior to January 1st, 2010, the profit center accounting in the classic GL will be activated. The purpose of this approach is so that all financial postings from January 1st onwards will be assigned to a profit center. When the New GL Migration (see the Technology section for a full explanation on the migration) is performed in Production, all the financial postings will be migrated along with their assigned profit center to enable full line of business reporting for both IFRS and CGAAP/OEB for the 2010 fiscal year.

Profit center will be defined as line of business as follows:

Bluewater Power Companies	Profit Center ID	Profit Center Description
Bluewater Power Distribution Corp. (BPDC)	2301	Poles/Wires
	2302	Water Billing
	2303	OPA Programs
	2304	Billables
Bluewater Power Services Corp.(BPSC)	5001	Civil Services
	5002	Street Light / Traffic Light Services
	5003	Water Metering Services
	5004	Lines Services
	5005	Admin & Management

There is no requirement from Bluewater Power to have the Balance Sheet be broken down by line of business. In order to have full income statement breakdown by profit center, the appropriate profit center number will be assigned to each cost center master data, since cost center is defined as an assignment for each income statement GL account. By a derivation rule, each P&L GL account will be broken down by profit center too.

Company	Cost center ID	Description	Profit Center ID
Bluewater Power Distribution Corp. (BPDC)	2101	Board of Directors	2301
	2102	Executive	2301
	2103	Legal	2301
	2201	Finance	2301
	2202	Purchasing	2301
	2203	Human Resources	2301
	2204	Information Tech	2301
	2205	Regulatory	2301
	2206	Environment & Safety	2301
	2207	Insurance	2301
	2210	Employee Benefits	2301
	2301	Design Services	2301
	2302	Control Room	2301
	2303	Lines	2301
	2304	Property Maintenance	2301
	2305	Civil Services	2301
	2306	Fleet	2301
	2307	GIS	2301
	2401	Call Center	2301
	2402	Billing/Market Serv	2301
	2403	Metering	2301
	2404	Energy Services	2301
	2405	Business Development	2301

Company	Cost center ID	Description	Profit Center ID
	2406	Admin Services	2301
	2407	Support Services	2301
	2408	C&DM	2301
	2409	OPA CDM Programs	2303
	2501	Distribution Rev	2301
	2502	Distribution	2301
	2503	Billable Costs	2304
	2504	Water Services Rev	2302
Bluewater Power Services Corp.(BPSC)	5001	Civil Services	5001
	5002	Street light/traffic light Services	5002
	5003	Water Meter Services	5003
	5004	Lines Services	5004
	5005	Admin & Management	5005

To migrate the Classic Profit Center Accounting (in CO) to Profit Center Accounting in the New GL, the Profit Center Scenario will be assigned to both ledgers and activated in the New GL configuration.

To ensure that the profit center entity appears in the FI documents, profit center will be defined as an optional entry in the following FI configuration menus: The first in “Maintain Field Status Variant” >> Field status group >> additional account assignments. The second in “Maintain Posting Key >> “Maintain Field Status Group” (Transaction code: OB41).

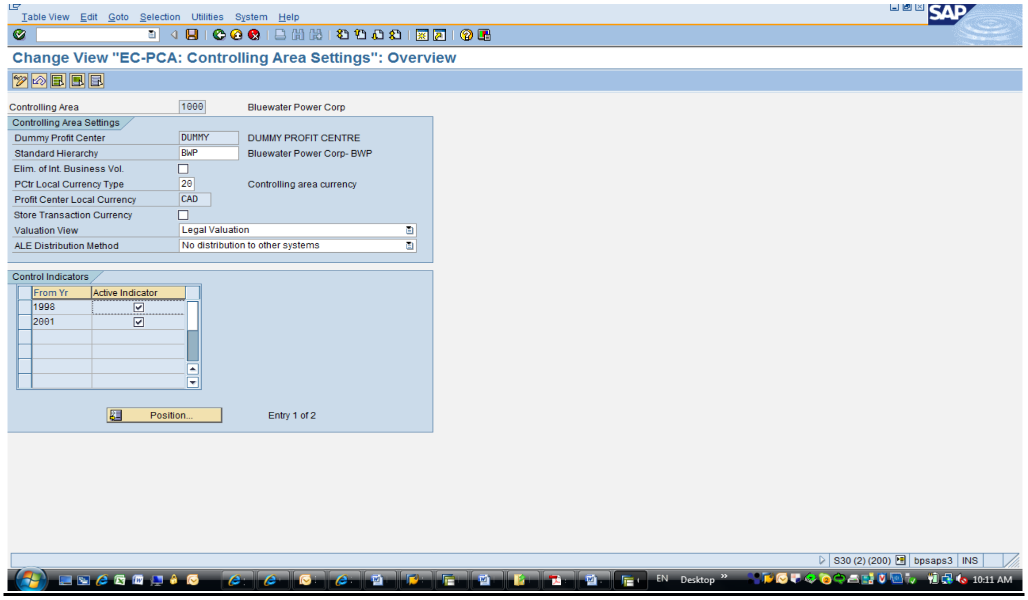
In order for the New GL to have the Profit Center account assignment from FI-CA (Contract Accounts Receivable and Payable), FI-CA document should include the profit center account assignment. Configuration will be made as follows:

- IMG Configuration menu >> Contract Accounts Receivable and Payable >> Basic Functions >> Contract Accounts >> Postings and Documents >> Document>>Define Account Assignment for Automatic Postings >> Define CO Account Assignment Key >> Definition of Profit Center based on the existing Cost Center for each CO account assignment.
- IMG configuration menu >> Contract Accounts Receivable and Payable >> Basic Functions >> Contract Accounts Postings and Documents >> General Ledger Posting Totals >> Define line layout for posting totals (T.C. FQKPS) add field PRCTR (Profit Center) to table DFKKSUM (Posting totals from FI-CA) >>Select Field for Search Function (add PRCTR) >>Select Field for Sort Function (add PRCTR)

In Controlling (CO), users will have to input the appropriate Cost Center and Profit Center values in the Cost Center and Profit Center fields in any open and new Internal Order master records. With regard to the open internal orders, this process should be completed before migration date. With regards to new internal orders, it should be done in an ongoing basis.

Configuration and Activation of Classic Profit Center Accounting (PCA)

1. Set controlling area in PCA - Transaction code OKKS (if it has not been created)
2. Insert the names of DUMMY profit center and the profit center hierarchy-Transaction code 0KE5



Change View "EC-PCA: Controlling Area Settings": Overview

Controlling Area 1000 Bluewater Power Corp

Controlling Area Settings

Dummy Profit Center	DUMMY	DUMMY PROFIT CENTRE
Standard Hierarchy	BWP	Bluewater Power Corp- BWP
Elim. of Int. Business Vol.	☐	
PCtr Local Currency Type	20	Controlling area currency
Profit Center Local Currency	CAD	
Store Transaction Currency	☐	
Valuation View	Legal Valuation	
ALE Distribution Method	No distribution to other systems	

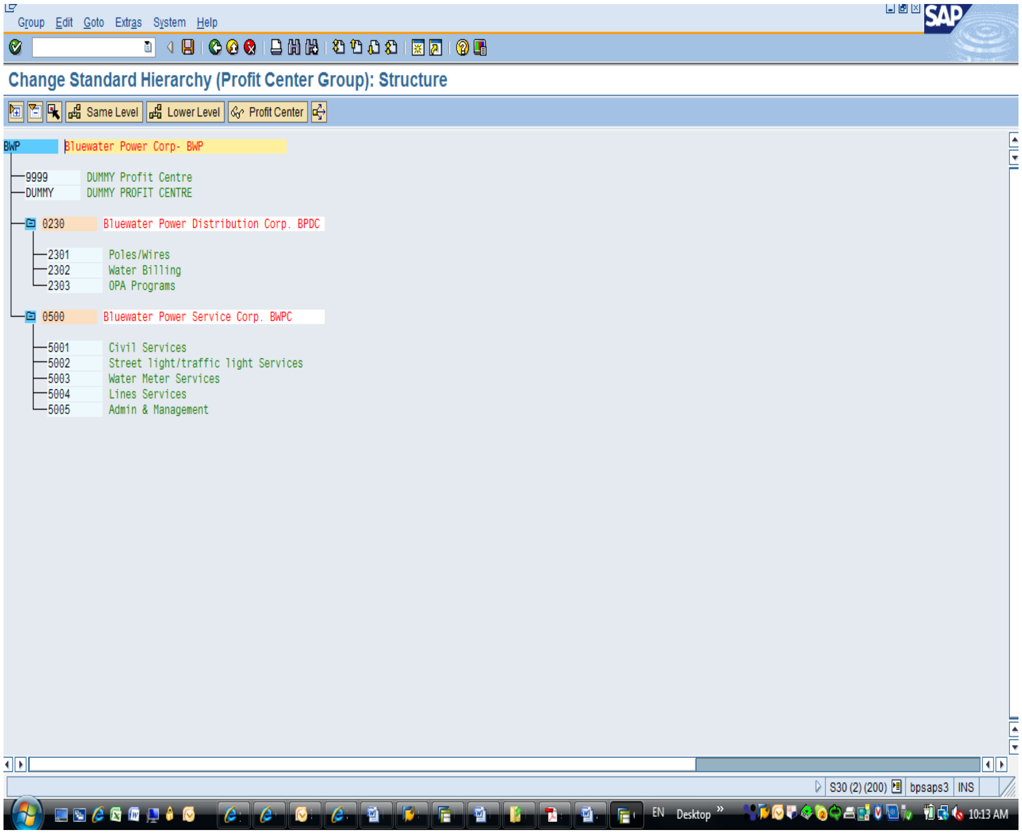
Control Indicators

From Yr	Active Indicator
1998	☑
2001	☑

Entry 1 of 2

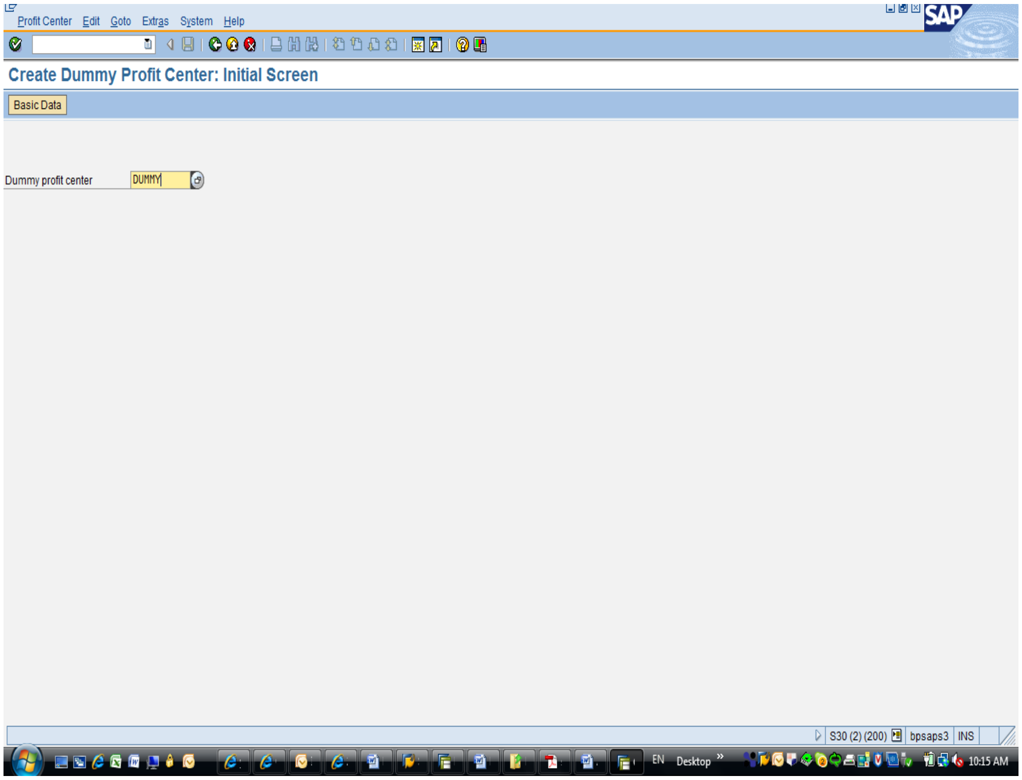
The "DUMMY" profit center is the term used for the default profit center selected when the system cannot determine the profit center by any of the configuration or master data.

3. Maintain profit center hierarchy - Transaction code KCH4



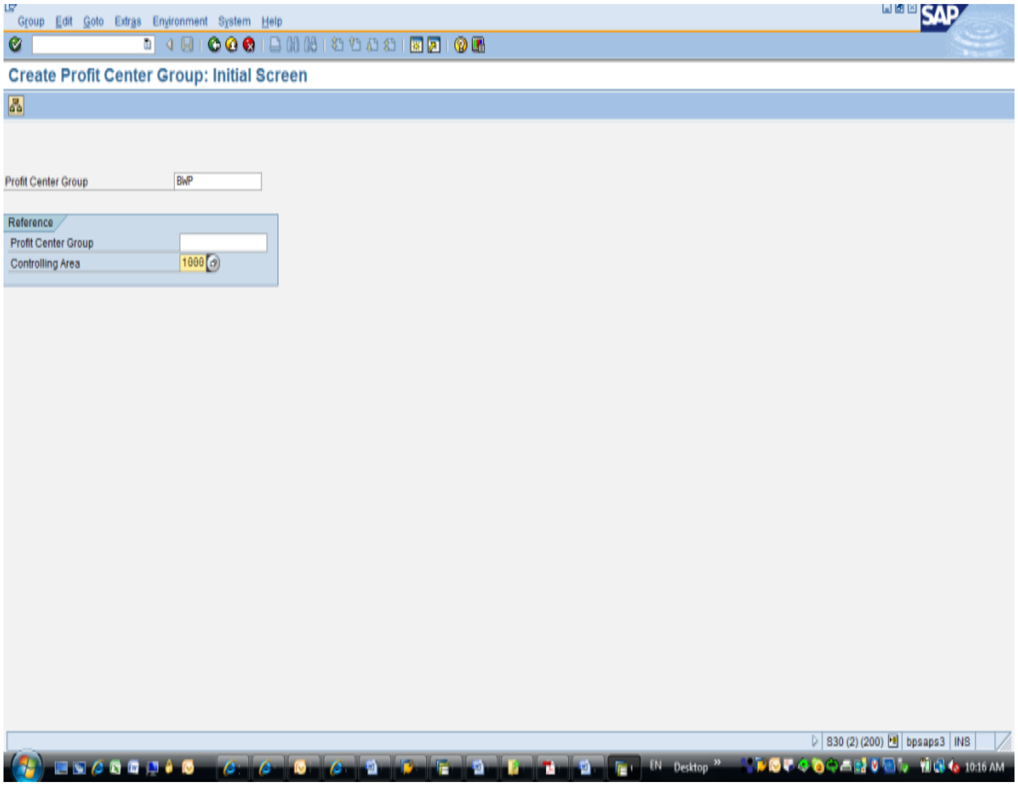
```
BWP     Bluewater Power Corp- BWP
 ├─9999      DUMMY Profit Centre
 ├─DUMMY     DUMMY PROFIT CENTRE
 ├─0230      Bluewater Power Distribution Corp. BPDC
 │  ├─2301      Poles/Wires
 │  ├─2302      Water Billing
 │  └─2303      OPA Programs
 └─0500      Bluewater Power Service Corp. BWPC
    ├─5001      Civil Services
    ├─5002      Street light/traffic light Services
    ├─5003      Water Meter Services
    ├─5004      Lines Services
    └─5005      Admin & Management
```

4 . Create DUMMY profit center - Transaction code KE59 (it must be valid in all company codes).



Dummy profit center DUMMY

5. Create profit center group - Transaction code KCH1



Create Profit Center Group: Initial Screen

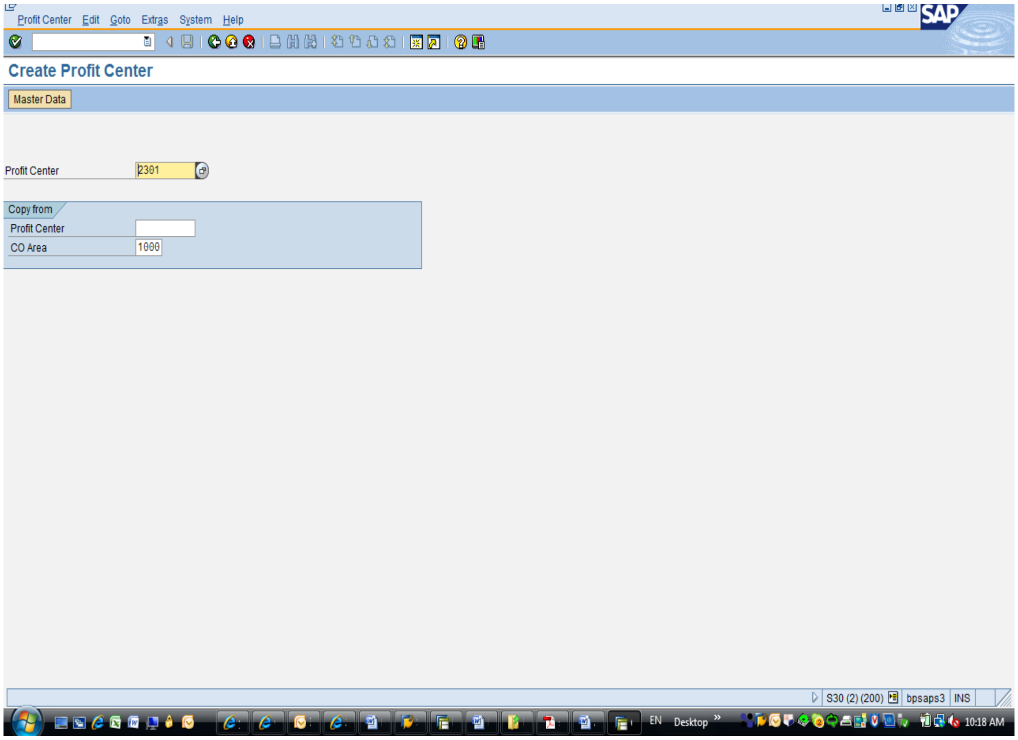
Profit Center Group BWP

Reference

Profit Center Group

Controlling Area 1000

6. Create profit centers and assign them to profit center groups - Transaction code KE51



Create Profit Center

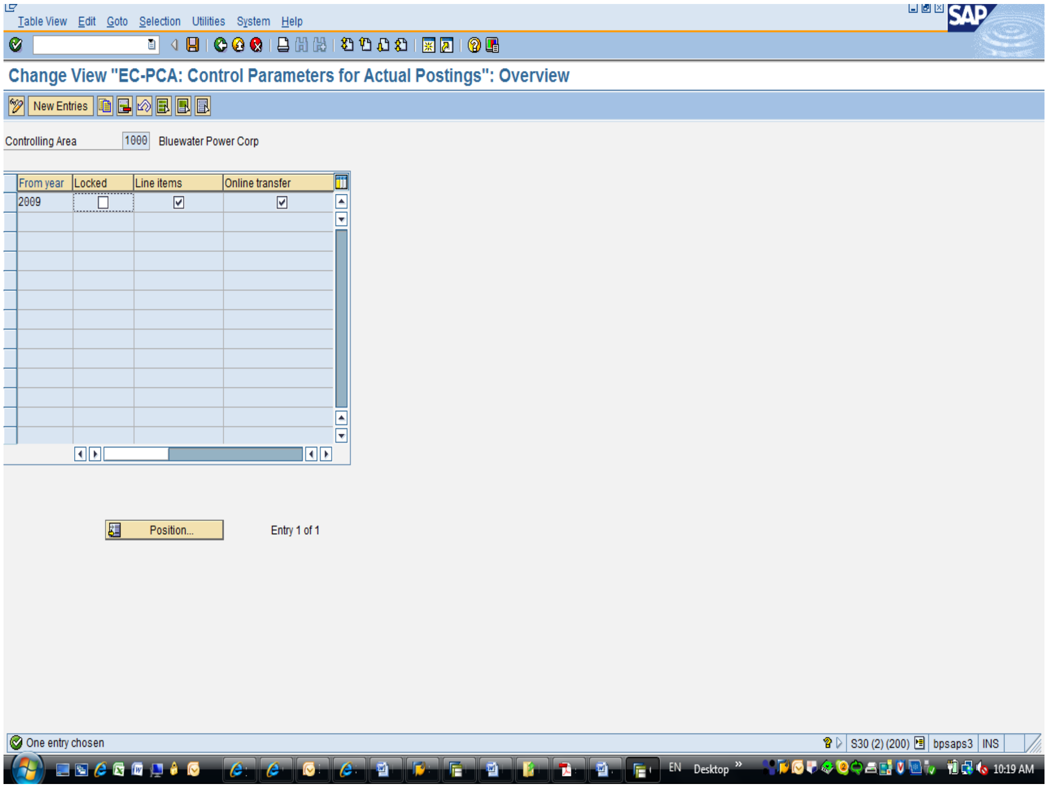
Profit Center 2301

Copy from

Profit Center

CO Area 1000

7. Maintain control parameters for actual data. Check the line item and online transfer check box for the applicable from year-Transaction Code 1KEF



Change View "EC-PCA: Control Parameters for Actual Postings": Overview

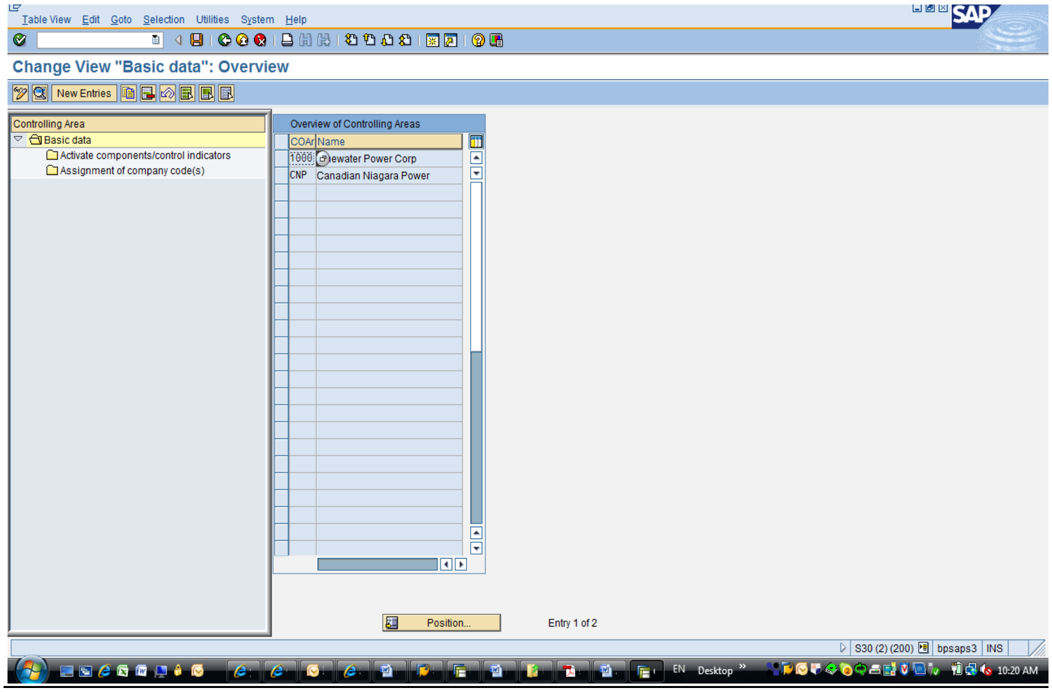
Controlling Area 1000 Bluewater Power Corp

From year	Locked	Line items	Online transfer
2009	☐	☑	☑

Entry 1 of 1

One entry chosen

8. Activate the profit center as a component in controlling area – Transaction Code OKKP



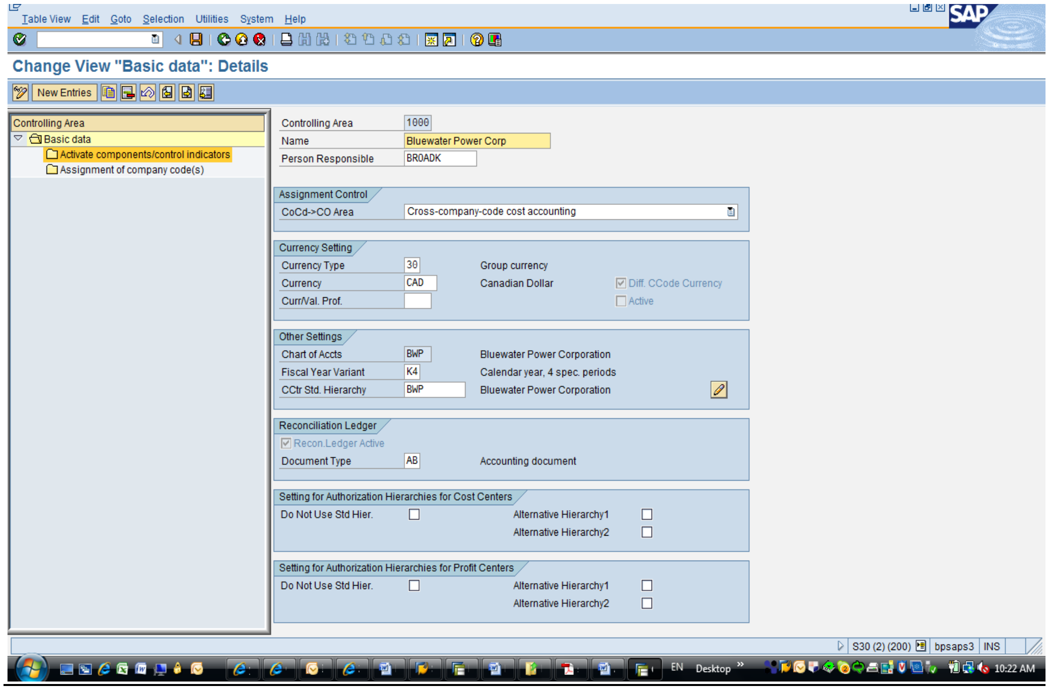
Change View "Basic data": Overview

Controlling Area
- Basic data
  - Activate components/control indicators
  - Assignment of company code(s)

Overview of Controlling Areas

COAr	Name
1000	ewater Power Corp
CNP	Canadian Niagara Power

Entry 1 of 2



Change View "Basic data": Details

Controlling Area
- Basic data
  - Activate components/control indicators
  - Assignment of company code(s)

Controlling Area: 1000
Name: Bluewater Power Corp
Person Responsible: BROADK

Assignment Control
CoCd->CO Area: Cross-company-code cost accounting

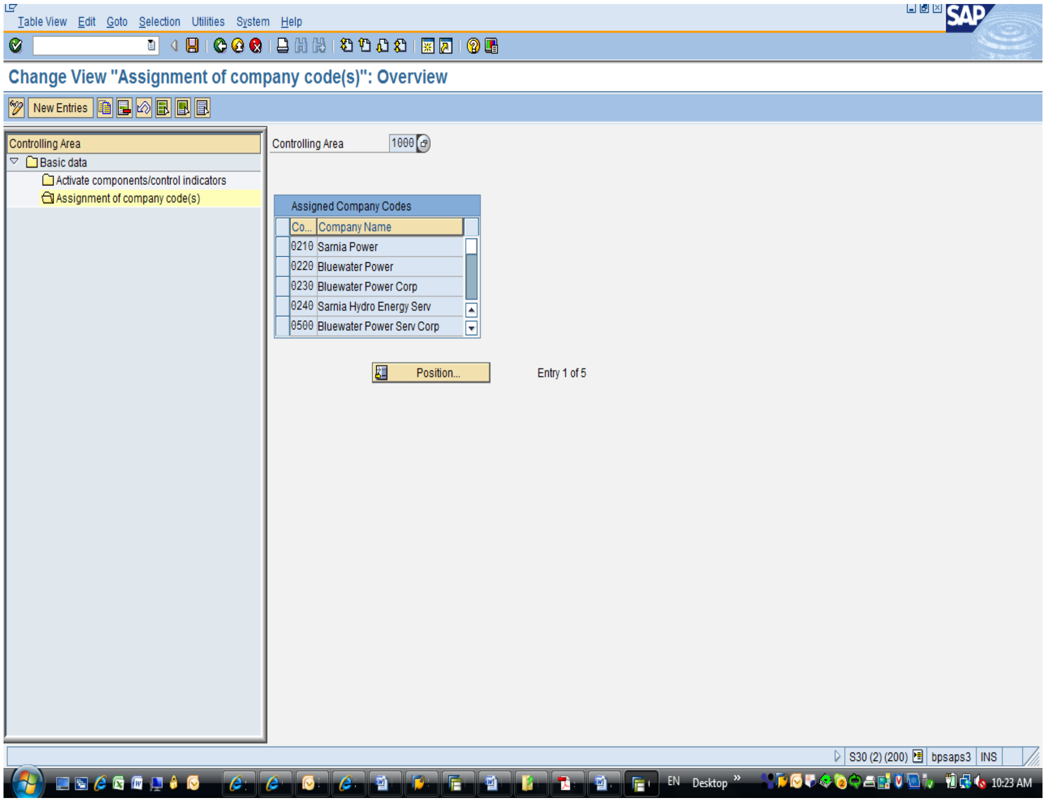
Currency Setting
Currency Type: 30 Group currency
Currency: CAD Canadian Dollar ☑ Diff. CCode Currency
Curr/Val. Prof.: ☐ Active

Other Settings
Chart of Accts: BWP Bluewater Power Corporation
Fiscal Year Variant: K4 Calendar year, 4 spec. periods
CCtr Std. Hierarchy: BWP Bluewater Power Corporation

Reconciliation Ledger
☑ Recon.Ledger Active
Document Type: AB Accounting document

Setting for Authorization Hierarchies for Cost Centers
Do Not Use Std Hier. ☐ Alternative Hierarchy1 ☐
Alternative Hierarchy2 ☐

Setting for Authorization Hierarchies for Profit Centers
Do Not Use Std Hier. ☐ Alternative Hierarchy1 ☐
Alternative Hierarchy2 ☐



Change View "Assignment of company code(s)": Overview

Controlling Area
- Basic data
  - Activate components/control indicators
  - Assignment of company code(s)

Controlling Area: 1000

Assigned Company Codes

Co...	Company Name
0210	Sarnia Power
0220	Bluewater Power
0230	Bluewater Power Corp
0240	Sarnia Hydro Energy Serv
0500	Bluewater Power Serv Corp

Entry 1 of 5

Deactivating Classic Profit Center Accounting

Direct posting will be deactivated (for actual data) by choosing Customizing -> Controlling -> Profit Center Accounting -> Basic Settings ->Controlling Area Settings-> Activate Direct Postings -> Set Control Parameters for Actual Data. Deactivate the actual real-time integration. In transaction 1KEF remove the online transfer indicator.

Activating PCA in New General Ledger Accounting by assigning the profit Center scenario to a ledger

Define the update of the characteristics 'Profit Center' in the ledger by selecting the scenario 'Profit center update' FIN_PCA (Customizing: Financial Accounting (New) -> Financial Accounting Basic Settings (New) -> Ledgers ->Ledger -> Assign Scenarios and Customer-Defined Fields to Ledgers).
Deactivate Classic PCA (SAP does not recommend to run both Classic PCA and New GL PCA in parallel for a long term basis due to the increased data volume and the increased time and effort required).

First Time Adoption

Requirement

Canada is moving to IFRS based financial statements effective January 1, 2011. IFRS 1 requires that the company prepares an opening IFRS balance sheet as of the date of transition to IFRS. In order to have comparative data available for 2010, Bluewater Power decided to present its IFRS opening balance sheet as at 1.1.2010 in a separate ledger. Since Bluewater Power has chosen assets Net Book Value as its “deemed cost”, Bluewater Power will have to present the same opening balance sheet in both, IFRS ledger and CGAAP/OEB ledgers.

Design

When fiscal year 2009 will be closed, non open item Balance Sheet GL accounts’ balances, and open items as at December 31 2009 of both Bluewater Power company codes (0230 and 0500), will be migrated from the classic GL ledger 0 to both New GL ledgers. Depreciation area 01 will be assigned to leading ledger 0L and Depreciation areas 40, which will be copied from depreciation area 01, will be assigned to non leading ledger OE. In addition, the delta depreciation area 60 (40-01) will be defined too. No configuration changes are planned before the activation of the New GL. Configuration changes to depreciation area 01 and 40 will be done after New GL activation date, in order to have different depreciation values in 0L and in OE ledgers for fiscal year 2010.

Although profit center accounting (PCA) will be activated in Controlling before the migration, there will be no data in 2009 to migrate from ledger 8A (PCA ledger) to the New GL ledgers, since it will contain P&L GL accounts data only.

Property, Plant & Equipment (PP&E)

General

Based on IAS 16 (which is part of IFRS), Bluewater Power adopted the “Cost model” as the accounting policy for PP&E.

Regulatory Assets

Requirement

There is a difference in presentation or valuation of Regulatory Assets such as Long Term Receivables, OMER and Timing differences, between IFRS and OEB/CGAAP. A reclassification of GL accounts which represent the Regulatory Assets is required in order to adjust them to IFRS.

Design

Journal entry to post deferred tax assets/ liabilities derived from time differences. These time differences are related to regulatory assets and liabilities. Journal entry will be posted to OE ledger using ledger group field. In addition, a reclassification from regulatory assets to PP&E will be needed (smart meters).

Asset Lives

Requirement

Wherever there is a difference in assets' lives, between IFRS and OEB/CGAAP, a change in the percentage of the depreciation will be required in the depreciation key.

Design

If necessary, a change in the percentage field in the depreciation key of the applicable depreciation area could be made in order to accommodate changes in asset class depreciation values

Asset Componentization

Requirement

IFRS requires more accounting details on assets records in PP&E. Bluewater Power will be required to add more asset classes and reclassify assets from current to new asset classes, in the fixed asset module within the IFRS ledger.

Design

The followings are the configuration changes in depreciation area 01 (for IFRS reporting):
Additional asset classes will be created along with new GL asset control accounts.

The process to reclassify is as follows:

- Create new asset class and assign the appropriate new GL accounts to it.
- Transfer asset from old asset class to new asset class using transaction type for transfers.
- Once all assets in the original class are transferred, the old asset class will be blocked from any future use.

Borrowing Costs

Requirement

IAS 23 (which is part of IFRS) requires that Borrowing Cost should be capitalized to their “qualified assets”. Due to the complexity of interest rates calculations, such as Shareholder Interest on promissory notes, a manual journal entry in the respective book/ledger is required.

Design

Interest rate calculations will be posted using manual journal entry with a specific ledger group.

Impairments

Requirement

IAS 36 (which is part of IFRS) requires that Impairment testing is conducted for a cash generating unit (CGU), which is usually at a lower level than an asset group used by CGAAP. In addition, IFRS impairment calculations differ than those in CGAAP’s. Impairment should be conducted in both ledgers, using different depreciation area.

Design

A unique asset transaction type for impairment will be created for the retirement of the impaired asset. In general, when retiring an asset with multiple units/quantities, the portion of the retired asset will be determined based on the quantity field in the asset master record. In addition, a new Gain/Loss GL account will be created for posting impairment.

A column for impairment will be added to Asset Continuity Schedule)-Report S_ALR_870_11990. Transaction type for impairment (Y99) will be defined within transaction type group 20 (retirement).

Intangibles

Requirement

IAS 38 (which is part of IFRS) requires that 2 asset classes from PP&E will be reclassified to Intangible assets.

Design

Asset classes 1806 (land rights) and 1925 (computer software) will be presented under intangible asset, rather than under PP&E. The GL accounts, assigned to those assets classes, will be reclassified from PP&E to Intangible assets in financial statement version only (transaction code OB58).

Provisions, Contingent Liabilities/Assets

Requirement

The measurement of a decommissioning provision differs in IFRS than in CGAAP, where in IFRS a portion of the provision is treated as an interest expense. The probability threshold for determining the provision differs in IFRS than in CGAAP too. IFRS requires discounting of provisions if the effect is material.

Design

A manual journal entry, specifying the IFRS ledger in the ledger group field, will be created in order to post the necessary adjustments.

Employee Benefit

Requirement

IFRS may require recognition of an additional pension Asset/Liability, if there is a contractual arrangement to share/fund any surplus/deficit.

Design

A manual journal entry, specifying the IFRS ledger in the ledger group field, will be created in order to post the additional pension asset/liability.

Major Spare Parts

Requirement

Treatment of inventory is the same in IFRS and CGAAP. However, some variation in treatment of cyclical and insurance spare parts between IFRS and OEB/CGAAP could occur.

Design

A manual journal entry, specifying the IFRS ledger in the ledger group field, will be created in order to post the necessary adjustments.

Customer Contributions

Requirement

IFRS recognizes customers' contributions at fair value to PP&E and revenue over the period of service. If the service is only a connection to a network, then revenue will be recognized at the connection date. If the services involve ongoing access to electricity supply on an ongoing basis, at a price lower than would be charged without the transfer of assets, revenue will be credited over the useful life of the asset.

Design

A separate financial statement version for IFRS reporting will be created to reclassify the individual GL account for reporting only. This will be created and maintained using transaction code OB58.

Decommissioning Costs

Requirement

IFRS requires legal and constructive obligation to be considered in determining decommissioning costs, while CGAAP requires legal obligations only. In addition, the measurement of obligation is different.

Design

Since Bluewater Power has never decommissioned any asset, the issue of posting liability against the decommissioning cost, based on IFRS, is still open. A transaction type (acquisition) for capitalization of these costs will be defined, and assets history sheet will be adjusted accordingly.

Regulatory Accounting, PP&E – Capital versus Expense

Requirement

Under current IFRS guidelines, there are certain costs that cannot be capitalized that are currently allowed to be capitalized under CGAAP and OEB.

There is an IFRS exposure draft in circulation that has the potential to allow these costs to be capitalized in a regulated industry but this is not yet finalized.

Types of expenses that cannot be capitalized under IFRS are:

- Overhead on Labor
- Overhead on Trucking
- Overhead on Material costs
- Indirect training (not directly associated to the installation of a capital asset)
- Meals and Travel costs (also cannot be capitalized under OEB)
- Research
- Feasibility studies done prior to a project commencing

Design

Any common cost, currently tracked in a single expense account, which could be capitalized or expensed, will have a new expense account created. For example, for training, there will be a direct training and indirect training account. For feasibility studies, there will need to be two accounts, one before the approval of a project and then one during the execution of a capital project.

Costing sheets will be configured for both work orders and internal orders. These costing sheets will control the calculation and posting of overhead against work order and internal order.

One costing sheet will be defined for Distco and one for Servco. This is so that the rates can be maintained separately as well as the credit cost center. This model is feasible as use of order types are separate between Distco and Servco.

As a result, the current standard rates set up in the system for labor and trucking will need to be adjusted as they currently include the overhead in the single rate. This can be referred to as “unloading” the current rates.

The use of the costing sheets will mean the current practice of calculating and posting the material overhead manually against the work orders and internal orders will no longer need to be performed.

For labor rates, additional activity types with associated secondary cost elements will be created. For each of these different labor activity types, a unique settlement account will be used for the capitalization of each type of labor. This is for OEB reporting. A full list of the new activity types will be provide by the Bluewater Power Finance department.

OEB G/L Account	Current OEB G/L name	Proposed Activity Type	Description of Capitalized Labor G/L
50051008	Operation Supervision & Engineering - Mgmt Salary	5005M	Capitalized Supervision & Engineering - Mgmt Salary
501000032	Load Dispatching - Labour	5010U	Capitalized Load Dispatching - Labour

Overhead will be posted to a single secondary cost element.

The current settlement configuration for work order to internal order settlement will be adjusted. This will be done so that costs settled from the work order to the internal order will be recorded in separate settlement cost element (secondary cost elements in the 7xxxx series) This is to ensure that when the overhead is calculated on the internal order, only direct costs posted to the internal order are taken into account and not the settled costs from the work order. If this were not done, then overhead would be calculated and posted twice.

New Settlement Accounts, for Work Order to Internal Order Settlement.

- WO Light Truck
- WO Heavy Truck
- WO Material
- WO Meals
- Multiple labor settlement accounts will be required based on the new labor activity types (see above)

The capitalization key which is part of the settlement configuration of the project will determine (by GL account) the amount that should be capitalized into the depreciation areas representing IFRS, CGAAP OEB. This can only be done by account. While the percentage rates are configured, it will typically be 0% or 100%.

The current settlement configuration for internal order to fixed asset settlement will be adjusted. This will be done so that there will be a breakdown of the capital costs specifically for the allocated costs (labor, trucking, meals, overtime) from the one account now (Capitalized labor) to the following accounts:

New Settlement Accounts, for Internal Order to Asset Settlement.

- Capitalized Labor (multiple accounts for each type of labor and overtime– see above)
- Capitalized Overtime Meals (new)
- Capitalized Light Truck
- Capitalized Heavy Truck

Other configuration needed is a new internal type for billable work as this will require a new settlement profile different from the current order type that billable orders are created against.

The following diagram is to illustrate how the costs would flow from the work order to an internal order and subsequent capitalization to the asset.

	Work Order		Internal Order		Capitalization Key	
					IFRS	GAAP
Direct						
	Operations	1,000				
	Light Truck	1,000				
	Material	1,000	Material	10,000	100%	100%
Indirect						
	Overhead	300				
			Overhead	1,000	0%	100%
Settlement						
	WO Op Labor	(1,000)	WO Op Labor	1,000	100%	100%
	WO Light Truck	(1,000)	WO Light Truck	1,000	100%	100%
	WO Material	(1,000)	WO Material	1,000	100%	100%
	Overhead	(300)	Overhead	300	0%	100%
			Final Settlement			
			Cap Op Labor	(1,000)		
			Cap Light Trk	(1,000)		
			Material	(10,000)		
			WO Material	(1,000)		
	Balance of Work Order	0	Overhead	(1,300)		

IFRS	
Asset	13,000
Cost Center	1,300
CGAAP	
Asset	14,300

Note – simple example of 10% for all types of OH is used in the about example. This is for illustration purposes only.

1) Direct Costs are incurred against the work order.
2) The overhead is calculated and applied to the work order. These are shown as secondary cost elements.
3) The Work orders are settled to the Internal. Settlement by original cost element cannot be used. New settlement cost elements to break out and show the direct and indirect costs from the work order on the internal order within the order reports.
4) Other direct costs (typically material purchases) can be made against the internal order directly.
5) Overhead will be calculated and posted against the internal for its direct costs. If settlement by original cost element was used, then the costing sheet of the order would recalculate and post overhead again (effectively double-counting)
6) The capitalization key which is part of the settlement configuration of the order will determine (by GL account) the amount that should be capitalized into the depreciation areas representing IFRS, GAAP/OEB. This can only be done by account. While the percentage rates are configured, it will typically be 0% or 100%.

Reporting

Existing Financial Statements

Report	Description	Source
Income Statement	Structure is based on the Financial Statement Version. There will be a new transaction code to execute in order to select the appropriate ledger Transaction code S_PL0_86000028	SAP ERP 6.0
Balance Sheet	Structure is based on the Financial Statement Version. There will be a new transaction code to execute in order to select the appropriate ledger. Transaction code S_PL0_86000028	SAP ERP 6.0

Existing Queries / Reports

Report	Description	Source
YBANJOURNAL	Journal entry information for a specified time period Program needs to be adjusted to select the financial data from the appropriate ledger. Currently the query is designed to select from BKPF (FI document header) and BESG (FI document line item)	SAP ERP 6.0
YBANGSTAUDITOR YBANGSTITEM	Summary of accounts payable information-GST audit Program needs to be adjusted to select the financial data from the appropriate ledger. Currently the query is designed to select from BKPF (FI document header) and BESG (FI document line item)	SAP ERP 6.0

New Reports

Report	Description	Source
Statement of Equity	New financial report as required by IFRS standards	BOBJ
Reconciliation Report	Trial Balance report showing balance, by G/L Account, of IFRS Leading ledger versus OEB/CGAAP Non-Leading Ledger	BOBJ

Example of report "Statement of Equity" structure:

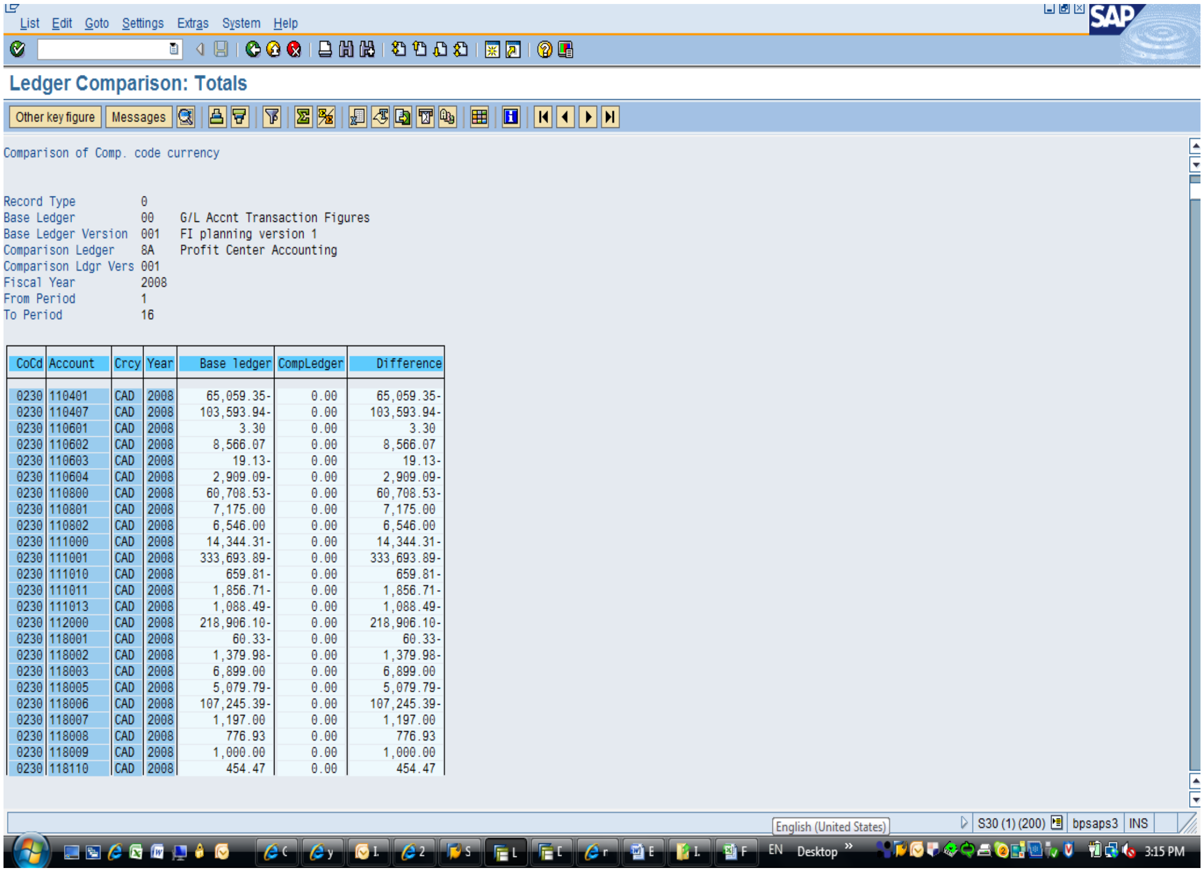
	Opening Balance	**Addition**	**Deletions**	**Transfers**	**Closing Balance**
Common shares					
Preferred shares					
Premium on shares					
Paid on capital					
Retained earning OB					
Retained earnings Current Year					
Currency translation differences					
Total Stockholders' Equity					

BOBJ Reporting

For the new reports, the goal is to run these reports from the BOBJ environment. In the event that the development of the BOBJ reports experiences any issues that may put the project timeline at risk, the source of the data will be changed to the SAP ERP 6.0 environment.

For the Statement of Equity, this would be done through the maintenance of a financial statement version or Reporting Tools.

For the Reconciliation Report, this would be through the transaction code GCAC. See an example of GCAC in the screen shot below:



Ledger Comparison: Totals

Comparison of Comp. code currency

```
Record Type          0
Base Ledger          00    G/L Accnt Transaction Figures
Base Ledger Version  001   FI planning version 1
Comparison Ledger    8A    Profit Center Accounting
Comparison Ldgr Vers 001
Fiscal Year          2008
From Period          1
To Period            16
```

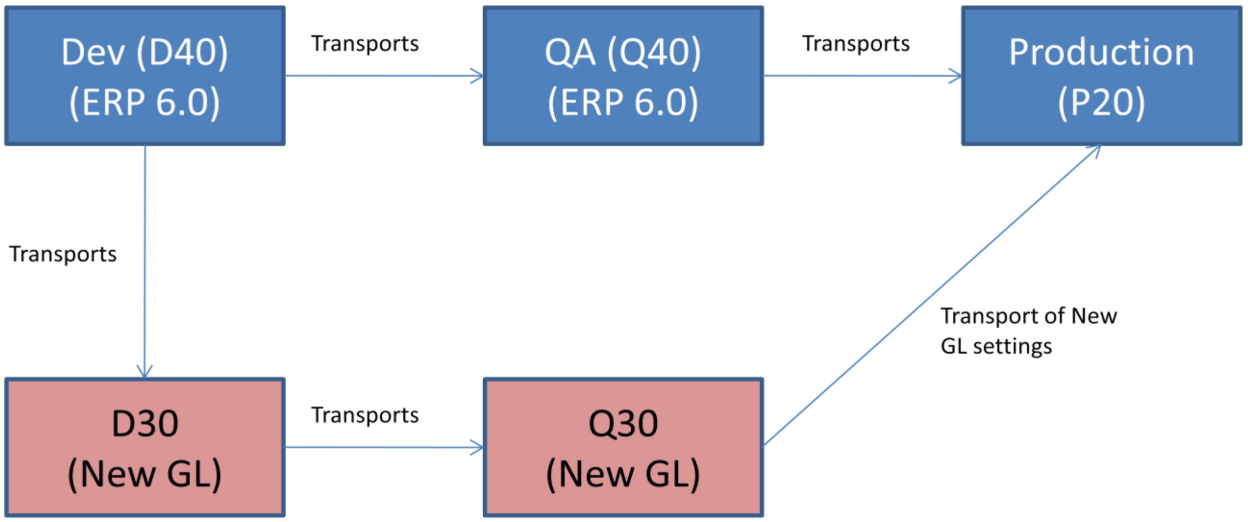
CoCd	Account	Crcy	Year	Base ledger	CompLedger	Difference
0230	110401	CAD	2008	65,059.35-	0.00	65,059.35-
0230	110407	CAD	2008	103,593.94-	0.00	103,593.94-
0230	110601	CAD	2008	3.30	0.00	3.30
0230	110602	CAD	2008	8,566.07	0.00	8,566.07
0230	110603	CAD	2008	19.13-	0.00	19.13-
0230	110604	CAD	2008	2,909.09-	0.00	2,909.09-
0230	110800	CAD	2008	60,708.53-	0.00	60,708.53-
0230	110801	CAD	2008	7,175.00	0.00	7,175.00
0230	110802	CAD	2008	6,546.00	0.00	6,546.00
0230	111000	CAD	2008	14,344.31-	0.00	14,344.31-
0230	111001	CAD	2008	333,693.89-	0.00	333,693.89-
0230	111010	CAD	2008	659.81-	0.00	659.81-
0230	111011	CAD	2008	1,856.71-	0.00	1,856.71-
0230	111013	CAD	2008	1,088.49-	0.00	1,088.49-
0230	112000	CAD	2008	218,906.10-	0.00	218,906.10-
0230	118001	CAD	2008	60.33-	0.00	60.33-
0230	118002	CAD	2008	1,379.98-	0.00	1,379.98-
0230	118003	CAD	2008	6,899.00	0.00	6,899.00
0230	118005	CAD	2008	5,079.79-	0.00	5,079.79-
0230	118006	CAD	2008	107,245.39-	0.00	107,245.39-
0230	118007	CAD	2008	1,197.00	0.00	1,197.00
0230	118008	CAD	2008	776.93	0.00	776.93
0230	118009	CAD	2008	1,000.00	0.00	1,000.00
0230	118110	CAD	2008	454.47	0.00	454.47

1. **Security-** Roles for New General ledger will be based on the Roles for the Classic new General Ledger and be defined, so that appropriate activities will be performed in either leading ledger or non leading ledger or both.

Technology

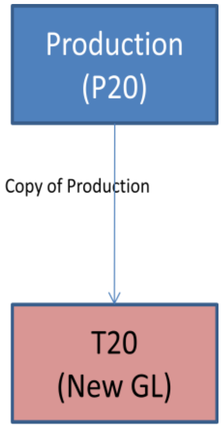
Landscape

During Realization



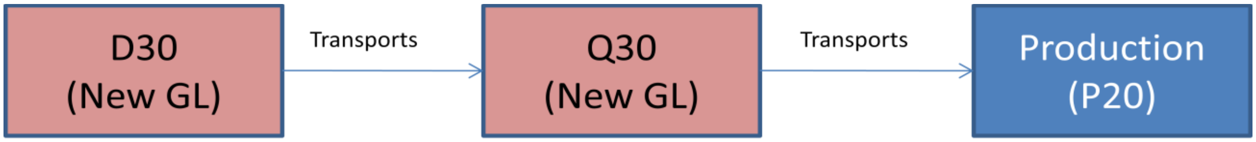
- D30 will be a copy of the ERP 6.0 Development environment (D40) after the ERP 6.0 upgrade go live.
- Q30 will be a copy of the ERP 6.0 QA environment (Q40) after the ERP 6.0 upgrade go live.
- The New GL functionality will be configured directly in D30.
- Any changes to the existing ERP 6.0 environment will need to be transported from D40 to D30 during the course of the project and tested.
- Transport of the New GL settings to production will occur at the completion of user acceptance testing before the commencement of the Final Preparation phase

During Final Preparation



- For each cycle of the Migration Testing done during the Final Preparation phase, a copy of the ERP 6.0 Production environment (P20) will be performed to a T20 environment at the beginning of each test cycle.
- The execution of the SAP Migration Cockpit for the migration testing will be done on T20.
- A single client will be used on the T20 as a copy of each migration test cycle is not required to be retained.

Upon Completion of the Project



- The D40 and Q40 and QA3 environments will be decommissioned as the D30 and Q30 will become the new SAP landscape.

Transport Management

As noted above, any changes to the existing ERP 6.0 environment will need to be transported from D40 to D30 during the course of the project and tested.

The Deloitte project manager must be notified of any changes through a transport to assess the impact on the New G/L configuration in D30 and schedule appropriate testing.

Migration Cockpit

Explain where migration cockpit will be run from

2. Migration Process (from Classic GL to New GL)-

- General- When the technical upgrade from 4.7 to ERP 6.0 completes, the transition from Classic GL to New GL, could start. This transition consists of a conceptual functional element and a technical element, where the existing financial accounting data must be migrated into the new structures of the general accounting. The process of migration is accompanied by SAP Migration services. The services include migration cockpit and 2 service sessions for the quality assurance of the data and the migration project.

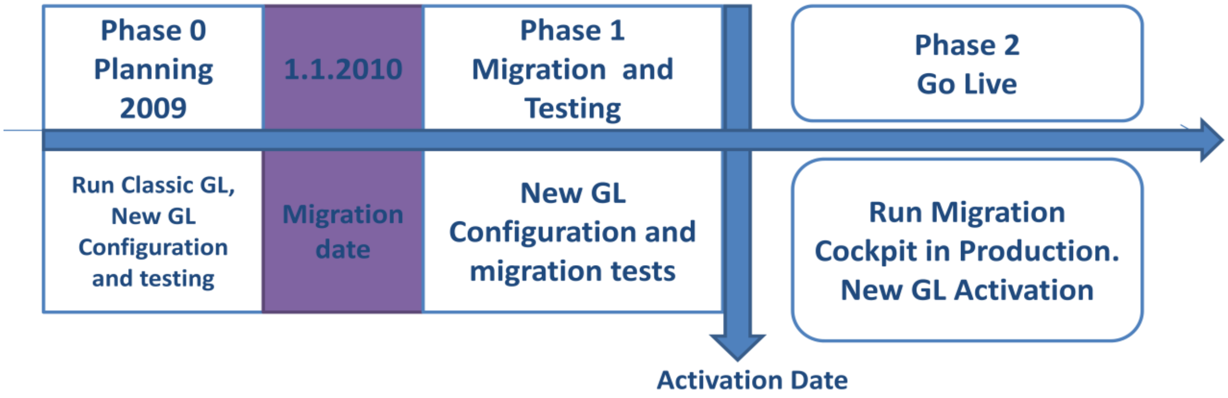
- Migration phases-the phase model for migration consists of three phases. Phase 0- the planning phase. Phase1- migration and testing. Phase 2- Go live. Two dates play an important role: migration date which is the date between phases 0 and 1, and always has to be the first day of the new fiscal year. The second date is the activation date which is the date that separates phase 1 and 2. SAP Migration services perform the 2 quality assurance sessions in phase 0 and phase 1.

- Migration Scenario- A migration scenario describes the various conditions dictating how the migration from Classic General Ledger Accounting to New General Ledger Accounting is performed. There are several conditions/options to move the existing data, each option/condition depends on the characteristic used and/or needed (profit center, segment, multiple ledgers etc.) each condition/option is defined as scenario. The scenario which is suitable to Bluewater Power is Scenario 2: migration from one ledger to parallel ledgers without document splitting, using Profit Center Accounting.
  This will be confirmed by SAP Migration Services.

- Migration cockpit- (Transaction code: CNV_MBT_NGLM). The migration cockpit is a tool for performing the migration and offers scenario based management. It contains a scenario dependent process tree with the individual activities of the migration which are tailored to the chosen scenario. These activities either involve steps to perform manually or programs that must be started to perform the activity. The cockpit is also contains a monitor that is used to follow the processing and the status of the individual steps. The cockpit created logs to view the programs' system. Annexation of notes and documents are also available. Other migration-specific information, such as the start and end times of the programs and the number of migrated datasets, are also stored. This tool help improve the transparency and traceability of the migration process, which are also important in auditing. The main advantage of the cockpit is the scenario- specific management through the migration process. The cockpit contains 6 major steps as follows: migration set-up, migration check-up, preparation of migration, migration validation and New GL activation. All migration activities are located in these steps. SAP provides access keys to install the cockpit. The cockpit will be installed in DEV and QA systems. It is important to note that the migration process is performed while New GL configuration is completed, but the New GL itself has not been activated yet.

- Migration cockpit role - a separate role SAP_NGLM_MASTER is stored for users who are assigned to work on the data migration process (migration cockpit). Users with SAP_ALL have access to the migration cockpit too.

Data Migration: Classic to New GL



Phase 0
Planning
2009

1.1.2010

Phase 1
Migration and
Testing

Phase 2
Go Live

Run Classic GL,
New GL
Configuration
and testing

Migration
date

New GL
Configuration and
migration tests

Run Migration
Cockpit in Production.
New GL Activation

Activation Date

Security & Controls

Scenarios

There are two main scenarios that will be encountered during the implementation of the functions to support IFRS.

- New transaction codes from the implementation of the New GL functions and Profit Center Accounting.
- Existing transactions codes that have been superseded by new transaction codes.

New Transaction Codes / Functions.

The table below identifies the new transaction codes as well as if they will be incorporated in an existing role or a new security role will be created.

Upon review the new transactions and their relation to the existing transaction codes for the specific module, the approach would be to incorporate these transactions into the existing security roles.

The rational for the role selected was based on the relationship to an existing transaction already assigned to an existing role.

MODULE	NEW TRANSACTION CODE	Role	Role Description	Related Transaction
FI-GL	S_PL0_86000031 - Transaction Figures: Account Balance	T_50000038_YB_FICCS	T 50000038 CCS Accountant Profile	S_ALR_87012277 – G/L Account Balances
FI-AA	ASKB - APC Values Posting	T_50000109_YB_FISR	T 50000109 Authorization for FI level 3	AFAB -Post Depreciation
		T_50000108_YB_FIMAN	T 50000108 Authorization for FI Level 4	
CO-IO	KGI2 - Actuals: Individual Processing	T_50000104_YB_COMAN	T 50000104 Authorization CO Level4	KO88 – Settle Order Individual
		T_50000103_YB_COSR	T 50000103 Authorization CO Level3	
CO-IO	KGI4 - Actuals: Collective Processing	T_50000109_YB_FISR	T 50000109 Authorization for FI level 3	KO8G – Settle Order Collective
		T_50000108_YB_FIMAN	T 50000108 Authorization for FI Level 4	
CO-IO	S_ALR_87005104 - Maintain Costing Sheet	T_50000104_YB_COMAN	T 50000104 Authorization CO Level4	KO8G – Settle Order
CO-PCA	KE51 - Create Profit Center	T_50000104_YB_COMAN	T 50000104 Authorization CO Level4	KS01 – Create Cost Center
		T_50000103_YB_COSR	T 50000103 Authorization CO Level3	
CO-PCA	KE52 - Change Profit Center	T_50000104_YB_COMAN	T 50000104 Authorization CO Level4	KS02 – Change Cost Center

MODULE	NEW TRANSACTION CODE	Role	Role Description	Related Transaction
		T_50000103_YB_COSR	T 50000103 Authorization CO Level3	
CO-PCA	KE53 - Display Profit Center	T_50000104_YB_COMAN	T 50000104 Authorization CO Level4	KS03 – Display Cost Center
		T_50000103_YB_COSR	T 50000103 Authorization CO Level3	
		T_50000109_YB_FISR	T 50000109 Authorization for FI level 3	
CO-PCA	KE54 - Delete Profit Center	T_50000104_YB_COMAN	T 50000104 Authorization CO Level4	KS02 – Change Cost Center
		T_50000103_YB_COSR	T 50000103 Authorization CO Level3	
CO-PCA	6KEA - Display Profit Center Changes	T_50000104_YB_COMAN	T 50000104 Authorization CO Level4	KS03 – Display Cost Center
		T_50000103_YB_COSR	T 50000103 Authorization CO Level3	
		T_50000109_YB_FISR	T 50000109 Authorization for FI level 3	
CO-PCA	KCH5N - Standard Hierarchy Change	T_50000103_YB_COSR	T 50000103 Authorization CO Level3	OKEON – Change Cost Center Standard Hierachy
CO-PCA	KCH6N - Standard Hierarchy Change	T_50000103_YB_COSR	T 50000103 Authorization CO Level3	OKENN – Change Cost Center Standard Hierachy
CO-PCA	KCH1 - Create Profit center group	T_50000104_YB_COMAN	T 50000104 Authorization CO Level4	KSH1 – Create Cost Center group
		T_50000103_YB_COSR	T 50000103 Authorization CO Level3	
CO-PCA	KCH2 - Change Profit Center Group	T_50000104_YB_COMAN	T 50000104 Authorization CO Level4	KSH2 – Change Cost Center group
		T_50000103_YB_COSR	T 50000103 Authorization CO Level3	
CO-PCA	KCH3 - Display Profit Center Group	T_50000104_YB_COMAN	T 50000104 Authorization CO Level4	KSH3 – Display Cost Center group
		T_50000103_YB_COSR	T 50000103 Authorization CO Level3	
CO-PCA	S_ALR_87013326 - Profit Center Group: Plan/Actual/Variance	T_50000038_YB_FICCS	T 50000038 CCS Accountant Profile	S_ALR_87013611 – Cost Center Actual/Plan/Variances
		T_50000109_YB_FISR	T 50000109 Authorization for FI level 3	
CO-PCA	S_ALR_87013327 - Profit Center Comparison: Plan/Actual/Variance	T_50000038_YB_FICCS	T 50000038 CCS Accountant Profile	S_ALR_87013611 – Cost Center Actual/Plan/Variances
		T_50000109_YB_FISR	T 50000109 Authorization for FI level 3	
CO-PCA	S_ALR_87013330 - Profit Center Group: Plan/Plan/Actual Versions	T_50000038_YB_FICCS	T 50000038 CCS Accountant Profile	S_ALR_87013611 – Cost Center Actual/Plan/Variances
		T_50000109_YB_FISR	T 50000109 Authorization for FI level 3	
CO-PCA	S_ALR_87013332 - Profit Center Group: Current Period/Aggregated/Year	T_50000038_YB_FICCS	T 50000038 CCS Accountant Profile	S_ALR_87013611 – Cost Center Actual/Plan/Variances
		T_50000109_YB_FISR	T 50000109 Authorization for FI level 3	

MODULE	NEW TRANSACTION CODE	Role	Role Description	Related Transaction
CO-PCA	S_ALR_87013334 - Profit Center Group: Compare Actual Quarters over 2 Years	T_50000038_YB_FICCS	T 50000038 CCS Accountant Profile	S_ALR_87013611 – Cost Center Actual/Plan/Variances
		T_50000109_YB_FISR	T 50000109 Authorization for FI level 3	
CO-PCA	S_ALR_87013336 - Profit Center Group: Balance Sheet Accounts Plan/Actual/Variance	T_50000038_YB_FICCS	T 50000038 CCS Accountant Profile	S_ALR_87013611 – Cost Center Actual/Plan/Variances
		T_50000109_YB_FISR	T 50000109 Authorization for FI level 3	
CO-PCA	S_ALR_87009712 - Profit Center List: Plan/Actual	T_50000038_YB_FICCS	T 50000038 CCS Accountant Profile	S_ALR_87013611 – Cost Center Actual/Plan/Variances
		T_50000109_YB_FISR	T 50000109 Authorization for FI level 3	
CO-PCA	S_ALR_87013340 - Profit Center Group: Plan/Actual/Variance	T_50000038_YB_FICCS	T 50000038 CCS Accountant Profile	S_ALR_87013611 – Cost Center Actual/Plan/Variances
		T_50000109_YB_FISR	T 50000109 Authorization for FI level 3	
CO-PCA	S_ALR_87009726 - Profit Center Group: Plan/Actual/Variance by Origin	T_50000038_YB_FICCS	T 50000038 CCS Accountant Profile	S_ALR_87013611 – Cost Center Actual/Plan/Variances
		T_50000109_YB_FISR	T 50000109 Authorization for FI level 3	
CO-PCA	S_ALR_87009734 - Profit Center Group: Plan/Plan/Variance	T_50000038_YB_FICCS	T 50000038 CCS Accountant Profile	
		T_50000109_YB_FISR	T 50000109 Authorization for FI level 3	
CO-PCA	S_ALR_87009717 - Profit Center Group: Quarterly Comparison of Actual Data	T_50000038_YB_FICCS	T 50000038 CCS Accountant Profile	S_ALR_87013611 – Cost Center Actual/Plan/Variances
		T_50000109_YB_FISR	T 50000109 Authorization for FI level 3	
CO-PCA	KE5Z - Profit Center: Actual Line Items	T_50000038_YB_FICCS	T 50000038 CCS Accountant Profile	S_ALR_87013611 – Cost Center Actual/Plan/Variances
		T_50000109_YB_FISR	T 50000109 Authorization for FI level 3	

Superseded Transaction Codes

The table below identifies the transactions codes impacted.

The approach for these transactions will be to leave the existing or old transaction code active in their existing Finance Roles roles and add the new transaction code to the role.

OLD CODE	NEW_CODE	Role
FS10N	FAGLB03 - Display Balances	*T_50000093_YB_CSBILL
FS10N	FAGLB03 - Display Balances	T_50000106_YB_FIAP
FS10N	FAGLB03 - Display Balances	T_50000107_YB_FIAR
FS10N	FAGLB03 - Display Balances	T_50000108_YB_FIMAN
FS10N	FAGLB03 - Display Balances	T_50000109_YB_FISR
F.16	FAGLGVTR - Balance Carry forward (New)	T_50000108_YB_FIMAN
F.16	FAGLGVTR - Balance Carry forward (New)	T_50000109_YB_FISR
FBL3N	FAGLL03 - Display Change Items	T_50000106_YB_FIAP
FBL3N	FAGLL03 - Display Change Items	T_50000107_YB_FIAR
FBL3N	FAGLL03 - Display Change Items	T_50000108_YB_FIMAN
FBL3N	FAGLL03 - Display Change Items	T_50000109_YB_FISR
F-02	FB01L - Enter GL Posting for Ledger Group	T_50000106_YB_FIAP
F-02	FB01L - Enter GL Posting for Ledger Group	T_50000107_YB_FIAR
F-02	FB01L - Enter GL Posting for Ledger Group	T_50000108_YB_FIMAN
F-02	FB01L - Enter GL Posting for Ledger Group	T_50000109_YB_FISR
FB03	FB03L - Display in General Ledger View	*T_500000131_YB_CS_DUNNING
FB03	FB03L - Display in General Ledger View	*T_50000085_YB_CSCSR
FB03	FB03L - Display in General Ledger View	T_50000087_YB_REGL1
FB03	FB03L - Display in General Ledger View	T_50000091_YB_PMLM
FB03	FB03L - Display in General Ledger View	T_50000095_YB_CSSRR
FB03	FB03L - Display in General Ledger View	T_50000098_YB_CCSLH
FB03	FB03L - Display in General Ledger View	T_50000106_YB_FIAP
FB03	FB03L - Display in General Ledger View	T_50000107_YB_FIAR
FB03	FB03L - Display in General Ledger View	T_50000108_YB_FIMAN
FB03	FB03L - Display in General Ledger View	T_50000109_YB_FISR
FB03	FB03L - Display in General Ledger View	*T_50000128_YB_EL41_DISPLAY
FB03	FB03L - Display in General Ledger View	*T_50000130_YB_DM_DISPLAY
FB03	FB03L - Display in General Ledger View	*T_50000134_YB_CSCLERK
FB03	FB03L - Display in General Ledger View	*T_50000135_YB_CSR_DISPLAY
FB50	FB50L - Enter GL document for Ledger Group	T_50000106_YB_FIAP
FB50	FB50L - Enter GL document for Ledger Group	T_50000107_YB_FIAR
FB50	FB50L - Enter GL document for Ledger Group	T_50000108_YB_FIMAN
FB50	FB50L - Enter GL document for Ledger Group	T_50000109_YB_FISR
S_ALR_87012249	S_PL0_86000028 - Financial Statement: Actual/Actual Comparison	T_50000038_YB_FICCS
S_ALR_87012284	S_PL0_86000029 - Financial Statement: Plan/Actual Comparison	T_50000038_YB_FICCS

OLD CODE	NEW_CODE	Role
S_ALR_87012284	S_PL0_86000029 - Financial Statement: Plan/Actual Comparison	T_50000109_YB_FISR
S_ALR_87012277	S_PL0_86000030 - G/L Account Balances (New)	T_50000038_YB_FICCS

* - It is not required to add the transaction to the non-FI roles

Security Build Approach

For the superseded transaction codes, the above roles will be adjusted in the new Development environment (D30) that will incorporate the New GL configuration and related functions.

For the new transactions in the FI-GL (General Ledger) FI-AA (Asset Accounting) and CO-IO (internal Orders) modules, these will also follow the same approach as the superseded transaction codes.

For the new transaction codes for the CO-PCA (Profit Center Accounting) modules, these roles will be adjusted in the current development environment (D40).

There will not be an analysis undertaken of segregation of duties of the existing users and assigned roles as part of the security build.

Security Testing Approach

Unit testing of the roles in the D30 and D40 environment will be performed by the Deloitte consultants remotely.

Integration and User Acceptance testing will be performed by the Bluewater project team members with either their own user IDs or testing user IDs based on existing end-users.

This is to gain efficiencies that both the functional configuration and security testing is performed concurrently rather than scheduling different rounds of testing.

Training Strategy

Training Objectives

The primary goal of the end user training is to support Bluewater Power by preparing end users to perform their job tasks for IFRS & CGAAP Reporting in SAP.

The Bluewater Power end-user training approach focuses on the following key objectives:

- Provide hands-on, scenario-based training to end-users in order to proficiently execute new or revised transactions and understand the rationale/context for these
- Involve end-users into User Acceptance Testing phase in order to increase their confidence and familiarity of the new transactions
- Ensure appropriateness and cost effectiveness of the training by concentrating on critical and essential training activities

Training Scope and Activities

Training Scope

The Bluewater Power training scope focuses on Financial Module and consists of the following main process threads:

Functional Area	Component	SAP Module
Financials	General Ledger	FI-GL
	Fixed Assets Accounting	FI-AA
	Cost Accounting (Including Profit Centers)	CO
	Reporting	GL, AA, BOBJ

Training Activities

Most of Bluewater Power end-users are familiar with the SAP system and many of them are power users. The conversion from CGAAP to IFRS will require specific training about the procedure and transaction changes required to be IFRS compliant.

Given the relatively small size of the impacted end-users (8) and their existing knowledge of SAP, training will be delivered to key users in the forms of:

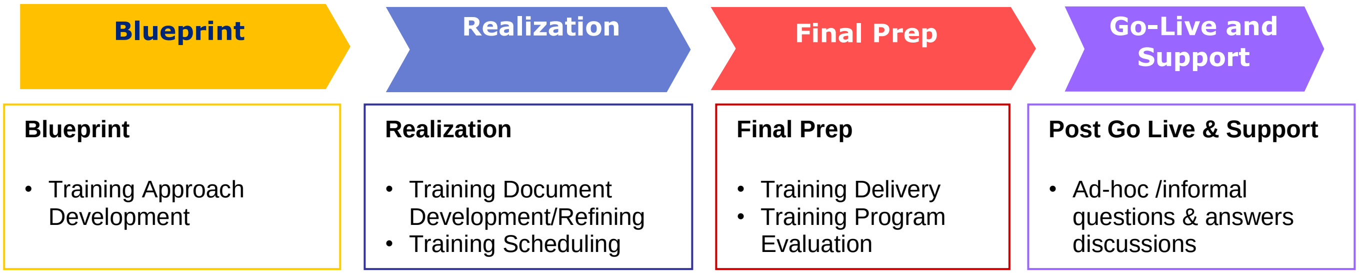
- Classroom Training - 3-day traditional classroom training to provide hands-on business process and procedure exercises
- Key User Involvement in UAT – Participation of selected individuals in User Acceptance Testing (UAT) and Integration testing, including introduction to and instruction in the testing process and their roles in the process.

End-User Training Approach

Training Approach by Phase

Deloitte consultants will be responsible for the development and delivery of the end-user training. The validated Business Process Procedure (BPP) documents will be used as the training guidelines and procedure document. The classroom training will be delivered in the Final Preparation phase. If necessary, additional questions-and-answers discussion could be set up prior to Go-Live.

Bluewater Power project is following Deloitte's methodology for implementing SAP application and associated business processes. The training approach follows the same steps, and produce training deliverables along the project. The following diagram describes the training deliverables and activities fall into the project's 4 phases:



Blueprint

- Training Approach Development

Realization

- Training Document Development/Refining
- Training Scheduling

Final Prep

- Training Delivery
- Training Program Evaluation

Post Go Live & Support

- Ad-hoc /informal questions & answers discussions

Target Audience Profiles

The target audience of end-user training are individuals who work in Finance team. They all currently work in SAP system and are familiar with interfaces and procedures in current SAP version.

Users Numbers impacted by superseded transactions

Transaction		Number of Users
F.16	Balance Carry Forward	8
F-02	Enter GL Posting	8
FB50	Enter GL Posting	8
FBL3N	Display Change Items	8
S_ALR_87012249	Financial Statement (Actual/Actual)	8
S_ALR_87012277	G/L Account Balance	8
S_ALR_87012284	Financial Statement (Plan/Actual)	8
FS10N	Display Balances	22
FB03	Display Document	50

The 8 users identified in the above list are the same 8 users each time.

There will not be a formal training session for FS10N or FB03 as the transactions themselves have changed little to the ledger based transactions.

Users Numbers impacted by new transactions

Transaction		Number of Users
ASKB	APC Asset Value Posting	6
KGI2 / KGI4	Overhead Processing	6
S_ALR_87005104	Costing Sheet Maintenance	6
	Profit Center Transactions	6
	Profit Center Reports	8

The 6-8 users identified are the same as the 8 identified in the prior table showing user numbers impacted by superseded transactions.

There are 8 impacted end-users in total, 4 of them are project members. They will all participate in the same classroom training to learn about the transaction changes. The 4 project team members will be super users in the classroom supporting the others in learning the transaction. The following is a list of all participants.

Department	Names
Finance Department	Addie Bell
	Sue Bernier
	Mark Hutson
	Laurie Jensen
	Liz Kelly
	Lindsay Marsh
	Vicki Walling
	Doug White

Training Requirements

The following requirements will be prepared and delivered for training purpose during the Realization and Final Preparation phases, as appropriate:

- Build a community of Key Users (from project team members and business SMEs) through testing and training activities
- Utilize the SAP ERP 6.0 sandbox to practice after they attend training classes
- Develop training schedule that allows for individual and business flexibility in scheduling training to accommodate work requirements as efficiently as possible
- Training to be held at Bluewater Power in Sarnia

Training Materials

Deloitte team will be responsible for developing the end-user training materials. The materials contain the critical contents that the targeted audience will need to perform their jobs.

The training materials will consist of:

- Business Process Procedures (BPPs)
- SAP processes overview documents
- Integration scenarios to be used as training exercises

Training Delivery

Deloitte consultants will deliver a 3-day class-room training session in the Final Preparation phase. The training sessions could be spread out over the one-week period to accommodate schedules. The project team will work closely with the business and schedule the training to allow for individual and business flexibility. In that week, all available end-users will attend the classroom training sessions, building their hands-on experience with the system. A Deloitte trainer will present procedure changes information, demonstrate superseded and new transactions, and guide end-users through hands-on exercises based on business scenarios to practice new procedures and transactions. Participants are able to log on to an SAP QA Client and perform exercises in a live environment.

If necessary, an additional discussion time (up to 2 days) could be set up in a week, ideally 3-6 weeks prior to Go-Live. End-users who miss the first week training or need a refresh discussion can have some questions-and-answers discussions with project team/consultants.

Bluewater Power will be responsible for ensuring end-users' participation to the training. If some user(s) cannot attend the scheduled training, they will be trained by the Bluewater Power project team members before Go-Live.

Format	Duration and Time Frame of the Course	Audience Size	Training Session Location
Classroom Training	• 24-hour • Could be spread out in one week time	6– 8 participants	Bluewater Power Sarnia Office
Additional Discussion Time (If necessary)	• Up to 16 hours • Could be set up 3-6 weeks prior to Go-Live	6 – 8 participants	Bluewater Power Sarnia Office

Training Evaluation

At the end of the training week, a training evaluation form will be used to evaluate the effectiveness of the end-user training. The objective of evaluation is to assess end user reaction to training, and the degree to which stated learning objectives are met.

The training evaluation form will measure the participants' reaction to the training regarding content, delivery, and materials. The form will also include knowledge assessments to measure the skills or knowledge gained by participants during the training program.

The information collected via training evaluation forms will be used in preparing for any further refresher Q&A sessions.

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2.0-Staff-14 - Capital budget process for IT

Ref: Exh 1-2-3

<u>Ref: Exh 2-4-2</u>

At Exh 1-2-3, Bluewater Power describes the directives and assumptions it applies in its budget process. The capital budgeting process is described on page 3 of the exhibit. The process conducted by the Planning and Design Department is described and the evidence states that the "Information Technology Department ("IT") follows a similarly disciplined process." At page 3 of Exh 2-4-2 it states that:

> With the guidance of the Asset Management Strategy, Bluewater Power undertook a comprehensive review of its capital assets with an eye to assess the direction of current capital projects and to identify gaps in its programs. The results of that process are the Capital Project Descriptions found as Exhibit 2, Tab 4, Schedule 3, Attachment 3. Together these capital projects represent the Asset management Plan that Bluewater Power is satisfied will respond to its current capital needs and address the reliability and power quality issues of its customers.

a) What specific guidance is provided in the Asset Management Strategy for IT generally and for the 21 IT capital projects specifically?

The Asset Management Strategy for Information Technology (IT) follows a similarly disciplined process to the process described in the document entitled "Asset Management Strategy" for the Operations group. The response to this IR will described the approach undertaken within the IT department at a general level and the 21 individual capital projects described in the Asset Management Plan stand alone in the context provided below.

Bluewater Power utilizes a general framework that follows industry leading Information Technology Infrastructure Library (ITIL) best practices, and more specifically, IT Service Management (ITSM). IT Asset Management is a subset of those practices which manages the lifecycle of IT assets.

At Bluewater Power, there is no formal document entitled IT Asset Management Strategy, however, there are a number of established industry best practices by which management of assets is governed. These practices include, as a basis, an asset process lifecycle that includes planning, acquiring, deploying, maintaining, and retiring IT assets.

IT asset management is inherently different than electricity distribution asset management. Where distribution assets are managed over 15 to 60 years, IT assets are managed over 2 to 6 years. In addition, the rate of change within the technology industry is rapid. As a result, IT assets change quickly, and are often life-cycled in response to technology development and industry, business, and regulatory requirements.

Bluewater Power IT assets are managed by utilizing technical support combined with the expert knowledge of IT staff through a disciplined yearly routine. More specifically, Bluewater Power manages IT assets employing the following practices.

Planning:

Each year, qualified IT staff work with internal business clients to determine IT service needs, and regulatory change requirements. Giving consideration to existing assets, the IT staff then plans the necessary hardware, software and services that will satisfy those needs. This is done formally during budgeting processes, but is also done informally on a routine basis throughout the year to ensure that service is adequate for the needs of the business.

During the planning stages, IT solutions are determined to have a certain level of business criticality. This helps to define the level of service that will be required to maintain the asset and determines how the asset will fit into the disaster recovery and business continuity strategies. These practices lead to the development of capital investment plans and maintenance budgets that address both the present and anticipated condition of IT services.

Acquiring:

Procuring IT assets is done through various means depending on the type, complexity, and size of the asset or service. Generally, acquisition is attained through RFPs or business partnerships, which come about through industry research and an assessment of specific business competency. Bluewater Power engages numerous IT business partners through which products and services are procured.

Deploying:

IT assets are deployed either by BWP IT staff alone, or by BWP IT staff in conjunction with qualified business partners. For example, BWP staff will roll out new computers and desktop software, but would work in conjunction with IBM or a qualified IBM Implementation partner to implement a new Storage Area Network or SAN.

When assets, including hardware and software, are deployed, they are entered into a BWP developed, web based asset tracking system. This system includes many pertinent pieces of data about the asset, such as purchase date, warranties, asset tag details, asset location, etc. This allows BWP IT staff to track an asset throughout its useful life, thereby better enabling the efficient management of the asset.

Maintaining:

Throughout the useful life of IT assets, they are maintained through a variety of tools, practices, and services. BWP monitors the various systems depending on the level of business criticality, as determined in the planning stages. This may include 7x 24 monitoring that produces logs and sends alerts based on pre-established thresholds. Some hardware and software solutions have support contracts associated with them which are provisioned by business partners. These could include 7 x 24 x 4 hour response or could involve incident management services that have associated service levels agreements. Other assets have less monitoring based on the determined level of criticality.

In maintaining IT assets, BWP operates a secure data centre that is remotely supportable. This data centre is supported with UPS and generator backup power management, heat sensitivity alerting and a fire suppression solution. The entire system is secured through a series of audited IT security measures and supported through acceptable industry best practice backup and disaster recovery and business continuity solutions.

Retiring:

The final stage of an IT asset at BWP is its retirement. This can take on various meanings depending on the asset. Generally, a device or solution is decommissioned and disposed of in a secure and environmentally sustainable manner.

With the guidance of these IT asset management practices, BWP is able to provision secure and reliable IT services.

b) Does Bluewater Power have a stand-alone IT strategy document? If yes, please file a copy.

There is no stand-alone document, but please see the response to (a) above.

2.0 - VECC 7 - IT Spending 2009 to 2013

Reference: Exhibit 2, Tab 4, Schedule 3, Attachment 3 – Asset Management Plan /Appendix 2-A

a) Please provide the following information for all information technology spending for 2009 through 2013 (forecast).

The table below includes hardware and software for 'Billing/Smart Meter related' items approved as part of the Smart Meter Rate Application; all other amounts are regular capital spending.

	2009	2010	2011	2012 CGAAP	Actual 2012 CGAAP	Actual 2012 MIFRS	2012 MIFRS	2013 CGAAP	2013 MIFRS
Hardware Billing/smart meter related	49,641	267,105	10,090						
Hardware SCADA related		6,350		15,000	13,431	13,431	15,000		
Other Computer Hardware	408,783	275,375	354,743	703,494	625,117	625,117	703,501	647,125	647,125
Total Computer hardware	458,424	548,830	364,833	718,494	638,548	638,548	718,501	647,125	647,125
Software Billing/smart meter related	47,948	549,587	2,167,515	770,255	770,255	770,255	770,255		
Software SCADA related				15,000	13,431	13,431	15,000		
Other Computer Software	582,679	2,020,991	647,135	1,717,040	1,374,444	1,374,444	1,717,042	560,500	560,500
Total Computer Software	630,627	2,570,578	2,814,649	2,502,295	2,158,130	2,158,130	2,502,297	560,500	560,500
Capitalized Labour & Overhead	311,156	775,003	447,140	894,003	827,186	483,143	488,418	707,986	475,689
Grand Total	**1,400,207**	**3,894,411**	**3,626,622**	**4,114,792**	**3,623,864**	**3,279,821**	**3,709,216**	**1,915,611**	**1,683,314**

2.0-Staff-15 - Building Expansion

Ref: Exh 2-4-3 Project O1

Bluewater Power is in the fourth phase of a multi-year program of Building Renovations/Expansion. The estimated 2012 capital cost is $1,870,500.

a) What was the total area (in sqft or m^2) of the head office at 855 Confederation Street before the renovation project?

The total area office space at the head office at 855 Confederation Street before the renovation was approximately 17,000 sqft above ground and 7,000 sqft in the basement.

We note that the building at 855 Confederation Street is more than just our head office. It is our operational center and includes garage space, storage space and workshop space that is not included in the square footage noted above.

b) How many Bluewater Power staff work from this location?

Approximately 105 staff members work at 855 Confederation Street.

c) What is the total area that will be added following the renovation?

The total area added following the renovation is approximately 4,200 sqft. Combining the addition with the existing office space of 24,000 sqft, this equates to approximately 270 sqft of office space per employee.

d) Of the 2012 estimate of $1,870,500, what is the breakdown for:

- Office space and meeting room
- Expanded restrooms
- Fire code requirements
- Water line capacity

The cost of the $1,870,500 is for a total project and separate breakdown of the items requested is not available from our contractor or the architect.

e) How much of the head office (in sqft or m^2) at 855 Confederation Street is occupied by affiliates of Bluewater Power? Will affiliates occupy more space following completion of the renovation project? If yes, please quantify.

Five offices/cubicles with a total aggregate square footage of 322 are occupied by affiliates and are accounted for in the transfer price study. This number will not change following the completion of the renovation project.

f) When was the project approved by Bluewater Power's Board of Directors? Please provide copies of documentation that were presented to the Board of Directors relating to this project.

This project was originally approved in November 2011 at $1.5M and was subsequently re-approved at $1,870,500 in June 2012. An excerpt of the Board of Directors presentation is attached from both June 2012 and November 2011.

Attachment 1 of 1

2.0 Staff 15 - Building Expansion - Board of Director's Presentation

Building Justification

“IT’S FINALLY TIME!”

Justification For Building Addition

Inadequate Space

- ☐ Many individuals are doubled up in offices.
- ☐ Currently using inappropriate space for offices.
- ☐ Some employees sit in hallways.
- ☐ There is no appropriate storage space so office space is additionally compromised.
- ☐ Some pictorial examples of this situation are as follows:


KEYS
fantastik


DELL
hp

- Office Renovations – We have tried to “make do”!
  - Over Last Ten Years:
    - Design Services – eliminated a training room/ built offices
    - Redesigned Customer Service to incorporate more cubicles
    - Added office spaces to Finance Department – eliminating a storage area for files
    - Redesigned IT to incorporate more offices
    - Redesigned one HR office to accommodate two staff members
    - Eliminated a First Aid Room to create an office
    - Added offices to Operations side – eliminating walk ways and splitting offices in half

Building Addition Update

- Board passed the following resolution in early June:

  "The Board of Bluewater Power Distribution Corporation approve the capital building addition project for 2012 at a total of $1,870,500."

- Total project costs of $1,870,500 versus architect original forecast of $1,500,000

Building Addition Update

Rationale for increased costs include:

- Second Floor future provision
- MOE – 6 months behind in approvals
- Fire Code changes
- Washroom to headcount issues
- IT Server Room – moved up from 2013
- New water Line – existing not sufficient

2.0 - VECC 6 - Building

Reference: Exhibit 2, Tab 4, Schedule 3, Attachment 3 –Asset Management Plan

a) For Project 01 – Building Renovations, the Asset Management Plan indicates the budget (MIFRS) is $1,870,500. Appendix 2-A shows the project budgeted as $2,022,198 (CGAAP). Please explain the difference between these two estimates.

The MIFRS amount of $1,870,500 does not include overhead. By adding the 13.8% overhead rate, the CGAAP amount becomes $2,128,629. The 13.8% rate is the 2012 overhead rate as discussed in Ex. 2-2-1 page 3. The overhead rate for 2013 was not calculated since 2013 was deemed to be on an MIFRS basis.

Per inspection of Appendix 2-A, there are two components that make up the total cost for Project O1 under CGAAP which total $2,128,629. First is the building costs of $2,022,198 (as per this question) and second is $106,431 furniture and equipment.

b) Please provide an update for the completion of this building.

See response to Energy Probe #12c.

2.0-Staff-16 - CN Lease

Ref: Exh 2-4-3 Project O6

Bluewater Power currently rents/leases land rights from CN. Project O6 consists of a $257,200 one-time payment which would eliminate recurring fees. In Exh 2-4-2 Attachment 2 page 32, under OM&A Budget for Operations – Line Department, the CN Lease is listed as item 6.

a) What is the historical cost of this lease?

The annual CN lease costs that were expensed in the past five historical years are as follows:

2012 - $13,801
2011 - $18,451
2010 - $13,501
2009 - $8,557
2008 - $13,476

CN missed billing Bluewater Power for certain amounts in 2009 which were later discovered and billed in 2011. The yearly average is approximately $13,500.

b) What account was the lease cost charged to? Has it been removed from the 2013 forecast?

This lease cost has historically been recorded in Account 5095 'Overhead Distribution Lines and Feeders – Rental Paid'. The average annual cost of $13,500 has not been removed from the 2013 forecast because the lump sum payment of $257,200 is not expected to be paid until near the end of 2013 once all the legal work is completed.

2.0-Staff-17 - Reliability Statistics

<u>Ref: Exh 2-6-1</u>

Bluewater Power provided the following reliability data, excluding loss of supply incidents:

YEAR	SAIDI	SAIFI	CAIDI
2008	2.16	2.10	1.03
2009	1.38	2.30	0.60
2010	1.50	2.10	0.72
2011	2.78	2.38	1.17
AVG	1.96	2.22	0.88

The reliability indicators were stable or improving in the period 2008 to 2010. Bluewater Power states that the contributing factors to 2011 performance were a winter storm event, a summer storm event, an incident related to defective equipment and an incident related to animal contact.

a) What additional measures were put in place following the incident related to the defective equipment (a failed arrestor)?

Arrestor failure is impossible to predict without performing destructive testing (DC Hipot) on the device. This testing would be extremely costly to the rate payer as it requires the equipment to be isolated from its supply in order to perform, and in a large number of instances the arrestor is damaged by the test and then requires replacement.

When an arrester fails we immediately replace the defective arrester and inspect the arresters in the immediate vicinity for any possible deficiencies. If any possible deficiencies are found, the arrestors are replaced.

As with insulator failure, annually we have a high pressure water wash contractor inspect arrestors at close range in areas where they perform their water wash. This contractor will take photos of potentially deficient equipment and it will be scheduled for immediate replacement.

b) Please provide the 2012 reliability results.

Table 1 – 2012 Results

	YEAR	SAIDI	SAIFI	CAIDI
1	2012	2.75	4.26	0.65
2	2012 (without October storm)	1.40	2.14	0.65

From October 29th to 31st, 2012 Bluewater Power's service territory felt significant impacts due to the strong winds from Tropical Storm Sandy. Downed trees, lines and poles caused numerous outages which affected 76,112 customers and caused 48,448 hours or 2.9 million minutes of customer interruption. All customers had power restored by the evening of November 2nd. In order to show the impact of the storm, SAIDI, SAIFI and CAIDI values excluding the storm have been detailed in Table 1.

Furthermore, work practices were modified after the fatality with a lineman which occurred on October 31st, 2012. Before the incident, work was performed 'live' on 27.6 kV and secondary services were disconnected and reconnected 'live'. Immediately after the incident and for approximately 2 months, no live work was performed on primary lines; all was worked on under permit, isolated and de-energized - this created many additional outages. All secondary work was performed with a transformer out of service, again creating additional outages with additional customers without power. These measures resulted in an additional 5000 customers experiencing outages, for approximately 1720 hours of customer interruption. The values in row 1 of Table 1 reflect the impact of the work modification, more specifically, the SAIDI, SAIFI, CAIDI values include the additional outages as required in the OEB reporting.

2.0 - VECC 12 - Outage Reasons 2009-2012

Reference: Exhibit 2, Tab 6, Schedule 1

a) For each year 2009 through 2012 please provide the reason for outages excluding supply loss (e.g. defective equipment, human element, animal interference; tree contact – see pg. 146 of Asset Management Program Review for outage reason categories).

Table 1 – Outage Reasons and Impact

	2009		2010		2011		2012	
	# Outages	# Customer Minutes Interrupted	# Outages	# Customer Minutes Interrupted	# Outages	# Customer Minutes Interrupted	# Outages	# Customer Minutes Interrupted
Animal Contact	17	305,205	13	117,203	20	457,206	22	147,113
Foreign Interference	10	95,191	25	445,340	16	161,645	28	126,011
Human Element	4	66,609	4	18,307	3	9,438	88	119,647
Defective Equipment	74	1,126,502	74	919,782	108	1,886,070	92	1,190,311
Adverse Weather	35	993,036	47	1,099,934	71	2,862,782	104	3,271,392
Tree Contacts	8	28,876	14	157,783	21	167,744	24	497,105
Scheduled	123	192,095	168	461,203	182	484,139	165	550,083
Unknown	12	124,690	8	8,616	16	79,818	12	14,071

The sharp increase in outages caused by “Human Element” in 2012 was due to work practices that were modified after the fatality that occurred on October 31st, 2012. Before the incident, work was performed live on 27.6 kV, secondary services were disconnected and reconnected ‘live’ and 2 man crews were utilized for most work. After the incident and for approximately 2 months, no live work was performed on primary lines; all was worked on under permit, isolated and de-energized- this created many additional outages. All secondary work was performed with a transformer out of service, again creating additional outages with additional customers without power. 83 of the 88 Human Element outages for 2012 were due to the changes in work practice. All normal work practice resumed as of January 1st, 2013. Approximately 5000 customers were affected by these modified work practices that caused about 100,000 minutes of customer interruption.

Both 2011 and 2012 were active weather years. Both winter and summer of 2011 were extreme. There were several winter storms with high winds and snow accumulation as well as an extremely hot summer which brought with it several severe storms. In 2012, weather during the winter and summer months was fairly moderate, while in the fall there were several days with very high winds, the worst being when Tropical Storm Sandy hit at the end of October 2012 and severely impacted Bluewater Power’s service territory causing downed trees, lines and poles. Tropical Storm Sandy accounted for approximately 70 of the adverse weather outages in 2012.

2. - AMPCO 6 - Reliability Statistics

Interrogatory #6

Reference: Exhibit 2, Tab 6, Schedule 1, Page 3

a) Does Bluewater Power track momentary outages?
  - If yes, please provide the MAIFI data from 2008 to 2012 and discuss the trend.
  - If no, please provide an explanation.

Bluewater Power has tracked momentary outages since 2009 detailed in Table 1 below.

Table 1 – Momentary Outages

	2009	2010	2011	2012
Number of Momentary Outages	92	115	208	148
MAIFI	0.00260454	0.00320634	0.005823362	0.00413064

The number of momentary outages generally follows the amount of active weather during the year. For example 2009 had a very cool summer and as such we did not see very active weather, whereas 2011 was extremely hot with many summer storms. Thirty seven of the momentary outages in 2012 were caused by Tropical Storm Sandy.

b) Please discuss if Bluewater Power has a service reliability indicator or program to address the reliability issues faced by the Large User class.

Reliability issues faced by our large user class are an important issue to Bluewater Power. In some cases, we have proactively replaced arrestors and installed animal protection on the circuits that not only feed our large customers but also on other circuits fed out of the main substations in an attempt to reduce the number of sympathetic voltage sags. These voltage sags can drag down the voltage on an entire bus at a substation and cause our large customers to lose operation of large motors and equipment thus upsetting their processes.

In addition, Bluewater Power's Power Systems Specialist's primary role is to review relay coordination, improve and maximize the reaction time of our feeder protection in our main substations on all feeders both those feeding our large customers and the adjacent feeders. Re-closures have been installed in some locations to sectionalize feeders in an effort to reduce exposure (length of feeder) for large customers. In some cases, when internal switching and load transfers are required and increase the exposure to feeders that supply our large customers, we will purposefully move them to alternate feeders for short periods of time if it is beneficial to do so.

c) Please provide Bluewater Power's internal SAIDI, SAIFI, CAIDI & MAIFI targets for 2013.

Bluewater Power strives to stay within the average of the 3 past historical years, therefore the targets produced in Table 2 provide the range of our historical average from 2010-2012.

Table 2 – 2013 Targets

	SAIDI	SAIFI	CAIDI	MAIFI
2013 Target	1.50 – 2.78	2.10 – 4.26	0.65 – 1.17	0.0032 – 0.0055

d) Please provide the number of interruptions, customers affected and customer minutes for each of the years 2008 to 2012.

Table 3 - Outages not including Loss of Supply Outages

	2008	2009	2010	2011	2012
Number of Interruptions	406	283	371	437	535
Customers Affected	75,556	80,799	74,522	85,483	152,816
Customer Minutes	4,684,868	2,932,204	3,228,168	6,108,842	5,915,733

Table 4 - Outages including Loss of Supply Outages

	2008	2009	2010	2011	2012
Number of Interruptions	427	300	380	459	559
Customers Affected	86,279	97,214	83,444	126,510	184,386
Customer Minutes	5,154,059	4,427,557	3,765,971	12,640,005	6,845,225

e) Please provide a breakdown of customer minutes by cause codes for the years 2008 to 2012.

Table 5 – Outage Reasons

	2008	2009	2010	2011	2012
	# Customer Minutes Interrupted	# Customer Minutes Interrupted	# Customer Minutes Interrupted	# Customer Minutes Interrupted	# Customer Minutes Interrupted
0-Unknown	33,575	124,690	8,616	79,818	14,071
1-Scheduled	804,659	192,095	461,203	484,139	550,083
2-Loss of Supply	469,191	1,495,353	528,803	6,531,163	929,492
3-Tree Contacts	617,672	28,876	157,783	167,744	497,105
4-Lightning	605,225	212,852	369,117	1,122,217	25,366
5-Defective Equipment	981,097	1,126,502	919,782	1,886,070	1,190,311
6-Adverse Weather	1,125,567	780,184	730,817	1,740,565	3,246,026
7- Adverse Environment	0	177	0	0	16,829
8- Human Element	300	66,609	18,307	9,438	119,647
9- Foreign Interference	516,773	400,219	562,543	618,851	256,295

f) Please provide a further breakdown of defective equipment on the basis of cause and customer minutes.

Table 6 – Defective Equipment

Equipment Category	Customer Minutes
Underground Cable	241,970
Overhead Cable	6,144
Transformer	139,842
Switch	24,197
Pole	20,419
Insulator	679,818
Fuse	77,601
Arrestor	230
Unknown	90

g) Please discuss how Bluewater Power compares to other utilities in its cohort in terms of reliability.

Bluewater Power does not believe that the data that is gathered in the OEB Yearbook in regard to reliability at this point provides an adequate basis in order to compare utilities. The OEB is in the process of reviewing reliability standards, and on November 23, 2011 commenced *Phase 2 – Initiative to Develop Electricity Distribution System Reliability Standards (EB-2010-0249).* The topics to be addressed through the consultation include:

- Collecting and reporting reliability data in the Board's RRR
    - Updating the current wording of the SAIDI, SAIFI, CAIDI definitions
- Normalizing reliability data for major events
- Reporting of reliability data for outages caused by distributor-controlled factors

- Standardizing certain customer-specific measures
- Standardizing a Worst Performing Circuit measure

Until the reliability definitions and standards have been revised, fully understood and implemented by distributors there is no basis on which to compare one utility with another.

2.0 - EP 7 - Stranded Meters and Smart Meters

Ref: Exhibit 2, Tab 1, Schedule 2, Attachment 2

a) Please explain why Bluewater Power has included adjustments for stranded meters and smart meters in the calculations shown for 2012. In particular, please confirm that smart meters are not included in the 2012 rate base and that the stranded meters are included in the calculation of the 2012 rate base and that these adjustments are made at year end 2012 to ensure the inclusion of smart meters and exclusion of stranded meters at the beginning of 2013 for rate base calculation purposes.

Bluewater Power has shown these calculations in order to be transparent and to better facilitate the cross-referencing to other areas within the evidence.

Smart Meters

The CGAAP NBV of $6,629,529 for smart meters is the net addition to capital assets effective December 31, 2012. This amount can be confirmed in Bluewater Power's Smart Meter rate application EB-2012-0263. This means that this amount was not included in the opening NBV of capital assets for 2012, but was included in the ending NBV balance for 2012. The 2012 opening and closing MIFRS NBV balances in Appendix 2-EB agrees to Exh 2-1-2 Attachment 1. This amount is also evident at Ex. 2-3-2 Attachment 2 "Appendix 2-B 2012 MIFRS (Details)" in the columns labeled "Smart Meter and Stranded Meter". It represents the sum of all additions.

As such, this amount is included in rate base at the beginning of 2013.

Stranded Meters

The CGAAP NBV of $1,926,646 for stranded meters is removed from capital assets effective December 31, 2012. This means that this amount was included in the opening NBV balance for 2012, but not the ending NBV balance for 2012. The opening and closing MIFRS NBV balances in Appendix 2-EB agree to Ex. 2-1-2 Attachment 1. This amount is also evident at Ex. 2-3-2 Attachment 2 “Appendix 2-B 2012 CGAAP” for Account 1860 ‘Meters’ where it is shown as a disposal in 2012.

As such, this amount is excluded from rate base at the beginning of 2013.

b) Please explain the difference in the stranded meter adjustments shown under CGAAP and MIFRS.

The difference relates to the change in depreciation useful lives under MIFRS for the 2012 fiscal year. Under CGAAP, meters are amortized straight-line over 25 years. Under MIFRS, effective January 1, 2012, the newly created ‘deemed cost’ (i.e. NBV at December 31, 2011) of meters are amortized over an estimated average remaining useful life of 14 years. Therefore, the NBV of the stranded meters under MIFRS will be slightly higher than under CGAAP.

2.0 - VECC 11 - Smart Meter Adjustments

Reference: Exhibit 1, Tab 2, Schedule 1, pg. 3/ Exhibit 2, Tab 4, Schedule 4, pg. 2

a) Please show the adjustment to rate base for smart meter costs subsequent to the Board decision in EB-2012-0263. Specifically please update Table 1 at page 2 of E2/T4/S4.

No adjustments to Table 1 are required. Refer to Energy Probe #3 and 9-Staff-54.

2.0 - EP 8 - Changes to Overhead Rate

Ref: Exhibit 2, Tab 2, Schedule 1

a) What is the impact on the 2013 test year rate base as a result of the change in the overhead rate from 10% to 12% in 2011?

The 2013 test year ratebase increases by $78,123. The ‘before’ and ‘after’ summary ratebase calculations are as follows:

original (OH=12% in 2011)		
	2012 Bridge MIFRS	**2013 Test MIFRS**
Net Capital Assets in Service:		
NBV - Opening Balance	42,443,130	52,424,917
NBV - Ending Balance	52,424,917	53,750,781
NBV - Average Balance	47,434,023	53,087,849
Working Capital Allowance:	11,641,795	13,348,086
Rate Base	59,075,819	66,435,935
IFRS - CGAAP Transitional Adjustment	0	364,881
Adjusted Rate Base	**59,075,819**	**66,800,816**

revised per 2-EP-8a (OH=10% in 2011)		
	2012 Bridge MIFRS	**2013 Test MIFRS**
Net Capital Assets in Service:		
NBV - Opening Balance	42,352,827	52,342,298
NBV - Ending Balance	52,342,298	53,675,849
NBV - Average Balance	47,347,563	53,009,074
Working Capital Allowance:	11,641,795	13,348,086
Rate Base	58,989,358	66,357,160
IFRS - CGAAP Transitional Adjustment	0	365,533
Adjusted Rate Base	**58,989,358**	**66,722,693**

b) What is the impact on the 2013 test year depreciation expense as a result of the change in the overhead rate from 10% to 12% in 2011?

The 2013 test year depreciation will change for two items. First, the regular depreciation will increase by $7,684. Second, the annual amortization of Account 1575 results in a decrease of $163. Therefore, the total impact is a net increase of $7,521 to depreciation expense for the 2013 test year.

c) What is the impact on the 2013 test year revenue requirement as a result of the change in the overhead rate from 10% to 12% in 2011?

The 2013 revenue requirement increases by $15,990 as a result of the change in the following items.

- Depreciation – increase of $7,521 as per part (b) above

- Return on RB – increase of $4,742 calculated as $78,123 from part (a) above multiplied by the originally filed WACC of 6.07% from Exh 5-1-1.

- PILs – increase of $3,727 calculated by changing both the Return on Equity (NIBT) and Depreciation Addback in Schedule 1 of the PILs model as per above.

Note that the 2011 UCC/CCA balances could not be changed in the PILs model as they are actual filed amounts. However, from a theoretical point of view, if the 2011 UCC balances increased by the additional 2% overhead being capitalized, then that would flow through to 2013 and result in additional CCA which would in effect lower the 2013 test year PILs amount.

d) What is the impact on the 2013 test year rate base as a result of the change in the overhead rate from 10% to 13.8% in 2012?

The 2013 test year ratebase increases by $330,991. The ‘before’ and ‘after’ summary ratebase calculations are as follows:

original (OH=13.8% in 2012)		
	2012 Bridge MIFRS	**2013 Test MIFRS**
Net Capital Assets in Service:		
NBV - Opening Balance	42,443,130	52,424,917
NBV - Ending Balance	52,424,917	53,750,781
NBV - Average Balance	47,434,023	53,087,849
Working Capital Allowance:	11,641,795	13,348,086
Rate Base	59,075,819	66,435,935
IFRS - CGAAP Transitional Adjustment	0	364,881
Adjusted Rate Base	**59,075,819**	**66,800,816**

revised per 2-EP-8d (OH=10% in 2012)		
	2012 Bridge MIFRS	**2013 Test MIFRS**
Net Capital Assets in Service:		
NBV - Opening Balance	42,443,130	52,424,917
NBV - Ending Balance	52,424,917	53,750,781
NBV - Average Balance	47,434,023	53,087,849
Working Capital Allowance:	11,641,795	13,348,086
Rate Base	59,075,819	66,435,935
IFRS - CGAAP Transitional Adjustment	0	33,889
Adjusted Rate Base	**59,075,819**	**66,469,824**

e) What is the impact on the 2013 test year depreciation expense as a result of the change in the overhead rate from 10% to 13.8% in 2012?

The 2013 test year depreciation will change for only one item because the regular depreciation will not change. The annual amortization of Account 1575 results in an increase of $82,748. Therefore, the total impact is a net increase of $82,748 to depreciation expense for the 2013 test year.

f) What is the impact on the 2013 test year revenue requirement as a result of the change in the overhead rate from 10% to 13.8% in 2012?

The 2013 revenue requirement increases by $107,947 as a result of the change in the following items.

- Depreciation – increase of $82,748 as per part (e) above

- Return on RB – increase of $20,091 calculated as $330,991 from part (d) above multiplied by the originally filed WACC of 6.07% from Exh 5-1-1.

- PILs – increase of $5,108 calculated by changing both the Return on Equity (NIBT), Depreciation Addback and UCC/CCA in Schedule 1 of the PILs model as per above.

2.0 - EP 9 - Depreciation Expense

Ref: Exhibit 2, Tab 2, Schedule 4

Please provide a table for each of 2009, 2010, 2011 and 2012 (if actual data is available) that shows the depreciation expense actually recorded in each year as compared to what the depreciation expense would have been if it had been calculated using the half year rule.

The table provided below provides a comparison for the years 2009, 2010 and 2011 of the Half-year rule versus the amount actually recorded using Bluewater Power's practice of recording assets in the month they come into service. Although we worked toward completing the 2012 Actuals, the information was not available with sufficient detail to permit an analysis of monthly data, so the amount shown as "Recorded" for 2012 is based on the half year rule.

	2009	2010	2011	2012
Recorded	3,968,013	3,939,847	4,259,216	4,682,004
Half year rule	3,983,192	3,946,142	4,289,958	4,682,004
Difference	(15,179)	(6,295)	(30,742)	-

The table provided demonstrates that the half-year rule is a reasonable approximation of the actual experience of recording depreciation on a monthly basis.

2.0 - SEC 18 - Depreciation Policy

[2/2/4] With respect to depreciation policy:

a. Please provide the full "internal analysis" used to establish new depreciation rates.

The Finance Department of Bluewater Power determined its new depreciation rates, where applicable, through discussions with the Manager of Lines and the Manager of Design Services. Through their knowledge and experience with respect to Bluewater Power's plant and equipment, more appropriate useful lives were set. The Kinectric's range of useful lives was used as a guide.

Similarly, the Director of the Bluewater Power's I.T. department considered the useful lives of computer hardware and software and no changes were deemed necessary based on experience.

b. Please advise if any external advice or assistance was obtained in the development of the new depreciation rates. If there was any such advice or assistance, please provide details of the consultants or other persons retained and the nature of their work. Please provide copies of any reports, presentations, memos, or other documents provided to the Applicant by those persons.

There was no formal external advice or assistance obtained. Bluewater Power made reference to the Kinectrics report which was prepared externally. As well, Bluewater Power conferred with other utilities in southwestern Ontario as a reasonability check.

c. Please provide any reports, presentations, memos or other documents provided to senior management, the Board of Directors, or the shareholders dealing in whole or in part with the proposed changes in useful lives/depreciation rates.

Bluewater Power's shareholders were not provided any information regarding the proposed change in useful lives. The senior management, Board of Directors, and the Audit Committee with KPMG external auditors were regularly updated at their respective meetings through verbal discussions. They were informed of the discussions between the Finance Department and senior Operations Department personnel to determine new useful lives, if applicable, and the overall forecasted annual change in depreciation expense between CGAAP and MIFRS.

d. Please explain in more detail why there is no change in depreciation for 2012, the year prior to the Applicant's first MIFRS year. Please confirm that the 2012 depreciation assumed for continuity purposes under MIFRS is $897,014 less than under CGAAP, and as a result net rate base as of January 1, 2013 is increased by that much.

Bluewater Power did not change its depreciation policy in 2012 primarily due to the SAP system work that is required to recalculate depreciation expense. During 2012, the Finance Department's resources were busy with Bluewater Power's smart meter rate application and 2013 cost of service rate application.

Bluewater Power confirms the difference in 2012 depreciation between CGAAP and MIFRS is $897,014 ($4,729,669 CGAAP less $3,832,655 MIFRS). This is evident at Exh 2-1-2, Attachment 2 - Appendix 2-EB "IFRS-CGAAP Transitional PP&E Amounts". This difference forms part of the overall transitional amount of $364,881 per Appendix 2-EB which is added to ratebase as discussed at Exh 2-1-1.

e. Please provide a justification for each change in depreciation rates in 2/2/4, Attach 1.

See response to part (a) above.

f. Please add a column to Attachment 1 showing the Kinectrics range applicable to each category of asset.

See response to 2-VECC-2.

2.0 - EP 13 - Commodity Price

Ref: Exhibit 2, Tab 5, Schedule 1

a) Please show the calculation of the weighted average commodity price of $0.810/kWh and provide the data upon which the RPP and non-RPP loads were determined. Please also show the RPP and non-RPP prices and how they were derived from the April 2, 2012 Navigant report.

Table 1 below details the calculation of the weighted average commodity price of $.0810/kWh utilizing the prices detailed in the OEB's April 2, 2012 report.

Table 1 – Weighted Average Commodity Price

Reference			2011 ACTUAL kWh's	
	Customer Class Name	Total	non-RPP	RPP
	Residential	257,450,968	31,484,477	225,966,491
	General Service < 50 kW	105,807,915	12,086,479	93,721,436
	General Service > 50 to 999 kW	225,133,479	173,496,871	51,636,608
	General Service 1000 to 4999 kW	160,156,759	160,156,759	
	Large Use	253,729,738	137,982,417	115,747,321
	Unmetered Scattered Load	2,238,935		2,238,935
	Sentinel Lighting	627,674		627,674
	Street Lighting	8,979,432	8,979,432	
	TOTAL	1,014,124,900	524,186,435	489,938,465
1	*%*	*100.00%*	*51.69%*	*48.31%*
	Forecast Price			
2	HOEP ($/MWh)		$23.62	
3	Global Adjustment ($/MWh)		$57.72	
4	TOTAL ($/MWh)		$81.34	$80.69
	$/kWh		*$0.08134*	*$0.08069*
5	%		51.69%	48.31%
6	WEIGHTED AVERAGE PRICE	$0.0810	$0.0420	$0.0390

The RPP and non-RPP prices were sourced from the OEB's Regulated Price Plan Report dated April 2, 2012. HOEP price (reference 2) is detailed at page 11 and we have used the period May 2013 through October 2013 as the most relevant period. Global Adjustment (reference 3) is detailed at page 18, and the RPP price (reference 4) is detailed at page 3.

b) Please update Attachment 1 to reflect the OEB's Regulated Price Plan Report dated October 17, 2012.

Table 2 below is an update of Table 1 with the HOEP, Global Adjustment and RPP price as indicated in the OEB’s report dated October 17, 2012. Following is Attachment 1 which is an updated Pass-Through Charges report which is an input into the Working Capital Allowance. The updated weighted average commodity price is $.0797/kWh. Bluewater Power has incorporated the updated price into the revised revenue requirement, RRWF, and bill impacts presented in response to these interrogatories.

Table 2 – Updated Weighted Average Commodity Price

		2011 ACTUAL kWh's	
Customer Class Name	Total	non-RPP	RPP
Residential	257,450,968	31,484,477	225,966,491
General Service < 50 kW	105,807,915	12,086,479	93,721,436
General Service > 50 to 999 kW	225,133,479	173,496,871	51,636,608
General Service 1000 to 4999 kW	160,156,759	160,156,759	
Large Use	253,729,738	137,982,417	115,747,321
Unmetered Scattered Load	2,238,935		2,238,935
Sentinel Lighting	627,674		627,674
Street Lighting	8,979,432	8,979,432	
TOTAL	1,014,124,900	524,186,435	489,938,465
%	*100.00%*	*51.69%*	*48.31%*
Forecast Price			
HOEP ($/MWh)		$20.65	
Global Adjustment ($/MWh)		$59.36	
TOTAL ($/MWh)		$80.01	$79.32
$/kWh		*$0.08001*	*$0.07932*
%		51.69%	48.31%
WEIGHTED AVERAGE PRICE	$0.0797	$0.0414	$0.0383

Attachment 1 of 1

2.0 - Energy Probe 13 - Updated Pass Through Charges

Bluewater Power (ED-2002-0517)

2013 EDR Application (EB-2012-0107) version: 1

October 12, 2012

C8 Pass-through Charges

Volumes from sheet C1, Account #s from sheet Y4

Enter rates for pass-through charges and estimated Low Voltage revenues

Electricity (Commodity)	**Customer**	**Revenue**	**Expense**	**2012**	*rate ($/kWh):*	**$0.07372**	**2013**	*rate ($/kWh):*	**$0.07970**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
kWh	Residential	4006	4705	270,599,104		19,948,566	266,451,788		21,236,208
kWh	General Service < 50 kW	4035	4705	107,805,875		7,947,449	101,536,145		8,092,431
kWh	General Service > 50 to 999 kW	4035	4705	230,107,696		16,963,539	225,109,558		17,941,232
kWh	General Service 1000 to 4999 kW	4035	4705	163,216,328		12,032,308	161,652,837		12,883,731
kWh	Large Use	4020	4705	137,557,069		10,140,707	132,995,614		10,599,750
kWh	Unmetered Scattered Load	4035	4705	2,333,194		172,003	2,333,194		185,956
kWh	Sentinel Lighting	4030	4705	654,099		48,220	654,099		52,132
kWh	Street Lighting	4025	4705	9,439,703		695,895	9,369,836		746,776
	TOTAL			**921,713,069**		**67,948,687**	**900,103,073**		**71,738,215**
Transmission - Network	**Customer**	**Revenue**	**Expense**		**2012**			**2013**	
	Class Name	**USA #**	**USA #**	**Volume**	**Rate**	**Amount**	**Volume**	**Rate**	**Amount**
kWh	Residential	4066	4714	270,599,104	$0.0068	1,840,074	266,451,788	$0.0064	1,705,291
kWh	General Service < 50 kW	4066	4714	107,805,875	$0.0063	679,177	101,536,145	$0.0060	609,217
kW	General Service > 50 to 999 kW	4066	4714	625,979	$2.5648	1,605,511	627,074	$2.4271	1,521,971
kW	General Service 1000 to 4999 kW	4066	4714	333,340	$2.7241	908,051	337,859	$2.5778	870,933
kW	Large Use	4066	4714	400,494	$3.0162	1,207,970	392,393	$2.8543	1,120,007
kWh	Unmetered Scattered Load	4066	4714	2,333,194	**$0.0063**	14,699	2,333,194	$0.0060	13,999
kW	Sentinel Lighting	4066	4714	1,452	**$1.9441**	2,823	1,452	$1.8397	2,671
kW	Street Lighting	4066	4714	24,338	**$1.9342**	47,075	24,157	$1.8304	44,217
	TOTAL			**382,123,776**		**6,305,380**	**371,704,063**		**5,888,307**
Transmission - Connection	**Customer**	**Revenue**	**Expense**		**2012**			**2013**	
	Class Name	**USA #**	**USA #**	**Volume**	**Rate**	**Amount**	**Volume**	**Rate**	**Amount**
kWh	Residential	4068	4716	270,599,104	$0.0057	1,542,415	266,451,788	$0.0054	1,438,840
kWh	General Service < 50 kW	4068	4716	107,805,875	$0.0050	539,029	101,536,145	$0.0047	477,220
kW	General Service > 50 to 999 kW	4068	4716	625,979	$1.9998	1,251,833	627,074	$1.8963	1,189,120
kW	General Service 1000 to 4999 kW	4068	4716	333,340	$2.1923	730,781	337,859	$2.0788	702,341
kW	Large Use	4068	4716	400,494	$2.5070	1,004,038	392,393	$2.3772	932,797
kWh	Unmetered Scattered Load	4068	4716	2,333,194	$0.0050	11,666	2,333,194	$0.0047	10,966
kW	Sentinel Lighting	4068	4716	1,452	$1.5783	2,292	1,452	$1.4966	2,173
kW	Street Lighting	4068	4716	24,338	$1.5461	37,629	24,157	$1.4660	35,414
	TOTAL			**382,123,776**		**5,119,683**	**371,704,063**		**4,788,871**
Wholesale Market Service	**Customer**	**Revenue**	**Expense**	**2012**	*rate ($/kWh):*	**$0.00520**	**2013**	*rate ($/kWh):*	**$0.00520**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
kWh	Residential	4062	4708	270,599,104		1,407,115	266,451,788		1,385,549
kWh	General Service < 50 kW	4062	4708	107,805,875		560,591	101,536,145		527,988
kWh	General Service > 50 to 999 kW	4062	4708	230,107,696		1,196,560	225,109,558		1,170,570
kWh	General Service 1000 to 4999 kW	4062	4708	163,216,328		848,725	161,652,837		840,595
kWh	Large Use	4062	4708	137,557,069		715,297	132,995,614		691,577
kWh	Unmetered Scattered Load	4062	4708	2,333,194		12,133	2,333,194		12,133
kWh	Sentinel Lighting	4062	4708	654,099		3,401	654,099		3,401
kWh	Street Lighting	4062	4708	9,439,703		49,086	9,369,836		48,723
	TOTAL			**921,713,069**		**4,792,908**	**900,103,073**		**4,680,536**
Rural Rate Protection	**Customer**	**Revenue**	**Expense**	**2012**	*rate ($/kWh):*	**$0.00110**	**2013**	*rate ($/kWh):*	**$0.00110**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
kWh	Residential	4062	4730	270,599,104		297,659	266,451,788		293,097
kWh	General Service < 50 kW	4062	4730	107,805,875		118,586	101,536,145		111,690
kWh	General Service > 50 to 999 kW	4062	4730	230,107,696		253,118	225,109,558		247,621
kWh	General Service 1000 to 4999 kW	4062	4730	163,216,328		179,538	161,652,837		177,818
kWh	Large Use	4062	4730	137,557,069		151,313	132,995,614		146,295
kWh	Unmetered Scattered Load	4062	4730	2,333,194		2,567	2,333,194		2,567
kWh	Sentinel Lighting	4062	4730	654,099		720	654,099		720
kWh	Street Lighting	4062	4730	9,439,703		10,384	9,369,836		10,307
	TOTAL			**921,713,069**		**1,013,884**	**900,103,073**		**990,113**
Debt Retirement Charge	**Customer**	**Revenue**	**Expense**	**2012**	*rate ($/kWh):*	**$0.00700**	**2013**	*rate ($/kWh):*	**$0.00700**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
	TOTAL								
Low Voltage Charges	**Customer**	**Revenue**	**Expense**		**2012**			**2013**	
	Class Name	**USA #**	**USA #**	**Volume**	**Rate**	**Amount**	**Volume**	**Rate**	**Amount**
kWh	Residential	4075	4750	259,667,118	**$0.0002**	51,933	255,687,351	**$0.0002**	51,137
kWh	General Service < 50 kW	4075	4750	103,450,605	**$0.0002**	20,690	97,434,167	**$0.0002**	19,487
kW	General Service > 50 to 999 kW	4075	4750	625,979	**$0.0722**	45,196	627,074	**$0.0750**	47,031
kW	General Service 1000 to 4999 kW	4075	4750	333,340	**$0.0792**	26,401	337,859	**$0.0822**	27,772
kW	Large Use	4075	4750	400,494	**$0.0905**	36,245	392,393	**$0.0940**	36,885
kWh	Unmetered Scattered Load	4075	4750	2,238,935	**$0.0002**	448	2,238,935	**$0.0002**	448
kW	Sentinel Lighting	4075	4750	1,452	**$0.0570**	83	1,452	**$0.0592**	86
kW	Street Lighting	4075	4750	24,338	**$0.0558**	1,358	24,157	**$0.0580**	1,401
	TOTAL			**366,742,261**		**182,353**	**356,743,388**		**184,247**
GRAND TOTAL						**85,362,896**			**88,270,289**

2.0 - VECC 9 - Asset Management Plan

Reference: Exhibit 2, Tab 4, Schedule 3, Attachment 3 – Asset Management Plan /Appendix 2-A

a) In a number of places the Asset Management Plan does not appear to be consistent with the Capital budget as set out in Appendix 2-A. This appears to be especially true for 2012 amounts. Please reconcile Appendix 2-A with any material differences from the Asset Management Plan.

The note at the bottom of Appendix 2-A states as follows:

> *"Please Note: The values presented above for each capital project do not include 'Assets Under Construction' in order to make all year's comparable with 2013 Test Year. The net assets under construction for the applicable years are added at the bottom of this schedule to ensure the grand total reconciles to that presented in Exhibit 2, Tab 4, Schedule 3, Attachment 1 – Table of Capital Expenditures 2009 to 2013*"

The same rule would apply when reconciling to the numbers in Appendix 2-A to the numbers in the Asset Management Plan. To put the note another way, the annual spending reflected in the Asset Management Plan is based on actual spending in that year (whether in service or under construction), whereas the values in Appendix 2-A reflect the assets capitalized in a given year. In fact, the only way to accurately break-down a capital asset into its component parts is after the project has been completed and is capitalized; whereas, the capital budgeting process requires more timely feedback and is, therefore, tracked on an "as spent" basis. In order to reconcile to two accounting methods, we have introduced Assets Under Construction as the bottom-line adjustment to Appendix 2-A.

As an illustration of this point, we direct the reader to UT4 – 27.6 kV Neutral Program. The Asset Management Plan shows spending of $45,326 (2009) and $19,024 (2010) for a total spending of $64,350; whereas Appendix 2-A shows $0(2009) and $64,306 (2010) for a nearly identical two-year total. If one carries out a longer-term comparison of capital spending versus amounts actually capitalized, the only difference would be (i) minor adjustments for actual spending that was not permitted to be capitalized because it did not meet the test for capital, and (ii) the starting balance of Assets Under Construction at the start of the comparison period.

As a further illustration of this point, we note that the 2013 amounts in the Asset Management Plan do coincide with the amounts reflected in Appendix 2-A because Assets Under Construction do not come into play. The 2013 comparison is essentially a budget to budget comparison as there is no benefit to projecting a 2012 Assets Under Construction balance.

Finally, we note for the sake of clarity that the amounts reflected in Appendix 2-A are the amounts that feed into Fixed Asset Accounts for the utility and ultimately form Rate Base.

2.0 - VECC 10 - Same values for 2012 and 2013 Capital projects

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2-VECC-10 Reference: Exhibit 2, Tab 4, Schedule 3, Attachment 4 Appendix 2-A

a) In a number of places in the capital budget the amounts set out for 2012 are identical to those for 2013 (see for example projects listed under U26 and U27). Please confirm that this is not an error in the table.

The capital budget items that are identical in 2012 and 2013 are generally multi-year projects. They are projects where the operations group intentionally budgets a consistent amount based on an assessment of the need for the work and, therefore, its level of priority amidst the competing demands for the resources within both engineering and lines departments. Although actuals may vary from year-to-year due to mid-year adjustments, the budgets are consistent year over year.

The one exception to this general rule is the vehicle replacement budget, which is identical in 2012 and 2013 by coincidence. The vehicle budgets are made-up of an individual assessment of vehicles requiring replacement and the estimated cost of those replacements happen to reach the same total in each year.

2.0 - SEC 16 - Continuity Schedules without Acc Dep and CC

[2/3/2, Attach. 2-B and 2/2/1, p.5] Please restate these tables in a manner consistent with items #1 and #2 in the Board-approved Supplementary Settlement Agreement for Hydro Ottawa in EB-2011-0054 (a copy of which is attached). That it, please show this continuity without closing out accumulated depreciation and contributed capital to gross fixed assets.

The tables in Exh 2-3-2, Attachment 2 that need to be restated for this request are the following:

- Appendix 2-B: 2012 MIFRS
- Appendix 2-B: 2013 MIFRS

Please find these two updated tables in Attachment 1 of this interrogatory.

Note that the 2012 and 2013 ending total NBV under MIFRS did not change. Also note that the originally filed table labeled Appendix 2-B: 2012 MIFRS (Details) can be ignored for this IR response.

Attachment 1 of 1

SEC 16 - Continuity Schedules

File Number:	EB-2012-0107
Exhibit:	2
Tab:	3
Schedule:	2
Attachment:	2
Date:	30-Jan-13

Appendix 2-B
Fixed Asset Continuity Schedule

SEC #16

Year **2012 MIFRS**

				Cost				**Accumulated Depreciation**				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance CGAAP**	**Additions**	**Smart Meter and Stranded Meter**	**Closing Balance under MIFRS**	**Opening Balance CGAAP**	**Additions**	**Smart Meter and Stranded Meter**	**Closing Balance under MIFRS**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)		$ 9,500,884	$ 2,012,306	$ 3,537,240	$ 15,050,430	-$ 6,007,128	-$ 1,501,021	-$ 1,037,528	-$ 8,545,677	$ 6,504,753
CEC	1612	Land Rights (Formally known as Account 1906)		$ 283,160		$ -	$ 283,160	-$ 267,342	-$ 1,217	$ -	-$ 268,559	$ 14,601
N/A	1805	Land		$ 497,489		$ -	$ 497,489	$ -		$ -	$ -	$ 497,489
47	1808	Buildings		$ -		$ -	$ -	$ -		$ -	$ -	$ -
13	1810	Leasehold Improvements		$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 6,455,582	$ 301,888	$ 0	$ 6,757,470	-$ 3,215,427	-$ 192,435	$ -	-$ 3,407,862	$ 3,349,608
47	1825	Storage Battery Equipment		$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 2,257,678	$ 985,044	$ -	$ 3,242,722	-$ 245,396	-$ 58,350	$ -	-$ 303,746	$ 2,938,976
47	1835	Overhead Conductors & Devices		$ 27,485,935	$ 810,478	$ -	$ 28,296,413	-$ 17,366,822	-$ 304,719	$ -	-$ 17,671,541	$ 10,624,872
47	1840	Underground Conduit		$ 1,150,356	$ 127,029	$ -	$ 1,277,385	-$ 105,793	-$ 22,574	$ -	-$ 128,367	$ 1,149,018
47	1845	Underground Conductors & Devices		$ 20,300,059	$ 915,874	$ -	$ 21,215,933	-$ 11,974,110	-$ 375,412	$ -	-$ 12,349,522	$ 8,866,411
47	1850	Line Transformers		$ 15,367,543	$ 715,088	$ -	$ 16,082,631	-$ 8,549,764	-$ 229,929	$ -	-$ 8,779,693	$ 7,302,938
47	1855	Services (Overhead & Underground)		$ 555,088	$ 43,116	$ -	$ 598,204	-$ 57,125	-$ 23,037	$ -	-$ 80,162	$ 518,042
47	1860	Meters		$ 7,862,812	$ 25,000	-$ 6,719,816	$ 1,167,996	-$ 4,840,300	-$ 213,162	$ 4,791,515	-$ 261,947	$ 906,049
8	1860	Meters (Smart Meters)		$ -		$ 4,661,948	$ 4,661,948	$ -		-$ 729,238	-$ 729,238	$ 3,932,710
N/A	1905	Land		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures		$ 6,009,894	$ 1,910,100	-$ 0	$ 7,919,994	-$ 1,943,405	-$ 129,237	$ -	-$ 2,072,642	$ 5,847,352
13	1910	Leasehold Improvements		$ -		$ -	$ -	$ -		$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 876,633	$ 108,014	$ -	$ 984,647	-$ 691,137	-$ 47,868	$ -	-$ 739,005	$ 245,642
8	1915	Office Furniture & Equipment (5 years)		$ -		$ -	$ -	$ -		$ -	$ -	$ -
10	1920	Computer Equipment - Hardware		$ 5,099,380	$ 994,250	$ 330,711	$ 6,424,341	-$ 3,953,890	-$ 479,539	-$ 174,816	-$ 4,608,245	$ 1,816,096
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -		$ -	$ -	$ -		$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -		$ -	$ -	$ -		$ -	$ -	$ -
10	1930	Transportation Equipment		$ 4,341,254	$ 554,434	$ -	$ 4,895,688	-$ 2,815,922	-$ 268,098	$ -	-$ 3,084,020	$ 1,811,668
8	1935	Stores Equipment		$ 81,138		$ -	$ 81,138	-$ 71,284	-$ 4,927	$ -	-$ 76,211	$ 4,927
8	1940	Tools, Shop & Garage Equipment		$ 887,821	$ 48,800	$ 54,087	$ 990,708	-$ 653,757	-$ 54,338	-$ 12,692	-$ 720,787	$ 269,921
8	1945	Measurement & Testing Equipment		$ 313,080	$ 52,852	$ -	$ 365,932	-$ 223,931	-$ 19,568	$ -	-$ 243,499	$ 122,433
8	1950	Power Operated Equipment		$ -		$ -	$ -	$ -		$ -	$ -	$ -
8	1955	Communications Equipment		$ 252,975		$ -	$ 252,975	-$ 161,893	-$ 16,526	$ -	-$ 178,419	$ 74,556
8	1955	Communication Equipment (Smart Meters)		$ -		$ -	$ -	$ -		$ -	$ -	$ -
8	1960	Miscellaneous Equipment		$ 784,532		$ -	$ 784,532	-$ 712,325	-$ 5,158	$ -	-$ 717,483	$ 67,049
47	1975	Load Management Controls Utility Premises		$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	1980	System Supervisor Equipment		$ 1,238,700		$ -	$ 1,238,700	-$ 794,694	-$ 38,354	$ -	-$ 833,048	$ 405,652
47	1985	Miscellaneous Fixed Assets		$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	1995	Contributions & Grants		-$ 6,487,773	-$ 491,240	$ -	-$ 6,979,013	$ 1,412,859	$ 152,812	$ -	$ 1,565,671	-$ 5,413,342
	1970	Load Management Controls - Customer Premises		$ 464,917		$ -	$ 464,917	-$ 464,917	$ -	$ -	-$ 464,917	$ -
	1990	Other Tangible Property (major spare parts)		$ 567,497		$ -	$ 567,497	$ -		$ -	$ -	$ 567,497
		Total		**$ 106,146,634**	**$ 9,113,033**	**$ 1,864,170**	**$ 117,123,837**	**-$ 63,703,503**	**-$ 3,832,657**	**$ 2,837,241**	**-$ 64,698,919**	**$ 52,424,918**

File Number: EB-2012-0107
Exhibit: 2
Tab: 3
Schedule: 2
Attachment: 2

Date: Jan 30,2013

Appendix 2-B
Fixed Asset Continuity Schedule

SEC 16

Year **2013 MIFRS**

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)		$ 15,050,430	$ 993,685	$ -	$ 16,044,115	-$ 8,545,677	-$ 2,179,195		-$ 10,724,872	$ 5,319,243
CEC	1612	Land Rights (Formally known as Account 1906)		$ 283,160	$ 257,200		$ 540,360	-$ 268,559	-$ 1,217		-$ 269,776	$ 270,584
N/A	1805	Land		$ 497,489			$ 497,489	$ -			$ -	$ 497,489
47	1808	Buildings		$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 6,757,470	$ 355,000		$ 7,112,470	-$ 3,407,862	-$ 125,857		-$ 3,533,719	$ 3,578,751
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 3,242,722	$ 834,250		$ 4,076,972	-$ 303,746	-$ 78,564		-$ 382,310	$ 3,694,662
47	1835	Overhead Conductors & Devices		$ 28,296,413	$ 617,000		$ 28,913,413	-$ 17,671,541	-$ 319,480		-$ 17,991,021	$ 10,922,392
47	1840	Underground Conduit		$ 1,277,385	$ 130,000		$ 1,407,385	-$ 128,367	-$ 25,144		-$ 153,511	$ 1,253,874
47	1845	Underground Conductors & Devices		$ 21,215,933	$ 1,185,000		$ 22,400,933	-$ 12,349,522	-$ 401,126		-$ 12,750,648	$ 9,650,285
47	1850	Line Transformers		$ 16,082,631	$ 704,750		$ 16,787,381	-$ 8,779,693	-$ 247,677		-$ 9,027,370	$ 7,760,011
47	1855	Services (Overhead & Underground)		$ 598,204	$ 55,000		$ 653,204	-$ 80,162	-$ 24,999		-$ 105,161	$ 548,043
47	1860	Meters		$ 1,167,996	$ 50,000	$ -	$ 1,217,996	-$ 261,947	-$ 57,588		-$ 319,535	$ 898,461
8	1860	Meters (Smart Meters)		$ 4,661,948		$ -	$ 4,661,948	-$ 729,238	-$ 282,779		-$ 1,012,017	$ 3,649,931
N/A	1905	Land		$ -			$ -	$ -	$ -		$ -	$ -
1	1908	Buildings & Fixtures		$ 7,919,994	$ 212,500		$ 8,132,494	-$ 2,072,642	-$ 148,447		-$ 2,221,089	$ 5,911,405
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 984,647	$ 10,000		$ 994,647	-$ 739,005	-$ 53,768		-$ 792,773	$ 201,874
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ 6,424,341	$ 912,840	$ -	$ 7,337,181	-$ 4,608,245	-$ 673,251		-$ 5,281,496	$ 2,055,685
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment		$ 4,895,688	$ 502,500		$ 5,398,188	-$ 3,084,020	-$ 323,161		-$ 3,407,181	$ 1,991,007
8	1935	Stores Equipment		$ 81,138			$ 81,138	-$ 76,211	-$ 4,927		-$ 81,138	$ -
8	1940	Tools, Shop & Garage Equipment		$ 990,708	$ 42,000	$ -	$ 1,032,708	-$ 720,787	-$ 63,558		-$ 784,345	$ 248,363
8	1945	Measurement & Testing Equipment		$ 365,932	$ 50,000		$ 415,932	-$ 243,499	-$ 24,711		-$ 268,210	$ 147,722
8	1950	Power Operated Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment		$ 252,975			$ 252,975	-$ 178,419	-$ 16,526		-$ 194,945	$ 58,030
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ 784,532			$ 784,532	-$ 717,483	-$ 5,158		-$ 722,641	$ 61,891
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment		$ 1,238,700	$ 20,000		$ 1,258,700	-$ 833,048	-$ 38,754		-$ 871,802	$ 386,898
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants		-$ 6,979,013	-$ 675,455		-$ 7,654,468	$ 1,565,671	$ 165,484		$ 1,731,155	-$ 5,923,313
	1970	Load Management Controls - Customer Premises		$ 464,917			$ 464,917	-$ 464,917	$ -		-$ 464,917	$ -
	1990	Other Tangible Property (major spare parts)		$ 567,497			$ 567,497	$ -			$ -	$ 567,497
		Total		**$ 117,123,837**	**$ 6,256,270**	**$ -**	**$ 123,380,107**	**-$ 64,698,919**	**-$ 4,930,403**	**$ -**	**-$ 69,629,322**	**$ 53,750,785**

2.0 - SEC 17 - Categories of expense that were Capitalized

[2/2/1, p. 6] Please provide a detailed table showing the particular categories of expense that were capitalized in 2011 (i.e. included in direct capitalization or included in the overhead), and indicating those that will not be capitalized under MIFRS in the Test Year. Please be as specific as possible, including at least the categories included in 2/2/2, p. 3.

The categories of expense that were capitalized in 2011 include the following:

- Direct labour (salary, wages, overtime)
- Burden on the direct labour (CPP, EI, WSIB, EHT)
- Extended benefits on the direct labour (OMERS, life insurance, dental, etc)
- Direct vehicle costs (fuel, insurance, maintenance, depreciation, cost of capital)
- Direct overtime meal costs
- Indirect overhead – the categories of expense relating to indirect overhead are outlined in Ex. 2-2-2, page 3

It is only indirect overhead that will not be capitalized under MIFRS in the 2013 test year. All direct costs will continue to be capitalized.

As per the discussion in Ex. 2-2-2, indirect overhead are those remaining costs that could not be directly attributed to the Operations, Affiliates, Billable and Capital functions of Bluewater Power. They include the CEO, VP of Corporate Services, VP of Finance, VP of Strategic Development, finance, board of directors, support services and purchasing. Thus, that portion of indirect overhead allocated to the Capital function will not be capitalized.

2.0 - AMPCO 2 - Maintenance Cycles

Interrogatory #2

Reference: Exhibit 2, Tab 4, Schedule 2, Page 7

a) For each of the maintenance activities listed on page 7, please provide the maintenance/ inspection cycle for each activity in 2009, 2012 and proposed for 2013.

Maintenance Activity	2009	2012	Proposed 2013
Pole Inspections	4,317 poles out of approximately 15,900 poles	3,503 poles out of approximately 15,900 poles	All rural areas and Northwest Sarnia and Point Edward
Thermography	Entire service area	Entire service area	Entire service area
Tree Trimming	Point Edward and South central Sarnia	Alvinston, Petrolia, Southeast Sarnia and rural East Sarnia	Point Edward and South central Sarnia
Insulator Washing	All insulators associated with 27.6kV feeders	All insulators associated with 27.6kV feeders	All insulators associated with 27.6kV feeders
Substation Inspection	Unknown- records could not be located	9 out of 12 months	12 times
Vault Inspection	All done 3 times	All done 5 times	All done monthly
Substation Maintenance (17 total)	2 completed (MS 11 and MS 12)	7 completed (MS 1, MS 8, MS 9, MS 10, MS 20, MS 32, MS 46)	4 substations proposed
Maintenance of subdivision transformers and switches	None completed	None completed	Petrolia

b) Please explain the reasons for any changes in the maintenance, inspection or testing cycles in 2009, 2012 and 2013.

Pole Inspections: Pole inspections are currently carried out on a 3-year cycle for both urban and rural areas. Depending upon the circumstance, such as the mix of urban and rural, the number of poles inspected in any given year varies. We also note that in the year 2010, Bluewater Power introduced ArcPad 8, a field mapping and data collection tool. With the implementation of this tool, Bluewater Power moved from a manual paper based and data entry system to an electronic tablet entry system which allows users to simply upload the gathered information into our Geographical Information System (GIS). This created transition issues with implementation and training impacting the inspection cycle, but the efficiencies introduced have help bring the inspection cycles on track.

Thermography: no changes in cycles from year to year, all completed annually.

Tree Trimming: performed on a 4 year cycle- where approximately one quarter of Bluewater Power's service territory is completed each year. No changes in this cycle from year to year.

Insulator washing: no changes in cycles from year to year, all completed annually.

Substation inspection: while the goal is to complete an inspection of all 17 substations every month, in 2012, 3 months were missed due to staff shortages. In 2013, we believe better planning and resourcing will allow for each substation to be inspected each month.

Vault Inspection: The goal is to complete an inspection of all 16 vaults monthly; we believe better planning and resourcing in 2013 will allow for all vaults to be inspected every month.

Substation Maintenance: The number completed each year depends upon related work. For example, in 2013 we plan to combine the completion of substation maintenance with RTU and radio upgrades to introduce efficiencies into the process.

Maintenance of subdivision transformers and switches: This program began in 1993 and a seven year cycle was determined to be appropriate based upon our assessment of the work load and the need for maintenance. Due to a lack of internal resources, inspections have been lagging since 2008. This does not impact the seven year cycle, but it does mean that there will be a catch-up period of maintenance.

2.0 - AMPCO 4 - Working Capital Allowance

Interrogatory #4

Reference: Exhibit 2, Tab 5, Schedule 1, Page 1, Table 1

a) Please add a column to Table 1 for 2013 projection with a working capital factor of 12%.

Bluewater Power has provided the calculation of the working capital allowance assuming a 12% working capital factor as requested in Table 1, however, Bluewater Power has followed the OEB guidelines whereby they have established a default factor to be used by distributors of 13% unless a lead/lag study has been undertaken. Accordingly, Bluewater Power supports the use of the working capital allowance calculated based on the default factor of 13%.

Table 1 – Working Capital Allowance Scenario at 12% for Original Application

Expenses for Working Capital	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Projection	2013 Projection	2013 Projection Sensitivity
Eligible Distribution Expenses:							
3500-Distribution Expenses - Operation	3,126,140	2,926,385	3,135,697	3,177,397	3,102,525	3,467,004	3,467,004
3550-Distribution Expenses - Maintenance	139,394	162,468	175,850	157,217	138,100	142,600	142,600
3650-Billing and Collecting	1,324,116	1,357,619	1,732,894	1,481,275	1,467,712	2,083,111	2,083,111
3700-Community Relations	191,769	213,194	191,747	256,299	270,425	258,483	258,483
3800-Administrative and General Expenses	5,210,000	5,112,516	5,018,632	5,991,270	6,479,176	7,127,630	7,127,630
3950-Taxes Other Than Income Taxes	262,750	247,231	180,940	189,527	194,128	223,914	223,914
Total Eligible Distribution Expenses	10,254,169	10,019,413	10,435,760	11,252,985	11,652,066	13,302,742	13,302,742
3350-Power Supply Expenses	72,509,220	53,779,084	63,323,311	60,757,697	85,362,896	89,374,845	89,374,845
Total Expenses for Working Capital	82,763,389	63,798,497	73,759,071	72,010,682	97,014,962	102,677,587	102,677,587
Working Capital factor	12.0%	12.0%	12.0%	12.0%	12.0%	13.0%	12.0%
Working Capital Allowance	9,931,607	7,655,820	8,851,089	8,641,282	11,641,795	13,348,086	12,321,310

2.0 - AMPCO 5 - Call Centre and Customer Service Indicators

Interrogatory #5

Reference: Exhibit 2, Tab 6, Schedule 1, Pages 1-2

a) Please provide the number of additional contract call centre staff hired in 2010, the positions, the start date for each position and the total cost by position in terms of salary and benefits.

Bluewater Power did not hire any additional contract call centre staff in 2010. While developing the budget for 2011 and reflecting on the 2010 call volume statistics experienced in 2010 Bluewater Power budgeted for additional staff adds in 2011 in anticipation of increased call volume throughout 2011 until the time that smart meter billing was instituted.

b) Please provide the Customer Service Indicators for 2012.

Table 1 details the Customer Service Indicators for 2012.

Table 1 – 2012 Customer Service Indicators

Customer Service Ratio's	OEB requirement %	2012
Total # appointments scheduled within 5 days & 4 hr window	90%	100%
Total # times arrived on time	90%	100%
Number of appointments rescheduled within 1 day (if needed)	100%	n/a
# Phone calls answered in less than 30 seconds	65%	80%
# of Qualified calls abandoned after 30 second wait	10%	3.8%
# Written responses to enquiries responded to in less than 10 days	80%	100%
# Low Voltage connections requests completed in less than 5 days	90%	90.4%
# High Voltage connection requests completed in less than 10 days	90%	100%
# Rural emergencies responded to within 120 minutes	80%	100%
# Urban emergencies responded to within 60 minutes	80%	100%

c) The evidence indicates in 2010 there was high heat, implementation of HST in July 2010, adverse media attention and changes to customer service rules. Please confirm the number of contract call centre staff referenced in part (a) still employed at Bluewater Power in 2011, 2012 and proposed for 2013 and discuss the need for each position in each year on the basis of quantity and length of calls.

In anticipation of smart meter installations and the transition to smart meter (time of use) billing Bluewater contracted 3 staff members to join our billing/customer service departments. One (1) staff member was utilized to back fill a vacancy created when the lead billing representative was assigned to the smart meter capital project and the other 2 contract staff members were additional customer call centre staff who assisted with increased call volume due to smart meter installs and time of use billing questions. Each of these contract staff were hired as 4th class customer service representatives earning approximately $36,000.00 (including benefit and payroll burden) each per year.

Bluewater Power began the transition to time of use billing in May 2012. One (1) of these staff members was employed on contract with Bluewater Power from May 2, 2011 until July 12, 2012 and the other 2 were contracted from May 2, 2011 until December 29, 2012. The costs for these 3 contract staff members were approved and recovered through the smart meter rate application and have no effect on the current 2013 Rate application.

There is no staff additions proposed for the call centre for 2013.

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Date Filed: February 4, 2013

Tab 5 of 11

Exhibit 3 - Revenue

3.0-Staff-18 - Load Forecasting

<u>Ref: Exh 3-1-2 Load Forecasting</u>

On page 1 of this exhibit, Bluewater Power states that the load forecasting methodology “uses actual unadjusted data for 2007 to 2011 which is then modelled through separate multiple regression equations to determine a weather normalized forecast for 2012 and 2013 for the weather sensitive classes.”

The Load Forecast Report prepared by Elenchus Research Associates Inc. contained in Exh 3-1-2 Attachment 1 reports regression ranges from 2006:01 (i.e. January 2006) to 2011:12 (i.e. December 2011).

a) Please confirm the regression range on which Bluewater Power’s load forecast is prepared.

The regressions are based on data ranging from 2006 to 2011.

b) Why does the regression range start in January 2006? Many other distributors have ranges going back to 2002 or even earlier.

Bluewater Power’s load forecast is based on class specific retail data. Bluewater Power suspects the load forecasts that are based on longer ranges the Board Staff is referring to may be based on wholesale data.

3.0-Staff-19 - Load Forecasting

Ref: Exh 3-1-2 Attachment 1 Load Forecasting

Bluewater Power states that separate multivariate regression modelling has been done on a class basis, and Attachment 1 shows separate regression models for: Residential; GS<50 kW; and 'net' GS>50 kW plus specific models for two reclassified customers.

For non-weather-sensitive classes, Bluewater Power has used a version of a Normalized Annualized Consumption ("NAC") approach. These classes for which the NAC approach has been used include: Intermediate; Large Use; Streetlighting; Sentinel Lighting; and Unmetered Scattered Load.

Please provide the definition of the 'billed kWh' used as the explanatory variable in the Residential, GS < 50 kW and GS > 50 kW customer classes. Is this the actual consumption in each calendar month? If not, please provide a detailed description of the source of, and any methodology used, to interpolate the data to get monthly data.

'Billed kWh' refers to kWh billed for the calendar month.

Prior to the summer of 2012 when TOU was adopted, the majority of residential and GS<50 meters were read bi-monthly with only a beginning and ending meter reads for the billing period. Billing portions were read every day, therefore there was 'rolling' billing periods. For example, one portion would have billing periods June 10th to August 9th, the next portion would have a billing period of June 11th to August 10th and so on.

In order to allocate billing quantities to a specific calendar month, a query was developed which assessed the billing quantity for the period for each customer weighted against the net system load shape ("NSLS") for the same period. This has the effect of allocating more consumption to days with higher overall system load, and less on days with lower overall system load, which more closely approximates actual consumption in the calendar month rather than simply prorating consumption equally over the billing period.

3.0-Staff-20 - Load Forecasting - residential

Ref: Exh 3-1-2 Attachment 1 Load Forecasting

For the multivariate regression model of Residential consumption, Bluewater Power shows that Residential kWh was regressed against the following explanatory variables:

- Constant;
- HDD (Heating Degree Days, as measured at Windsor International Airport);
- CDD (Cooling Degree Days, as measured at Windsor International Airport);
- MonthDays (Number of Days in the calendar month); and
- W_S_FTE (Windsor-Sarnia full-time employment).

a) W_S_FTE is used as a proxy for economic activity in Bluewater Power's service territory. What other variables for community size (population) and economic activity were tried in the model? Why were each of these variables rejected from the load forecast model?

No other variables were considered. Bluewater's consultant believes using monthly employment is the most appropriate variable to use to represent monthly changes in economic activity for the purposes of load forecasting and has had success doing so for many years. This is based on the fact that income from employment and labour sources represents the largest portion of GDP on an income basis, and employment data is available on a monthly basis in a very timely manner, unlike GDP or population data. For example, in the latest Provincial Economic Accounts, which released annual GDP figures for 2011 for Ontario on November 19, 2012, compensation for employees represents over 53 per cent of Ontario current dollar GDP in 2011. In addition, in an article published in May 2009, Statistics Canada's then Chief Economic Analyst indicated that "turning points in the growth of output and employment appear to have been virtually the same over the past three decades." [1]

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[1] Philip Cross, "Cyclical changes in output and employment," Canadian Economic Observer, May 2009.

b) The Durbin-Watson ("D-W") statistic shown in the regression results on page 3 of the Elenchus study has a value of 1.2. This would suggest some degree of serial correlation of the residuals. While serial correlation (or autocorrelation) does not imply biased coefficients, it would imply that the Ordinary Least Squares regression methodology would not be optimal. More importantly, the presence of serially correlated residuals suggests that there may be omitted variables. Please provide Bluewater Power's views on the significance of a Durbin-Watson statistic of 1.2 and the implications of serially correlated residuals.

Autocorrelated errors in the regression model can be can be present for three main reasons[2]:

- influence of omitted variables on the errors, as Board Staff has suggested,
- misspecification of the form of relationship,
- measurement error in the dependent variable.

Autocorrelation is not an uncommon problem in applied econometric work. It is the opinion of Bluewater's consultant that omitted variables and misspecification of relationship is unlikely to be the cause in this case, as the form of the residential specification used for Bluewater's residential equation has been used successfully in many other instances, and conforms to what would be expected based on observation and common sense. Indeed, residential class consumption should be one of the most regular and easily specifiable and predictable customer classes. Likely, the cause of the autocorrelation is measurement error in the dependent variable. This would not be a surprising result when using class retail metered data as the dependent variable.

In the present case, given the signs of the coefficients, as well as the adjusted-R^2 and annual mean absolute percentage error, Bluewater has taken a pragmatic approach. There are several

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[2] See J. Johnston, "Econometric Methods," 3rd Edition (McGraw-Hill), pp.309-310 for detailed discussion.

possible alternatives. One alternative would be to abandon the class specific approach and use a single equation wholesale approach to normalization. This approach has been used by many other LDCs and approved by the Board. However, it is Bluewater's understanding that generally parties and the Board have indicated the class specific approach may be preferable. Another approach is to use some form of historical average use per customer. Again, it is Bluewater's understanding that parties would prefer this approach not be used unless absolutely necessary.

Another alternative is to use other regression techniques to transform the data in order to correct for the first order autocorrelation. For example, a common technique used in econometrics to do this is the Cochrane-Orcutt (C-O) procedure. This procedure is an iterative process that calculates residuals from the OLS regression, uses this result to estimate the first-order autocorrelation coefficient (again using an OLS regression), then using the estimate to transform the original data (dependent and independent variables) into a lagged structure to again re-estimate. This can be represented by the equations below:

$$yt = xt' \beta + \varepsilon t \quad ; \quad t = 1, 2, 3, ..., T$$

$$\varepsilon t = \rho\varepsilon t\text{-}1 + ut \quad ; \quad |\rho| < 1$$

$$(yt - \rho yt\text{-}1) = (xt' - \rho xt\text{-}1') \beta_{CO} + ut \ ; \ t = 2, 3, ..., T$$

While readily available statistical packages for the computer can calculate the resulting system and parameters with ease, forecasting requires transformation of the data as the resulting coefficients β_{CO} are based on the transformed data. This adds an additional layer of complexity and opacity to an already complicated process. In addition, the Cochrane-Orcutt procedure only corrects for first-order autocorrelation of the error term. It does not correct for 4th order (quarterly) or 12th order (annual) autocorrelation, or any other autocorrelation process seen in the error term. Therefore, Bluewater's consultant did not use this technique for the load forecasting process. Bluewater's consultant has confirmed that the relative magnitude and signs of the estimated coefficients using the C-O procedure are similar to the standard OLS model. The coefficients will differ in magnitude, however, as the data have been transformed, as is illustrated in the above equations.

c) What, if any, efforts, did Bluewater Power undertake to address any serial correlation of the residuals?

Please see response in part (b).

d) Table 2 on page 3 of the Elenchus study provides summary statistics of the “fit” of the model in terms of annual percentage error and the mean absolute percentage error. As the regression model is based on monthly data, the residual analysis based on annual results will understate the actual residual error, as summing over the monthly values which smooth the deviations. Please provide the following:

i. Actual and predicted Residential kWh, residual and % error, by month, for the regression period and also including the predicted values for the bridge and test years by month, up to and including December 2013; and

ii. The Mean Absolute Percentage Error of the monthly residuals over the actual regression range from June 2006 to December 2011.

Bluewater Power Response

Please see tables below.

Residential kWh

Date	Actual kWh	Predicted kWh	Error	% Error
Jan-06	24,480,903	22,371,061	-2,109,842	-8.6%

Residential kWh

Date	Actual kWh	Predicted kWh	Error	% Error
Feb-06	20,524,833	20,541,759	16,926	0.1%
Mar-06	19,424,366	21,797,306	2,372,940	12.2%
Apr-06	17,078,972	17,712,860	633,888	3.7%
May-06	19,578,106	19,815,104	236,998	1.2%
Jun-06	21,563,425	21,013,562	-549,863	-2.5%
Jul-06	28,880,095	29,874,616	994,521	3.4%
Aug-06	26,019,759	26,404,376	384,617	1.5%
Sep-06	18,650,988	17,376,714	-1,274,275	-6.8%
Oct-06	18,624,962	19,543,056	918,094	4.9%
Nov-06	19,742,355	20,013,373	271,018	1.4%
Dec-06	24,194,253	22,153,506	-2,040,747	-8.4%
Jan-07	24,347,952	23,866,902	-481,050	-2.0%
Feb-07	22,127,312	22,689,808	562,496	2.5%
Mar-07	19,379,564	21,049,427	1,669,863	8.6%
Apr-07	16,746,164	18,349,537	1,603,373	9.6%
May-07	18,277,261	19,686,843	1,409,581	7.7%
Jun-07	23,905,459	24,124,664	219,206	0.9%
Jul-07	26,287,334	26,088,374	-198,960	-0.8%
Aug-07	27,357,985	27,622,468	264,483	1.0%
Sep-07	21,121,797	20,612,575	-509,222	-2.4%
Oct-07	19,870,326	20,187,718	317,392	1.6%
Nov-07	21,432,876	20,346,810	-1,086,066	-5.1%
Dec-07	25,764,368	23,808,769	-1,955,599	-7.6%
Jan-08	24,848,614	23,931,212	-917,402	-3.7%
Feb-08	23,055,544	22,549,437	-506,107	-2.2%
Mar-08	21,384,753	22,944,207	1,559,454	7.3%
Apr-08	16,101,187	17,825,575	1,724,388	10.7%
May-08	15,910,613	18,251,843	2,341,230	14.7%
Jun-08	21,188,738	23,574,367	2,385,629	11.3%
Jul-08	28,141,825	28,969,570	827,745	2.9%
Aug-08	26,260,231	25,854,166	-406,065	-1.5%
Sep-08	20,285,306	19,425,052	-860,254	-4.2%

Residential kWh

Date	Actual kWh	Predicted kWh	Error	% Error
Oct-08	18,244,234	18,717,119	472,885	2.6%
Nov-08	21,690,357	20,320,249	-1,370,108	-6.3%
Dec-08	26,455,037	24,091,325	-2,363,712	-8.9%
Jan-09	24,960,545	26,192,878	1,232,332	4.9%
Feb-09	19,953,437	20,086,469	133,032	0.7%
Mar-09	20,524,060	21,095,939	571,879	2.8%
Apr-09	18,496,184	18,263,817	-232,367	-1.3%
May-09	18,284,979	16,712,568	-1,572,410	-8.6%
Jun-09	19,466,105	19,195,427	-270,678	-1.4%
Jul-09	21,739,845	21,031,107	-708,738	-3.3%
Aug-09	24,494,361	23,816,522	-677,839	-2.8%
Sep-09	20,156,918	17,889,995	-2,266,923	-11.2%
Oct-09	19,466,280	18,398,407	-1,067,873	-5.5%
Nov-09	20,504,663	18,592,032	-1,912,631	-9.3%
Dec-09	24,910,673	23,367,461	-1,543,211	-6.2%
Jan-10	24,166,684	24,351,404	184,719	0.8%
Feb-10	19,948,614	20,339,632	391,018	2.0%
Mar-10	18,890,757	20,247,017	1,356,260	7.2%
Apr-10	15,983,500	16,640,251	656,751	4.1%
May-10	18,929,559	19,722,938	793,379	4.2%
Jun-10	22,970,742	23,131,137	160,395	0.7%
Jul-10	31,043,845	30,494,488	-549,357	-1.8%
Aug-10	29,851,786	28,596,839	-1,254,947	-4.2%
Sep-10	20,076,834	18,374,149	-1,702,685	-8.5%
Oct-10	16,662,882	17,432,005	769,123	4.6%
Nov-10	19,942,902	19,507,337	-435,565	-2.2%
Dec-10	26,297,374	24,340,211	-1,957,163	-7.4%
Jan-11	24,017,315	25,268,806	1,251,491	5.2%
Feb-11	19,878,448	21,108,307	1,229,859	6.2%
Mar-11	20,257,727	22,166,150	1,908,423	9.4%
Apr-11	17,263,545	18,116,509	852,964	4.9%
May-11	17,819,512	18,843,488	1,023,976	5.7%

Residential kWh

Date	Actual kWh	Predicted kWh	Error	% Error
Jun-11	22,173,694	21,809,747	-363,947	-1.6%
Jul-11	31,893,306	32,499,290	605,984	1.9%
Aug-11	26,239,675	25,741,360	-498,315	-1.9%
Sep-11	19,385,085	18,617,586	-767,499	-4.0%
Oct-11	17,377,847	18,104,339	726,492	4.2%
Nov-11	19,525,604	18,632,298	-893,306	-4.6%
Dec-11	21,619,209	21,889,134	269,924	1.2%
			MAPE	4.7%

Residential kWh

Forecast values - monthly

Residential

Date	Forecast
Jan-12	*24,384,191*
Feb-12	*21,597,758*
Mar-12	*21,634,621*
Apr-12	*17,915,949*
May-12	*18,365,371*
Jun-12	*21,970,621*
Jul-12	*27,641,414*
Aug-12	*25,783,872*
Sep-12	*19,031,154*
Oct-12	*18,647,684*
Nov-12	*19,409,667*
Dec-12	*23,284,817*
Jan-13	*24,457,163*
Feb-13	*20,868,774*
Mar-13	*21,707,593*

Apr-13	*17,991,623*
May-13	*18,441,045*
Jun-13	*22,046,295*
Jul-13	*27,719,791*
Aug-13	*25,859,546*
Sep-13	*19,109,531*
Oct-13	*18,723,358*
Nov-13	*19,485,341*
Dec-13	*23,363,194*

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3.0-Staff-21 - Load Forecasting - GS<50

Ref: Exh 3-1-2 Attachment 1 Load Forecasting

For the multivariate regression model of GS<50 kW consumption, Bluewater Power shows that GS<50 kW consumption, in kWh, was regressed against the following explanatory variables:

- Constant;
- HDD (Heating Degree Days, as measured at Windsor International Airport);
- CDD (Cooling Degree Days, as measured at Windsor International Airport);
- MonthDays (Number of Days in the calendar month);
- Time (a linear time trend variable starting at 1 and increasing by 1 each month); and
- d_W_S_FTE (first difference of Windsor-Sarnia full-time employment).

a) d_W_S_FTE effectively measures the change in full-time employment in the Windsor-Sarnia area. The expected sign of the coefficient is positive and this is observed in the regression results. However, the coefficient is statistically insignificant with a t-statistic of 1.1 (p=13.75%).

   i. Why was d_W_S_FTE chosen as the economic measure?

   ii. What other variables for community size (population) and economic activity were tried in the model? Why were each of these variables rejected from the load forecast model?

   i. The coefficient on the variable d_W_S_FTE is significant to the 15% level (p=13.75%), which in an empirical study such as a load forecast should be sufficient to reject the hypothesis that the coefficient is not significantly different from zero. This is the approach Bluewater's consultant has taken. The variable represents the first difference of W_S_FTE, or the monthly change in full-time employment in the Windsor-Sarnia Economic Region. For the GS<50 class, this resulted in the best estimate including employment as a variable representing economic activity. Please see response to Board Staff IR #3-20 (a) for reasons why Bluewater's consultant considers employment to be an appropriate measure of economic activity.

ii. Please see response to Board Staff IR #3-20 (a).

b) The trend variable 'time' is a simple linear trend. Bluewater Power states that its use is supported by the trend shown in Chart 1 on page 4 of the attachment.

   i. How has the trend line on Chart 1 been fitted to actual data?
   ii. How have any other explanatory factors been taken into account in Chart 1?
   iii. What is Bluewater Power's explanation and rationale that the simple linear trend adequately captures drivers such as market size, economic activity, etc.? Please explain what drivers Bluewater Power believes are being explained by 'time'.

i. The trend line was fitted using an OLS regression with a linear time trend equal to 1 in 2006:01 and increasing by 1 in each month thereafter as the explanatory variable and monthly GS<50 consumption as the dependent variable.

ii. No other explanatory variables have been taken into account in Chart 1. Chart 1 simply depicts the declining trend in actual consumption in this class over time.

iii. The time trend captures the downward trend in GS<50 that has been occurring for a number of years, and represents a structural shift in consumption specific to the GS<50 class, beyond general market conditions. It reflects the decline of the small business sector in the downtowns of smaller cities and towns. Often, smaller establishments, such as independently-owned hardware stores, furniture stores, shoes stores, and similar commercial establishments, have been closing and being replaced by retailers located in box mall type locations, that are likely not GS<50 customers, and depending on location, may be outside of the LDC's service area.

c) Please explain Bluewater Power's rationale for believing that the combination of d_W_S_FTE and 'time' adequately serve as proxies for the drivers of demand for the GS<50 kW customer class in Bluewater Power's service territory.

Please see response to Board Staff #3-21 (a) i and Board Staff #3-21 (b) (iii).

d) Table 4 on page 4 of the Elenchus study provides summary statistics of the "fit" of the model in terms of annual percentage error and the mean absolute percentage error. As the regression model is based on monthly data, the residual analysis based on annual results will understate the actual residual error, as summing over the monthly values which smooth the deviations. Please provide the following:

i. Actual and predicted GS<50 kW kWh, residual and % error, by month, for the regression period and also including the predicted values for the bridge and test years by month, up to and including December 2013; and

ii. The Mean Absolute Percentage Error of the monthly residuals over the actual regression range from June 2006 to December 2011.

Please see the tables below:

1

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GS<50 kWh

Date	Actual kWh	Predicted kWh	Error	% Error
Jan-06	11,120,198	10,645,865	-474,333	-4.3%
Feb-06	10,137,271	9,777,405	-359,867	-3.5%
Mar-06	10,067,942	10,470,384	402,443	4.0%
Apr-06	8,422,890	8,938,394	515,504	6.1%
May-06	9,420,948	9,473,954	53,006	0.6%
Jun-06	9,402,482	9,481,836	79,354	0.8%
Jul-06	12,185,730	11,939,944	-245,786	-2.0%
Aug-06	10,867,359	10,960,696	93,337	0.9%
Sep-06	8,262,280	8,375,945	113,665	1.4%
Oct-06	9,077,792	9,347,494	269,702	3.0%
Nov-06	8,750,564	9,404,910	654,346	7.5%
Dec-06	10,199,915	10,238,987	39,072	0.4%
Jan-07	10,969,794	10,813,516	-156,278	-1.4%
Feb-07	10,370,998	10,222,860	-148,139	-1.4%
Mar-07	9,972,561	9,971,692	-869	0.0%
Apr-07	8,533,333	9,051,722	518,389	6.1%
May-07	8,945,395	9,240,824	295,429	3.3%
Jun-07	10,470,085	10,130,544	-339,541	-3.2%
Jul-07	10,627,134	10,725,453	98,319	0.9%
Aug-07	10,927,336	11,090,048	162,712	1.5%
Sep-07	9,182,721	9,011,493	-171,229	-1.9%
Oct-07	9,481,472	9,144,250	-337,223	-3.6%
Nov-07	9,159,265	9,363,138	203,873	2.2%
Dec-07	11,258,490	10,714,980	-543,511	-4.8%
Jan-08	10,992,744	10,756,685	-236,059	-2.1%
Feb-08	10,320,763	10,123,400	-197,364	-1.9%
Mar-08	10,638,507	10,460,550	-177,957	-1.7%
Apr-08	8,655,252	8,470,087	-185,165	-2.1%
May-08	8,104,799	8,571,080	466,281	5.8%
Jun-08	8,930,213	9,576,178	645,965	7.2%

GS<50 kWh

Date	Actual kWh	Predicted kWh	Error	% Error
Jul-08	10,953,417	11,122,199	168,782	1.5%
Aug-08	10,361,706	10,319,590	-42,116	-0.4%
Sep-08	8,896,044	8,394,601	-501,443	-5.6%
Oct-08	8,479,632	8,695,267	215,634	2.5%
Nov-08	9,184,741	9,168,686	-16,054	-0.2%
Dec-08	11,998,525	10,627,987	-1,370,538	-11.4%
Jan-09	11,142,828	11,350,940	208,112	1.9%
Feb-09	8,052,381	8,912,546	860,165	10.7%
Mar-09	9,647,049	9,656,690	9,641	0.1%
Apr-09	8,558,968	8,545,877	-13,090	-0.2%
May-09	8,499,895	8,031,471	-468,424	-5.5%
Jun-09	8,627,270	8,414,267	-213,003	-2.5%
Jul-09	9,364,372	9,049,505	-314,867	-3.4%
Aug-09	10,337,990	9,762,318	-575,672	-5.6%
Sep-09	9,260,763	8,013,331	-1,247,432	-13.5%
Oct-09	8,522,661	8,548,848	26,188	0.3%
Nov-09	8,254,653	8,465,093	210,440	2.5%
Dec-09	10,019,530	10,310,425	290,895	2.9%
Jan-10	10,507,071	10,614,479	107,408	1.0%
Feb-10	9,173,401	8,889,421	-283,980	-3.1%
Mar-10	8,775,439	9,132,700	357,260	4.1%
Apr-10	7,622,620	7,787,100	164,480	2.2%
May-10	8,473,856	8,575,769	101,913	1.2%
Jun-10	8,819,317	9,137,530	318,212	3.6%
Jul-10	10,805,518	11,170,301	364,783	3.4%
Aug-10	10,984,604	10,660,029	-324,575	-3.0%
Sep-10	8,199,345	7,796,968	-402,378	-4.9%
Oct-10	7,466,062	7,892,150	426,088	5.7%
Nov-10	8,577,101	8,522,020	-55,081	-0.6%
Dec-10	10,766,819	10,374,914	-391,905	-3.6%
Jan-11	9,860,482	10,693,648	833,165	8.4%
Feb-11	8,748,335	8,823,197	74,862	0.9%

GS<50 kWh

Date	Actual kWh	Predicted kWh	Error	% Error
Mar-11	9,615,930	9,544,031	-71,899	-0.7%
Apr-11	7,649,299	7,935,143	285,844	3.7%
May-11	7,699,600	8,109,890	410,290	5.3%
Jun-11	8,484,575	8,529,060	44,485	0.5%
Jul-11	11,250,739	11,508,240	257,501	2.3%
Aug-11	9,404,848	9,658,512	253,665	2.7%
Sep-11	8,006,698	7,566,578	-440,120	-5.5%
Oct-11	7,711,828	7,755,595	43,767	0.6%
Nov-11	8,066,109	7,861,692	-204,417	-2.5%
Dec-11	9,309,471	9,174,806	-134,665	-1.4%

GS<50 kWh

Forecast values - monthly

Date	Forecast
Jan-12	10,176,104
Feb-12	8,850,607
Mar-12	9,081,111
Apr-12	7,618,293
May-12	7,720,294
Jun-12	8,303,555
Jul-12	9,914,595
Aug-12	9,390,732
Sep-12	7,387,757
Oct-12	7,688,508
Nov-12	7,898,993
Dec-12	9,420,055
Jan-13	9,872,157
Feb-13	8,211,199
Mar-13	8,823,504
Apr-13	7,365,319
May-13	7,465,003
Jun-13	8,048,265
Jul-13	9,661,621
Aug-13	9,133,124
Sep-13	7,134,783
Oct-13	7,430,900
Nov-13	7,643,702
Dec-13	9,167,081

3.0-Staff-22 - Load Forecasting - GS>50

Ref: Exh 3-1-2 Attachment 1 Load Forecasting

To develop the load forecast for the GS>50 kW class, Bluewater Power shows that GS>50 kW consumption, in kWh, was modelled through three separate regression equations:

- ‘Net’ GS>50 kW;
- Customer ‘A’ reclassified from Intermediate to GS>50 kW; and
- Customer ‘B’ reclassified from Intermediate to GS>50 kW.

Each of the three equations has a different set of explanatory variables. Bluewater Power states that customers ‘A’ and ‘B’ are weather-sensitive, but only with respect to cooling.

The consumption in kWh is regressed against the following explanatory variables in each of the three equations, where an ‘X’ indicates that the explanatory variable was included in the documented model:

Explanatory Variables	‘net’ GS>50 kW	Customer ‘A’	Customer ‘B’
Constant	X	X	X
HDD	X		
CDD	X	X	X
Monthdays	X	X	
Peakdays			X
Time (trend variable)			X
W_S_FTE	X	X	
d_W_S_FTE			X

a) Please provide the definition of ‘Peakdays’.

Peakdays refers to the number of non-holiday weekdays in the month.

b) In the ‘net’ GS > 50 kW model, the variable W_S_FTE is statistically insignificant with a t-statistic of 1.1 (p=27.21%).

   i. Please provide Bluewater Power’s rationale for inclusion of this variable.
   ii. What other variables to measure economic activity were tried? What were the results of these attempts, and why were these measures ultimately rejected?
   iii. Why is ‘Monthdays’ the chosen measure for the duration of consumption of these higher demand customers, as opposed to a measure of the number of non-holiday business days in the calendar month?

   i. Bluewater Power included this variable in order to have a measure of economic activity in the regression model specification.

   ii. The following alternative variables were also tried: Windsor-Sarnia Employment, Ontario Full-Time Employment, Ontario Employment, Change in Windsor-Sarnia Full-time Employment, Change in Windsor-Sarnia Employment, Change in Ontario Full-Time Employment, Change in Ontario Employment, Number of Customers, Change in Number of Customers (all change variables are first difference). Lags of many of the above variables were also explored. None performed any better than the chosen variable and many exhibited incorrect signs.

   iii. Monthdays yielded superior results, likely due to the large amount of consumption that is associated with industrial operations or operations that do not shut down on holidays or weekends.

c) The documented regression equation for customer ‘B’ has a different specification, with three different explanatory variables. Furthermore, two of these variables (‘Peakdays’ and d_W_S_FTE) are statistically insignificant, with t-statistics around 1.5 (p=14-15%).

   i. Please explain Bluewater Power’s rationale for the specification of the regression equation for customer ‘B’’s consumption, including the inclusion of these two statistically insignificant variables.
   ii. Please provide a rationale for the inclusion of the ‘Time’ trend variable. What is it about the nature of this customer’s consumption that justifies this variable?
   iii. Please explain what is different about customer ‘B’’s consumption that requires a different specification than that for other GS > 50 kW customers.
   iv. What other variables were tried? Please provide a summary of any other model results, and an explanation of why such models were rejected in preference of the one shown in the Application.

Preamble

Customer B (along with Customer A and Customer C) were dealt with separately from the GS>50 class due to the fact that these customers were reclassified from the Intermediate Class. In order to appropriately forecast GS>50 class consumption, the consumption of these customers needed to be dealt with separately.

i. The two referenced coefficients in the “Customer B” regression are significant at the 15% level.

ii. This customer is an institutional/administrative type customer and has reduced the activity on the premises due to downsizing. The time series of data for the analysis is very short (only 2 years, 24 months). In order to provide as accurate a prediction as possible, the regression model with the suggested parameters, including time trend, was developed.

iii. As indicated in the preamble, these customers needed to be added to the GS>50 class due to recent reclassification. The reason for reclassification was due to declining consumption volumes (these were previously Intermediate Class customers). The GS>50 class as a whole has diversity, including industrial, commercial and institutional customers. These individual customers are site specific (for example, usage restricted to cooling and lighting, weekdays only, etc.).

iv. The answer is similar to Board Staff 3-22 (b) (ii) with the exception that HDD was also tried.

d) Table 8 on pages 8-9 of the Elenchus study provides summary statistics of the “fit” of the GS>50 kW models in terms of annual percentage error and the mean absolute percentage error. As the regression models are based on monthly data, the residual analysis based on annual results will understate the actual residual error, as summing over the monthly values which smooth the deviations. Please provide the following:

  i. Actual and predicted GS>50 kW kWh, residual and % error, by month, for the regression period and also including the predicted values for the bridge and test years by month, up to and including December 2013; and
  ii. The Mean Absolute Percentage Error of the monthly residuals over the actual regression range from June 2006 to December 2011.

Please see tables below. Please note, the values for GS>50 kWh include the regression model results for GS>50 kWh Net plus the consumption for Customers A, B, and C after they have been reclassified to GS>50.

GS>50 kWh

Date	Actual kWh	Predicted kWh	Error	% Error
Jan-06	18,791,625	19,125,108	333,483	1.8%
Feb-06	18,202,016	17,196,308	-1,005,708	-5.5%
Mar-06	18,336,355	18,847,063	510,708	2.8%
Apr-06	15,724,707	16,379,187	654,479	4.2%
May-06	17,523,433	17,350,104	-173,329	-1.0%
Jun-06	17,507,851	17,120,688	-387,163	-2.2%
Jul-06	21,436,512	20,781,442	-655,071	-3.1%
Aug-06	18,942,145	19,511,346	569,201	3.0%
Sep-06	15,921,551	15,877,515	-44,036	-0.3%
Oct-06	17,377,566	17,551,719	174,153	1.0%
Nov-06	18,795,514	17,501,375	-1,294,138	-6.9%
Dec-06	19,081,225	18,962,714	-118,511	-0.6%
Jan-07	19,829,752	19,904,889	75,138	0.4%
Feb-07	18,651,602	18,351,413	-300,189	-1.6%
Mar-07	18,930,516	18,514,824	-415,693	-2.2%
Apr-07	16,042,618	16,762,813	720,195	4.5%
May-07	17,116,032	17,271,083	155,051	0.9%
Jun-07	18,200,649	18,261,444	60,796	0.3%
Jul-07	18,937,759	19,411,716	473,957	2.5%
Aug-07	19,273,348	19,974,498	701,150	3.6%
Sep-07	16,970,830	17,009,262	38,432	0.2%
Oct-07	18,003,180	17,491,769	-511,412	-2.8%
Nov-07	16,915,017	17,726,430	811,413	4.8%
Dec-07	20,211,014	19,866,136	-344,878	-1.7%
Jan-08	19,516,100	19,949,374	433,273	2.2%
Feb-08	18,080,188	18,581,335	501,147	2.8%
Mar-08	19,197,038	19,438,696	241,658	1.3%
Apr-08	16,620,971	16,428,388	-192,583	-1.2%
May-08	15,797,744	16,861,266	1,063,522	6.7%
Jun-08	16,234,660	18,046,284	1,811,625	11.2%
Jul-08	19,744,136	20,460,974	716,838	3.6%

GS>50 kWh

Date	Actual kWh	Predicted kWh	Error	% Error
Aug-08	19,430,080	19,324,886	-105,194	-0.5%
Sep-08	17,737,691	16,553,388	-1,184,303	-6.7%
Oct-08	16,927,731	17,199,387	271,656	1.6%
Nov-08	17,653,650	17,752,041	98,391	0.6%
Dec-08	22,565,724	20,057,211	-2,508,514	-11.1%
Jan-09	20,863,282	21,194,248	330,966	1.6%
Feb-09	14,909,287	17,084,287	2,175,000	14.6%
Mar-09	18,814,960	18,620,476	-194,484	-1.0%
Apr-09	16,480,471	16,701,076	220,605	1.3%
May-09	16,454,737	16,179,996	-274,741	-1.7%
Jun-09	16,199,724	16,523,583	323,860	2.0%
Jul-09	17,655,046	17,590,872	-64,174	-0.4%
Aug-09	19,001,720	18,615,226	-386,494	-2.0%
Sep-09	18,557,112	16,043,967	-2,513,145	-13.5%
Oct-09	16,581,391	17,156,486	575,094	3.5%
Nov-09	15,411,456	16,933,997	1,522,541	9.9%
Dec-09	18,859,866	19,741,674	881,808	4.7%
Jan-10	20,860,855	20,268,944	-591,911	-2.8%
Feb-10	18,461,952	17,215,662	-1,246,290	-6.8%
Mar-10	17,361,044	18,163,272	802,229	4.6%
Apr-10	16,198,074	15,928,840	-269,234	-1.7%
May-10	17,678,593	17,304,608	-373,985	-2.1%
Jun-10	17,631,270	17,906,383	275,113	1.6%
Jul-10	20,705,306	21,031,820	326,514	1.6%
Aug-10	21,541,028	20,338,065	-1,202,963	-5.6%
Sep-10	17,024,325	16,249,786	-774,540	-4.5%
Oct-10	16,173,377	16,623,383	450,006	2.8%
Nov-10	17,798,980	17,388,274	-410,706	-2.3%
Dec-10	21,408,129	20,224,751	-1,183,378	-5.5%
Jan-11	19,661,227	20,708,148	1,046,920	5.3%
Feb-11	17,248,854	17,653,309	404,455	2.3%
Mar-11	19,996,093	19,196,945	-799,147	-4.0%

GS>50 kWh

Date	Actual kWh	Predicted kWh	Error	% Error
Apr-11	16,513,212	16,768,776	255,564	1.5%
May-11	17,185,465	17,864,885	679,420	4.0%
Jun-11	18,084,168	18,316,169	232,001	1.3%
Jul-11	23,063,606	22,745,519	-318,086	-1.4%
Aug-11	19,834,013	20,224,291	390,278	2.0%
Sep-11	18,258,039	17,201,239	-1,056,800	-5.8%
Oct-11	17,411,914	17,719,344	307,431	1.8%
Nov-11	17,582,387	17,730,494	148,107	0.8%
Dec-11	20,294,502	19,796,759	-497,743	-2.5%
			MAPE	3.3%

GS>50 kWh

Forecast values - monthly

Date	Forecast
Jan-12	*20,394,195*
Feb-12	*17,586,201*
Mar-12	*19,002,247*
Apr-12	*16,705,505*
May-12	*17,020,162*
Jun-12	*17,667,041*
Jul-12	*20,179,937*
Aug-12	*19,519,640*
Sep-12	*16,689,050*
Oct-12	*17,375,193*

Nov-12	*17,554,145*
Dec-12	*19,876,577*
Jan-13	*20,387,913*
Feb-13	*17,514,406*
Mar-13	*18,899,041*
Apr-13	*16,614,864*
May-13	*16,935,803*
Jun-13	*17,591,656*
Jul-13	*20,092,886*
Aug-13	*19,425,409*
Sep-13	*16,594,819*
Oct-13	*17,287,243*
Nov-13	*17,461,708*
Dec-13	*19,797,602*

1

3.0-Staff-23 - Load Forecast Methodology

Ref: Exh 3-1-2 Attachment 1 Load Forecast Methodology

In the multivariate regression models used by Bluewater Power for its load forecast, the models used included explanatory variables such as HDD, CDD, month of the days and Windsor-Sarnia Employment data.

a) In many load forecasting multivariate regression models filed in cost of service applications in recent years, distributors often include binary seasonal variables (i.e. spring/fall flag) to account for seasonal variability (beyond that of HDD and CDD). Was the inclusion of a spring/fall flag attempted? If so, please explain the reason for excluding it in the final model.

A spring/fall binary variable was not attempted. Bluewater did not believe there was any apparent a priori reason for a behavioural change in consumption in the spring and fall periods beyond what is observed in the degree day observations.

b) The load forecasting models documented by Bluewater Power in its application do not include any variables for CDM activity/impacts during the regression period.
   i. Was any CDM activity variable tried?
   ii. If not, why not?
   iii. If a CDM variable was tried, please define the CDM variable attempted, the regression results, and the reasons that the variable was rejected in the final model. Please provide the data for the variable.

No CDM activity variable was tried. Bluewater's consultant is of the opinion that CDM (referring specifically to program-related conservation and demand management) should be dealt with in a deterministic way as opposed to using statistical techniques. Therefore, specifically documented ex-post forecast adjustments are preferable to using arbitrary adjusted data to determine the CDM adjusted load forecast statistically.

3.0 - VECC 15 - Regression Model Variables

3-VECC-15 Reference: Exhibit 3, Tab 1, Schedule 2, Attachment 1, pages 2-4

a) With respect to pages 2-3, did Elenchus test a regression model that included Residential customer count as an explanatory variable? If yes, please provide the results similar to those shown in Table 1.

No.

b) If the response to part (a) is no, please undertake such an analysis.

Please find the results in the table displayed below:

OLS, using observations 2006:01-2011:12 (T = 72)

Dependent variable: ResKWh

	Coefficient	*t-ratio*	*p-value*
const	-4.16588e+07	-1.8434	0.06976
HDD_Wind	14186.3	16.8298	<0.00001
CDD_Wind	71817.4	22.7167	<0.00001
Monthdays	771643	4.2687	0.00006
W_S_FTE	38570.9	2.4909	0.01526
ResCust	754.216	1.1677	0.24714

R-squared	0.90	Adjusted R-squared	0.89
F(5, 66)	117.45	P-value(F)	1.81e-31
Theil’s U	0.32	Durbin-Watson	1.2

c) Please provide a revised model for GS<50 that uses full-time employment as opposed to the first difference of full-time employment as the explanatory variable.

Please find the results in the table displayed below:

OLS, using observations 2006:01-2011:12 (T = 72)

Dependent variable: GSlt50kWh

	Coefficient	*t-ratio*	*p-value*
const	-3.43125e+06	-1.5609	0.12334
HDD_Wind	4936.44	17.4994	<0.00001
CDD_Wind	19126.2	17.8708	<0.00001
Monthdays	392968	6.4938	<0.00001
time	-21981.6	-6.6661	<0.00001
W_S_FTE	-1906.73	-0.3366	0.73752

R-squared	0.88	Adjusted R-squared	0.87
F(5, 66)	98.71477	P-value(F)	2.92e-29
Theil's U	0.30	Durbin-Watson	1.7

d) Please confirm that, based on the equation proposed for GS<50 that if employment is going up every month over the course of the year but each absolute increase is less than the month before, then unless the other explanatory variables change the estimated monthly consumption in each month will decline from that for the preceding month. If not confirmed, please explain and demonstrate why this result will not occur.

The situation that VECC refers to can only occur if each month in the year has exactly the same number of days and exactly the same degree days. This is a situation that will never occur. The regression is estimated with real data where each month has the appropriate number of days and degree days, and is used to forecast a realistic situation. Using the correct number of days for the month, the 10-year average normal definition of heating degree days and cooling degree days for each month, and a change of employment that is increasing, but is less in each successive month, Bluewater cannot confirm that the estimated monthly consumption in each month will decline from that for the preceding month.

e) Did Elenchus test a regression for the GS<50 class that included customer count as an explanatory variable? If yes, please provide the results.

No.

f) If the response to part (e) is no, please provide revised models that do so where one includes the time trend variable and the second does not.

Please see tables displayed below.

OLS, using observations 2006:01-2011:12 (T = 72)
Dependent variable: GSlt50kWh

	Coefficient	*t-ratio*	*p-value*
const	7.56855e+06	1.3527	0.18084
HDD_Wind	5213.81	15.1619	<0.00001
CDD_Wind	18827.8	18.2313	<0.00001
Monthdays	383918	6.5955	<0.00001
time	-15366	-4.3005	0.00006
d_W_S_FTE	30690.9	1.4614	0.14873
GSlt50Cust	-3331.24	-2.1352	0.03652

R-squared	0.89	Adjusted R-squared	0.88
F(6, 65)	89.05668	P-value(F)	2.04e-29
Theil's U	0.28	Durbin-Watson	1.83

OLS, using observations 2006:01-2011:12 (T = 72)
Dependent variable: GSlt50kWh

	Coefficient	*t-ratio*	*p-value*
const	2.51624e+07	5.8611	<0.00001
HDD_Wind	5250.64	13.5797	<0.00001
CDD_Wind	18447.3	15.9402	<0.00001
Monthdays	375584	5.7399	<0.00001
d_W_S_FTE	40749.4	1.7359	0.08724
GSlt50Cust	-8527.01	-7.6806	<0.00001

R-squared	0.86	Adjusted R-squared	0.85
F(5, 66)	81.6	P-value(F)	6.84e-27
Theil's U	0.32	Durbin-Watson	1.55

3.0 - VECC 16 - Cooling Degree Days and clarification

Reference: Exhibit 3, Tab 1, Schedule 2, Attachment 1, pages 5-8

a) Please explain why the model includes Cooling Degree Days but not Heating Degree Days.

Please see response to Board Staff IR #3-22 (c) (iii).

b) With respect to page 5, are the “several customers” that have been reclassified into GS>50, Customers A-D that are discussed on the following pages?

Correct, with the exception of Customer D.

3.0 - VECC 17 - Employment Forecast

Reference: Exhibit 3, page 10, Schedule 2, Attachment 1, page 10

a) Please update the employment forecasts for 2012 and 2013 based on the most recent information available from each of the banks.

Actual full-time employment for the Windsor-Sarnia Economic Region for 2012 is now available from Statistics Canada. The annual change over 2011 is displayed in the update below along with the most recent chartered bank forecasts and the forecast at the time of Bluewater's the load forecast preparation.

Employment Forecast – Ontario

(figures in annual percentage change)

	BMO	RBC	Scotia	TD	avg
	(Mar 2, 2012)	*(Dec 2011)*	*(Mar 6, 2012)*	*(Jan 4,2012)*	
2012	0.5	1.0	0.7	0.7	0.7
2013	1.1	1.4	1.0	1.4	1.2
	(Jan 11, 2013)	*(Dec 2012)*	*(Dec 20, 2012)*	*(Dec 19,2012)*	
2012	**Actual Windsor-Sarnia Economic Region = 0.5**				
2013	1.0	1.2	1.0	1.0	1.1

3.0 - EP 14 - Customer and Load Forecast update for 2012

Energy Probe # 14

Ref: Exhibit 3, Tab 1, Schedule 1

a) Please update Tables 6, 7 and 8 to reflect actual 2012 data.

The data in the column labeled ‘2012 Update’ in Tables 1, 2 and 3 reflect the following:

- Actual customer/connection count for all classes for 2012 based on the annual average for year.
- kWh and Kw for Intermediate, Large User and Streelighting classes to the end of December 2012.
- kWh and kW data for GS>50 and Sentinel classes to the end of October 2012.
- kWh and kW data for Residential, GS<50 and USL to the end of September 2012.
-

For the period of time in 2012 where actual data is not available, the data presented is forecast values (normalized) for the remainder of the year. Further details and a breakdown of what portion of the data is ‘actual’ vs. ‘forecast’ are in response to Energy Probe #15 (d).

Table 1 – Customer Count (updated for 2012 Actual)

Customer Class Name	2009 Approved	2009 Actual	2010 Actual	2011 Actual	2012 Forecast	2012 Update	2013 Forecast
Residential	31,560	31,554	31,552	31,787	31,954	31,896	32,122
General Service < 50 kW	3,890	3,412	3,511	3,507	3,525	3,480	3,544
General Service > 50 to 999 kW	399	380	393	409	423	429	438
General Service 1000 to 4999 kW	15	16	16	13	12	12	12
Large Use	3	4	3	3	3	3	3
Unmetered Scattered Load (connections)	266	257	257	260	260	263	260
Sentinel Lighting (connections)	526	497	497	497	497	447	445
Street Lighting (connections)	10,009	9,837	9,899	9,965	10,052	10,019	10,140
TOTAL	46,668	45,957	46,128	46,441	46,726	46,726	46,964

Table 2 – Energy Forecast (kWh) updated for 2012 data

Customer Class Name	2009 EDR Approved	2009 Actual	2010 Actual	2011 Actual	2011 Normalized	2012 Forecast	2012 Update	2013 Forecast
Residential	261,847,739	252,958,052	264,765,479	257,450,968	258,340,857	259,667,118	257,859,592	255,687,351
General Service < 50 kW	120,287,121	110,288,359	110,171,154	105,807,915	105,949,255	103,450,605	102,884,392	97,434,167
General Service > 50 to 999 kW	214,354,332	209,789,052	222,842,935	225,133,479	224,210,382	226,737,748	226,813,093	221,905,974
General Service 1000 to 4999 kW	165,546,229	168,518,709	179,379,861	160,156,759	157,283,380	158,216,681	158,156,603	156,701,083
Large Use	280,461,771	246,885,214	257,951,054	253,729,738	253,729,738	252,652,298	256,089,950	247,541,912
Unmetered Scattered Load	2,188,838	2,215,434	2,257,871	2,238,935	2,238,935	2,238,935	2,258,409	2,238,935
Sentinel Lighting	684,138	652,414	644,654	627,674	627,674	627,674	587,690	627,674
Street Lighting	8,719,920	8,550,828	8,583,820	8,979,432	8,979,432	9,058,347	8,988,842	8,991,302
TOTAL	1,054,090,088	999,858,062	1,046,596,828	1,014,124,900	1,011,359,653	1,012,649,406	1,013,638,571	991,128,398

Table 3 – Demand (kW) forecast updated for 2012

Customer Class Name	2009 EDR Approved	2009 Actual	2010 Actual	2011 Actual	2011 Normalized	2012 Forecast	2012 Update	2013 Forecast
Residential								
General Service < 50 kW								
General Service > 50 to 999 kW	588,341	580,406	593,349	623,028	620,473	625,979	637,712	627,074
General Service 1000 to 4999 kW	372,459	366,321	382,392	338,998	331,374	333,340	343,049	337,859
Large Use	421,890	404,711	398,614	402,202	402,202	400,494	402,880	392,393
Unmetered Scattered Load								
Sentinel Lighting	1,637	1,543	1,463	1,452	1,452	1,452	1,308	1,452
Street Lighting	23,562	23,964	24,037	24,126	24,126	24,338	24,278	24,157
TOTAL	1,407,889	1,376,945	1,399,855	1,389,806	1,379,627	1,385,603	1,409,227	1,382,935

b) Is the customer count based on the average of the opening and closing number of customers in the year, or the average of each of the 12 months in the year?

The customer count in Table 1 above is based on the average of the 12 months in the year.

c) Please provide the normalized figures for each rate class for 2009 and 2010 in Tables 7 and 8.

Tables 4 and 5 are detailed below with normalized values provided for the weather sensitive rate classes, namely; residential, GS<50 and GS>50. The remaining rate classes are non-weather sensitive therefore the ‘actual’ and ‘normalized’ results are the same. You will note the only difference in Table 4 is for the General Service 1000 to 4999 kW class for 2011, whereby the data reflects the ‘net consumption’. Specifically, there are different values for 2011 Actual and 2011 Normalized which reflects the reallocation of customers as described in Exhibit 3, Tab 1, Schedule 2, Attachment 1 page 11-12. Similarly, Table 5 for the GS>50 rate class also reflects the movement of customers in 2009 and 2010 which constitutes the variance between ‘actual’ and ‘normalized’ for those years.

Table 4 – kWh with 2009 and 2010 Normalized values

Customer Class Name	2009 EDR Approved	2009 Actual	2009 Normalized	2010 Actual	2010 Normalized	2011 Actual	2011 Normalized	2012 Forecast	2013 Forecast
Residential	261,847,739	252,958,052	255,651,704	264,765,479	257,211,136	257,450,968	258,340,857	259,667,118	255,687,351
General Service < 50 kW	120,287,121	110,288,359	111,867,708	110,171,154	109,179,568	105,807,915	105,949,255	103,450,605	97,434,167
General Service > 50 to 999 kW	214,354,332	209,789,052	216,250,255	222,842,935	216,768,079	225,133,479	224,210,382	226,737,748	221,905,974
General Service 1000 to 4999 kW	165,546,229	168,518,709		179,379,861		160,156,759	157,283,380	158,216,681	156,701,083
Large Use	280,461,771	246,885,214		257,951,054		253,729,738	253,729,738	252,652,298	247,541,912
Unmetered Scattered Load	2,188,838	2,215,434		2,257,871		2,238,935	2,238,935	2,238,935	2,238,935
Sentinel Lighting	684,138	652,414		644,654		627,674	627,674	627,674	627,674
Street Lighting	8,719,920	8,550,828		8,583,820		8,979,432	8,979,432	9,058,347	8,991,302
TOTAL	1,054,090,088	999,858,062		1,046,596,828		1,014,124,900	1,011,359,653	1,012,649,406	991,128,398

Table 5 – kW with 2009 and 2010 Normalized Values

Customer Class Name	2009 EDR Approved	2009 Actual	2009 Normalized	2010 Actual	2010 Normalized	2011 Actual	2011 Normalized	2012 Forecast	2013 Forecast
Residential								0	
General Service < 50 kW								0	
General Service > 50 to 999 kW	588,341	580,406	598,282	593,349	577,174	623,028	620,473	625,979	627,074
General Service 1000 to 4999 kW	372,459	366,321		382,392		338,998	331,374	333,340	337,859
Large Use	421,890	404,711		398,614		402,202	402,202	400,494	392,393
Unmetered Scattered Load								0	
Sentinel Lighting	1,637	1,543		1,463		1,452	1,452	1,452	1,452
Street Lighting	23,562	23,964		24,037		24,126	24,126	24,338	24,157
TOTAL	1,407,889	1,376,945		1,399,855		1,389,806	1,379,627	1,385,603	1,382,935

d) Please provide the normalized figures for each rate class for 2012 in Tables 7 and 8.

The values provided in Tables 7 and 8 of the evidence with the columns labeled ‘2012 Estimated’ and ‘2013 Normalized’ are both normalized for the weather sensitive rate classes, and for the non-weather sensitive rate classes the values represent the trend analysis as discusses in Exhibit 3, Tab 1, Schedule 2, Attachment 1. Both columns should have been labeled ‘2012 Forecast’ and ‘2013 Forecast’ respectively, and are relabeled accordingly in this response.

e) Please update Tables 9, 10 and 11 to reflect actual normalized data for 2012.

Tables 9, 10, and 11 in the prefiled evidence are graphs of the trend of ‘Average Use per Customer’. As indicated earlier in this response, ‘actual normalized data’ for 2012 is not available, consequently an accurate ‘average use per customer for 2012 actual data’ is also not available. As a result, updating the graphs to include data that is a combination of actual (not normalized), and forecast would not portray a proper comparison with the data for the other years, and given the immaterial difference between 2012 ‘normalized’ and 2012 ‘update’, the trend line would not change.

f) Please update the second set of Tables 10 and 11 to reflect actual data for 2012 for the large use and USL customers.

Table 6 – Large Use Average Use per Customer with 2012 Actual Data

Year	Large User	% change	# customers
2007	92,306,146		3
2008	88,059,512	-4.6%	3
2009	86,746,652	-1.5%	3
2010	85,983,685	-0.9%	3
2011	84,576,579	-1.6%	3
2012	85,363,317	0.9%	3
2013 F	83,859,811	-1.8%	3

As discussed in earlier in this response and in more detail in response to Energy Probe # 15 (d), Bluewater Power does not have full 2012 billing data for all rate classes available. The USL rate category only has data available until September 2012. The values for the table below represent 9 months of actual data (Jan-Sept 2012), and 3 months of forecast data (Oct-Dec 2012) presented as 'average use per connection'.

Table 7 – USL Average Use per Connection with 2012 Updated data

Year	USL	% Change
2007	12,515	
2008	9,293	*-25.7%*
2009	8,620	*-7.2%*
2010	8,785	*1.9%*
2011	8,611	*-2.0%*
2012 Update	8,587	*-0.3%*
2013	8,611	*0.3%*

g) Please update the tables in Attachment 1 to reflect actual and normalized actual data for 2012.

Please see response to Energy Probe # 15 (d).

3.0 - VECC 19 - Customer count update

Reference: Exhibit 3, page 10, Schedule 2, Attachment 1, page 17

a) With respect to Table 22, please provide the customer count for the most recent 2012 month available. If this is December 2012, please also provide the average 2012 customer count by class. If not December 2012, please provide the customer count, by class, for comparable month in 2011.

Please find below an updated table with annual average 2012 actual (2012A) and December 2012 actual values (2012YE).

Updated Table 22: Annual Average Customer Count

Customers	Res	%chg	GS<50	%chg	GS>50	%chg	Intermediate	%chg	LU	%chg	Street	%chg	Sent	%chg	USL
2007	31,161	*0.6%*	3,410	*-0.2%*	332	*-3.8%*	15	*6.5%*	5	*0.0%*	9,618	*0.8%*	526	*0.0%*	238
2008	31,412	*0.8%*	3,404	*-0.2%*	364	*9.8%*	16	*5.6%*	4	*-16.7%*	9,742	*1.3%*	526	*0.0%*	232
2009	31,554	*0.5%*	3,412	*0.2%*	380	*4.3%*	16	*0.5%*	4	*-12.0%*	9,837	*1.0%*	497	*-5.5%*	257
2010	31,552	*0.0%*	3,511	*2.9%*	393	*3.3%*	16	*0.5%*	3	*-18.2%*	9,899	*0.6%*	497	*0.0%*	257
2011	31,787	*0.7%*	3,507	*-0.1%*	409	*4.1%*	13	*-18.8%*	3	*0.0%*	9,965	*0.7%*	497	*0.0%*	260
2012	31,954	*0.5%*	3,525	*0.5%*	423	*3.5%*	12	*-7.7%*	3	*0.0%*	10,052	*0.9%*	497	*0.0%*	260
2013	32,122	*0.5%*	3,544	*0.5%*	438	*3.5%*	12	*0.0%*	3	*0.0%*	10,140	*0.9%*	497	*0.0%*	260
2012A	31,896	*0.3%*	3,480	*-0.8%*	429	*5.0%*	12	*-7.7%*	3	*0.0%*	10,019	*0.5%*	447	*-10.1%*	263
2012YE	31,948		3,430		427		12		3		10,021		432		263

3.0 - VECC 13 - Load Forecast Update for 2012

3-VECC-13 Reference: Exhibit 3, Tab 1, Schedule 1, pages 4-5 and Attachment 1

a) If available, please update Tables 6, 7 and 8 to include a column for 2012 actuals.

Please see response to Energy Probe # 14 (a)

b) If available, please revise the second table shown in Attachment 1, to show average actual use per customer for 2012 by customer class.

Please see response to Energy Probe # 15 (k).

3.0 - VECC 14 - Large Use Average use per customer

3-VECC-14 Reference: Exhibit 3, Tab 1, Schedule 1, page 8

a) Please provide a schedule similar to Table 10 that includes only the 3 current large users for all years.

Table 1 below has been updated to reflect only the three current customers in the large use rate class, and reflects actual usage.

Table 1 – Large Use Average Use per customer (kWh)

Year	Large User	% change	# customers
2007	92,306,146		3
2008	88,059,512	-4.6%	3
2009	86,746,652	-1.5%	3
2010	85,983,685	-0.9%	3
2011	84,576,579	-1.6%	3
2012	85,363,317	0.9%	3
2013 F	83,859,811	-1.8%	3

3.0 - EP 15 - Forecast and Growth Rate

Ref: Exhibit 3, Tab 1, Schedule 2, Attachment 1

a) Was any attempt made at forecasting average use per customer using econometric analysis? If not, why not?

No. Bluewater Power's consultant has had mixed results in the past using use per customer as the dependent variable. However, the number of customers was tried as an explanatory variable for GS>50. Please see response to Board Staff IR# 3-22 (b) ii.

b) Please confirm that Bluewater Power had monthly sales data by rate class beginning in January, 2006. If this cannot be confirmed, please indicate when it had monthly sales data by rate class.

Confirmed. Bluewater Power has monthly sales data by rate class from January, 2006. Bluewater Power also has monthly sales data by rate class prior to this date, if that is the intent of this question.

c) Please provide the consumption for Customer D (page 8) for the May through December, 2012 and the corresponding period in 2011. Please also provide the cooling degree days for each of these two periods.

Please see table below:

Customer D Consumption & Degree Days		
	May-Dec 2011	May-Dec 2012
Consumption		
kWh	2,805,322	1,217,898
kW	7,595	4,534
CDD	579.7	589.8

d) Please update Tables 12 through 22 to reflect actual data for 2012.

The referenced tables 12 through 22 refer to actual, normalized (where applicable) and forecast kWh and kW by class, average use by class and customer connections by class. The request is to update these tables to reflect actual data for 2012. At time of writing, not all of this data is available for the entire calendar year 2012. In order to seek clarification on the intent of this question, Bluewater initiated a brief conference call with Board Staff, Energy Probe and VECC, which took place on January 24. On January 28, Bluewater confirmed with parties the approach to take in responding to this request without complete data being available for 2012 for all classes. Bluewater has been requested to provide the actual data available for 2012 and a forecast value (normalized) for the remainder of the year 2012.

At time of writing, the following data are available for the entire 2012 calendar year:

- Customer connections for all classes;
- kWh and kW for Intermediate, Large User and Street lighting classes.

Data available up to and including October 2012:

- kWh and kW for the GS>50 and Sentinel light classes.

Data available up to and including September 2012:

- kWh for Residential, GS<50 and USL classes.

For updates to customer connections for all classes, please see response to VECC IR #19.

Please see the table below for updates to consumption:

kWh

Year	Residential[2]	GS<50	GS>50	Intermediate	Large User	Street Light	Sentinel Light	USL
2011	257,450,968	105,807,915	225,133,479	160,156,759	253,729,738	8,979,432	627,674	2,238,935
2012 YTD	196,517,425	78,642,709	189,553,783	n/a	n/a	n/a	483,078	1,698,675
2012 to YE[1]	61,342,167	24,241,683	37,259,310	n/a	n/a	n/a	104,612	559,734
2012 Total	257,859,592	102,884,392	226,813,093	158,156,603	256,089,950	8,988,842	587,690	2,258,409

[1] 2012 to YE is forecast normal monthly 2012: Oct-Dec for Residential, GS<50 and USL; Nov-Dec for GS>50 and Sentinel.

[2] Residential, GS<50, & USL 2012 actual is January to September

[3] No monthly forecast is available for Sentinel & USL. 2012 to YE is calculated as (2012 forecast)/12 x number of months.

Requested HDD and CDD are in the table below:

	HDD	CDD
2011	3,341.3	579.7
2012	2,857.7	596.6
Jan-Sept 2011	2,341.1	575.1
Jan-Sept 2012	1,748.6	592.5

Updated kW is in the following table:

kW

Year	GS>50	Intermediate	Large User	Street Light	Sentinel Light
2011	623,028	338,998	402,202	24,126	1,452
2012 Jan-Oct	542,294	n/a	n/a	n/a	1,101
2012 Nov-Dec[1]	95,418	n/a	n/a	n/a	207
2012 Total	637,712	343,049	402,880	24,278	1,308

[1] kW is not forecast on a monthly basis. Nov-Dec 2012 is assumed to be Nov-Dec 2011.

e) With respect to Table 14, please explain why the average growth rate of 0.6% for 2007 through 2011 was used instead of the average annual compound growth rate for 2006 to 2011? Please provide the 2012 and 2013 figures based on the use of the average annual compound growth rate in volumes between 2006 and 2011.

Bluewater Power used the arithmetic average of annual growth rates for the period starting in 2006 up to 2011; that is, the arithmetic average of the growth from 2006 to 2007, 2007 to 2008, …, 2010 to 2011. This yields an annual percentage change of roughly 0.6%. An alternative is the geometric mean (or compound growth rate). This can be calculated as $(2011/2006)^{1/5}$ or about 0.45% (0.4473% rounded up). Bluewater Power is unaware of any direction of the Board with respect to calculation of averages, but would be willing to comply with these directions if it is available. A table comparing the values based on the arithmetic mean of the growth rate with the values based on the geometric mean of the growth rate is presented below.

Intermediate Class

kWh

Date	Actual Int kWh	*%chg*	Reclassified kWh	Net Int kWh	*%chg*	Net Int kWh	*%chg*
2006	174,273,598		20,461,223	153,812,375		153,812,375	
2007	170,522,010	*-2.20%*	24,736,496	145,785,513	-5.22%	145,785,513	-5.22%
2008	179,952,089	*5.50%*	35,534,071	144,418,017	-0.94%	144,418,017	-0.94%
2009	168,518,709	*-6.40%*	29,228,093	139,290,617	-3.55%	139,290,617	-3.55%
2010	179,379,861	*6.40%*	25,723,943	153,655,917	10.31%	153,655,917	10.31%
2011	160,156,759	*-10.70%*	2,873,379	157,283,380	2.36%	157,283,380	2.36%
2012				158,216,681	0.59%	157,986,924	0.45%

2013	159,155,521	0.59%	158,693,616	0.45%
	Arithmetic Mean		Geometric Mean	

f) Please explain how the 0.6% growth rate used for 2012 and 2013 shown in Table 15 was derived, since it does not appear to be the average of the percent changes shown for 2007 through 2011, which average 0.8%.

The rate of growth of the kW forecast was kept equivalent to the rate of growth of the kWh forecast in order to maintain the most recent historical year ratio of kW/kWh. This is the basis for the kW growth forecast in Table 15.

g) Please calculate the 2012 and 2013 figures in Table 15 using the average annual compound growth rate for 2006 to 2011.

Bluewater calculates the compound growth rate (geometric mean) as 0.69%, not 0.8% as stated by Energy Probe in part (f) above [(331,375/320,170)$^{1/5}$]. Please see table below using this average growth:

Intermediate Class kW

Date	Actual Int kW	*%chg*	Reclassified kW	Net Int kW	*%chg*
2006	357,342		37,172	320,170	
2007	370,714	*3.7%*	48,670	322,044	*0.6%*
2008	394,728	*6.5%*	67,247	327,482	*1.7%*
2009	366,321	*-7.2%*	58,221	308,100	*-5.9%*
2010	382,392	*4.4%*	53,445	328,947	*6.8%*
2011	338,998	*-11.3%*	7,624	331,374	*0.7%*
2012				333,661	*0.7%*
2013				335,965	*0.7%*

h) With respect to Table 16, please explain why the average growth rate of -0.4% for 2007 through 2011 was used instead of the average annual compound growth rate for 2006 to 2011? Please provide the 2012 and 2013 figures based on the use of the average annual compound growth rate in volumes between 2006 and 2011.

Please see response to part (e) above. The average compound growth rate (geometric mean) from 2006 to 2011 is -0.84% (note: Bluewater assumes that 2007 is a typographic error and Energy Probe is referring to the 2006 to 2011 period as above). Please see revised figures for 2012 and 2013 in the table below.

Large User Class kWh

Date	Actual LU kWh	*%chg*	Reclassified kWh	Net LU kWh	*%chg*
2006	339,361,533		74,672,149	264,689,384	
2007	349,966,983	*3.1%*	73,048,546	276,918,437	*4.6%*
2008	301,005,345	*-14.0%*	40,486,067	260,519,278	*-5.9%*
2009	246,885,214	*-18.0%*	20,281,809	226,603,405	*-13.0%*
2010	257,951,054	*4.5%*	0	257,951,054	*13.8%*
2011	253,729,738	*-1.6%*	0	253,729,738	*-1.6%*
2012				251,592,877	*-0.8%*
2013				250,524,510	*-0.8%*

i) Please explain how the -0.4% growth rate used for 2012 and 2013 shown in Table 15 was derived, since it does not appear to be the average of the percent changes shown for 2007 through 2011, which average -0.5%.

Please see response to part (f) above.

j) Please calculate the 2012 and 2013 figures in Table 17 using the average annual compound growth rate for 2006 to 2011.

The average compound growth rate (geometric mean) from 2006 to 2011 is –0.72%. Please see the table below for updated result.

Large User Class kW

Date	Actual LU kW	*%chg*	Reclassified kW	Net LU kW	*%chg*
2006	552,133		135,150	416,983	
2007	544,917	*-1.3%*	123,844	421,073	*1.0%*
2008	483,880	*-11.2%*	76,093	407,788	*-3.2%*
2009	404,711	*-16.4%*	41,601	363,110	*-11.0%*
2010	398,614	*-1.5%*	0	398,614	*9.8%*
2011	402,202	*0.9%*	0	402,202	*0.9%*
2012				399,309	*-0.7%*
2013				397,613	*-0.7%*

k) Please update Tables 23 and 24 to reflect actual and normalized data for 2012.

Please see response to part (d) above for updated consumption. Updated actual use per customer is shown in the table below. The table is based on consumption reported in part (d) above and average annual customer counts as reported in response to VECC 19.

Use Per Customer (kWh)

Year	Residential	GS<50	GS>50	Intermediate	Large User	Street Light	Sentinel Light	USL
2011	8,099	30,170	550,449	12,319,751	84,576,579	901	1,263	8,611
2012	8,084	29,564	528,702	13,179,717	85,363,317	897	1,315	8,587

l) Please provide an explanation of how the normalized figures have been calculated. Please provide an example that shows how the 2011 actual residential consumption shown in Table 23 was converted into the normalized figure shown.

As briefly outlined on page 10 of the Elenchus report, the normalized consumption is calculated by incorporating the economic variables, 10-yr weather normal heating and cooling degree days, and calendar and index variables into the regression equation. Therefore, for the residential class, the 2011 normalized residential kWh consumption would be the sum of the monthly values predicted by the regression equation. These values are based on the equation displayed in Table 1 in the report. An example is shown below:

Residential Normalized

	Norm HDD	Norm CDD	Monthdays	Employment	Const	Norm kWh
Factor:	14,064.6	71,999.4	804,658.6	27,026.6	-16,212,084.1	
Jan-11	668.58	0	31	231.5		24,392,299
Feb-11	591.42	0	28	227.4		20,782,289
Mar-11	482.59	0.02	31	226.4		21,640,027
Apr-11	253.99	3.94	30	224.1		17,840,274
May-11	119.42	24.28	31	226.7		18,286,994
Jun-11	13.38	105.23	30	229.2		21,886,839
Jul-11	0.53	174.35	31	233.9		27,614,388
Aug-11	1.82	147.21	31	238		25,789,277
Sep-11	32.56	58.63	30	237.6		19,028,451
Oct-11	204.12	8.69	31	235.9		18,604,441
Nov-11	364.03	0	30	232.1		19,320,479
Dec-11	585.61	0	31	228.9		23,155,089
						258,340,847

3.0 - VECC 18 - Growth Rates

Reference: Exhibit 3, page 10, Schedule 2, Attachment 1, pages 12-16

a) What is the basis for the 0.6% growth rate used for the Intermediate class for 2012 and 2013?

Please see response to Energy Probe IR #15 (e).

b) If available, please update the analysis for the Intermediate class to include 2012 actual usage.

a) Actual consumption for 2012 is shown in the updated tables below in highlighted text:

Updated Table 14: Intermediate Class kWh

Date	Actual Int kWh	*%chg*	Reclassified kWh	Net Int kWh	*%chg*
2006	174,273,598		20,461,223	153,812,375	
2007	170,522,010	*-2.2%*	24,736,496	145,785,513	*-5.2%*
2008	179,952,089	*5.5%*	35,534,071	144,418,017	*-0.9%*
2009	168,518,709	*-6.4%*	29,228,093	139,290,617	*-3.6%*
2010	179,379,861	*6.4%*	25,723,943	153,655,917	*10.3%*
2011	160,156,759	*-10.7%*	2,873,379	157,283,380	*2.4%*
2012	158,156,991	*-1.2%*		158,216,681	*0.6%*
2013				159,155,521	*0.6%*

Updated Table 15: Intermediate Class kW

Date	Actual Int kW	*%chg*	Reclassified kW	Net Int kW	*%chg*
2006	357,342		37,172	320,170	
2007	370,714	*3.7%*	48,670	322,044	*0.6%*
2008	394,728	*6.5%*	67,247	327,482	*1.7%*
2009	366,321	*-7.2%*	58,221	308,100	*-5.9%*
2010	382,392	*4.4%*	53,445	328,947	*6.8%*
2011	338,998	*-11.3%*	7,624	331,374	*0.7%*
2012	343,044	*1.2%*		333,340	*0.6%*
2013				335,318	*0.6%*

c) What is the basis for the -0.4% growth rate use for the Large User class?

Please see response to Energy Probe IR #15 (h).

d) If available, please update the analysis for the Large User class to include 2012 actual usage?

Actual consumption for 2012 is shown in the updated tables below in highlighted text:

Updated Table 16: Large User Class kWh

Date	Actual LU kWh	*%chg*	Reclassified kWh	Net LU kWh	*%chg*
2006	339,361,533		74,672,149	264,689,384	
2007	349,966,983	*3.1%*	73,048,546	276,918,437	*4.6%*
2008	301,005,345	*-14.0%*	40,486,067	260,519,278	*-5.9%*
2009	246,885,214	*-18.0%*	20,281,809	226,603,405	*-13.0%*
2010	257,951,054	*4.5%*	0	257,951,054	*13.8%*
2011	253,729,738	*-1.6%*	0	253,729,738	*-1.6%*
2012	256,089,950	*0.9%*		252,652,298	*-0.4%*
2013				251,579,433	*-0.4%*

Updated Table 17: Large User Class kW

Date	Actual LU kW	*%chg*	Reclassified kW	Net LU kW	*%chg*
2006	552,133		135,150	416,983	
2007	544,917	*-1.3%*	123,844	421,073	*1.0%*
2008	483,880	*-11.2%*	76,093	407,788	*-3.2%*
2009	404,711	*-16.4%*	41,601	363,110	*-11.0%*
2010	398,614	*-1.5%*	0	398,614	*9.8%*
2011	402,202	*0.9%*	0	402,202	*0.9%*
2012	402,870	*0.2%*		400,494	*-0.4%*
2013				398,793	*-0.4%*

3.0-Staff-24 - CDM Adjustment of Load Forecast

Ref: Exh 3-1-3
<u>Ref: Exh 3-1-3 Attachment 1 CDM Adjustment of Load Forecast</u>

In Exh 3-1-3, Bluewater Power describes the methodology it has used to adjust the load forecast data to account for the impact and persistence of CDM programs from 2006 to 2011, and to derive the adjustment for the 2013 load forecast to reflect the impact of 2011 to 2013 CDM programs to achieve the CDM target that is a condition of its distribution licence. The data is provided in Attachment 1 of Exh 3-1-3.

a) Please provide Exh 3-1-3 Attachment 1 in working Microsoft Excel format if available.

Please see excel file: ‘IRR_Board Staff 24_Copy of CDM Adjusted_Bluewater_20130130.xlsx.

b) What is the rationale for using the average of 2006 to 2011 CDM savings to gross-up the base 2013 forecast arising from the model? In particular, estimated savings in 2006 would be smaller that year because only one year’s worth of CDM would be involved. CDM savings would generally increase, with some drop off in the persistence of prior year CDM programs with the passage of time, so it would be expected, all other thing being equal, that the 2006-2011 CDM program average impact would understate the cumulative persistence even to 2013.

At the time of calculation the final 2011 OPA results had not been released. It was universally expected that the 2011 results would be lower than previous years given the late start in the OPA releasing the programs for LDC use. It was determined by Bluewater Power that using the 2006 to 2011 average as a reasonable and available proxy at the time, would compensate for the low amount of savings accumulated in 2006. Bluewater Power also reasoned that ultimately the LRAMVA would be trued up and any significant change in the calculation would not be materially harmful to any affected party.

c) Bluewater has included 2011 actual data in the regression analysis, and the 2011 actual consumption would be impacted by 2011 CDM programs. However, the 2011 CDM program impact is excluded from the adjustment. Please explain how Bluewater or its consultant Elenchus have taken into account the presence and influence of 2011 CDM programs on the load forecast before the 2013 CDM adjustment.

As indicated in response to part (a), the 2011 results were not available at the time of the calculation so a proxy was used. In response to VECC #21, the 2011 actual results were included as a sensitivity analysis, and the results were a 0.3% further reduction to both the kWh and kW forecast.

d) Why has Bluewater adopted the approach of setting the target as 30% of the cumulative 2011-14 CDM target, rather than taking into account measured 2011 CDM savings and setting the adjustment to reflect both what was achieved in 2011 and hence what remains to be achieved in each of 2012, 2013 and 2014 to meet the cumulative CDM target?

At the time of calculation the final 2011 OPA results had not been released. The 30% factor is simply a proxy calculation for what Bluewater Power estimates will be the net impact of new CDM programs introduced in 2013 as well as persistence from 2011 and 2012 programs that will ultimately reduce Bluewater Power retail consumption. This is premised on Bluewater Power's commitment to meet its licenced CDM targets. The 30% is factored on a simple acceleration model of program implementation to meet the 2014 target (10% in 2011, 20% in 2012, 30% in 2013 and finally 40% in 2014). Ultimately the true test of success will be upon the final publication of 2013 net CDM results and the calculation of the LRAMVA. Bluewater Power understands that this is a method to incorporate some component of CDM impact on the load forecast and is intended to smooth rates to the customer and hold the LDC whole for the losses.

Attachment 1 of 1

Board Staff - 24

3.0 - VECC 20 - CDM Forecast

REFERENCE: EXHIBIT 3, TAB 1, SCHEDULE 3, PAGE 1

a) Please confirm that the 30% factor includes the effect (in 2013) of Bluewater's 2011, 2012 and 2013 CDM programs. If not, please explain the basis for the 30%.

The 30% factor is simply a proxy calculation for what Bluewater Power estimates will be the net impact of new CDM programs introduced in 2013 as well as the persistence related to the 2011 and 2012 programs that will ultimately reduce Bluewater Power retail consumption. This is premised on Bluewater Power's commitment to meet its licenced CDM targets. The 30% is factored on a simple acceleration model of program implementation to meet the 2014 target (10% in 2011, 20% in 2012, 30% in 2013 and finally 40% in 2014). Ultimately the true test of success will be upon the final publication of 2013 net CDM results and the calculation of the LRAMVA. Bluewater Power understands that this is a method to incorporate some component of CDM impact on the load forecast and is intended to smooth rates to the customer and hold the LDC whole for the losses.

b) Since 2011 customer class usage data was used in the estimation of the load forecast models/trend analyses, please explain why the load forecast prepared by Elenchus doesn't already capture the impact of 2011 CDM programs.

Elenchus has employed best practice tools and methodology to formulate a weather normalized 2013 load forecast. Intrinsic in the calculation is the effects of energy conservation, either naturally occurring or produced by programmatic CDM initiatives. Measurable OPA CDM programs commenced in 2006 and have influenced provincial and LDC specific consumption since the inception. For the manufacture of a realistic 2013 weather normalized load forecast Elenchus did use 2011 customer data which has been influenced by the OPA CDM programs. However at the time of calculation of the CDM adjustment the reported final CDM program results had not been released. Without certainty of the reported results Elenchus developed a proxy model to reasonably estimate the impact of uncertainty of new programs being introduced tempered by reported persistence. Elenchus reasoned that without the final reported data the proposed methodology would temper any uncertainty. Elenchus also reasoned that the potential difference would not be materially harmful to any affected party. Elenchus would agree that 2011 CDM impacts are included, however, that is the rationale for the analysis to ‘add-back’ the average of the 2006-2011 results to the base load forecast in order to account for the intrinsic impacts of CDM. After the add-back, an adjustment is made to account for the 2013 anticipated CDM impact with the intent to model a more accurate forecast.

3.0 - VECC 21 - CDM Forecast and OPA Results

REFERENCE: EXHIBIT 3, TAB 1, SCHEDULE 3, PAGES 2-3

Exhibit 3, Tab 1, Schedule 3, Attachment 1

a) Please provide a copy of the OPA's final Report regarding Bluewater's 2006-2010 CDM programs.

Please reference "IRR_VECC 21_2006-2010 Final OPA CDM Results.Bluewater Power Distribution Corporation.xls" attached with this submission.

b) With respect to Table 1, the third column in the first row of the header is titled "2006-2010 CDM Programs". However the column immediately below it is titled "6 yr. Avg". Please confirm that the averages in Column B are the average of the savings in years 2006-2011 from the impact of CDM programs for the years 2006-2010.

Bluewater Power confirms that the averages in Column B are the average of the savings in years 2006-2011 from the impact of CDM programs for the years 2006-2010.

c) If part (b) is confirmed, please explain why the actual savings from the 2011 CDM programs was not included in the CDM adjustment calculation.

At the time of creation of Attachment 1 the final OPA 2011 results were not available and therefore not included in the calculation. It was reasonably expected then that lack of 2011 data would not be materially significant .

d) Please provide a copy of OPA Report regarding Bluewater's final 2011 CDM results.

The report is found at Exhibit 9, Tab 3, Schedule 1, Attachment 1 of the prefiled evidence.

An electronic copy is provided “IRR_VECC 21_2011 Final Annual Report Data_Bluewater Power Distribution Corporation.xlsx”.

e) Please provide revised versions of Table 1 and Attachment 1 that:

- Include the results of 2011 CDM programs in the calculation of the historical average savings and 2013 persistence.
- Base the CDM Target Adjustment on 20% of Bluewater’s CDM target.

In order to respond to this question, Bluewater Power has provided three sets of results. Tables 1 and 2 detail the impact of including 2011 results in the calculation of the historical average savings and 2013 persistence.

Tables 3 and 4 detail the impact of basing the adjustment on 20% of Bluewater Power’s target, but not including the 2011 results.

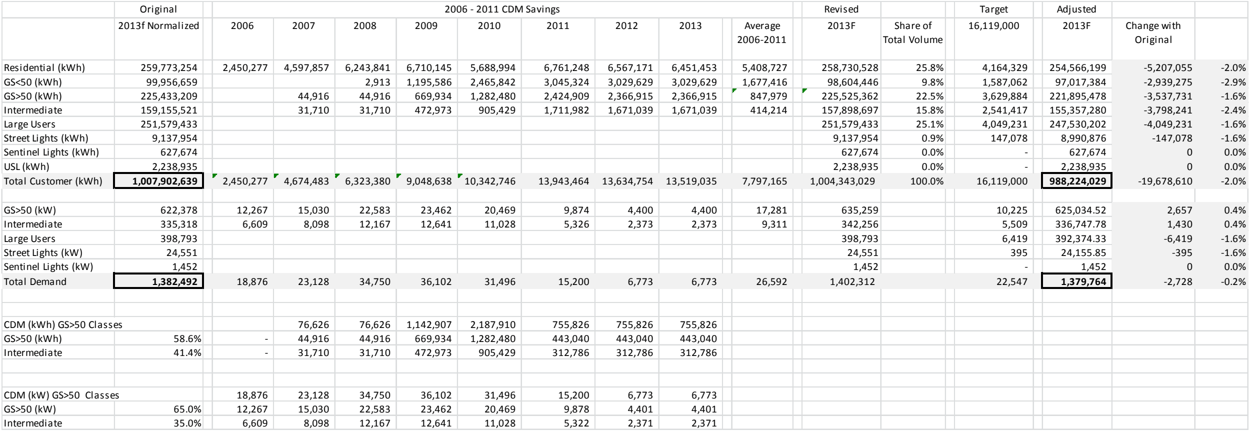
Tables 5 and 6 detail the combined results of including the 2011 results and revising the CDM target to 20% for 2013.

Table 1 – Including 2011 Results

ENERGY (kWh)

	Weather Normalized	2006-2011 CDM Programs		Weather Normalized	2011-2014 CDM Target	Weather Normalized
	2013F	6 yr. Avg.	2013	Revised	(30% of Target)	Adjusted
	(Elenchus)	(2006/11)	Persistence	2013F		2013F
	A	B	C	D = A + B -C	E	F = D - E
Residential (kWh)	259,773,254	5,408,727	6,451,453	258,730,528	4,164,329	254,566,199
GS<50 (kWh)	99,956,659	1,677,416	3,029,629	98,604,446	1,587,062	97,017,384
GS>50 (kW)	225,433,209	847,979	755,826	225,525,362	3,629,884	221,895,478
Intermediate	159,155,521	414,214	1,671,039	157,898,697	2,541,417	155,357,280
Large Users	251,579,433	0	0	251,579,433	4,049,231	247,530,202
Street Lights (kW)	9,137,954	0	0	9,137,954	147,078	8,990,876
Sentinel Lights (kW)	627,674	0	0	627,674	0	627,674
USL (kWh)	2,238,935	0	0	2,238,935	0	2,238,935
Total Customer (kWh)	1,007,902,639	7,797,165	13,519,035	1,004,343,029	16,119,000	988,224,029

Table 2 - Revised Attachment 1 Includes the results of 2011 CDM programs in the calculation of the historical average savings and 2013 persistence.

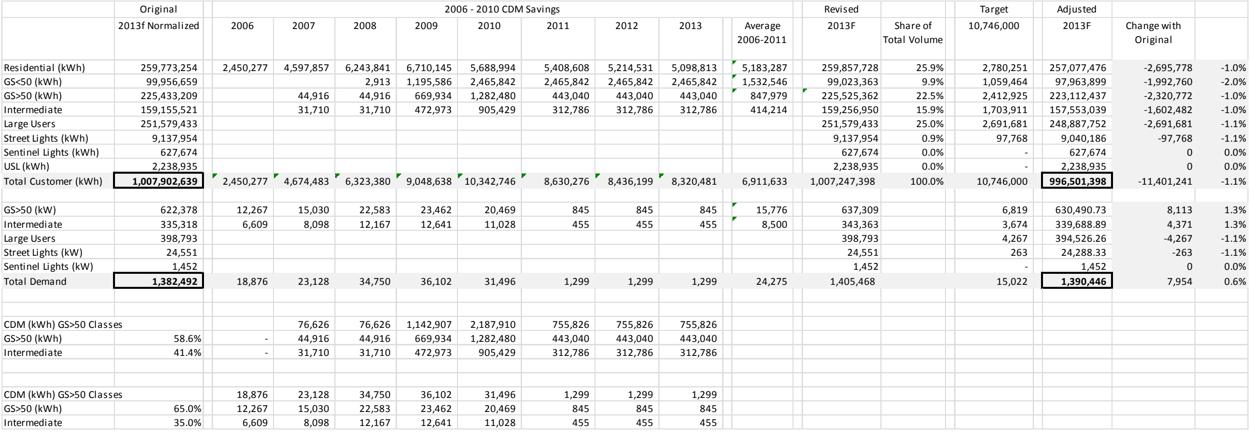


	Original	2006 - 2011 CDM Savings									Revised		Target	Adjusted		
	2013f Normalized	2006	2007	2008	2009	2010	2011	2012	2013	Average 2006-2011	2013F	Share of Total Volume	16,119,000	2013F	Change with Original	
Residential (kWh)	259,773,254	2,450,277	4,597,857	6,243,841	6,710,145	5,688,994	6,761,248	6,567,171	6,451,453	5,408,727	258,730,528	25.8%	4,164,329	254,566,199	-5,207,055	-2.0%
GS<50 (kWh)	99,956,659			2,913	1,195,586	2,465,842	3,045,324	3,029,629	3,029,629	1,677,416	98,604,446	9.8%	1,587,062	97,017,384	-2,939,275	-2.9%
GS>50 (kWh)	225,433,209		44,916	44,916	669,934	1,282,480	2,424,909	2,366,915	2,366,915	847,979	225,525,362	22.5%	3,629,884	221,895,478	-3,537,731	-1.6%
Intermediate	159,155,521		31,710	31,710	472,973	905,429	1,711,982	1,671,039	1,671,039	414,214	157,898,697	15.8%	2,541,417	155,357,280	-3,798,241	-2.4%
Large Users	251,579,433										251,579,433	25.1%	4,049,231	247,530,202	-4,049,231	-1.6%
Street Lights (kWh)	9,137,954										9,137,954	0.9%	147,078	8,990,876	-147,078	-1.6%
Sentinel Lights (kWh)	627,674										627,674	0.0%	-	627,674	0	0.0%
USL (kWh)	2,238,935										2,238,935	0.0%	-	2,238,935	0	0.0%
Total Customer (kWh)	**1,007,902,639**	2,450,277	4,674,483	6,323,380	9,048,638	10,342,746	13,943,464	13,634,754	13,519,035	7,797,165	1,004,343,029	100.0%	16,119,000	**988,224,029**	-19,678,610	-2.0%
GS>50 (kW)	622,378	12,267	15,030	22,583	23,462	20,469	9,874	4,400	4,400	17,281	635,259		10,225	625,034.52	2,657	0.4%
Intermediate	335,318	6,609	8,098	12,167	12,641	11,028	5,326	2,373	2,373	9,311	342,256		5,509	336,747.78	1,430	0.4%
Large Users	398,793										398,793		6,419	392,374.33	-6,419	-1.6%
Street Lights (kW)	24,551										24,551		395	24,155.85	-395	-1.6%
Sentinel Lights (kW)	1,452										1,452		-	1,452	0	0.0%
Total Demand	**1,382,492**	18,876	23,128	34,750	36,102	31,496	15,200	6,773	6,773	26,592	1,402,312		22,547	**1,379,764**	-2,728	-0.2%
CDM (kWh) GS>50 Classes			76,626	76,626	1,142,907	2,187,910	755,826	755,826	755,826							
GS>50 (kWh)	58.6%	-	44,916	44,916	669,934	1,282,480	443,040	443,040	443,040							
Intermediate	41.4%	-	31,710	31,710	472,973	905,429	312,786	312,786	312,786							
CDM (kW) GS>50 Classes		18,876	23,128	34,750	36,102	31,496	15,200	6,773	6,773							
GS>50 (kW)	65.0%	12,267	15,030	22,583	23,462	20,469	9,878	4,401	4,401							
Intermediate	35.0%	6,609	8,098	12,167	12,641	11,028	5,322	2,371	2,371							

Table 3 - Basing the CDM Target Adjustment on 20% of Bluewater's CDM target.

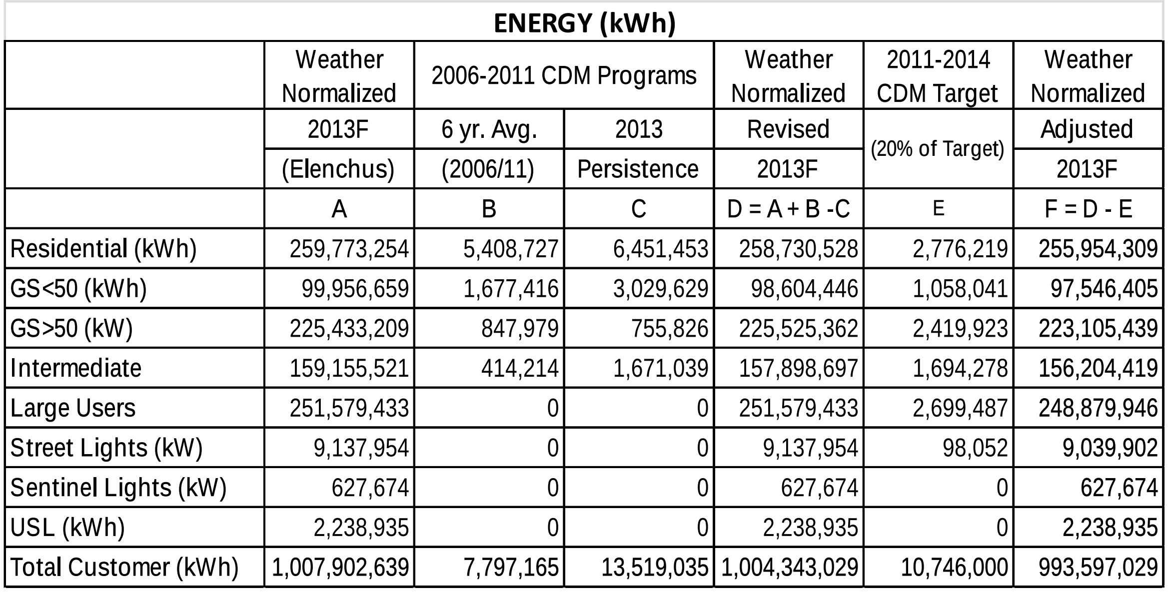
ENERGY (kWh)						
	Weather Normalized	2006-2010 CDM Programs		Weather Normalized	2011-2014 CDM Target	Weather Normalized
	2013F	6 yr. Avg.	2013	Revised	(20% of Target)	Adjusted
	(Elenchus)	(2006/11)	Persistence	2013F		2013F
	A	B	C	D = A + B - C	E	F = D - E
Residential (kWh)	259,773,254	5,183,287	5,098,813	259,857,728	2,780,251	257,077,476
GS<50 (kWh)	99,956,659	1,532,546	2,465,842	99,023,363	1,059,464	97,963,899
GS>50 (kW)	225,433,209	847,979	755,826	225,525,362	2,412,925	223,112,437
Intermediate	159,155,521	414,214	312,786	159,256,950	1,703,911	157,553,039
Large Users	251,579,433	0	0	251,579,433	2,691,681	248,887,752
Street Lights (kW)	9,137,954	0	0	9,137,954	97,768	9,040,186
Sentinel Lights (kW)	627,674	0	0	627,674	0	627,674
USL (kWh)	2,238,935	0	0	2,238,935	0	2,238,935
Total Customer (kWh)	1,007,902,639	6,911,633	8,320,481	1,007,247,398	10,746,000	996,501,398

Table 4 - Revised Attachment 1 •Basing the CDM Target Adjustment on 20% of Bluewater's CDM target.



	Original	2006 - 2010 CDM Savings									Revised		Target	Adjusted		
	2013f Normalized	2006	2007	2008	2009	2010	2011	2012	2013	Average 2006-2011	2013F	Share of Total Volume	10,746,000	2013F	Change with Original	
Residential (kWh)	259,773,254	2,450,277	4,597,857	6,243,841	6,710,145	5,688,994	5,408,608	5,214,531	5,098,813	5,183,287	259,857,728	25.9%	2,780,251	257,077,476	-2,695,778	-1.0%
GS<50 (kWh)	99,956,659			2,913	1,195,586	2,465,842	2,465,842	2,465,842	2,465,842	1,532,546	99,023,363	9.9%	1,059,464	97,963,899	-1,992,760	-2.0%
GS>50 (kWh)	225,433,209		44,916	44,916	669,934	1,282,480	443,040	443,040	443,040	847,979	225,525,362	22.5%	2,412,925	223,112,437	-2,320,772	-1.0%
Intermediate	159,155,521		31,710	31,710	472,973	905,429	312,786	312,786	312,786	414,214	159,256,950	15.9%	1,703,911	157,553,039	-1,602,482	-1.0%
Large Users	251,579,433										251,579,433	25.0%	2,691,681	248,887,752	-2,691,681	-1.1%
Street Lights (kWh)	9,137,954										9,137,954	0.9%	97,768	9,040,186	-97,768	-1.1%
Sentinel Lights (kWh)	627,674										627,674	0.0%	-	627,674	0	0.0%
USL (kWh)	2,238,935										2,238,935	0.0%	-	2,238,935	0	0.0%
Total Customer (kWh)	**1,007,902,639**	2,450,277	4,674,483	6,323,380	9,048,638	10,342,746	8,630,276	8,436,199	8,320,481	6,911,633	1,007,247,398	100.0%	10,746,000	**996,501,398**	-11,401,241	-1.1%
GS>50 (kW)	622,378	12,267	15,030	22,583	23,462	20,469	845	845	845	15,776	637,309		6,819	630,490.73	8,113	1.3%
Intermediate	335,318	6,609	8,098	12,167	12,641	11,028	455	455	455	8,500	343,363		3,674	339,688.89	4,371	1.3%
Large Users	398,793										398,793		4,267	394,526.26	-4,267	-1.1%
Street Lights (kW)	24,551										24,551		263	24,288.33	-263	-1.1%
Sentinel Lights (kW)	1,452										1,452		-	1,452	0	0.0%
Total Demand	**1,382,492**	18,876	23,128	34,750	36,102	31,496	1,299	1,299	1,299	24,275	1,405,468		15,022	**1,390,446**	7,954	0.6%
CDM (kWh) GS>50 Classes			76,626	76,626	1,142,907	2,187,910	755,826	755,826	755,826							
GS>50 (kWh)	58.6%	-	44,916	44,916	669,934	1,282,480	443,040	443,040	443,040							
Intermediate	41.4%	-	31,710	31,710	472,973	905,429	312,786	312,786	312,786							
CDM (kWh) GS>50 Classes		18,876	23,128	34,750	36,102	31,496	1,299	1,299	1,299							
GS>50 (kWh)	65.0%	12,267	15,030	22,583	23,462	20,469	845	845	845							
Intermediate	35.0%	6,609	8,098	12,167	12,641	11,028	455	455	455							

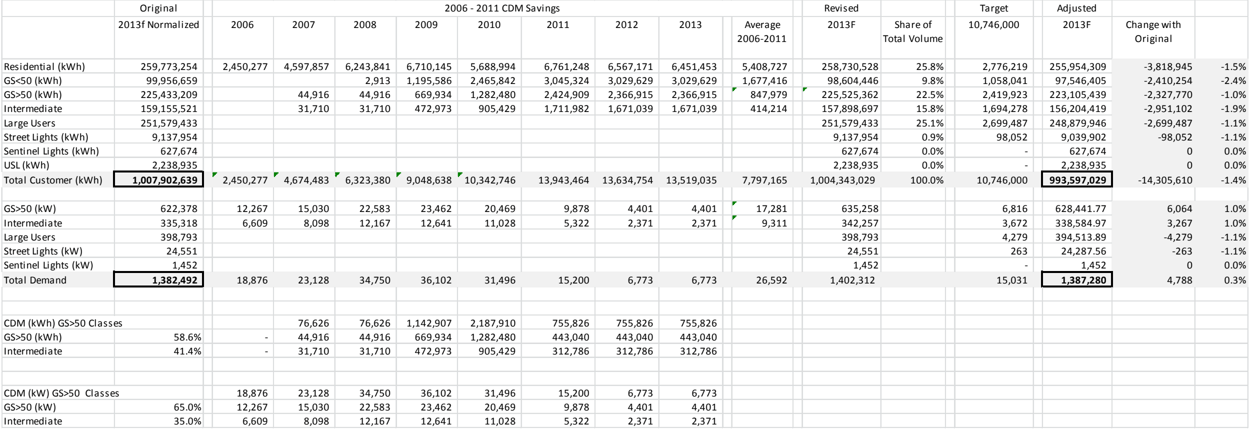
Table 5 – Including 2011 Results Basing the CDM Target Adjustment on 20% of Bluewater's CDM target.



ENERGY (kWh)

	Weather Normalized	2006-2011 CDM Programs		Weather Normalized	2011-2014 CDM Target	Weather Normalized
	2013F	6 yr. Avg.	2013	Revised	(20% of Target)	Adjusted
	(Elenchus)	(2006/11)	Persistence	2013F		2013F
	A	B	C	D = A + B -C	E	F = D - E
Residential (kWh)	259,773,254	5,408,727	6,451,453	258,730,528	2,776,219	255,954,309
GS<50 (kWh)	99,956,659	1,677,416	3,029,629	98,604,446	1,058,041	97,546,405
GS>50 (kW)	225,433,209	847,979	755,826	225,525,362	2,419,923	223,105,439
Intermediate	159,155,521	414,214	1,671,039	157,898,697	1,694,278	156,204,419
Large Users	251,579,433	0	0	251,579,433	2,699,487	248,879,946
Street Lights (kW)	9,137,954	0	0	9,137,954	98,052	9,039,902
Sentinel Lights (kW)	627,674	0	0	627,674	0	627,674
USL (kWh)	2,238,935	0	0	2,238,935	0	2,238,935
Total Customer (kWh)	1,007,902,639	7,797,165	13,519,035	1,004,343,029	10,746,000	993,597,029

Table 6 - Revised Attachment 1 Includes the results of 2011 CDM programs in the calculation of the historical average savings and 2013 persistence basing the CDM Target Adjustment on 20% of Bluewater's CDM target.



	Original	2006 - 2011 CDM Savings									Revised		Target	Adjusted		
	2013f Normalized	2006	2007	2008	2009	2010	2011	2012	2013	Average 2006-2011	2013F	Share of Total Volume	10,746,000	2013F	Change with Original	
Residential (kWh)	259,773,254	2,450,277	4,597,857	6,243,841	6,710,145	5,688,994	6,761,248	6,567,171	6,451,453	5,408,727	258,730,528	25.8%	2,776,219	255,954,309	-3,818,945	-1.5%
GS<50 (kWh)	99,956,659			2,913	1,195,586	2,465,842	3,045,324	3,029,629	3,029,629	1,677,416	98,604,446	9.8%	1,058,041	97,546,405	-2,410,254	-2.4%
GS>50 (kWh)	225,433,209		44,916	44,916	669,934	1,282,480	2,424,909	2,366,915	2,366,915	847,979	225,525,362	22.5%	2,419,923	223,105,439	-2,327,770	-1.0%
Intermediate	159,155,521		31,710	31,710	472,973	905,429	1,711,982	1,671,039	1,671,039	414,214	157,898,697	15.8%	1,694,278	156,204,419	-2,951,102	-1.9%
Large Users	251,579,433										251,579,433	25.1%	2,699,487	248,879,946	-2,699,487	-1.1%
Street Lights (kWh)	9,137,954										9,137,954	0.9%	98,052	9,039,902	-98,052	-1.1%
Sentinel Lights (kWh)	627,674										627,674	0.0%	-	627,674	0	0.0%
USL (kWh)	2,238,935										2,238,935	0.0%	-	2,238,935	0	0.0%
Total Customer (kWh)	**1,007,902,639**	2,450,277	4,674,483	6,323,380	9,048,638	10,342,746	13,943,464	13,634,754	13,519,035	7,797,165	1,004,343,029	100.0%	10,746,000	**993,597,029**	-14,305,610	-1.4%
GS>50 (kW)	622,378	12,267	15,030	22,583	23,462	20,469	9,878	4,401	4,401	17,281	635,258		6,816	628,441.77	6,064	1.0%
Intermediate	335,318	6,609	8,098	12,167	12,641	11,028	5,322	2,371	2,371	9,311	342,257		3,672	338,584.97	3,267	1.0%
Large Users	398,793										398,793		4,279	394,513.89	-4,279	-1.1%
Street Lights (kW)	24,551										24,551		263	24,287.56	-263	-1.1%
Sentinel Lights (kW)	1,452										1,452		-	1,452	0	0.0%
Total Demand	**1,382,492**	18,876	23,128	34,750	36,102	31,496	15,200	6,773	6,773	26,592	1,402,312		15,031	**1,387,280**	4,788	0.3%
CDM (kWh) GS>50 Classes			76,626	76,626	1,142,907	2,187,910	755,826	755,826	755,826							
GS>50 (kWh)	58.6%	-	44,916	44,916	669,934	1,282,480	443,040	443,040	443,040							
Intermediate	41.4%	-	31,710	31,710	472,973	905,429	312,786	312,786	312,786							
CDM (kW) GS>50 Classes		18,876	23,128	34,750	36,102	31,496	15,200	6,773	6,773							
GS>50 (kW)	65.0%	12,267	15,030	22,583	23,462	20,469	9,878	4,401	4,401							
Intermediate	35.0%	6,609	8,098	12,167	12,641	11,028	5,322	2,371	2,371							

f) With respect to Attachment 1 (and Table 2) please explain why average savings from CDM over the 2006-2010 period was used to determine the “Revised 2013F” as opposed to the simply the 2010 or 2011 savings.

Bluewater Power Response:

At the time of calculation the final 2011 OPA results had not been released. It was universally expected that the 2011 results would be lower than previous years given the late start in the OPA releasing the programs for LDC use. It was determined by Bluewater Power that in using the 2006 to 2011 average as a reasonable and available proxy at the time, that it would compensate for the 2006 shortfall questioned in. Bluewater Power also reasoned that ultimately the LRAMVA would be trued up and any significant change in the calculation would not be materially harmful to any affected party.

g) It is not clear how the kW forecast of CDM was developed. Please confirm that for the relevant classes the kW CDM adjustment is proportional to the class’ kWh CDM adjustment. If not, please explain why not.

Bluewater Power Response:

The kW forecast is proportional to the kWh CDM Adjustment as detailed in Table 7.

Table 7 – Example of kW adjustment

	Revised 2013 Forecast	Adjusted 2013 Forecast	Variance	% reduction
GS>50 Class (kWh)	225,525,362	221,905,974	- 3,619,388	-1.6%
GS>50 kW adjustment	637,309	=637,309*(1-.016) =627,081	- 10,228	-1.6%

3.0 - EP 16 - Other Revenue Updated for 2012

Ref: Exhibit 3, Tab 2, Schedule 1

a) Please update Table 1 to reflect actual data for 2012. If actual data is not yet available for 2012, please provide the most recent year-to-date actuals for 2012 in the same level of detail as shown in Table 1, along with the figures for the corresponding year-to-date period in 2011.

Table 1 – Summary of Other Revenue updated with 2012 Draft Results

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 CGAAP	2012 MIFRS	2012 Draft Actual (CGAAP)	2013 MIFRS
Specific Service Charges	135,320	1,105,751	209,404	174,751	151,520	151,520	173,990	157,724
Late Payment Charges	225,433	285,586	230,017	244,953	240,000	240,000	255,934	232,694
Other Distribution Revenue	294,111	577,137	577,970	538,535	526,902	526,902	532,447	413,474
Other Income or Deductions	316,850	397,514	396,875	628,599	214,394	209,394	102,727	180,257
Investment Income	- 243,636	52,701	111,557	312,894	169,332	169,332	255,642	86,099
Total	728,078	2,418,689	1,525,823	1,899,732	1,302,148	1,297,148	1,320,740	1,070,248

In addition to updating the 2012 results to reflect the draft actual results, there is one change made to the 2013 values.

1. A reduction of $10,000 for Investment Income. Please refer to Energy Probe #30 (c).

b) Please update Table 2 to reflect actual data for 2012. If actual data is not yet available for 2012, please provide the most recent year-to-date actuals for 2012 in the same level of detail as shown in Table 2, along with the figures for the corresponding year-to-date period in 2011.

Table 2 – Specific Service Charge Revenue – Account 4235

Account Description	OEB Account	2009 Board Approved	2009	2010	2011	2012 CGAAP	2012 IFRS	2012 Draft Actual (CGAAP)	2013 IFRS
Miscellaneous - Micro Fit Monthly Charge	4235	-	-	-	-	1,500	1,500	4,714	5,184
Miscellaneous - Special Meter Reading	4235	-	-	-	30	120	120		30
Miscellaneous - Meter Dispute Test (new 2013)	4235	-	-	-	-	-	-		30
Miscellaneous - Duplicate Invoice for previous billing	4235	-	-	-	-	-	-		150
Miscellaneous - NSF Cheques	4235	9,120	6,992	5,941	5,822	6,200	6,200	3,860	6,255
Miscellaneous - Reconnect Nighttime	4235	1,110	370	555	490	500	500	250	370
Miscellaneous - Reconnect Daytime	4235	7,280	13,023	6,810	11,799	9,200	9,200	10,975	10,530
Miscellaneous - Account History (New 2013)	4235	-	-	-	-	-	-		150
Miscellaneous - Income Tax Statements	4235	1,935	3,645	3,798	3,452	4,000	4,000	1,765	3,630
Miscellaneous - Arrears/Lawyers Certificate	4235	5,145	3,821	4,255	3,521	4,000	4,000	2,900	3,855
Miscellaneous - Collection Charges	4235	60,900	84,445	60,742	82,354	74,000	74,000	70,387	75,840
Miscellaneous - Change of Occupancy Charge	4235	50,350	47,361	47,596	48,154	48,000	48,000	48,871	47,700
Miscellaneous - Miscellaneous One Time	4235		946,094	79,707	19,130	4,000	4,000	30,268	4,000
TOTAL		135,840	1,105,751	209,404	174,751	151,520	151,520	173,990	157,724
Year over Year variance			969,911	-896,347	-34,653	-23,231	0	-761	-16,266

c) Please update Table 3 to reflect actual data for 2012. If actual data is not yet available for 2012, please provide the most recent year-to-date actuals for 2012 in the same level of detail as shown in Table 3, along with the figures for the corresponding year-to-date period in 2011.

Table 3 – Late Payment Charge Revenue

Account Description	OEB Account	2009 Board Approved	2009	2010	2011	2012 CGAAP	2012 IFRS	2012 Draft Actual (CGAAP)	2013 MIFRS
Late Payment Charges - Water	4225	-	62,475	-	-	-	-		-
Late Payment Charges	4225	225,433	223,111	230,017	244,953	240,000	240,000	255,934	232,694
Total		225,433	285,586	230,017	244,953	240,000	240,000	255,934	232,694
Year over Year variance			60,153	-55,569	14,936	-4,953	0	10,981	-23,240

d) Please update Table 8 to reflect actual data for 2012. If actual data is not yet available for 2012, please provide the most recent year-to-date actuals for 2012 in the same level of detail as shown in Table 8, along with the figures for the corresponding year-to-date period in 2011.

Table 4 – Accounts 4325/4330 – Net Revenue from Jobbing

	OEB Account	2009 Board Approved	2009	2010	2011	2012 CGAAP	2012 MIFRS	2012 Draft Actual (CGAAP)	2013 IFRS
Management Fees and Rent Earned from Affiliates		134,310							
Revenues from Jobbing	4325	226,774	597,536	1,655,256	1,475,205	757,575	757,575	521,097	641,026
Expenses from Jobbing	4330	-92,578	-372,896	-1,304,982	-896,293	-568,181	-568,181	-454,661	-480,769
Net Revenue		268,506	224,640	350,274	578,912	189,394	189,394	66,436	160,257
Year over Year variance			-43,866	125,634	228,638	-389,518	0	-512,476	93,821

3.0 - VECC 22 - Transition to MIFRS and impact on Other Revenue

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3-VECC-22 Reference: Exhibit 3, Tab 2, Schedule 1, page 1

a) Please confirm whether Bluewater is still proposing to transition to MFIRS for 2013 and, if so, explain why.

Bluewater Power's audit committee of the board of directors made the decision in November 2012 to take the additional one year deferral. Therefore, Bluewater Power will be adopting IFRS as of January 1, 2014 (with 2013 as the comparative year).

See also Energy Probe #2.

b) What would be the impact if Other Revenue was based on CGAAP?

There would be one impact. As per discussion at Exh 3-2-1, page 10, the gain on retirement of $10,000 would not be a reduction to depreciation expense, but instead would be reclassified with Other Revenue.

c) Please provide the 2012 year-to-date Other Revenue broken down according to Table 1 and provide the 2011 year-to-date values for the comparable month.

Please see response to Energy Probe #16.

3.0 - VECC 23 - SSS Admin Fee and Retailer Revenue

3-VECC-23 Reference: Exhibit 3, Tab 2, Schedule 1, pages 6-7

a) Please explain why both the SSS Admin Fee revenues and the Retailer revenues are lower in 2013 as compared to 2011.

Retailer revenues are projected to be lower in 2013 as compared to 2011 due to the slow but steady decline in the number of customers enrolled with retailers. The quarterly report filed with the OEB for the period ending December 2011 reported 4025 retail customers, and the report filed with the OEB for the period ending September 2012 reported 3680 retail customers.

The decline in retail customers would lead to an increase in standard supply customers thus an anticipated increase in the SSS Administration fee. Bluewater Power used a three year average analysis for the SSS Administration whereas we could have used 2011 as a more reasonable approximation of the revenue. The amount of SSS Admin Fee revenue in 2011 is $93,861, and the amount included in the 2013 forecast is $90,394 for a variance of $3,466, which is an estimate and not considered a material difference.

3.0 - VECC 24 - Margin on Jobbing

3-VECC-24 Reference: Exhibit 3, Tab 2, Schedule 1, page 8

a) Please explain why net margin on Jobbing (as a percent of expenses) is significantly lower in 2013 than in the historic years shown.

The 2013 net margin is the same net margin included in the 2012 budget. In fact, the 2013 net margin is higher than the 2010 actuals and the 2012 draft actuals (see response to 3-EP-16d). The only historical years with higher net margins than 2013 are 2009 and 2011. Those years have higher net margin because those years include margin associated with the connection of very large renewable generation facilities under the RESOP program. The net margin on those projects was higher because the magnitude of the projects required greater project management where the costs were imposed at higher margins, and because management felt that the risk involved in these projects warranted a higher margin.

3.0 - AMPCO 7 - Distribution revenue variance

Interrogatory #7

Reference: Exhibit 3, Tab 1, Schedule 6, Page 2

Preamble: The evidence indicates that for 2012 Bridge Year vs. 2011 Actual related to the variance on distribution revenue, there was a positive variance of $233,666 mainly in the residential and GS>50 rate offset by a slight decrease in the Large User rate class.

a) Please confirm the reason for the variances identified above.

For the residential and GS>50 rate classes there is a projected increase in both the number of customers and the load in 2012 over 2011 which would lead to an increase in the distribution revenue in 2012. The increase represents a 2% increase over 2011 actual revenue.

The large use class had slightly higher demand in 2011 as compared to 2012 thus there is a decrease in revenue projected for 2012, however approximately $50,000 of the downward revenue variance in 2012 is attributable to short term load transfers between Bluewater Power and Hydro One that occurred in 2011. The revenue from these transactions is booked to the large use revenue accounts, however, this is an accounting entry only and is not related to the revenue associated with the three customers in the large use rate class.

File Number: EB-2012-0107

Date Filed: February 4, 2013

Tab 6 of 11

Exhibit 4 - Operating Costs

4.0-Staff-25 - Miscellaneous Distribution Expenses

Ref: Exh 1-2-3

Ref: Exh 4-2-1 Appendix 2-G

At page 2 of Exh 1-2-3, it states that:

> 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. There was no assumption for inflation and 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.

a) Please describe how the zero based methodology was applied to determine the test year expense for 5085 Miscellaneous Distribution Expenses.

Bluewater Power reviewed past actual expenditures recorded in Account 5085. Items that were non-recurring in nature were ignored. However, certain expenditures are recurring in nature year after year and therefore formed the basis for determining the 2013 test year amount.

Examples of the more significant recurring expenditures included in this account in the 2013 test year include wages and burden for operations administrative staff and fleet mechanics, environmental related costs and ESRI/GIS software costs. Some of the less significant recurring expenditures include cell phones, training, road permits and office supplies.

b) Appendix 2-G provides detailed OM&A expenses by account. Please expand the table by one additional column and provide 2012 actual OM&A expenses.

The updated Appendix 2-G can be found at Attachment 1 in response to VECC #26. The 2012 'actual' OM&A expenses that are added to this appendix are draft amounts.

4.0-Staff-26 - Asset Management Plan

Ref: Exh 2-4-2
Ref: Exh 4-1-1

At page 3 of Exh 2-4-2, it states that the AESI review "confirmed that Bluewater Power's asset condition assessment process provided a solid foundation for its asset management program. To the extent that areas of improvement were identified through the review, those issues have been addressed by the utility in 2011."

At page 5 of Exh 4-1-1, Bluewater Power summarizes its focus on the Asset Management Plan:

> As discussed in the Asset Management Planning Process (Exhibit 2, Tab 4, Schedule 2) Bluewater Power renewed its asset management planning process and, as discussed in the Human Resource Strategy (Exhibit 4, Tab 4, Schedule 1, Attachment 2), we have realigned certain management positions to maximize leadership in the operational departments. The expected result in 2012 and 2013 is improved productivity reflected in an increase in the level of Capitalized Labour. Accordingly, Capitalized Labour is forecast at $1.8M and $1.9M in 2012 and 2013, respectively, compared to the three year average for 2009-2011 of $1.1M (not including Smart Meters). The reduction in OM&A due to the increase in capitalized labour is, therefore, a reduction to OM&A built into the 2013 Test Year.

a) With respect to "improved productivity", please specify and explain the measures of productivity referred to in the above summary.

Fundamentally, there are two ways for an organization to become more efficient: do the same amount of work with fewer people, or do more work with the same number of people. The strategy described in the preamble to this question is akin to the latter.

Bluewater Power operates in an industry where its workforce of trades and professionals are in high-demand. This is clearly evidenced by the challenges faced in recruiting both linemen and a VP of Operations. We believe in that context, that it is better business planning to retain staff and increase the workload rather than chase efficiencies through the elimination of staff that may prove to be difficult to replace down the road. Key to this direction resulting in efficiencies is to ensure that the increase in workload is funded from sources other than ratepayers.

In that context, the focus on Asset Management Planning and the realignment of management help to improve efficiencies by redirecting costs that would otherwise be borne by ratepayers through O&M. This redirection of resources is possible because Bluewater Power performs its capital work utilizing internal resources; unlike some utilities that employ a skeleton workforce to respond to maintenance and perform capital work using third party contractors. If one accepts that a certain level of staff is required in order to provide coverage for normal maintenance and to allow an appropriate response to storms, then efficiencies can be achieved by utilizing staff for capital work without limiting their ability to perform maintenance. In that situation, the amount capitalized is a direct savings in O&M to be recovered from ratepayers and, provided the capital work is justified by an Asset Management Plan, ratepayers are not funding extra capital then would otherwise be funded if performed by third party contractors.

Therefore, the point being made in the pre-filed evidence (referenced in the pre-amble to this question) is that we have increased the level of management in an effort to get more out of the same resources.

Further to that point, these efficiencies are built into the 2013 Rebasing application and, if certain assumptions are not met through the course of this application process (as discussed in Exhibit 4, Tab 1, Schedule 1, page 5), then the O&M claimed would need to be increased in this application. To provide a specific example, if a particular project within the 2013 Capital Budget were not approved, then O&M would increase by the amount of capital labour built into that project; even if the capital labour built into a project was the equivalent of 1 FTE, it would not be reasonable to expect that one FTE could be eliminated at the utility. Current staffing levels are required to provide coverage and what is lost is the efficiency to use the so-called downtime in certain positions for capital projects. This is the best way to improve efficiency when the alternative of reducing staff is not reasonably available.

b) Please identify the specific AESI analysis and recommendations that lead to the realignment of management positions and increase in the level of capitalized labour.

The decision to realign certain management positions was not driven by any of the analysis undertaken by our consultants, AESI. Rather the decision to reinforce the management within the operations and customer service department was driven by an internal assessment that management ratios were low. Please see 4-SEC-24.

4.0-Staff-27 - Net OM&A Table

Ref: Exh 4-1-1 Table 2

Table 2 summarizes capitalization and re-allocations to produce net OM&A from gross OM&A.

a) Please provide references to application exhibits for each line item in this table.

Reallocation to Affiliates:	Exh 4-5-1
Reallocation OPA:	Exh 4-2-8
Capitalized Internal:	Exh 4-1-1 (page 5, lines 14 & 15), Exh 4-2-2 (page 7)
Smart Meter:	Exh 4-2-2 (page 1)
Billable:	Exh 3-2-1 (Table 8), Exh 4-2-2 (page 5)
Overhead:	Exh 4-2-2 (page 5)

b) What is the relationship between the “Capitalized Internal” data and the “Total Compensation Capitalized” as shown in Appendix 2-K? Please explain any differences in the data for each year.

The ‘Total Compensation Capitalized’ in Appendix 2-K represents direct salary, wages, and benefits that are capitalized.

The ‘Capitalized Internal’ in Exh 4-1-1 Table 2 represents total OM&A items that are capitalized. In addition to salary, wages and benefits, this would also include direct overtime and truck costs.

4.0 - AMPCO 9 - Total Recoverable Expenses

Interrogatory #9

Reference: Exhibit 4, Tab 1, Schedule 1, Attachment 1

a) Please confirm the Total Recoverable Expenses for 2013.

The total amount Bluewater Power considers as 'recoverable expenses' for 2013 is $13,302,742. This includes an amount of $223,914 related to 'Taxes other than Income Taxes' which is property taxes (also please see update to property taxes in 4-EP-24). The OEB appendices related to OM&A (ie. Appendix 2-I and 2-G at Ex. 4-2-1) do not include a line item for property taxes, therefore other areas of the application indicate the Total OM&A for 2013 at $13,078,828.

4.0 - EP 20 - OM&A Reconciliation

Ref: Exhibit 4, Tab 1, Schedule 1

Please reconcile the total recoverable expenses shown in Attachment 1 with the net OM&A figures shown in Table 2.

Please refer to 4.0 – AMPCO #9.

4.0 - EP 19 - OM&A updated for 2012

Ref: Exhibit 4, Tab 1, Schedule 1, Attachment 1

Please update the table shown in Attachment 1 to reflect actual data for 2012. If actual data for all of 2012 is not yet available, please provide the most recent year-to-date actual data available for 2012 in the same level of detail as shown in Attachment 1. Please also provide the figures for the corresponding period in 2011.

Please see Attachment #1 to this interrogatory.

File Number:EB-2012-0107

Tab: 6
Schedule: 6

Date Filed:February 4, 2013

Attachment 1 of 1

4.0 - Energy Probe 19 - OM&A Updated for 2012

Total Recoverable Expenses

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 CGAAP	2012 Actual CGAAP (Draft)	2012 MIFRS	2012 Actual MIFRS (Draft)	2013 Test Year
Operations	$ 3,126,141	$ 2,926,385	$ 3,135,697	$ 3,177,397	$ 2,964,970	$ 3,067,286	$ 3,102,525	$ 3,191,017	$ 3,467,004
Maintenance	$ 139,393	$ 162,468	$ 175,850	$ 157,217	$ 138,100	$ 851,586	$ 138,100	$ 851,586	$ 142,600
Billing and Collecting	$ 1,324,117	$ 1,357,619	$ 1,732,894	$ 1,481,275	$ 1,454,659	$ 1,521,685	$ 1,467,712	$ 1,533,427	$ 2,055,877
Community Relations	$ 191,769	$ 213,194	$ 191,747	$ 256,299	$ 237,181	$ 239,168	$ 270,425	$ 269,071	$ 258,483
Administrative and General	$ 5,209,999	$ 5,161,300	$ 5,073,080	$ 6,021,899	$ 5,401,700	$ 5,596,820	$ 6,479,176	$ 6,565,040	$ 7,154,864
Total	**$ 9,991,419**	**$ 9,820,966**	**$ 10,309,268**	**$ 11,094,087**	**$ 10,196,610**	**$ 11,276,545**	**$ 11,457,938**	**$ 12,410,141**	**$ 13,078,828**
Less: donations	$ -	$ (48,784)	$ (54,448)	$ (30,629)	$ -	$ (1,650)	$ -	$ (1,650)	$ -
Total OM&A Expenses	**$ 9,991,419**	**$ 9,772,182**	**$ 10,254,820**	**$ 11,063,458**	**$ 10,196,610**	**$ 11,274,895**	**$ 11,457,938**	**$ 12,408,491**	**$ 13,078,828**
Taxes Other Than Income Taxes	262,750	247,231	180,940	189,527	194,128	184,930	194,128	184,930	223,914
Total Recoverable Expenses	**10,254,169**	**10,019,413**	**10,435,760**	**11,252,985**	**10,390,738**	**11,459,825**	**11,652,066**	**12,593,421**	**13,302,742**

4.0 - SEC 25 - 2012 OM&A

[4/2/3, p. 1] Please confirm that the amounts included in the 2012 Bridge Year column were incurred in 2012, and have been included in 2012 OM&A totals.

Not confirmed. The amounts shown under the heading for 2012 Bridge Year are the forecast amounts to be incurred in 2012, but are not included in the 2012 OM&A totals anywhere else in the application. The costs from 2012 are proposed to be included with the costs forecast for 2013 that will be recovered as one-time costs amortized over the IRM period.

1.0 - SEC 7 - OM&A 2009 to 2013

1/2/1, p. 5-6] Please confirm that the following percentages are correct, and reconcile these numbers with the statement “Table 4 demonstrates a steady and smooth increase in OM&A from 2009 to 2013”:

a. 2.3% drop from 2009 Board approved to 2009 actual.

b. 4.2% increase from 2009 actual to 2010 actual.

c. 7.8% increase from 2010 actual to 2011 actual.

d. 7.7% drop from 2011 actual to 2012 actual (CGAAP).

e. 12.4% increase from 2012 actual (CGAAP) to 2012 actual (MIFRS).

f. 14.2% increase from 2012 actual (MIFRS) to 2013 forecast.

The calculations presented above are based on the line labeled “Subtotal” – which is the Total OM&A plus Taxes Other Than Income Taxes. All of the percentages are correct except part (e). Bluewater Power calculates this percentage to be a 12.1% increase.

If we look to the line labeled “Total Distribution Expenses”, which includes Amortization, we see a clearer picture of what was intended by the general description of a “steady and smooth” increase. The line labeled “Total Distribution Expenses” is the more relevant cost to compare since it is the total of all costs sought to be recovered from Ratepayers through rates.

In calculating the annual increase on the line labeled “Total Distribution Expenses”, there are two things that need to be kept in mind. First, it is difficult to comment on a four-year trend when there is a change in accounting methodology (from CGAAP to MIFRS) at the mid-way point of the comparison. Second, the cost increase in the 2013 Test Year is explained in the pre-filed evidence, but there are two costs that ought to be removed when performing this analysis: first, the $1,010,000 in amortization and O&M related to Smart Meters introduced and, second, the $320,000 net cost of moving to Monthly Billing. Accounting for those changes, the annual increases are as follows.

2009 Actual	2010 Actual	2011 Actual	2012 MIFRS	2013 MIFRS
$ 13,987,426	$ 14,375,607	$ 15,512,202	$ 15,499,721	$ 17,002,565
	2.78%	7.91%	-0.08%	9.69%

Accordingly, the comment that the increases were “steady and smooth” were made in the context of a change in accounting from CGAAP to MIFRS while simultaneously introducing material new costs in the form of Smart Meters and Monthly Billing.

4.0 - VECC 26 - Updated Appendix 2-G for 2012

Reference: Exhibit 4, Tab 1, Schedule 1 / Appendix 2-G

a) Please update Appendix 2-G to show actual year-end 2012 OM&A

Please see Attachment #1 to this Interrogatory response. There is one item that should be noted in the 2012 draft figures. 'Account 5175 – Maintenance of Meters' contains an entry of $648,986. In accordance with the OEB guidelines for smart meter disposition, Bluewater Power was required to dispose of the balances in Account 1556 - Smart Meter OM&A deferral account at December 31, 2012. As a result, the amount of $648,986 in this account was reallocated to Account 5175.

File Number:EB-2012-0107

Tab: 6
Schedule: 9

Date Filed:February 4, 2013

Attachment 1 of 1

4.0 - VECC 26 - Appendix 2-G Updated for 2012

File Number: EB-2012-0107
Exhibit: 4
Tab: 2
Schedule: 1
Attachment: 2

Response to VECC #26

Appendix 2-G
Detailed, Account by Account, OM&A Expense Table
(excluding Depreciation and Amortization)

Account	Description	2009 Board Approved	Last Rebasing Year (2009 Actuals)	2010 Actual	2011 Actual[2]	Bridge Year 2012[3]	2012 Actual (Draft)	Bridge Year 2012[3]	2012 Actual (Draft)	Test Year 2013
Reporting Basis		**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**
Operations										
5005	Operation Supervision and Engineering	835,073	$ 626,703	$ 888,541	$ 814,674	$ 728,594	$ 819,948	$ 763,498	$ 851,345	$ 792,514
5010	Load Dispatching	184,799	$ 187,893	$ 215,197	$ 212,873	$ 210,731	$ 209,651	$ 215,812	$ 214,221	$ 221,350
5012	Station Buildings and Fixtures Expense	88	$ 53,112	$ 17,440	$ 1,917		$ 28,851		$ 28,851	$ 500
5014	Transformer Station Equipment - Operation Labour	22,991								
5015	Transformer Station Equipment - Operation Supplies and Expenses	-								
5016	Distribution Station Equipment - Operation Labour	-								
5017	Distribution Station Equipment - Operation Supplies and Expenses	371	$ 9,026	$ 148	$ 25,130	$ 26,600	$ 2,650	$ 26,600	$ 2,650	$ 26,600
5020	Overhead Distribution Lines and Feeders - Operation Labour	-								
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	204,588	$ 233,839	$ 291,515	$ 267,780	$ 256,298	$ 228,989	$ 256,298	$ 228,989	$ 289,300
5030	Overhead Sub-transmission Feeders - Operation	-								
5035	Overhead Distribution Transformers - Operation	1,738	$ 342	$ 241	$ 1,878		$ 4,538		$ 4,538	
5040	Underground Distribution Lines and Feeders - Operation Labour	795,488	$ 741,539	$ 831,743	$ 995,046	$ 866,141	$ 821,855	$ 961,197	$ 907,358	$ 1,089,225
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	270,909	$ 337,253	$ 167,941	$ 120,553	$ 90,808	$ 109,646	$ 90,808	$ 109,646	$ 124,669
5050	Underground Sub-transmission Feeders - Operation	-								
5055	Underground Distribution Transformers - Operation	-	$ -	$ -	$ 1,122	$ -	$ 773	$ -	$ 773	$ -
5060	Street Lighting and Signal System Expense	-	$ 392	$ -	$ -	$ -		$ -		$ -
5065	Meter Expense	386,874	$ 335,735	$ 355,175	$ 359,545	$ 395,202	$ 413,056	$ 397,503	$ 415,126	$ 435,738
5070	Customer Premises - Operation Labour	-	$ 200	$ -	$ -	$ -		$ -		$ -
5075	Customer Premises - Operation Materials and Expenses	38,217	$ 1,508	$ -	$ -	$ -		$ -		$ -
5085	Miscellaneous Distribution Expenses	357,866	$ 376,855	$ 340,815	$ 344,988	$ 363,596	$ 400,091	$ 363,809	$ 400,282	$ 451,608
5090	Underground Distribution Lines and Feeders - Rental Paid	-								
5095	Overhead Distribution Lines and Feeders - Rental Paid	27,138	$ 21,988	$ 26,941	$ 31,891	$ 27,000	$ 27,238	$ 27,000	$ 27,238	$ 35,500
5096	Other Rent	-								
Total - Operations		$ 3,126,141	$ 2,926,385	$ 3,135,697	$ 3,177,397	$ 2,964,970	$ 3,067,286	$ 3,102,525	$ 3,191,017	$ 3,467,004

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Appendix 2-G
Detailed, Account by Account, OM&A Expense Table
(excluding Depreciation and Amortization)

Account	**Description**	**2009 Board Approved**	**Last Rebasing Year (2009 Actuals)**	**2010 Actual**	**2011 Actual^2**	**Bridge Year 2012^3**	**2012 Actual (Draft)**	**Bridge Year 2012^3**	**2012 Actual (Draft)**	**Test Year 2013**
Maintenance										
5105	Maintenance Supervision and Engineering	-								
5110	Maintenance of Buildings and Fixtures - Distribution Stations	-								
5112	Maintenance of Transformer Station Equipment	-								
5114	Maintenance of Distribution Station Equipment	6,433	$ 29,453	$ 68,428	$ 30,357	$ 18,000	$ 87,281	$ 18,000	$ 87,281	$ 18,000
5120	Maintenance of Poles, Towers and Fixtures	12,645	$ 11,295	$ 4,881	$ 4,986	$ 8,000	$ 3,855	$ 8,000	$ 3,855	$ 9,000
5125	Maintenance of Overhead Conductors and Devices	73,853	$ 79,516	$ 54,937	$ 64,602	$ 64,000	$ 60,534	$ 64,000	$ 60,534	$ 68,000
5130	Maintenance of Overhead Services	-								
5135	Overhead Distribution Lines and Feeders - Right of Way	-								
5145	Maintenance of Underground Conduit	-	$ 48	$ 10	$ 14	$ -	$ 3	$ -	$ 3	$ -
5150	Maintenance of Underground Conductors and Devices	14,944	$ 21,071	$ 19,139	$ 25,926	$ 19,200	$ 19,480	$ 19,200	$ 19,480	$ 19,200
5155	Maintenance of Underground Services	4,549	$ 5,650	$ 3,637	$ 775	$ 400	-$ 1,746	$ 400	-$ 1,746	$ 400
5160	Maintenance of Line Transformers	22,991	$ 14,829	$ 23,761	$ 30,102	$ 27,500	$ 33,193	$ 27,500	$ 33,193	$ 27,500
5165	Maintenance of Street Lighting and Signal Systems	-								
5170	Sentinel Lights - Labour	-								
5172	Sentinel Lights - Materials and Expenses	-								
5175	Maintenance of Meters	3,979	$ 606	$ 1,057	$ 455	$ 1,000	$ 648,986	$ 1,000	$ 648,986	$ 500
5178	Customer Installations Expenses - Leased Property	-								
5195	Maintenance of Other Installations on Customer Premises	-								
Total - Maintenance		$ 139,393	$ 162,468	$ 175,850	$ 157,217	$ 138,100	$ 851,586	$ 138,100	$ 851,586	$ 142,600
Account	**Description**	**2009 Board Approved**	**Last Rebasing Year (2009 Actuals)**	**2010 Actual**	**2011 Actual^2**	**Bridge Year 2012^3**	**2012 Actual (Draft)**	**Bridge Year 2012^3**	**2012 Actual (Draft)**	**Test Year 2013**
Billing and Collecting										
5305	Supervision	110,356	$ 122,263	$ 170,710	$ 208,714	$ 214,677	$ 208,348	$ 214,997	$ 208,636	$ 230,451
5310	Meter Reading Expense	130,998	$ 126,551	$ 110,314	$ 55,952	$ 161,099	$ 142,655	$ 161,099	$ 142,655	$ 241,109
5315	Customer Billing	784,936	$ 791,098	$ 768,194	$ 818,456	$ 790,720	$ 785,830	$ 797,284	$ 791,735	$ 1,179,268
5320	Collecting	206,153	$ 214,394	$ 193,454	$ 191,529	$ 185,763	$ 214,974	$ 191,932	$ 220,523	$ 242,549
5325	Collecting - Cash Over and Short	-	$ 104	-$ 84	$ 120	$ -		$ -		$ 100
5330	Collection Charges	697	$ 440	$ 162	$ 309	$ 400	$ 252	$ 400	$ 252	$ 400
5335	Bad Debt Expense	90,976	$ 102,769	$ 490,144	$ 206,195	$ 102,000	$ 169,626	$ 102,000	$ 169,626	$ 189,234
5340	Miscellaneous Customer Accounts Expenses	-								
Total - Billing and Collecting		$ 1,324,117	$ 1,357,619	$ 1,732,894	$ 1,481,275	$ 1,454,659	$ 1,521,685	$ 1,467,712	$ 1,533,427	$ 2,083,111

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Appendix 2-G

Detailed, Account by Account, OM&A Expense Table

(excluding Depreciation and Amortization)

Account	Description	2009 Board Approved	Last Rebasing Year (2009 Actuals)	2010 Actual	2011 Actual[2]	Bridge Year 2012[3]	2012 Actual (Draft)	Bridge Year 2012[3]	2012 Actual (Draft)	Test Year 2013
Community Relations										
5405	Supervision	-								
5410	Community Relations - Sundry	45,981	$ 43,958	$ 44,624	$ 106,039	$ 115,867	$ 145,276	$ 115,867	$ 145,276	$ 95,900
5415	Energy Conservation	40,269	$ 49,799	$ 33,708	$ 27,391	$ 20,882	-$ 13,921	$ 26,966	-$ 8,448	$ 39,342
5420	Community Safety Program	105,519	$ 119,437	$ 113,415	$ 122,273	$ 100,432	$ 107,813	$ 127,592	$ 132,243	$ 123,241
5425	Miscellaneous Customer Service and Informational Expenses	-	$ -	$ -	$ 596	$ -		$ -		$ -
5505	Supervision	-								
5510	Demonstrating and Selling Expense	-								
5515	Advertising Expenses	-								
5520	Miscellaneous Sales Expense	-								
Total - Community Relations		$ 191,769	$ 213,194	$ 191,747	$ 256,299	$ 237,181	$ 239,168	$ 270,425	$ 269,071	$ 258,483
Account	**Description**	**2009 Board Approved**	**Last Rebasing Year (2009 Actuals)**	**2010 Actual**	**2011 Actual[2]**	**Bridge Year 2012[3]**	**2012 Actual (Draft)**	**Bridge Year 2012[3]**	**2012 Actual (Draft)**	**Test Year 2013**
Administrative and General Expenses										
5605	Executive Salaries and Expenses	851,116	$ 1,046,191	$ 935,378	$ 1,213,294	$ 1,044,857	$ 1,142,262	$ 1,324,165	$ 1,393,501	$ 1,338,330
5610	Management Salaries and Expenses	184,825	$ 67,390	$ 68,523	$ 74,042	$ 64,195	$ 68,958	$ 81,726	$ 83,752	$ 85,356
5615	General Administrative Salaries and Expenses	1,515,325	$ 972,326	$ 992,791	$ 1,352,575	$ 1,147,418	$ 1,228,398	$ 1,470,414	$ 1,518,934	$ 1,591,130
5620	Office Supplies and Expenses	2,529	$ 2,637	$ 5,919	$ 5,269	$ 3,476	$ 3,509	$ 4,646	$ 4,562	$ 4,569
5625	Administrative Expense Transferred - Credit	- 543,487								
5630	Outside Services Employed	157,994	$ 273,402	$ 267,635	$ 281,162	$ 243,132	$ 172,712	$ 306,658	$ 229,854	$ 389,845
5635	Property Insurance	146,853	$ 160,266	$ 110,030	$ 127,829	$ 116,570	$ 92,426	$ 144,964	$ 117,966	$ 148,023
5640	Injuries and Damages	-								
5645	OMERS Pensions and Benefits	1,756,541	$ 1,495,682	$ 1,557,222	$ 1,707,958	$ 1,718,110	$ 1,761,419	$ 1,818,515	$ 1,851,734	$ 2,075,079
5646	Employee Pensions and OPEB	-								
5647	Employee Sick Leave	-								
5650	Franchise Requirements	-								
5655	Regulatory Expenses	387,047	$ 287,143	$ 321,433	$ 322,518	$ 287,692	$ 293,687	$ 359,330	$ 358,127	$ 374,545
5660	General Advertising Expenses	18,569	$ 10,237	$ 8,491	$ 39,301	$ 6,800	$ 10,314	$ 6,800	$ 10,314	$ 7,000
5665	Miscellaneous General Expenses	640,900	$ 682,251	$ 647,754	$ 719,664	$ 657,773	$ 672,486	$ 817,641	$ 816,288	$ 947,730
5670	Rent	-								
5672	Lease Payment Charge	-								
5675	Maintenance of General Plant	91,788	$ 114,991	$ 103,430	$ 146,944	$ 111,677	$ 150,209	$ 144,317	$ 179,568	$ 166,023
5680	Electrical Safety Authority Fees	-	$ -	$ 26	$ 714		$ 440		$ 440	
5681	Special Purpose Charge Expense	-								
5685	Independent Electricity System Operator Fees and Penalties	-								
5695	OM&A Contra Account	-								
6205	Donations	-	$ 48,784	$ 54,448	$ 30,629					
6205	Donations, Sub-account LEAP Funding	-								
Total - Administrative and General Expenses		$ 5,209,999	$ 5,161,300	$ 5,073,080	$ 6,021,899	$ 5,401,700	$ 5,596,820	$ 6,479,176	$ 6,565,040	$ 7,127,630
Total OM&A		$ 9,991,419	$ 9,820,966	$ 10,309,268	$ 11,094,087	$ 10,196,610	$ 11,276,545	$ 11,457,938	$ 12,410,141	$ 13,078,828
Adjustments for non-recoverable items										

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Response to VECC #26

Appendix 2-G
Detailed, Account by Account, OM&A Expense Table
(excluding Depreciation and Amortization)

5681 Special Purpose Charge Expense									
6205 Donations[1]		$ 48,784	$ 54,448	$ 30,629		$ 1,650		$ 1,650	
Total Recoverable OM&A	$ 9,991,419	$ 9,772,182	$ 10,254,820	$ 11,063,458	$ 10,196,610	$ 11,274,895	$ 11,457,938	$ 12,408,491	$ 13,078,828

[1] Account 6205 - Donations is generally non-recoverable. However, the sub-account LEAP funding of account 6205 is generally recoverable.

Note:

1 If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.

2 If the applicant is adopting IFRS or an alternate accounting standard as of January 1, 2012 for financial reporting purposes, 2011 must be presented on both a CGAAP and MIFRS (or alternate accounting standard) basis.

3 If the applicant is adopting IFRS or an alternate accounting standard as of January 1, 2013 for financial reporting purposes, 2012 must be presented on both a CGAAP and MIFRS (or alternate accounting standard) basis.

4.0 - VECC 27 - Account 5410 and 5630

4-VECC-27 Reference: Exhibit 4, Tab 1, Appendix 2-G

a) Please explain the 100% growth in Account 5410 “Sundry” as between 2009 and 2013 forecast.

This account captures the amounts Bluewater Power has provided to various agencies and other organizations that assist people in need. An example of this would be payments made to the Inn of the Good Sheppard who assist low income customers to pay their electricity bills. Bluewater Power has increased its level of community support to these agencies due to the poor local economic environment experienced over the past few years, which includes the loss of some major employers in our distribution territory. This account also increased in 2011 by approximately $24,000 related to LEAP funding, which is also reflected in 2012 and 2013.

This account does not capture donation payments which are recorded in Account 6205 ‘Donations’.

b) Please explain the increase in Account 5630 “Outside Services” employed as between 2009 and 2013 forecast.

The increase of $116,443 in this account is primarily attributable to the level of students in 2009 versus 2013.

In 2009, one lines co-op student was hired for 14 weeks and in 2013, two lines co-op students are budgeted for the full year. This accounts for $67,000 of the variance.

In 2013, an I.T. co-op student is budgeted at a cost of $34,000 and 2009 was NIL.

In 2013, two students are budgeted for transformer painting at a cost of $16,000 and 2009 was NIL.

4.0 - VECC 28 - Bad Debt Expense

4-VECC-28 Reference: Exhibit 4, Appendix 2-G

a) Please explain how the Bad Debt forecast for 2013 is derived/calculated. Specifically address how the forecast was adjusted for the change to monthly billing.

The 2013 test year forecast for bad debts is primarily based on recent historical trends surrounding unrecoverable customer accounts. A discussion on bad debts is found at Exh 4-2-2 page 3.

The 2013 forecast was not adjusted for the change to monthly billing. See response to 1-SEC-9.

b) Please provide the actual year-end bad debt expense for 2012.

The 2012 draft actual is $169,626. This amount will increase for the 2012 year end adjustments to be made in February 2013 in preparation for the financial statement audit in March 2013.

4.0 - VECC 29 - LEAP calculation

4-VECC-29 Reference: Exhibit 4, Tab 2, Schedule 3, Appendix 2-M

a) Please show the calculation which provides the proposed 2013 LEAP amount of $24,000.

The amount of LEAP is calculated based on the OEB formula of 0.12% of a distributor's Board-approved distribution revenue requirement as outlined in the '*Report of the Board – Low Income Energy Assistance Program*' dated March 10, 2009.

Bluewater Power's last Board-approved Service Revenue Requirement was for rates effective May 1, 2009 in the amount of $19,389,209 x .0012 = $23,267. This amount was used as a proxy for the 2013 amount to be included in the application.

4.0-Staff-28 - OM&A Smart Meter Fees

Ref: Exh 4-1-1

Ref: Exh 2-4-4

Ref: Exh 4-2-2

Ref: EB-2012-0263

Bluewater Power states that the net incremental increase to OM&A from ongoing smart meter costs in 2013 is $191,000.

a) Bluewater Power indicates that Sensus meter reading fees are $174,000 in Exh 2-4-4. However, in response to interrogatories in the smart meter proceeding EB-2012-0263, Bluewater stated that "the annual cost of, instead, transmitting that customer usage data from smart meters over communications lines is approximately $142,647." Please explain the difference.

The smart meter application was filed in May 2012 wherein the amount of $142,647 was the estimated meter reading costs as we understood them at that time. The amount of $174,000 provided in Exhibit 2-4-4 is a revised estimate taking into account actual costs and, more specifically, the following two items:

(i) throughout the year 2012 the system was still being stabilized and it was determined by management, upon the recommendation of Sensus, that a third Tower Gateway Base station(TGB) was required at an additional cost $26,000 per year; and

(ii) the Sensus AMI fee has increased from $.08 per meter to $.0827 per meter.

b) Bluewater Power states that there is a savings of $30,000 related to manual meter reading. The savings are less than anticipated because manual meter reading costs were already shared with its affiliate, BPSC, for the reading of water meters. In interrogatory responses and submissions file in EB-2012-0263, Bluewater Power stated that the actual full year cost for manual meter reading was $110,000. Please explain the difference.

Bluewater Power acknowledges that the variance analysis of Smart Meter Costs provided in Exhibit 2-4-4 inadvertently understated the savings associated with manual meter reading. If we use the starting point for 2011 costs, the actual amount is $105,178 instead of the rounded figure of $110,000 reflected in the response to IR#14(c) in EB-2012-0263. This was the total cost incurred by Bluewater Power in 2011 to manually read electricity meters. What we were suggesting in the pre-filed evidence is that this cost is less than might otherwise be expected because we had already achieved a level of efficiency through the ability to read both electricity and water meters at the same time (with associated water meter reading costs allocated to the water billing function).

The original manual meter reading cost were only $105,178 in 2011 and the manual meter reading cost to read non-smart meters is approximately $40,000 in the 2013 Test Year. Included in the 2013 Test Year is the cost associated with ½ FTE for manually reading those customers without Smart Meters at a fully-loaded cost of $35,000 plus vehicle, equipment and miscellaneous costs of $5,000. Accordingly, the correct savings attributed to a reduction in manual meter reading activity is $65,000 ($105,000 less $40,000) instead of $30,000 as stated in Exhibited 2-4-4.

It is important to point out that the misstated variance does not in any way impact the amount claimed for recovery through this Rebasing Application. The amount claimed in the model is accurate and correct, and the $30,000 in savings was simply an incorrect estimate of a variance. Two errors occurred in preparing the estimate: first, the estimate represents only 8 months' worth of savings since the transition to Smart Meter occurred on May 1, 2012, and second, the estimate represents pure labour costs only. If we gross-up the $30,000 estimate for benefits and revised it to reflect a twelve month figure, we arrive at an estimate of $56,000. If we add to that the expected savings in vehicles, equipment and miscellaneous costs, we arrive at a number very close to the $65,000 in savings reflected above.

Accordingly, the updated Table 1 entitled "Net Incremental Smart Meter OM&A" in Exhibit 2-4-4 would show a net incremental cost of $156,000 attributable to Smart Meters. The descriptions in the table also needs to be corrected to reflect the fact the savings represent more than just labour savings and the table would, therefore, appear as follows.

Sensus Meter Reading Fees	$ 174,000
SAP Software Maintenance	$ 47,000
LESS: meter reading ~~labour~~ savings	($ 65,000)
	$ 156,000

c) At Exh 4-2-2, Bluewater Power provides cost driver explanations. The evidence states that the 2013 variance with respect to smart metering includes "$47,000 for software fees impacting 2013 for the first time and an incremental cost of $30,000 in annual fees for a new TGB required in order to improve read rates to meet our Service Level Agreement." Please provide further explanation of both of these factors.

The evidence at Exhibit 2-4-4 page 3 details that the "SAP software maintenance fees of $47,000 pertain to SAP AMI extensions software licence maintenance , XI/PI software license maintenance, and Cleo AS2 software license maintenance. These are annual maintenance fees for software that are required to interface Bluewater Power systems to the central MDM/R."

Please see response to part (a) above in regard to the $30,000 fee for a new TGB.

4.0 - EP 22 - EDA Costs

Ref: Exhibit 4, Tab 2, Schedule 2

a) Please indicate in which account costs associated with membership in the Electricity Distributors Association (EDA) are recorded.

Account 5665 ‘Miscellaneous General Expenses’

b) Please provide the actual and forecasted costs associated with the EDA membership in each of 2009 through 2013, including the actual cost for 2012.

2009: $48,500 actual
2010: $50,500 actual
2011: $52,100 actual
2012: $55,000 actual
2013: $56,800 budget for test year ($57,700 actual – invoice received Dec 2012)

Refer also to 4-VECC-32 and SEC #37.

4.0 - VECC 32 - EDA Fees and MEARIE premiums

4-VECC-32 Reference: Exhibit 4, Tab 2, Schedule 3 / Schedule 5

a) Please provide the amount paid in membership fees to the EDA for each year 2009 through 2013 (forecast)

See response to Energy Probe #22b. See also SEC #37.

b) Please explain what insurance coverage is provided by MEARIE, the annual premiums in 2012 and 2013, and the due diligence that BWP takes to ensure that is receives value for money for this policy(ies).

Mearie provides liability and vehicle insurance coverage for Bluewater Power. The property insurance is sourced through a local brokerage.

The annual premiums for Comprehensive Liability are $61,750 (2012) and $82,584 (2013).

The annual premiums for Vehicle are $23,669 (2012) and $25,567 (2013).

Bluewater Power’s due diligence has left it satisfied that it receives value for money from its insurance with MEARIE in two ways. First, management with Bluewater Power is familiar with insurance and currently has, or recently has had, insurance in place with brokers/insurers other than MEARIE (ie. Property Insurance for Bluewater Power and RenewCo, and all insurance for Electek); in fact, our dealings with other insurers on affiliates specifically allowed us to conclude that equivalent insurance is available through MEARIE at substantially lower rates because MEARIE operates on a non-profit, income-tax exempt basis and, in the event it overestimates exposure, it is able to provide “refunds” of premiums in the form of Premium Reductions determined by its Board of Directors (in fact, the increase from 2012 to 2013 reflects the fact that 2012 was a year in which a Premium Reduction was available for the Comprehensive Liability Policy). Secondly, our claims experience with MEARIE has shown the entity to be responsive to claims and we have never experienced a disruption in coverage nor have MEARIE ever disputed coverage to the extent of the availability or quality of coverage.

4.0 - SEC 37 - EDA and MEARIE

[4/6/1, p. 3] Please advise the amounts paid by the Applicant to EDA as membership fees or dues in each of 2009 through 2012 (actuals), and 2013 (forecast). Please confirm that the Applicant is unable to obtain insurance from MEARIE if the EDA fees are not paid each year.

See response to Energy Probe #22b for the amounts from 2009 to 2013.

We have been advised that participation in MEARIE would be at the discretion of the MEARIE Board, but we understand that a utility is not automatically disqualified from participation in MEARIE based on a lack of membership in the EDA.

4.0-Staff-29 - Regulatory Costs

Ref: Exh 4-2-3

Ref: Appendix 2-M

Appendix 2-M summarizes regulatory costs and provides a breakdown for one-time costs related to the cost of service application.

a) Please identify the resources related to line 8 “operating expenses associated with other resources allocated to regulatory matters”.

The resources allocated to regulatory matters include the Vice President, Corporate Services, the Chief Financial Officer, and any other internal personnel that assist specifically in the regulatory proceedings.

b) Bluewater Power’s proposal with respect to regulatory costs reflects a 4 year period, consistent with 3rd generation IRM. The *Report of the Board – Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, states, “The Board has determined that the term for 4th Generation IR will be five years (rebasing plus 4 years).” Has Bluewater Power considered the impact of this change to a five year term and how it will affect the proposal in the current application? If yes, please explain.

Please see response to Board Staff Interrogatory #4.

4.0 - EP 23 - Regulatory Costs

Ref: Exhibit 4, Tab 2, Schedule 3

a) Please confirm that none of the rate application costs shown in Table 1 in the 2012 bridge year column have been, or will be, recorded as an expense in 2012. If this cannot be confirmed, please provide an estimate of, or the actual amount associated with the current rate proceeding that will be booked as an expense in 2012.

Confirmed. None of the rate application costs have been, or will be, recorded as an expense in 2012.

b) What assumptions have been made with respect to the consultant, legal and intervenor costs related to time associated with the potential need for an oral hearing and submissions?

Bluewater Power's budget for this proceeding assumes either: i) an oral hearing with submissions; or ii) the preparation and finalization of a settlement proposal. The cost of either outcome would be approximately the same. If there is a partial settlement such that both the preparation of a settlement proposal and an oral hearing with submissions are necessary, the amount included for the rebasing application would be deficient.

4.0 - VECC 30 - Regulatory Costs 2-G

Reference: Exhibit 4, Tab 2, Schedule 3, pg. 2 /Appendix 2-G

a) The regulatory costs shown in Account 5655 at Appendix 2-G is $374,545. The description of regulatory costs at page 2 of the above reference states that the regulatory costs for 2013 are comprised of on-going expenses of $292,859 and 2013 Rebasing Application costs amortized over four years at $100,200 for a total 2013 regulatory costs of $393,059. Please reconcile this difference.

There are some costs that are considered ‘Regulatory’ in nature, but are not booked to Account 5655, such as the amount related to LEAP funding which is booked to Account 5410 ‘Community Relations’, and research costs have been booked to account 5665.

In addition, the burdens/overhead amount were inadvertently not included in Appendix 2-M, thus a revised Appendix 2-M is attached, and the reconciliation is below.

Table 1 – Reconciliation of Account 5655 and Regulatory Cost per Appendix 2-M

To reconcile to Account 5655 per 2-G	$	299,845	On-going costs from Appendix 2-M
	-$	24,000	Account 5410
	-$	1,500	Account 5665
	$	100,200	Amortization of rebasing costs
	$	374,545	Per Account 5655 in Appendix 2-G

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Attachment 1 of 1

4.0 VECC 30

File Number: EB-2012-0107
Exhibit:
Tab:
Schedule:
Attachment:

Date:
REVISED for VECC 30

Appendix 2-M
Regulatory Cost Schedule

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	Last Rebasing Year (2009 Board Approved)	Most Current Actuals Year 2011	2012 Bridge Year	Annual % Change	2013 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655		On-Going	$ 107,592	$ 122,864	$ 134,757	9.68%	$ 132,190	-1.90%
2	OEB Section 30 Costs (Applicant-originated)	5655		On-Time	$ 11,506				$ 12,000	
3	OEB Section 30 Costs (OEB-initiated)	5655		On-Going	$ 5,097	$ 5,303	$ 4,000	-24.57%	$ 4,000	0.00%
4	Expert Witness costs for regulatory matters	5655								
5	Legal costs for regulatory matters	5655		On-Going	$ 390	$ 173	$ 5,000	2790.17%	$ 5,000	0.00%
5a	Legal costs for regulatory matters			On-Time	$ 141,817		$ 80,000		$ 64,000	
6	Consultants' costs for regulatory matters	5655		On-Going	$ 1,500				$ 10,000	
6a	Consultants' costs for regulatory matters			On-Time	$ 132,373		$ 88,000		$ 42,000	
7	Operating expenses associated with staff resources allocated to regulatory matters	5655		On-Going	$ 84,858	$ 98,240	$ 90,498	-7.88%	$ 102,155	12.88%
8	Operating expenses associated with other resources allocated to regulatory matters [1]	5655		On-Time	$ 13,023		$ 4,800		$ 10,000	108.33%
9	Other regulatory agency fees or assessments	5655		On-Going	$ 18,257	$ 19,937	$ 22,000	10.35%	$ 22,500	2.27%
10	Any other costs for regulatory matters (LEAP costs)	5410		On-Going		$ 30,217	$ 23,267	-23.00%	$ 24,000	3.15%
11	Intervenor costs	5655		On-Time	$ 94,495				$ 100,000	
12	Sub-total - Ongoing Costs [3]		$ -		$ 217,694	$ 276,734	$ 279,522	1.01%	$ 299,845	7.27%
13	Sub-total - One-time Costs [4]		$ -		$ 393,214	$ -	$ 172,800		$ 228,000	31.94%
14	Total		$ -		$ 610,908	$ 276,734	$ 452,322	63.45%	$ 527,845	16.70%

To reconcile to Account 5655 per 2-G	**$ 299,845**	**On-going costs from above**
	-$ 24,000	**Account 5410**
	-$ 1,500	**Account 5665**
	$ 100,200	**Amortization of rebasing costs**
	$ 374,545	**Per Account 5655**

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[1] Please identify the resources involved.

[2] Where a category's costs include both one-time and ongoing costs, the applicant should prove a separate breakdown

[3] Sum of all ongoing costs identified in rows 1 to 11 inclusive.

[4] Sum of all one-time costs identified in rows 1 to 11 inclusive.

Please fill out the following table for all one-time costs related to this cost of service application

		2009 Rebasing Costs	2012 Bridge Year	2013 Test Year	Total Incremental Rebasing Costs for 2013
4	Expert Witness costs for regulatory matters		$ -	$ -	$ -
6	Consultants' costs for regulatory matters	$ 132,373	$ 88,000	$ 42,000	$ 130,000
	Legal Costs	$ 141,817	$ 80,000	$ 64,000	$ 144,000
7	Operating expenses associated with staff resources allocated to regulatory matters		$ -	$ -	$ -
8	Operating expenses associated with other resources allocated to regulatory matters [1]	$ 13,023	$ 4,800	$ 10,000	$ 14,800
	OEB Hearing Costs	$ 11,506		$ 12,000	$ 12,000
11	Intervenor costs	$ 94,495	$ -	$ 100,000	$ 100,000
	Total	**$ 393,214**	**$ 172,800**	**$ 228,000**	**$ 400,800**

4.0 - AMPCO 11 - Regulatory legal and consulting fees

Interrogatory #11

Reference: Exhibit 4, Tab 2, Schedule 3, Page 2

a) Please provide a breakdown of annual (non-rebasing) consulting and legal fees.

For the 2013 Test year, the budget includes $5,000 for legal costs, and $10,000 for consulting fees related to regulatory activities that might be expected in a non-rebasing year.

Throughout any given year, there are issues that potentially arise that require outside consulting or legal services for. Legal opinions in the past have been sought for:

- Issues surrounding retailer operations in our service territory
- Contractual issues related to Affiliate Relationships Code
- Bad debt and the potential to claim as a z-factor
- Contractual issues related to Conservation and Demand Management

Consulting services have also been required in prior years and are expected to recur in future years, including the Test Year. Some examples of items that require consulting services include:

- Future IRM applications that include claims for LRAM recovery require a third party report to validate the CDM savings and resulting LRAM.
- Tax advice is required from time-to-time related to PILs calculations.
- Customer specific issues arise and leads to the need to consider updates to the utility's Conditions of Service

4.0 - VECC 31 - Coal Tar Clean up

Reference: Exhibit 4, Tab 2, Schedule 4, pg. 2

a) In the explanation of the inclusion of $67,500 for environmental costs related to coal tar clean-up at Centennial Park BWP states that in the alternative (to amortized costs) it would seek a deferral account. Please explain whether in one or both cases it is the Utility's intent to recovery all costs incurred or only the budgeted amount of $270,000.

Bluewater Power would be agreeable to either approach (amortized costs or deferral account), but they do differ in their treatment of actual versus forecast. The approach proposed in the application would amortize the forecast cost of $270,000 over four years and require Bluewater Power take the risk if the cost of its response exceeds $270,000 but would also permit Bluewater Power to receive the benefit if costs were less than the $270,000 forecast. Recovery through a deferral account would permit Bluewater Power to recover all of its prudently incurred costs to be accumulated until project completion.

The approach proposed with the application provides greater certainty. It creates greater certainty of recovery for Bluewater Power and it creates greater certainty as to the final cost for Ratepayers. To that extent, it also creates an incentive for the utility to ensure that its response is measured in order to contain costs. In other words, the utility will be incented to follow the least costly path that provides a reasonable response rather than another path which might be justifiable but assumes less risk than might otherwise be prudently tolerated. In making that statement, we must highlight that if the results of the risk assessment dictates that a full-scale remediation of the site is required (which is not anticipated), then the utility would be forced to seek further recovery through a deferral account for these extra costs.

4.0 - EP 24 - Property Taxes

Ref: Exhibit 4, Tab 1, Schedule 1, Attachment 1

a) Please provide the actual Taxes Other Than Income Taxes for 2012.

2012: $184,930 draft actual
2012: $194,128 bridge year budget (see response to part (d) below)

b) Please confirm that this line item contains only property taxes in 2012 and 2013. If this cannot be confirmed, please indicate what other expenses are recorded here in 2012 and 2013.

Confirmed.

c) Please provide the actual property taxes for 2009 through 2012, along with the forecast for 2013.

2009: $162,763
2010: $178,380
2011: $189,527
2012: $184,930 draft actual
2012: $194,128 bridge year budget
2013: $219,952 test year budget

d) How much of the increase in property taxes between 2012 and 2013 is related to the building addition?

The building addition represents the majority of the $4,601 increase from 2011 actuals to the 2012 Bridge Year budget. This represents only a part year increase in property taxes as the building addition was forecast to be complete in Q4 of 2012. The building addition also represents the majority of the $25,824 increase from the 2012 Bridge Year to the 2013 Test Year.

Therefore, the overall increase currently included in the 2013 test year related to the building addition is approximately $30,425. While preparing these IR responses, Bluewater Power received an estimated property tax cost from the City of Sarnia related to the building expansion of $79,164. This creates a shortfall of approximately $48,500 in property taxes baked into the rate application as filed.

Accordingly, Bluewater Power has incorporated the increase in property taxes based on this new information into the revised revenue requirement, the RRWF and the bill impacts presented in the response to 1-Staff-2 and 1-Staff-3.

4.0-Staff-30 - Monthly Billing

Ref: Exh 4-2-5
Ref: Exh 4-3-1
Ref: Appendix 2-G

Bluewater Power currently bills 32,000 customers on a bi-monthly basis. Bluewater Power has included $322,641 of incremental costs related to a proposed move to monthly billing in the 2013 application. The costs are related to paper, envelopes, postage and three additional staff.

a) What is the status of the plans to move to monthly billing for all customers?

Bluewater Power's efforts to implement monthly billing continue to be in the planning stage. As noted in our pre-filed evidence the project is intended to coincide with this rebasing application. There were discussions within the electricity distribution sector about the possibility of a mandatory move to monthly billing for January 2013, however no such direction was received.

b) When does Bluewater Power expect to complete the move to monthly billing?

The investment required for monthly billing represents a net cost of approximately $1.2 Million over a 4 year regulatory window. The beneficiaries of this upgrade in service are customers (see response to SEC IR #9), so the move cannot prudently be undertaken without certainty of recovery through rates. Once we receive OEB approval, our pre-planning will permit us to be in a position to implement within 2-4 weeks.

c) How many FTEs worked on customer billing in 2009-2012? What is the total cost for customer billing in 2009-2012? Please provide the data for each year.

It would be difficult to complete the FTEs within customer billing, so the analysis provided below is based on head count. The values for Customer Billing include Call Centre, Billing Representatives, Credit, Mailroom, Cashier, Reception, Junior Clerk, meter readers and supervision. The costs for Customer Billing were determined based on the costs in Accounts 5305-5340, adjusted for contract employees, vehicles and miscellaneous billing costs.

Customer Billing Head Count	Customer Billing Costs
2009 – 20	2009 - 1,747,919
2010 – 21	2010 – 2,151,253
2011 – 23	2011 – 1,939,128
2012 – 22	2012 – 1,796,429

d) Has Bluewater Power considered how increased cash flow from this change would reduce the requirement for a working capital allowance?

Bluewater Power utilized a working capital allowance of 13% in accordance with the OEB letter to all distributors on April 12, 2012. See response to VECC IR #33.

1.0 - EP 4 - Monthly Billing

Ref: Exhibit 1, Tab 2, Schedule 1, page 7

Bluewater Power states that it intends to move from bi-monthly billing to monthly billing at an incremental cost of $322,000.

a) Which rate classes does Bluewater Power currently bill on a monthly basis and how long has this frequency been in place?

The rate classes that are billing monthly include: Large User, General Service 1000-4999 kW, General Service >50 kW, and Streetlighting. In addition, approximately 3,000 residential and small commercial customers who have chosen the Equal Payment Plan option are provided with a bill each month. This frequency has been in place since the creation of Bluewater Power in 2000.

b) Which rate classes does Bluewater Power currently bill on a bi-monthly basis that will be moved to monthly and how has this frequency been in place?

The majority of the Residential and the General Service <50Kw rate class, meaning all but the 3,000 Equal Payment Plan participants mentioned above, are billed bi-monthly. In addition, the unmetered scattered load and sentinel light accounts are currently billed on a bi-monthly basis. This represents approximately 31,000 of Bluewater Power's approximately 36,000 customers. This frequency has been in place since the creation of Bluewater Power in 2000.

c) What impact will the move from bi-monthly to monthly billing have on the cash flow of the company?

The cash flow of the Company will have a positive cash flow impact of approximately $20,000. This has been incorporated in the 2013 Test Year, so that customers will receive the benefit.

4.0 - EP 18 - Monthly Billing

Ref: Exhibit 4, Tab 1, Schedule 1, page 9

Has Bluewater Power done any cost benefit analysis of the impacts of moving from bi-monthly to monthly billing on such things as bad debt expense, cash flow improvement, etc.? If not, why not? If yes, please provide all of the analysis completed on the subject.

Please see response to SEC IR #9.

4.0 - VECC 33 - Monthly Billing and Working Capital

Reference: Exhibit 4, Tab 2, Schedule 5

a) The move to monthly billing will cause a further $322,000 in incremental costs. Please explain why BWP is not proposing a downward adjustment to working capital due to the change in billing frequency.

Bluewater Power has not performed a lead-lag study to determine its working capital allowance. It has relied on the default value of a 13% working capital allowance. It is our understanding that monthly billing is common among Ontario LDCs and hence the OEB's current standardized 13% working capital allowance is consistent with the working capital requirement that would result from monthly billing. We are prepared to rely on that default value and the default value is not contingent upon a particular business process and, more specifically, does not vary depending upon whether a utility performs monthly or bi-monthly billing.

1.0 - SEC 9 - Monthly Billing cost benefit analysis

[1/2/1, p. 7] Please provide a copy of the business case or cost/benefit analysis justifying to the move to monthly billing. Please confirm that the effect of the increased cost is approximately a 3% increase in rates. Please identify the rate classes that will bear the additional $322,641 cost, and the net rate increase for each class resulting from the change. Please provide a detailed calculation of the impact of the change on:

a. Working capital (e.g. billing, payment and other lags);

b. Bad debts;

c. Collection costs; and

d. All other material impacts.

As stated in the section on Monthly Billing (Exhibited 4, Tab 2, Schedule 5) the benefit of moving to monthly billing lies with customers. Given that the purpose of moving to monthly billing is driven by the desire to improve the customer experience, a cost benefit analysis was not performed. In fact, the discussion in the Monthly Billing schedule acknowledges that the incremental cost of moving to monthly billing could not be justified for the corporation and that is why we have proposed to move to monthly billing as part of this 2013 Rebasing Application so that the costs associated can be passed on to the customers who are the beneficiaries of upgrade in service.

With respect to the specific items enumerated above, we can comment as follows:

(a) Working Capital: as discussed in answer to VECC IR#33, we are relying upon the OEBs default Working Capital Allowance.

(b) Bad Debts: it would be purely speculative to forecast a decrease in bad debt attributable to monthly billing; in any event, the bad debt included in the 2013 Test Year appears to be "tight" in light of the continuing downturn in the local economy.

(c) Collection Costs: we have not assumed a direct increase to collection costs, but we have included one FTE whose responsibilities could include collection. Further, the amount projected to be paid to collection agencies is expected to be consistent under either monthly or bi-monthly billing.

(d) Other material impacts: the only benefit accounted for in the cost claim for the move to Monthly Billing is that the incremental cost of $322,641 is offset by the cash flow benefit estimated to be approximately $20,000.

With respect to the question of which rate class will bear the additional cost, we can confirm that the costs form part of regular O&M and would, therefore, be allocated to all rate categories in accordance with our cost allocation methodology.

4.0-Staff-31 - FTE Count

Ref: Exh 4-4-1

At pages 1 and 2, Bluewater Power explains the approach it took to reflect the settlement reached in the 2009 cost of service proceeding. Capital items removed from the capital budget and the associated adjustments were made to revenue requirement. The remaining revenue requirement adjustment was allocated to OM&A.

a) The FTE (Executive, Management, non-Union and Union) count proposed with the 2009 application was 99. The 2009 "Board Approved" FTE count was reduced to 88 for the purposes of analysis. Please confirm that the actual 2009 FTE count was 90.

Confirmed.

b) What are the actual 2012 FTE's? Please provide the information for each employee group and explain any differences from the data provided in the application.

The 2012 total actual of the four categories listed in part (a) above is 93.87.

Executive: 2012 Budget = 9.0, 2012 Actual = 8.83

A new VP of Operations was budgeted for 12 months in 2012, but was hired in February 2012.

Management: 2012 Budget = 8.0, 2012 Actual = 7.25

The former Manager of Lines retired in March 2012. The replacement position was budgeted for 12 months in 2012, but will be replaced in early 2013.

Union: 2012 Budget = 51.0, 2012 Actual = 49.29

A lineman resigned at the end of 2011 and was budgeted to be replaced in 2012. This position will not be replaced until early 2013. A second lineman position was budgeted for 12 months in 2012, but only hired later in the year.

Non-Union: 2012 Budget = 28.0, 2012 Actual = 28.5

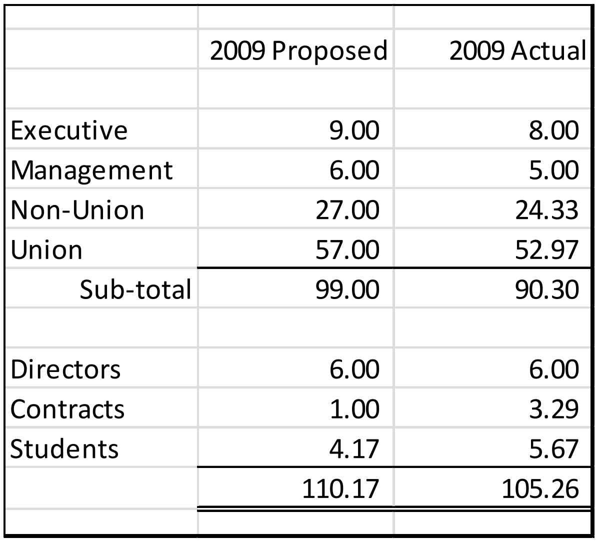
A new administrative position for the lines department was hired during 2012, but this position was not budgeted.

4.0 - VECC 34 - FTE count 2009 forecast vs. 2009 actual

4-VECC-34 Reference: Exhibit 4, Tab 4, Schedule 1, pgs. 2-5

a) BWP states that it proposed an FTE value of 99 in its 2009 rate application. Actual FTEs shown in Appendix 2-K for 2009 were 105.26. What were there the 6 incremental positions and why were they not anticipated in the 2009 application?

The 2009 proposed FTE value of 99 does not include Directors, Students or Contracts. The 2009 actual FTE value of 105.26 includes these three additional categories (please see discussion at Ex.4-4-1, pages 1-2). There were not 6 incremental positions added between 2009 proposed and 2009 Actual. In fact, there are approximately 5 fewer positions in 2009 Actuals compared to 2009 Proposed as shown in the following summary chart.



	2009 Proposed	2009 Actual
Executive	9.00	8.00
Management	6.00	5.00
Non-Union	27.00	24.33
Union	57.00	52.97
Sub-total	99.00	90.30
Directors	6.00	6.00
Contracts	1.00	3.29
Students	4.17	5.67
	110.17	105.26

4.0 - SEC 21 - Statement about growth of FTE's

[4/1/1, p. 8] Please explain the statement “much of the growth in FTEs between 2009 and 2013 was in the area of contract employees”, when contract went from 0.88 to 2.00, while total FTEs excluding directors went from 97.67 to 114.50.

Appendix 2-K entitled “Employee Costs” (exhibit 4, Tab 4, Schedule 1, Attachment 1) demonstrates that contract employees went from 0.88 in the 2009 Board Approved to 6.58 in the 2011 Actuals. The question correctly asserts that contract employees went back down to 2.00 in the 2013 Test Year. The point of the comment, however, was that the peak in FTEs occurred in 2011, which correlates with the peak in FTEs for contract employees. As the next sentence following the one referenced above states “Bluewater Power utilized contract employees to “flex” its workforce in order to respond to industry demands.”

4.0 - SEC 22 - OM&A and capitalized labour

[4/1/1, p. 8] Please identify in detail what OM&A did not get done during 2011 and 2012 due to the capitalized labour allocated to smart meters in those years. Please explain how the work done on smart meters in those years was incremental and thus separately recoverable from ratepayers.

The Smart Meter project primarily impacted three departments within the utility, being Operations, IT and Customer Service. Of those three departments, only IT would be considered to have had "OM&A" not completed in 2011 or 2012. The specific items identified as not fully completed are as follows:

(1) System patching is a regular maintenance function required in order to maintain secure and functioning systems. During the Smart Meter project, patching was limited to security patches and only those patches determined to be critical.

(2) PC Rollout was completed in 2011 and 2012, but the PCs replaced remain onsite awaiting secure and proper disposal.

(3) Website was not maintained to our normal standards and reliability issues were not addressed with our Internet Service Provider. This has become a major focus for late 2012 and January of 2013 in order to prepare for the implementation of MyAccount.

(4) IT Policy Review was not completed in 2011 and 2012.

(5) Business Process reviews and documentation were not completed in 2011 and 2012 to our normal standards.

We note that the last two items in this list might not fit the normal definition of "keeping the wheels on the bus" associated with OM&A. However, the IT industry moves at a rapid pace and if you are not addressing policies, processes and documentation in a timely manner then the operation runs the risk of moving into a break-fix approach which introduces lumpy OM&A because outside resources may be required.

Although the other departments involved in the Smart Meter project did not identify specific OM&A items that were not completed in 2011 or 2012, they did still experience artificially lower OM&A costs in those years because any position backfilled in those departments was backfilled at a lower cost. Contract employees were brought in as both long-term and short-term replacements in order to keep pace with the workload, but they were brought in at a lower cost than the employees they replaced (whose wages were being capitalized). Therefore, when the employee working on Smart Meters returned to his or her regular duties, the full impact of the higher wage and benefits hit OM&A in 2013.

4.0 - SEC 23 - FTEE variance

[4/2/2, p. 2] Please explain the ($57,000) variance under 2009 actuals, in light of the 8.6 FTEE increase from 2009 Board-approved to 2009 actuals.

As stated in the pre-filed evidence, it is difficult to carry-out any analysis using 2009 Board Approved amounts. The assumptions used in preparing Appendix 2-K contains a note that the 2009 Rebasing application was resolved by a settlement that did not specifically address the reductions to Revenue Requirement (see Ex 4-4-1, page 1-2). Accordingly, for the purposes of the analysis the 2009 Board Approved employee costs were reduced by their pro-rata share of the $1M reduction to OM&A.

To the extent the $57,000 reduction attributed to the net change in FTEs does not coincide with an increase in FTEs (actually a 7.6 FTE increase) large part of the explanation lies in the assumptions made in providing 2009 Board Approved values. In light of that caution, we can provide the following comments to further explain the apparent discrepancy.

First, the analysis that derived the ($57,000) variance was derived from two OEB Accounts that demonstrated material year-over-year variance (Account 5005 represented a $180,000 decrease and Account 5630 represented a $123,000 increase). The movement in FTEs may have impacted the variance in other OEB accounts, but those variances were not material so they were not included in the figure of ($57,000) that was calculated for the summary level analysis carried out for Ex.4-2-2.

Second, the amounts indicated in Appendix 2-K are gross FTEs and gross payroll dollars before any reallocations for billable work, affiliates, smart meters, capitalization, etc. The annual variances related to the OEB accounts, which is the basis for the high level cost drivers, are net amounts after reallocations.

Thirdly, we do note that the apparent inconsistency may be partially driven by the fact that the increase in FTEs were lower cost positions. Certain positions in the 2009 Board Approved could have been budgeted as full-time positions, but were actually filled/replaced in 2009 by i) lower cost employees on a one for one basis, or ii) greater number of lower cost employees. An example to highlight the above point is the combination of contracts and students as presented in Exh 4-4-1 Appendix 2-K. The 2009 Board Approved FTE amount is 4.55 (0.88 plus 3.67) and the 2009 Actual FTE amount is 8.96 (3.29 plus 5.67), for a total increase of 4.41. The average cost of those positions was $23,070 per FTE ($101,737 / 4.41).

4.0 - AMPCO 10 - FTEE Increase Drivers

Interrogatory #10

Reference: Exhibit 4, Tab 2, Schedule 1, Page 2

Preamble: The evidence indicates the FTEEs is not driven by increases in demand from a growing customer base but by increased demands due to regulation, government directions such as the Green Energy Act, and demands related to infrastructure renewal.

a) Please provide the number of new FTEEs driven by the Green Energy Act vs. infrastructure renewal.

Within the Operations group there is one incremental lineman and two frontline supervisors that are directly related to the increased focus on infrastructure renewal:

- In 2009, Bluewater Power employed 20 linemen; that number has fluctuated due to retirements and the challenge of recruiting qualified lineman, but the 2013 Test Year includes 21.4 FTEs in the position of lineman.
- The demands associated with infrastructure renewal drove the need to reinforce management within the lines group by adding 2 front-line supervisors. This issue is also discussed in response to 4-SEC-24.

Although the Engineering Group has faced significant increased workload due to both the Green Energy Act and the focus on infrastructure renewal, the department has not increased its FTEs. This is partially due to two factors:

- The addition of 2 front-line supervisors helped streamline interaction between engineering and the lines group; and

- The ability to rely upon the administrator in the operations group and the assistant to the VP (discussed next) eased the administrative burden in the department.

The executive position filled in 2011, and the assistant associated with that position, spend approximately 50% of their time each on the Green Energy Act, related to both Smart Grid and Renewable Energy. The positions were not created to respond to the demands of the Green Energy Act, but the positions were justified in part because of the demands introduced by this legislation.

4.0 - SEC 24 - Documents regarding increased asset management

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[4/2/2, p. 7] Please provide all reports, presentations, memos or other documents provided to senior management or the Board of Directors dealing with the change in focus to increased asset management, and the related changes to personnel.

The pre-filed evidence contains the *Asset Management Program Review* dated December 2010 as Exhibit 2, Tab 4, Schedule 2, Attachment 1, which was reviewed by select members of senior management with the engineering consultants (AESI) in draft throughout the Summer and Fall of 2010. The final document was reviewed on December 9, 2010 and a go-forward plan developed. There are no formal minutes or memos produced from those meetings, but the go-forward plan was to engage AESI in the next phase of the process. A proposal was received from AESI and reviewed by select members of senior management on April 6, 2011.

The pre-filed evidence contains the *Asset Management Strategy* dated December 2011 as Exhibit 2, Tab 4, Schedule 2, Attachment 2. The strategy was an iterative process with AESI providing guidance as Bluewater Power fine-tuned its asset management planning practices. Select members of senior management met with AESI on October 20, 2011 to discuss the findings but no formal minutes were produced for the meeting.

Neither the *Asset Management Program Review* nor the *Asset Management Strategy* were presented to the Board of Directors for Bluewater Power. The initiative was undertaken as an internal review and to assist staff in the development of a plan forward. Had either report suggested that significant change in processes or that further resources were required, then the matter would have been addressed with the Board of Directors. Based on the results, however, staff continued to move forward in the development of a formal Asset Management Plan.

Asset Management Planning for an electrical distributor is always a work in progress and lessons learned in the course of the review and strategy were incorporated into the capital budget for the year 2012, when it was set in November of 2011. The formal Asset Management Plan was launched with internal resources following the October 20, 2011 meeting. An update meeting was held on February 29, 2012 involving select senior staff. Ongoing meetings were held between the primary author of the Asset Management Plan and the regulatory department in the months of May through to June in preparation for the filing of the 2013 Rebasing Application. No minutes are available and the ultimate product of all such meetings is the *Asset Management Plan* is found at Exhibit 2, Tab 4, Schedule 3, Attachment 3.

With respect to the reorganization of personnel in the Operations department, there were ongoing discussions during Senior Management Team (SMT) meetings and the request would have ultimately impacted the 2010 O&M Budget so discussions would have taken place during the senior management review of the budget. The SMT minutes do not contain specific notation regarding the reorganization in operations. The issue was presented to the Board of Directors and the following excerpt is taken from the November 2009 Operations Board report:

> *"We have been reluctant in previous budgets to recommend increasing our trade staff levels beyond what is essential to meet the requirements of our succession plan. However, consistently high work load is showing us quite clearly now that a growth in trades staff is absolutely required. I am now confident that we will continue or increase our future work load which will support proposed new staff hires in 2010*
>
> *I am proposing to expand the BPDC Line staff levels to facilitate the growth necessary to meet customer demand. The expanded Line Group will be utilized to support affiliates as well as complete Capital and O&M work for the Distribution Company. I will also be proposing to hire two frontline supervisors. These positions are warranted due to the increased work load and the growth of the Line Division.*"

Although improvements in efficiency within the Line Department relate to many factors, we have seen significant performance improvements and cost savings between 2009 and 2012. Overtime has decreased, for example, from a high of approximately $400,000 in 2008 to approximately $300,000 in 2012. The level of line capitalized labour has been increased from 70% of budget in 2009 to 90% of budget in 2012. In addition, the number of maintenance work orders completed has increased by over 15% from 2009 to 2012.

4.0-Staff-32 - Compensation

Ref: Exh 4-4-1

Bluewater Power made certain assumptions in forecasting compensation for the 2013 test year.

a) At page 3, it states that certain benefits are discretionary and require the employee to agree to pay a certain percentage of the total cost of the benefit. Bluewater Power assumes that each employee takes advantage of the maximum available benefit.

   i. Is the current employee participation in these benefits 100%?
   ii. If not, what is the current participation rate?
   iii. What is the 2013 revenue requirement impact if the current participation rate is assumed?

   i. No
   ii. 92%
   iii. Bluewater Power assumed that each ***“new”*** employee takes advantage of the maximum available benefit. As such, the current participation rate for current staff was assumed in the 2013 revenue requirement.

b) Similarly, Bluewater Power has assumed that all employees eligible for progression successfully reach the next progression.

   i. Was the assumption valid for 2012?
   ii. If not, what is the current success rate?
   iii. What is the 2013 revenue requirement impact if the current success rate is assumed?

   i. Yes
   ii. N/A
   iii. N/A

4.0-Staff-33 - Compensation Appendix 2-K and 75 percentile

Ref: Exh 4-4-1 Attachment 1 and Attachment 2

The following table is an excerpt from Appendix 2-K.

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year	2011 vs 2009 Actual	2013 vs 2009 BA	2013 vs 2009 Actual
Compensation - Equivalent Annual Average Yearly Base Wages									
Executive	**$ 120,908**	**$ 121,257**	**$ 134,696**	**$ 135,251**	**$ 145,306**	**$ 151,811**	**11.5%**	**25.6%**	**25.2%**
Management	**$ 82,475**	**$ 80,499**	**$ 85,974**	**$ 86,548**	**$ 91,678**	**$ 93,925**	**7.5%**	**13.9%**	**16.7%**
Non-Union	**$ 64,837**	**$ 64,534**	**$ 70,026**	**$ 71,441**	**$ 72,529**	**$ 74,406**	**10.7%**	**14.8%**	**15.3%**
Union	**$ 58,927**	**$ 57,750**	**$ 61,744**	**$ 58,885**	**$ 63,894**	**$ 64,735**	**2.0%**	**9.9%**	**12.1%**

a) At Exh 4-4-1 Attachment 2, it states that there is a 5 year collective agreement with the IBEW Local 1802 which resulted in 3% annual increases in unionized wages from 2009 to 2014. Please explain why the 2011 equivalent annual average yearly base wages for union staff in Appendix 2-K are lower than 2010 averages.

In 2011, we experienced 6 retirements and each position was replaced with an employee at lower pay classification. In addition, there was a water billing clerk transferred to the Services affiliate. The total of these staff movements is an approximate $97,000 reduction in wages.

Finally, we can note that in 2011 Bluewater Power received a $64,000 hiring credit which reduced the wages expense further.

b) The last two columns of the table compare 2013 forecast base wages with 2009 Board approved and 2009 actual. The % increases for the Executive staff are twice the increases for union staff. The third last column compares 2011 actual base wages with 2009 actual base wages. The % increases for all staff groups are multiples of the increases for union staff. Please provide the rationale for these results.

For the executive category, Bluewater Power has been implementing market based adjustments to executive salaries beyond the 3% annual increase agreed to with Union staff. The approach was undertaken utilizing the Hay Group Canada's compensation database in an effort to move toward the 75th percentile. This is further discussed at Exh 4-4-1 Attachment 2 on page 10.

For the management and non-union categories, there have been a number of positions where employees are still moving through progression levels. The employee would experience a progression in pay and the new pay scale would also increase by 3%.

The union average yearly base wage is understated for 2011 as discussed in the response to part (a) above.

c) At Exh 4-4-1 Attachment 2, it states that, "In managing compensation for Executive employees, every year we participate in The Hay Group Salary Survey … This information is utilized by our Board of Directors with a goal to work toward the 75th percentile, although we have not achieved that objective."

  i. Please explain the rationale for the 75th percentile goal for Executive Staff.

The rationale for the 75th percentile for Executive Staff is to achieve satisfactory employee retention and recruitment. Please see 4-VECC-36.

  ii. Is the compensation goal for management staff also the 75th percentile?

Confirmed.

4.0 - SEC 30 - Appendix 2-K without affiliate employees

[4/4/1, Attach 1] Please restate the Appendix 2-K removing, with respect to all of the employees transferred to affiliates during the period (including but not limited to those referred to in 1/1/10, p. 2), the FTEEs and associated costs applicable to those employees.

From 2009 to 2013, there were only 3 employees transferred from Bluewater Power to affiliates. This included one water billing representative transferred on April 1, 2011 and two water meter readers transferred on January 1, 2012. All three transfers were to the Services affiliate. Therefore, the highlighted FTEs and related costs in Appendix 2-K have been updated as follows:

2009 BA – eliminate these three employees for full year
2009 Actual – eliminate these three employees for full year
2010 Actual – eliminate these three employees for full year
2011 Actual – eliminate water billing rep for first three months, eliminate meter readers full year
2012 Bridge – no change
2013 Test Year – no change

The restated Appendix 2-K can be found in Attachment #1 to this interrogatory response.

File Number:EB-2012-0107

Tab: 6
Schedule: 37

Date Filed:February 4, 2013

Attachment 1 of 1

4.0 - SEC 30 - Appendix 2-K

File Number:
Exhibit:
Tab:
Schedule:
Page:

Date: January 30, 2013

IRR SEC #30

Appendix 2-K
Employee Costs

	2009 LRY - Board Approved	2009 LRY - Actual	2010 Historical Year 2	2011 Historical Year 1	2012 Bridge Year	2013 Test Year
Number of Employees (FTEs including Part-Time)[1]						
Director's	6.00	6.00	6.00	6.00	6.00	6.00
Executive	7.92	8.00	8.00	9.00	9.00	9.00
Management	5.28	5.00	8.00	8.00	8.00	8.00
Non-Union	23.76	24.33	26.33	27.50	28.00	28.00
Union	47.52	46.97	48.34	50.88	51.00	56.17
Contract	0.88	3.29	6.21	4.28	3.92	2.00
Students = FTE	3.67	5.67	5.44	6.33	5.67	5.33
Total	95.03	99.26	108.32	111.99	111.58	114.50
Number of Part-Time Employees						
Executive	-	-	-	-	-	-
Management	-	-	-	-	-	-
Non-Union	-	-	-	-	-	-
Union	-	-	-	-	-	-
Total	-	-	-	-	-	-
Total Salary and Wages - note the numbers in this category reflect regular gross earnings only						
Director's	$ 89,462	$ 101,500	$ 105,900	$ 118,050	$ 111,515	$ 106,515
Executive	$ 957,595	$ 970,059	$ 1,077,568	$ 1,217,262	$ 1,307,751	$ 1,366,301
Management	$ 435,470	$ 402,497	$ 687,791	$ 692,386	$ 733,425	$ 751,397
Non-Union	$ 1,540,523	$ 1,570,110	$ 1,843,781	$ 1,964,633	$ 2,030,808	$ 2,083,355
Union	$ 2,836,145	$ 2,925,222	$ 3,022,566	$ 3,018,285	$ 3,258,578	$ 3,635,941
Contract	$ 23,390	$ 146,464	$ 268,570	$ 261,048	$ 184,390	$ 136,593
Students	$ 132,067	$ 110,730	$ 135,331	$ 125,796	$ 174,688	$ 218,225
Total	$ 6,014,651	$ 6,226,582	$ 7,141,506	$ 7,397,461	$ 7,801,155	$ 8,298,327
Current Benefits						
Director's	$ 3,500	$ 3,414	$ 3,493	$ 4,001	$ 2,175	$ 2,077
Executive	$ 196,691	$ 251,928	$ 272,564	$ 342,753	$ 304,586	$ 357,763
Management	$ 107,944	$ 118,695	$ 175,356	$ 196,522	$ 218,161	$ 251,704
Non-Union	$ 366,327	$ 393,491	$ 461,919	$ 538,727	$ 527,037	$ 550,800
Union	$ 671,515	$ 760,307	$ 717,609	$ 804,550	$ 895,747	$ 1,034,431
Contract	$ 10,000	$ 12,905	$ 22,872	$ 24,652	$ 5,542	$ 9,321
Students	$ 10,000	$ 10,613	$ 12,804	$ 11,966	$ 11,408	$ 22,814
Retirees	$ 200,000	$ 226,951	$ 244,644	$ 285,786	$ 304,263	$ 334,852
Total	$ 1,565,978	$ 1,778,305	$ 1,911,261	$ 2,208,958	$ 2,268,919	$ 2,563,763
Accrued Pension and Post-Retirement Benefits						
Executive						
Management						
Non-Union						
Union						
Total	$ -	$ -	$ -	$ -	$ -	$ -
Total Gross Benefits (Current + Accrued)						
Director's	$ 3,500	$ 3,414	$ 3,493	$ 4,001	$ 2,175	$ 2,077
Executive	$ 196,691	$ 251,928	$ 272,564	$ 342,753	$ 304,586	$ 357,763
Management	$ 107,944	$ 118,695	$ 175,356	$ 196,522	$ 218,161	$ 251,704
Non-Union	$ 366,327	$ 393,491	$ 461,919	$ 538,727	$ 527,037	$ 550,800
Union	$ 671,515	$ 760,307	$ 717,609	$ 804,550	$ 895,747	$ 1,034,431
Contract	$ 10,000	$ 12,905	$ 22,872	$ 24,652	$ 5,542	$ 9,321
Students	$ 10,000	$ 10,613	$ 12,804	$ 11,966	$ 11,408	$ 22,814
Retirees	$ 200,000	$ 226,951	$ 244,644	$ 285,786	$ 304,263	$ 334,852
Total	$ 1,565,978	$ 1,778,305	$ 1,911,261	$ 2,208,958	$ 2,268,919	$ 2,563,763

	2009	2009	2010	2011	2012	2013
Total Compensation (Salary, Wages, & Benefits)						
Director's	$ 92,962	$ 104,914	$ 109,393	$ 122,051	$ 113,690	$ 108,592
Executive	$ 1,154,286	$ 1,221,987	$ 1,350,132	$ 1,560,015	$ 1,612,337	$ 1,724,064
Management	$ 543,414	$ 521,192	$ 863,146	$ 888,908	$ 951,586	$ 1,003,101
Non-Union	$ 1,906,850	$ 1,963,601	$ 2,305,700	$ 2,503,360	$ 2,557,845	$ 2,634,155
Union	$ 3,507,661	$ 3,685,529	$ 3,740,174	$ 3,822,835	$ 4,154,325	$ 4,670,372
Contract	$ -	$ 159,369	$ 291,442	$ 285,700	$ 189,932	$ 145,914
Students	$ -	$ 121,343	$ 148,135	$ 137,762	$ 186,096	$ 241,039
Retirees	$ -	$ 226,951	$ 244,644	$ 285,786	$ 304,263	$ 334,852
Total	$ 7,580,630	$ 8,004,886	$ 9,052,767	$ 9,606,419	$ 10,070,074	$ 10,862,089
Compensation - Equivalent Annual Average Yearly Base Wages						
Director's	**$ 14,910**	**$ 16,917**	**$ 17,650**	**$ 19,675**	**$ 18,586**	**$ 17,753**
Executive	**$ 120,908**	**$ 121,257**	**$ 134,696**	**$ 135,251**	**$ 145,306**	**$ 151,811**
Management	**$ 82,475**	**$ 80,499**	**$ 85,974**	**$ 86,548**	**$ 91,678**	**$ 93,925**
Non-Union	**$ 64,837**	**$ 64,534**	**$ 70,026**	**$ 71,441**	**$ 72,529**	**$ 74,406**
Union	**$ 59,683**	**$ 62,279**	**$ 62,534**	**$ 59,327**	**$ 63,894**	**$ 64,735**
Contract	**$ 26,580**	**$ 44,495**	**$ 43,260**	**$ 60,969**	**$ 47,078**	**$ 68,296**
Students	**$ 36,018**	**$ 19,541**	**$ 24,857**	**$ 19,863**	**$ 30,827**	**$ 40,917**
Total	**$ 405,412**	**$ 409,522**	**$ 438,996**	**$ 453,075**	**$ 469,898**	**$ 511,842**
Compensation - Total Yearly Overtime						
Executive	$ -	$ 1,902	$ 4,828	$ -	$ -	$ -
Management	$ 13,220.00	$ 4,505	$ 46,608	$ 42,541	$ -	$ 30,000
Non-Union	$ 9,000.00	$ 26,237	$ 8,323	$ 8,096	$ 26,500	$ 6,000
Union	$ 421,228.00	$ 426,270	$ 552,083	$ 476,814	$ 295,500	$ 280,000
Contract	$ -	$ 1,079	$ 2,118	$ 2,060	$ 1,500	$ -
Students	$ -	$ 367	$ 1,677	$ 17	$ -	$ -
Total	$ 443,448	$ 460,359	$ 615,638	$ 529,529	$ 323,500	$ 316,000
Compensation - Total Yearly Incentive Pay (represents 90% of gross)						
Executive	$ 129,215	$ 129,829	$ 114,545	$ 158,170	$ 160,398	$ 174,563
Management	$ 21,912	$ 19,637	$ 27,989	$ 51,272	$ 33,201	$ 37,463
Non-Union	$ 45,141	$ 42,819	$ 43,753	$ 45,794	$ 52,308	$ 49,751
Union	$ 48,924	$ 31,851	$ 38,257	$ 37,764	$ 37,147	$ 45,899
Total	$ 245,192	$ 224,136	$ 224,544	$ 292,999	$ 283,054	$ 307,677
Compensation - Equivalent Annual Average Yearly Benefits						
Director's	$ 583	$ 569	$ 582	$ 667	$ 362	$ 346
Executive	$ 24,835	$ 31,491	$ 34,071	$ 38,084	$ 33,843	$ 39,751
Management	$ 20,444	$ 23,739	$ 21,919	$ 24,565	$ 27,270	$ 31,463
Non-Union	$ 15,418	$ 16,173	$ 17,543	$ 19,590	$ 18,823	$ 19,671
Union	$ 14,131	$ 16,187	$ 14,847	$ 15,814	$ 17,564	$ 18,417
Contract	$ 11,364	$ 3,921	$ 3,684	$ 5,758	$ 1,415	$ 4,660
Students	$ 2,727	$ 1,873	$ 2,352	$ 1,889	$ 2,013	$ 4,278
Retirees	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 89,502	$ 93,953	$ 94,998	$ 106,367	$ 101,290	$ 118,587
Total Compensation	$ 7,205,173	$ 8,004,886	$ 9,052,767	$ 9,606,419	$ 10,070,074	$ 10,862,089
Total Compensation Charged to OM&A	$ -	$ 6,623,862	$ 7,203,947	$ 7,704,230	$ 7,758,975	$ 8,866,752
Total Compensation Affiliates	$ -	$ 299,321	$ 356,830	$ 363,745	$ 448,106	$ 482,499
Total Compensation Smart Meter	$ -	$ 14,992	$ 232,251	$ 425,396.00	$ 364,078.00	$ -
Total Compensation Billable	$ -	$ 160,885	$ 425,643	$ 243,090.00	$ 191,280.00	$ 138,731.00
Total Compensation Capitalized	$ 1,086,186	$ 905,826	$ 834,096	$ 869,958	$ 1,307,635	$ 1,374,107

Note:

[1] If an applicant wishes to use headcount, it must also file the same schedule on an FTE basis.

4.0 - VECC 36 - Salaries at 75 percentile

Reference: Exhibit 4, Tab 4, Schedule 1, Attachment 2, pg. 10 of 29

a) The evidence states that Bluewater's objective is to work toward the 75th percentile in respect to comparable salaries. Please explain why this target was chosen. In addressing this question please explain how relative utility size and locational cost of living are factored into the choice.

The 75th percentile was selected as the compensation target with a focus on employee retention and recruitment. Utility size and locational costs are secondary factors when faced with recruiting executive positions in a market that is truly Ontario-wide. Our recent challenge filling the Vice President of Operations role, which was vacant for eight months, is a good example of the challenge we face in recruiting. Those efforts not only looked across the province, but we also considered candidates from across Canada.

For all positions, including executive and management, local conditions actually place upward pressure on compensation because our local market includes Chemical Valley, where compensation levels are higher than the electricity industry in Ontario. In that regard, we note that Bluewater Power lost a manager in Finance to a Chemical Valley company and the Vice President of Operations role was eventually filled from a company within Chemical Valley.

Finally, we note that, while our goal is to work towards the 75th percentile, we have not achieved that target to date. While the eight manager positions are compensated at, or near, the 75th percentile, only two executive positions are compensated near the 75th percentile. The remaining seven members of the executive group are compensated closer to the 50th percentile. Therefore, the costs included in this Rate Application are not based on the goal of paying the executive and management at the 75th percentile. The ultimate decision on a position-by-position basis lies with the Compensation Committee of our Board of Directors.

4.0 - SEC 33 - Hay analysis for President

[4/4/2, Attach 2, p. 24] Please provide the Hay analysis showing the 1566 Hay points for the President and CEO.

Enclosed as Attachment #1 to this response is the Hay analysis for the President and CEO showing the score on each of the criteria for "know-how", "problem-solving" and "accountability". The analysis was completed by a representative with Hay Consultants on June 8, 2005 and the document produced contains those scores along with a general description of the process and definition for each criteria.

Attachment 1 of 1

4.0 - SEC 33 - HAY Evaluation

Hay Evaluation for: **President & CEO**

KNOW-HOW – is the sum total of every kind of knowledge and skill, *however acquired,* needed for acceptable job performance. Know-How has three dimensions – the requirement for:

- Practical procedures, specialized techniques, or scientific disciplines.
- Planning-organizing, integrating, coordinating, staffing, directing and/or controlling the activities and resources associated with an organizational unit or function. This skill may be exercised consultatively or directly.
- Active, face-to-face skills needed for various relationships with other people.

Measuring Practical, Technical Know-How: This type of knowledge and skill may be characterized by breadth (variety), or depth (complexity), or both. Jobs may require, in varying combinations, some knowledge about many things or a good deal of knowledge about a few things. Thus, the measuring of Practical, Technical Know-How requires an understanding of "How much knowledge is needed about how many things and how complex are they?

1. **Scientific Disciplines/Specialized Techniques/Practical Procedures:**

   G – Mastery of theories, principles, and complex techniques OR the diverse, cumulative equivalent gained through broad seasoning AND/OR special development.

2. **Managerial Know-How**

   III – Management of all units and functions in the organization.

3. **Human Relations Skills**

   3 –Alternative or combined skills in understanding and motivation people are important in the highest degree

Results (possible results are 608 or 700 or 800)*:* GIII3 = 608 points

PROBLEM SOLVING – is the amount and nature of the thinking required in the job in the form of analyzing, reasoning, evaluating, creating, using judgement, forming hypotheses, drawing inferences, arriving at conclusions and the like. Problem Solving has two dimensions:

- The environment in which the thinking takes place – the extent to which assistance or guidance is available from others or from past practice and precedents.
- The challenge of the thinking to be done – the novelty and complexity of the thinking required.

Measuring Problem Solving: All thinking requires the presence of knowledge in the form of facts, principles, procedures, standards, concepts, etc. This is the raw material to which the thinking processes are applied. Problem Solving measures the degree to which thinking processes must be applied to the required knowledge in order to obtain the results expected of the job. To the extent that thinking is limited or reduced by job demands or structure, covered by precedent, simplified by definition, or assisted by others, Problem Solving is diminished and results are obtained by the automatic application of skills rather than by the application of the thinking processes to knowledge.

Thinking Environment – the extent to which assistance or guidance is available from others or from past practice and precedents.

G – Thinking within concepts, principles, and broad guidelines towards the organization's objectives or functional goals; many nebulous, intangible, or unstructured aspects to the environment.

Thinking Challenge - the novelty and complexity of the thinking required.

4 – Variable situations requiring analytical, interpretative, evaluative, AND/OR constructive thinking.

Results (possible results either 57% or 66%)*:* G4 = 57%, which equates to 350 points

ACCOUNTABILITY – is related to the ***opportunity*** which a job has to bring about some results and the importance of those results to the organization. Tied closely to the amount of opportunity is the degree to which the person in the job must answer for (is accountable for) the results. There are three components of Accountability, in the following order of importance:

- **Freedom to Act** – the degree to which personal or procedural control exists
- **Job Impact on End Results** – the degree to which the job affects or brings about the results expected of the unit or function being considered.
- **Magnitude** – the size of the unit or function (usually indicated by dynamic, annual dollars) most clearly affected by the job.
- The degree to which the person in the job must answer for (is accountable for) the results.

Freedom to Act

F – These jobs are subject to the guidance of broad organization policies and directives from the Board.

Job Impact and End Results

P- Primary – Controlling impact – the position has effective control over the significant activities and resource which produce the results and is the sole position (at this level of Freedom to Act) which must answer for the results.

Magnitude

(4) Very Large - $10M to $100M

Results (possible results are 460/528/608)*:* F (4) P = 608

Job Content Points = 608 + 350 + 608 = **1566**

4.0 - AMPCO 8 - Salary Increase

Interrogatory #8

Reference: Exhibit 4, Tab 1, Schedule 1, Page 2

Preamble: The evidence states that the salaries represent an increase of 3% over 2012 levels as set out in Bluewater Power's Collective Agreement, which does not expire until after the Test Year.

a) Please confirm when it expires.

The current Collective Agreement expires March 31, 2014.

b) Please confirm the types of positions where a 3% increase in salaries is applied (i.e. union, non-union etc.)

If we use the employee categories found in Appendix 2-K, the only types of position not assumed to receive a 3% increase are Directors (annual stipend and meeting fee is the same). That includes the following types of positions (NOTE: the 3% does not apply to any position red-circled; further, any individual receiving a progression moves to the higher classification which, itself, would increase by 3%):

- Executive
- Management
- Non-union
- Union
- Contract
- Students (due to rounding, the increase is actually 2.08%)

4.0 - VECC 37 - Incentive pay and reliability metrics

Reference: Exhibit 4, Tab 4, Schedule 1, Attachment 2, pgs. 28 of 29 –Incentive Pay

a) What is the maximum incentive envelope in 2012 and 2013 respectively?

If all four categories were met, and all employees were rated at the highest performance levels, then the maximum incentive envelope for 2012 is $352,784 and 2013 is $373,660. The amount paid in those years was 89% and 91%, respectively, of the maximum envelop (please see response to 4-EP-25).

As a reminder, the 2013 Test Year includes incentive pay calculated at 90% relating to the benefit of ratepayers. This calculated amount assumes all four categories are met, and the most recent actual year end employee performance appraisal ratings were maintained. The remaining 10% is to the benefit of shareholders as per discussion at Exh 4-4-1, page 3.

b) Please confirm that the incentive reliability and service metrics do not include SAIDI/SAIFI or CAIDI targets. If this is true please explain why. If not, then please provide the incentive reliability targets 2013 through 2017.

The Incentive Reliability and Service metrics do not include SAIDI/SAIFI or CAIDI targets. These are not used since the metric can be strongly influenced by variables outside of our control; for example, the majority of Bluewater Power outages are caused by weather, Hydro One loss of supply and car accidents. Another primary consideration is that our greatest concerns must always be safety, so we do not want to incent speed of work for fear of the potential safety implications.

That is not to suggest that reliability is not considered for factors beyond SAIDI/SAIFI or CAIDI. The Incentive Compensation programs does include target for 2013 and beyond that incent reliability in positive ways as follows:

1. # Low Voltage connections requests completed in less than 5 days
2. # High Voltage connection requests completed in less than 10 days
3. # Rural emergencies responded to within 120 minutes
4. # Urban emergencies responded to within 60 minutes

These metrics are more fundamental to reliability and are deemed to be within our control.

4.0 - EP 21 - Compensation Sensitivities

Ref: Exhibit 4, Tab 2, Schedule 2

a) What is the impact in the test year if the assumed 3% increase for non-unionized employees was reduced to 2%?

The annual cost of living increase for non-union employees is effective April 1st of each year. Therefore, for the 2013 test year, the payroll impact of a 1% reduction from April to December would be $14,646.

b) What is the impact in the test year if the assumed 3% increase for non-union employees was reduced to 2%?

Bluewater Power assumes this question relates to 'union' employees as the impact on non-union employees was addressed in part (a) above.

The annual cost of living increase for union employees is effective April 1st of each year. Therefore, for the 2013 test year, the payroll impact of a 1% reduction from April to December would be $25,986.

c) What is the impact, based on parts (a) and (b) above relative to the $344,000 increase shown for the test year shown in the table under driver 2?

Parts (a) and (b) above relate solely to union and non-union employees, whereas the $344,000 variance relates to all employees. In addition, the $344,000 variance pertains to cost of living and progressions.

According for the changes in parts (a) and (b) above, the $344,000 variance will decrease by $40,632 to $303,368.

d) What is the impact, based on parts (a) and (b) above, on the increase shown for the test year under driver 6 (benefits) and under drive 8 (OMERS)?

Driver 6 represents extended benefits and excludes OMERS and burden. The increase shown for Driver 6 would be reduced by $462 for non-union employees and $897 for union employees. The benefits impacted include life insurance, long term disability and accidental death & dismemberment. Since life insurance has an earning cap, its impact is minimal.

The increase shown for Driver 8 ‘OMERS’ would be reduced by $1,972 for non-union employees and $3,662 for union employees.

e) Please provide more details on the need to improve read dates to meet the Service Level Agreement noted under driver 4.

Bluewater Power's AMI network was installed in the Spring of 2010 and installation of all smart meters was completed by October 2011. Bluewater Power began working with Sensus in August of 2011 to ensure that we were achieving the requirement to communicate 98% of meter reads to the MDM/R as set out in the Functional Specifications and as required by the Service Level Agreement between Bluewater Power and Sensus. Network tuning was undertaken by Sensus and Radio Frequency interference on two different occasions resulted in additional infrastructure requirements such as Repeaters and Directional Antennas within our service territory. In September of 2012, a second network propagation study was completed by Sensus and we were notified that to achieve the 98% daily read requirement, an additional TGB would be required. Although there would be no upfront costs due to language built into our contract, there would be ongoing monthly fees associated with this addition to our network. Bluewater Power is still trying to mitigate RF noise interference within our territory and determine our best course of action to achieve this 98% daily read requirement along with many other utilities in the Province.

f) Are the software fees of $47,000 noted under driver 4 an annual expense or a one-time expense?

The SAP software maintenance fees of $47,000 pertain to SAP AMI extensions software license maintenance, XI/PI software license maintenance, and Cleo AS2 software license maintenance. These are annual maintenance fees for software that are required to interface Bluewater Power systems to the central Meter Data Management/Repository (MDM/R).

g) Please explain the increase in 2012 shown under driver 5 related to the net change in FTEs despite the reduction in the number of FTEs in 2012.

The increase in 2012 for Driver 5 is $121,000 is a high level variance derived from the OEB Account year over year OM&A variance analysis presented in Exh 4-3-1. Although Account 5040 shows a $57,000 increase due to the replacement of a lineman who left in 2011, it is offset by a $64,000 hiring credit received in 2011 but not in 2012. The combination of these two amounts is the $121,000 variance.

Exh 4-4-1 Appendix 2-K shows the 2011 actual FTE amount of 116.54 and the 2012 actual FTE amount of 111.58, for an overall decrease of 4.96. The FTE totals are from the seven categories presented in Appendix 2-K (executive, management, non-union, union, directors, contracts and students).

It becomes difficult to directly compare the results for a number of reasons.

First, the movement in FTEs is also captured in other OEB accounts. However, due to materiality, only significant variance drivers were included in the calculation for Exh 4-3-1. The movement in FTEs may have impacted the variance in other OEB accounts, but those variances were not material so they were not included in the figure of ($57,000) that was calculated for the summary level analysis carried out for Ex.4-2-2.

Second, Appendix 2-K presents gross FTEs and gross payroll dollars before any reallocations for billable work, affiliates, smart meters, capitalization, etc. The annual variances related to the OEB accounts, which is the basis for the high level cost drivers, are net amounts after reallocations. An example of this point is the fact there were contract customer service reps (CSRs) and two permanent meter readers included in the 2011 FTE count, but not the 2012 FTE count. The payroll dollars for the CSRs were reallocated to the smart meter project in 2011 but ceased in 2012. The meter readers were present in 2011 but were permanently moved to the Services affiliate in 2012.

h) Has Bluewater Power made any adjustment to the 2013 bad debt cost (driver 7) to reflect the impact of moving to monthly billing for customers? If not, why not?

Please see the response to 4-VECC-28.

i) Given the increase in FTEs forecast for 2013 versus 2012 for unionized positions, why is there no addition savings shown in driver 13 related to overtime in 2013?

The increase from 2012 to 2013 for unionized positions is 5.17 FTEs as per Exh 4-4-1 Appendix 2-K. The 5 FTEs are made up of 3 FTEs related to the implementation of monthly billing and 2 FTEs relating to linemen.

Driver 13 relates to overtime, primarily pertaining to linemen. There is no overtime pertaining to the new monthly billing positions for the 2013 test year. The reason overtime did not materially change for linemen from 2012 to 2013, is due to the nature of the overtime budgeted. Bluewater Power has consistently incurred overtime at night and on weekends for storm work, unplanned repairs and maintenance, certain capital projects to avoid customer interruptions, etc. A normalized level of overtime for this type of work is budgeted in 2012 and 2013.

The reduction of $130,000 from 2011 to 2012 shown in Driver 13 relates to the movement of overtime back to normal levels. The 2011 actuals were abnormally high due to the overtime required as a direct and indirect result of connecting very large renewable generation projects to our distribution system.

The addition of the two linemen is primarily required to handle the increased work load as dictated by the demands of the Asset Management Plan for the distribution system. See discussion in Exh 4-4-1, Attachment 2, pages 3 and 4 of 29.

4.0 - EP 25 - HR Policies

Ref: Exhibit 4, Tab 4, Schedule 1

a) How was the COLA adjustment of 3% determined? Was the figure of 3% part of a negotiated agreement or is it related to some measure of inflation? If the latter, please explain what the COLA is related to.

The 3% is required under our Collective Agreement in effect from April 1, 2009 to March 31, 2014. The increase is effective on April 1st of each year in the term of the contract.

b) What is Bluewater Power's policy with respect to unused vacation and the associated payouts?

Unused vacation will only be paid out with Chairman of the Board signed authorization, and only where due to unforeseen events that resulted in an employee being unable to fully utilize their vacation time. There is no vacation payout budgeted for 2013.

c) Which group of employees are eligible for overtime and which group of employees are not eligible for overtime?

Union Staff and Non-Union Emergency Response Staff are eligible for overtime.

d) For each of 2009 through 2012, please provide the total number of employees that were eligible for progression and the corresponding number that successfully reached their next progression in each of those years.

Table 1

	2009	**2010**	**2011**	**2012**
Eligible for Progression	8	11	20	23
Progressed	8	11	19	23
Not Progressed	0	0	1*	0

**Did not have hours for apprenticeship, received progression as soon as hours were accomplished.*

e) Have employees taken advantage of the maximum available benefit in each of 2009 through 2012? If not, please provide the percentage of the maximum available benefit that was utilized. Please also provide the reduction in costs to Bluewater Power as a result of employees not taking advantage of the maximum available benefit.

Dental coverage is the only benefit that staff are allowed to opt out of because it is a shared cost to the employee. The table reflects the total number of staff that have dental coverage; the cost reduction represents the savings to Bluewater Power for those employees opting out of dental coverage.

Table 2

Dental	**2009**	**2010**	**2011**	**2012**
Utilization	88%	92%	92%	92%
Cost Reduction	$10,235	$9,839	$10,178	$10,563

Note: the statement '*we have assumed that each employee takes advantage of the maximum available benefit*' should read '*we have assumed that each **"new"** employee will take advantage of the maximum available benefit*'.

f) For each year shown in Appendix 2-K, please indicate what percentage the total incentive pay shown is of the total potential incentive pay.

Table 3

Year	**Appendix 2-K**	**Potential Incentive Pay**	**Percentage**
2009	225,403	220,884	102%
2010	226,017	329,898*	69%
2011	293,614	279,023	105%
2012	283,054	317,506	89%
2013	307,677	336,294	91%

**Incentive Targets and Market Salary changes for some staff due to Market Salary Data to bring some Management up to the Average Percentile while some still continue to be below.*

The variances seen in the percentages shown in Table 3 are driven by accruals and true-ups during the year. Absent these adjustments, the percentage of the mazimum envelop paid is approximately 90% (the average of 2009, 2010 and 2011 is 89%). The amount budgeted for the years 2012 and 2013 reflect this level of pay-out.

g) There is an increase of 5.17 Union FTEs shown for 2013 as compared to 2012. Do any of these FTEs represent apprentice positions? If yes, please indicate how many are the result of the forecast hiring of apprentices. Are these positions being used to plan for retirements over the next few years?

No. There are no apprentice positions included in the increase of 5.17 Union FTE's. These include 1 additional Lineman, 1 Billing Representative, 1 Mailroom Clerk, 1 Cashier, 50% of one Meter Reader and 0.66 of an overlap for training for one retirement.

4.0 - VECC 25 - Inflation Factors

Reference: Exhibit 4, Tab 1, Schedule 1

a) Please provide the inflation factors BWP has assumed in this application each year from 2009 for 2013. Please provide the source of the inflation assumption

There are no inflation factors required in the years 2009 to 2011 as the numbers reflected in the application are actuals. With respect to the years 2012 and 2013, the issue is addressed in Exhibit 1, Tab 2, Schedule 3 under the heading "Operating and Maintenance Expense Forecast" wherein we state:

> *"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. There was no assumption for inflation and 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."*

A related issue is addressed in the same schedule under the heading "Payroll Labour Forecast" wherein we state:

> *"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. We applied the 3% increase required by our Collective Agreement to both union and non-union positions. A payroll accrual adjustment was made to ensure that the budgeted costs fall within the applicable forecast year. These issues are addressed in detail in Exhibit 4, Tab 4, Schedule 1 entitled "Staffing and Compensation Levels".*

4.0-Staff-34 - Workforce Retirements

Ref: Exh 4-4-1 Attachment 2

Bluewater Power notes the challenge relating to the age of its workforce, and an increase in the number of employees electing to retire at age 55 or at the earliest unreduced eligibility date. Please provide retirement data in the following table:

See table below.

Year	Eligible in Year	Eligible Cumulative	Actual Retirement in Year	Balance Cumulative
	A	B=A+D[1]	C	D=B-C
Prior Period				
2009	3	3	1	2
2010	3	5	2	3
2011	6	9	6	3
2012	2	5	2	3
Total	14		11	

Note 1 - From previous period/year

4.0 - VECC 35 - Retirements

4-VECC-35 Reference: Exhibit 4, Tab 4, Schedule 1, Attachment 2 /Appendix 2-K

a) How many FTEs in 2013 are being filled in anticipation of retirements?

There are two FTEs in 2013 that are being filled in anticipation of a retirement. As of the time of writing these responses to IRs, one individual has already filed notice of their intention to retire in March.

b) Please identify the number of FTEs incremental to the 99 FTEs forecast in the 2009 application that were or are being hired to address new responsibilities (e.g. smart meter related, regulatory etc.). Please identify separately incremental FTEs related to call center or customer service positions

The 99 FTEs was the original requested amount (before settlement) relating to the 2009 rate application. It included the categories of executive, management, union and non-union. To reconcile the 2009 originally submitted 99 FTEs to the 2013 test year 101.17 FTEs, the following summary is presented:

- 2 lines planning supervisors (workload) – already hired
- 1 call center representative (monthly billing) – not hired yet
- 1 billing representative (monthly billing) – not hired yet
- 1 mailroom/junior clerk representative (monthly billing) – not hired yet

Thus, the 99 FTEs from 2009 plus 5 new FTEs per above less 3 FTEs reallocated to Services affiliate equals the 101.17 FTEs for the 2013 test year. We should note that there are positions within Bluewater Power that were reclassified within departments or reallocated between departments, but these movements did not impact the FTEs.

c) With reference to the FTEs shown in Appendix 2-K, please show the number of FTEs allocated to affiliates in 2009 through 2013.

The response to 4-SEC-30 shows a restated Appendix 2-K for the removal of three positions that were permanently transferred to the Services affiliate in 2011/2012.

Beyond this restated Appendix 2-K, a high level estimate can only be done to reflect the equivalent remaining Bluewater Power FTEs that are allocated to the affiliates. This is because numerous positions at all levels of Bluewater Power have a certain percentage of their fully allocated costs covered by the affiliates. See discussion Exh 4-5-1.

Therefore, a high level estimate for 2013 is to take the $482,499 allocated to affiliates (shown at bottom of the Appendix 2-K) and divide this by an approximate $99,157 average annual cost (also derived from Appendix 2-K). This produces a high level approximation of 4.87 FTEs allocated to affiliates. Therefore, if this calculation is done for all years, the high level allocations are as follows:

2009 Actual = 3.41 FTEs
2010 Actual = 3.92 FTEs
2011 Actual = 3.95 FTEs
2012 Bridge = 4.64 FTEs
2013 Test = 4.87 FTEs

4.0 - SEC 31 - Retirement statistics

[4/4/1, Attach 2] Please confirm that:

a. If 24% of employees retire over any given ten year period, that implies an average service period of 42 years for all employees;

Not confirmed. The calculation assumes that the workforce is hired at a consistent rate of hire year over year and that the age at the time of hiring is the same for all employees.

b. If 20% of employees retire over any given ten year period, that implies an average service period of 50 years for all employees;

Not confirmed. The calculation assumes that the workforce is hired at a consistent rate of hire year over year and that the age at the time of hiring is the same for all employees.

4.0-Staff-35 - Actuarial Report

Ref: Exh 4-4-1 Attachment 7

On page 2 of the actuarial report as at January 1, 2011 provided by Dion Durell, it states that "Pursuant to Appendix section D10 of IFRS 1 (First-Time Adoption of IFRS), the attached results are prepared based on the understanding that the Corporation will book an adjustment for all unrecognized actuarial gains and losses at the date of transition to IFRS, i.e. January 1, 2011."

Please confirm that Bluewater Power has booked the adjustment for all unrecognized actuarial gains and losses on January 1, 2011 as suggested by Dion Durell. If not, please provide Bluewater Power's plan in terms of the unrecognized actuarial gains and losses at the date of transition to IFRS.

This actuarial report was first prepared by Dion Durrell on November 16, 2011. Since that point in time, Bluewater Power has elected to defer adoption of IFRS until 2014 as discussed in the response to Energy Probe #2. Therefore, no adjustment has been made for unrecognized actuarial gains and losses.

It is noted that under IFRS this transitional one-time adjustment will ultimately end up being a reduction to shareholders' equity due to the required increase to the Employee Future Benefit Obligation liability. Based on the updated actuarial report received late in 2012 for CGAAP, this adjustment would be in excess of $2 million (the unamortized actuarial loss), which is significantly higher than Bluewater Power's materiality threshold.

If the conversion to IFRS never occurred, then this unrecognized actuarial loss would eventually form part of the employee benefit obligation expense, which is included in the OM&A that is recovered from ratepayers both now and in the future. If this one-time adjustment under IFRS was made, then this entire amount would never be collected from ratepayers in future rates under current rate-setting mechanisms.

Therefore, in order to preserve the fair and equitable treatment between Bluewater Power's shareholders and ratepayers, and the intergenerational equity between current and future ratepayers, Bluewater Power will be requesting a deferral account in the future that will coincide with the timing of when the transition to IFRS occurs. At this point, this is likely to be in 2014.

The request for a deferral account will be pursuant to the discussion in the Addendum to the Report of the Board issued June 13, 2011 regarding Implementation of IFRS in an IRM environment (EB-2008-0408). On page 24, it states that "Individual utilities that can demonstrate the likelihood of large variances can seek an individual variance account from the Board."

4.0-Staff-36 - Transfer Pricing

Bluewater Power contracted with BDR North America Inc. to review its transfer pricing practices and methodologies. What changes, other than allocating certain Board of Director costs to affiliates, were implemented as a result of the review?

The changes that were implemented as a result of the review undertaken with BDR North America can be summarized as follows:

1) Increase the cost allocated for management services to affiliates. The analysis carried out for the response to VECC IR #38 demonstrates a 47% increase in management related services from 2009 to 2013. The increase was the result of a thorough review of every management position providing services to affiliates. Although some allocations decreased to better reflect management's judgement of time spent on affiliates, on balance the primary drivers of the increase were as follows:
    a. Approximately $20,000 increase in the allocation to affiliates in 2013 in relation to time spent by HR and IT.
    b. The increase in management fee (heading of Exectuvie, Functional Management, Finance, Payroll) of $30,000 is primarily driven by an increase in the allocation of costs from Finance and Payroll.
    c. Allocation for the Fleet Mechanic was increased to reflect the growth in the each fleet owned by the affiliates.
2) There was a change to the methodology used to allocated executive and management time. This did not impact the quantum allocated to affiliates for executive and management (as discussed above there was a significant increase). The change in methodology is discussed in the response to VECC IR #44.

3) Water Billing: The allocation of costs for the Water Billing function was reviewed. These costs had been reviewed in 2011 when the Water Billing function began to be performed by BPSC for the municipalities instead of directly by Bluewater Power for the municipalities. The adjustments to allocation were driven by these operational changes (further discussed in the response to VECC IR #43), and those operation changes are the primary driver of the variance. We note, however, three changes in methodology that impacted 2013 that were reviewed as part of the Transfer Pricing Study:
    a. Previous allocations included a portion of the cost for billing representatives, but in 2013 no time is allocated to reflect the conclusion that the full-time Billing Representative employed by BPSC performs all water-billing related functions.
    b. Direct management for water billing previously included approximately $10,000. An allocation continues to be made for management, but is included in the Functional Management discussed above.
    c. The methodology for allocating a Return on Invested Capital for the billing system was re-evaluated, the result of which was an allocation of $55,402, which was within 1.2% of the previous allocation.
4) The methodology for determining rent was updated using market rents. The result was a decrease in rent charges from $22,800 in 2012 to $17,200 in 2013.
5) Labour charges on all allocations were updated to include an uplift to account for the office space, I.T. support and H.R. support for each position.

4.0-Staff-37 - PILs consistency with Smart Meter application

Ref: Exh 4-8-3 Attachment 1

The Board issued the decision for Bluewater Power’s smart meter application (EB-2012-0263) on October 18, 2012.

Please confirm whether the 2013 PILs model submitted with the current application is consistent with the tax treatment related to smart meters as presented by Bluewater Power in the smart meter draft rate order submitted on October 23, 2012. If not, please update.

Confirmed.

4.0-Staff-38 -PILs adjustment

Ref: Exh 4-8-1

Bluewater Power is proposing an adjustment of $92,369 related to the 2013 addition of smart meter software to the 2013 PILs calculation. The adjustment amount is calculated based on Bluewater Power's final spending on smart meter software of $770,255 in the year 2012. For PILs purpose, the capital expenditure of $770,255 was included in the smart meter model as a Class 12, resulting in a one-time tax saving of $123,158 in 2013.

Bluewater Power claims that the adjustment is required because the $123,158 grossed-up tax savings is a one-time tax savings pertaining to the 2013 test year only and without the adjustment it would result in a total under-recovery of $369,474 ($123,158 over 3 years) of grossed-up PILs.

In the 2013 PILs model, it is noted that there is a total addition of $993,685 for class 12 computer software on Schedule 8 CCA for 2013.

a) Please update the figure of $770,255 with the Board approved amount for smart meter application in EB-2012-0263 and update the adjustment amount accordingly.

Bluewater Power's smart meter application EB-2012-0263 was approved with the OEB's Decision and Order dated October 18, 2012. This decision approved Bluewater Power's smart meter capital expenditures in their entirety. Therefore no adjustments are required to the $770,255.

b) Please explain why Bluewater Power would not be able to claim CCA on the 50% of the smart meter software in its 2014 tax return based on the half–year rule prescribed by Canada Revenue Agency.

The remaining capital expenditure of $770,255 relating to smart meter software was incurred in 2012. Nothing was capitalized in 2013 relating to smart meters. Therefore, the $770,255 is allocated to Class 12 (100% CCA rate) in 2012. Due to the half-year rule, the first 50% (being $385,128) forms part of the total CCA deduction in 2012, and the remaining 50% forms part of the total CCA deduction in 2013. Therefore, there is nothing to claim in 2014.

c) Please confirm that smart meter software is included in the total addition on schedule 8 CCA for 2013. If so, please provide the reasons why the PILs treatment of smart meter software should be different than any other software addition for the test year.

There are no smart meter software expenditures budgeted in 2013 and thereafter. Bluewater Power's smart meter project was completed in 2012. Therefore, the 2013 additions to the UCC Class 12 'Computer Software' do not include anything related to smart meters.

d) Please provide any regulatory precedence of adjusting the PILs provision to spread out the tax savings over the IRM period.

As discussed in Bluewater Power's evidence on page 1 in Exh 4-8-1, this treatment is no different than certain one-time costs that are spread evenly over the IRM period. In fact, one-time savings are technically negative one-time costs, which are typically amortized over the IRM period (i.e. application costs). It would be asymmetrical to amortize one-time costs and not amortize one-time tax savings. Furthermore, if this treatment was not done, it would result in unfair and unjust rates during the IRM period, since rates during the IRM period would be deficient by assuming savings that do not exist.

e) Bluewater Power's proposal with respect to the PILs adjustment reflects a 4 year period, consistent with 3rd generation IRM. The *Report of the Board – Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, states, "The Board has determined that the term for 4th Generation IR will be five years (rebasing plus 4 years)." Has Bluewater Power considered the impact of this change to a five year term and how it will affect the proposal in the current application? If yes, please explain.

Not applicable. Please see response to part (a) of question '2-Staff-4'.

4.0-Staff-39 - Tax Credits

Ref: Exh 4-8-3 page 3

Ref: Exh 4-8-3 Attachment 1

Bluewater Power states that it does not anticipate having any tax credits in 2013 and therefore no amounts are included in the final PILs calculation.

It is noted in the PILs tax provision calculation for historical year 2011 in the PILs model that $93,530 is included in the line of miscellaneous tax credits for the 2011 historical year but no miscellaneous credit amounts are included for 2012 bridge year PILs provision and 2013 test year PILs provision.

Please explain the nature of miscellaneous tax credits of $93,530 in 2011 and explain why the tax credits are not applicable for 2012 and 2013.

This was an oversight by Bluewater Power. When preparing the PILs model, no tax credits were assumed in 2012 and 2013 because it was thought that these credits only related to Investment Tax Credits (SR&ED). However, upon a more thorough review of the 2011 PILs return, the tax credits included other items in addition to SR&ED.

The 2011 tax credits of $93,530 are broken down as follows:

$30,691 – Federal investment tax credit from Schedule 31. This relates to a Scientific Research and Experimental Development (SR&ED) Expenditures claim. There will be no claims made in 2012 and 2013.

$1,101 – Provincial transitional tax credit from Sch 506. This relates to the difference in Provincial and Federal Schedule 8 UCC balances due to combining the T2 and CT23 corporate tax returns. This credit will continue in 2012 and 2013.

$4,875 – Provincial R&D tax credit from Sch 508. This relates to a Scientific Research and Experimental Development (SR&ED) Expenditures claim. There will be no claims made in 2012 and 2013.

$3,663 – Provincial co-op education tax credit from Sch 550. This relates to one to two lineman co-op placements of four months each. This will continue in 2012 and 2013.

$50,000 – Combined Federal and Provincial apprenticeship training tax credit from Sch 552. This relates to four linemen going through apprenticeship levels. These positions will continue in 2012 and 2013.

$3,200 – Provincial business-research institute tax credit from Sch 568. This relates to an expenditure made to the University of Western Ontario. This was a one-time expenditure in 2011. There will be no claims in 2012 and 2013.

Revised 2012 and 2013 Credit Amount

As per above, the revised credit amount will be $54,764 ($1,101 + $3,663 + $50,000) and the 2013 test year PILs model has been updated accordingly.

Bluewater Power has incorporated this PILs change into the revised revenue requirement, into the RRWF and the bill impacts presented in the response to these interrogatories

4.0 - EP 17 - Capitalization and Reallocation

Ref: Exhibit 4, Tab 1, Schedule 1, Table 2

a) Do the figures in Table 2 represent year-end figures of monthly averages for the year?

The figures in Table 2 do not represent year-end figures of monthly averages for the year. The figures are annual year-end amounts.

b) Please update Table 2 to reflect actual data for 2012.

The 2012 'actual' amounts in the following table are draft results at the time of writing.

Table 2 Draft Revised - Capitalization and Re-Allocations to Produce Net OM&A

	2013 MIFRS	2012 MIFRS	Actual 2012 IFRS	Actual 2012 GAAP	2012 CGAAP	2011 CGAAP	2010 CGAAP	2009 CGAAP
Gross	15,711,043	14,438,654	15,127,129	15,127,129	14,438,654	14,322,274	13,634,580	12,008,204
Reallocation to Affilaites	(417,763)	(392,786)	(310,000)	(310,000)	(392,786)	(541,277)	(538,018)	(557,724)
Reallocation OPA	(97,783)	(111,004)	(172,636)	(172,636)	(112,088)	(118,925)	(97,195)	(56,748)
Capitalized internal	(1,885,900)	(1,794,670)	(1,679,254)	(1,679,254)	(1,794,670)	(1,179,969)	(1,138,338)	(905,826)
Smart Meter	0	(364,078)	(334,499)	(334,499)	(364,078)	(437,088)	(240,673)	(15,159)
Billable	(165,229)	(227,815)	(165,514)	(165,514)	(227,815)	(289,520)	(486,436)	(203,766)
Overhead	(65,541)	(90,364)	(55,084)	(1,188,679)	(1,350,608)	(692,035)	(879,100)	(496,797)
Net OM&A	**13,078,827**	**11,457,937**	**12,410,143**	**11,276,547**	**10,196,610**	**11,063,459**	**10,254,821**	**9,772,184**

c) If Table 2 does not represent year-end figures, please show the year-end FTE counts for 2012.

Not applicable. Table 2 represents annual year-end figures.

4.0 - EP 26 - Depreciation Expense Policy

Ref: Exhibit 4, Tab 7, Schedule 1

The evidence indicates that Bluewater Power's historical accounting practice is to commence recording depreciation expense in the month an asset enters service. However, the depreciation expense calculated for 2011 in Attachment 1 appears to show the use of the half year rule to arrive at the total for depreciation.

a) Has Bluewater Power adjusted the depreciation rates shown in Attachment 1 in order to balance the depreciation calculated using the half year rule with its practice of recording depreciation expense in the month an asset enters service?

Bluewater Power confirms that the depreciation rates were adjusted in order to balance the schedule. This was facilitated by modifying the values in the column labeled “Years”. By doing so, the Depreciation Rate in the next column was automatically updated by the worksheet.

b) If the response to part (a) is no, please reconcile the calculation shown in Attachment 1 with the written evidence and explain how the two different methodologies arrive at the same depreciation expense.

Not applicable.

4.0 - EP 27 - PILs

Ref: Exhibit 4, Tab 8, Schedule 1

a) Was the tax savings related to the CCA deduction in 2012 related to the smart meter software reflected in the amount of the final disposition of the smart meter costs in EB-2012-0263?

Bluewater Power confirms that the tax savings related to the 2012 CCA deduction for smart meter software of $385,128 was reflected in EB-2012-0263.

To reiterate the discussion in Exh 4-8-1, this 2012 CCA deduction is the first 50% of the total 2012 smart meter software expenditure of $770,255 with the remaining 50% to be deducted in 2013.

b) Please confirm that Bluewater Power will have increased CCA claims over the IRM period associated with all capital expenditures in those years.

For normal and recurring capital expenditures, this is likely the case. However, whether there is increased CCA claims would depend on the CCA class, amount of additions if any, and amount of disposals, if any.

For abnormal and non-recurring capital expenditures, this might not be the case. For example, if there is an addition to Class 12 (100% CCA rate) in 2013, but none in subsequent years, there would be no CCA claims for Class 12 in 2015 and beyond.

c) Please confirm that Bluewater Power will have increased CCA claims in 2014 and subsequent years because of the all of additions in 2013 as a result of the half year rule being applied in 2013.

Same answer as part (b) above.

d) Please provide an estimate of the CCA claim for each of 2014, 2015 and 2016 based on the current capital expenditures forecast for each of these years. Based on this forecast, what would be the amount associated with the PILs calculation if these amounts were amortized over four years to reduce current rates to customers?

An estimate of the CCA claim for 2014, 2015 and 2016 related solely to the forecasted additions in each of those years are:

2014: $1,089,795
2015: $1,187,970
2016: $1,187,970

Bluewater Power does not believe there is any probative value to the second part of this question. If these CCA amounts for each of these three years were amortized over four years, it would effectively reduce the CCA claim in each of those years versus what it would have otherwise been. By doing so, the resulting CCA deduction is less, which would result in a greater level of PILS to be recovered from ratepayers. Only in the fourth year would there be four years' worth of amortized CCA amounts to arrive at an 'annualized' CCA amount.

e) What is the NBV amount included in the test year rate base associated with the smart meter software?

For smart meter software, the December 31, 2012 NBV amount included in Account 1611 “Computer Software” is $2,499,712 as per Exh 2-3-2 Attachment 2 – Appendix 2-B “2013 MIFRS (Details)”. All smart meter capital amounts from EB-2012-0263 were ‘capitalized’ to asset accounts effective December 31, 2012.

For smart meter software, as filed, the December 31, 2013 MIFRS NBV amount included in Account 1611 “Computer Software” is $1,873,727 ($2,499,712 less $625,985 MIFRS depreciation in 2013). There were no smart meter software additions in 2013.

Upon further investigation, it has been determined that this NBV amount is incorrect because the 2013 MIFRS depreciation figure of $625,985 for smart meter software is incorrect. In fact, all 2013 MIFRS depreciation amounts pertaining to all smart meter capital costs were calculated incorrectly (software, hardware, meters, and equipment). The new deemed cost (NBV) amount brought in at the end of 2012 was incorrectly depreciated on a 5 year straight-line basis to calculate the 2013 depreciation amount. It should have been depreciated over the remaining useful lives, which are a shorter period.

As an example, a smart meter asset that cost $600,000 in 2010 that had 2.5 years depreciated (for a 5 year life) by the end of 2012 would have had a NBV of $300,000. This $300,000 amount was divided by 5 years to determine the incorrect 2013 MIFRS depreciation amount of $60,000. The depreciation should have been calculated by taking the $300,000 over 2.5 years (or $600,000 over 5 years since the useful life did not change between CGAAP and MIFRS) which would have calculated the correct 2013 depreciation amount of $120,000. Thus, in this example, depreciation was understated by $60,000 in 2013.

When recalculating the 2013 MIFRS depreciation for all smart meter capital assets, the correct total amount is $1,089,067. The previous incorrect amount was $958,007. Thus, an understatement in the originally filed depreciation amount of $131,060. Contained within these totals is the smart meter software. The correct 2013 depreciation amount is $707,106 and the previous incorrect amount was $625,985, resulting in a shortfall of $81,121.

Therefore, the corrected December 31, 2013 NBV of smart meter software is $1,792,606 ($2,499,712 less $707,106 MIFRS depreciation in 2013). Again, no additions in 2013.

Therefore, the amount included in the test year rate base is the average of these two amounts, being $2,146,159 (average of $2,499,712 + $1,792,606).

Bluewater Power has incorporated this correction into the revised revenue requirement, into the RRWF and the bill impacts presented in the response to these interrogatories.

f) What is the depreciation expense included in the revenue requirement for the test year associated with the smart meter software?

The corrected amount is $707,106. See response to part (e) above.

g) Please provide the NBV amount for each of 2014, 2015 and 2016 associated with the smart meter software.

2014: $1,090,340 (2013 NBV $1,792,606 – 2014 depreciation $702,266)
2015: $447,827 (2014 NBV $1,090,340 – 2015 depreciation $642,513)
2016: $77,025 (2015 NBV $447,827 – 2016 depreciation $370,802)
2017: $NIL (2017 depreciation is $77,025 remaining from 2012 addition)

h) Please provide the depreciation expense for each of 2014, 2015 and 2016 associated with the smart meter software.

2014:	$702,266
2015:	$642,513
2016:	$370,802

4.0 - EP 28 - PILs and tax credits

Ref: Exhibit 4, Tab 8, Schedule 3

a) Please explain why Bluewater Power believes that the $91,220 associated with account 1575 should be added to the depreciation expense for PILs purposes?

The Account 1575 adjustment to depreciation of $91,220 per the rate application will be recorded in the income statement as depreciation expense. This is why Bluewater Power has included this amount as an addback to depreciation expense on Schedule 1 of the PILs Model. It is to match the total depreciation included in rates, and therefore distribution revenue. Since the PILs model is intended to be a proxy calculation, Bluewater Power believes that it is reasonable and rationale that the $91,220 be an addback of depreciation expense.

b) Did Bluewater Power have any tax credits in 2011 or 2012, such as the SR&ED Tax Credit, Federal Apprenticeship Job Creation Tax Credit, the Ontario Co-Operative Education Tax Credit or the Ontario Apprenticeship Training Tax Credit? If so, please provide the actual amount for each of the credits.

See Bluewater Power's response to OEB staff IR# "4-Staff-39".

c) If Bluewater Power did have any of the tax credits noted in part (b) above, please explain why no tax credits have been forecast for 2013.

See Bluewater Power's response to OEB staff IR# "4-Staff-39".

d) Please provide the number of positions eligible for each of the tax credits noted in part (b) related to job creation, apprenticeship training and co-operative education.

See Bluewater Power's response to OEB staff IR# "4-Staff-39".

4.0 - EP 29 - CCA Classes

Ref: Exhibit 2, Tab 3, Schedule 2, Attachment 2 &
Exhibit 4, Tab 8, Schedule 3, Attachment 1

a) It appears that in both 2012 and 2013 that Bluewater Power has put computer equipment - hardware (account 1920) into CCA Class 10 rather than Class 50. Please explain.

This was an oversight by Bluewater Power caused by referring to the Class 10 description 'Computer Hardware/Vehicles' on Schedule 8 of the PILs model. Bluewater Power recognizes that additions relating to Account 1920 should be in CCA Class 50.

b) Did Bluewater Power claim computer equipment - hardware (account 1920) as CCA Class 10 or 50 in its 2011 PILs filing?

Bluewater Power's 2011 PILs filing correctly recorded additions from Account 1920 in CCA Class 50.

c) Please provide the change to the 2013 test year CCA claim if the capital expenditures in account 1920 for both 2012 and 2013 are put in CCA Class 50 rather than Class 10.

The originally filed 2013 test year CCA claim for Class 10 was $908,787 and Class 50 was $86,999 for a total $995,786 for these two CCA classes.

The addition to Account 1920 in 2012 is $1,122,129 and in 2013 is $912,840.

By adjusting Account 1920 additions in both 2012 and 2013, the revised 2013 CCA claim (before any other adjustments) for Class 10 is $485,718 and for Class 50 is $785,479 for a total of $1,271,197 for these two CCA classes.

Therefore, the correction to the 2013 test year CCA claim is an increase of $275,411 relating to these two CCA classes.

Bluewater Power has incorporated this correction into the revised revenue requirement, into the RRWF and the bill impacts presented in the response to these interrogatories.

d) Please explain why the costs in account 1908 (buildings and fixtures) have been put in CCA Class 1 in both 2012 and 2013 rather than in Class 1 Enhanced. Do the expenditures in account 1908 in 2012 qualify to be in CCA Class 1 Enhanced? If no, please explain fully.

Bluewater Power was not aware that it qualified for CCA Class 1 Enhanced. It was previously thought that only purchases of buildings qualified, not building additions. Upon further review, it is apparent that building additions do qualify; therefore the building addition in 2012 should be reclassified in Schedule 8 accordingly for both 2012 and 2013. No other expenditures in Class 1 would qualify.

Therefore, of the total Account 1908 additions in Schedule 8 of $2,178,441 in Class 1 for the 2012 bridge year, $2,022,198 relates solely to the building addition (excluding furniture) which is confirmed on Exh 2-4-3, Attachment 4. This amount has been reallocated to 'Class 1 Enhanced' with a total CCA rate of 6% in 2012. Similarly, this carries through to Schedule 8 of the 2013 test year.

Bluewater Power has incorporated this correction into the revised revenue requirement, into the RRWF and the bill impacts presented in the response to these interrogatories.

4.0 - VECC 38 - 2009 to 2013 charge to Affiliates

Reference: Exhibit 4, Tab 5, Schedule 1, Attachment 2 – BDR Study of Affiliate Services

a) Please provide the 2009 and 2013 charge to affiliates for each time listed in Table ES:1 of the BDR study (pgs. 4-5).

Please see Table 1 below, which utilizes the headings under the column “Nature of Service” taken from Table ES:1 in the Transfer Pricing Study. Adjacent to each service description we have provided the associated charges to affiliates based on 2009 Actuals and 2013 Test Year.

Most of the costs indicated are not materially different between 2009 and 2013, but we note the following key points from this comparison:

- The total for all management related services (Executive, Functional Management, Finance, Payroll, Human Resources and IT Labour) has increased by 47% from 2009 ($127,144) to 2013 ($186,938).
- Meter reading labour allocated to non-distribution accounts in 2009 is not found in 2013 because the affiliate employs its own meter readers so no cost allocation for water meter reading is required.
- Likewise, the billing administration labour allocated to non-distribution accounts in 2009 is not found in 2013 because the affiliate employs its own Billing Clerk so no cost allocation is required for water billing administration.
- The items labelled as Warehouse Services, Vehicle Usage and Shared Employees are driven entirely by the level of demand and 2009 was a high demand year for non-distribution work.

Table 1 – Services Provided by BPDC to Affiliates

Table ES:1 - Services Provided by BPDC to Affiliates

Nature of Service	2013	2009
Executive	24,805	124,087
Functional Management	53,975	
Finance services other than payroll	66,803	
Payroll	9,652	
Call center labour	49,237	47,589
Meter Reading	-	89,793
Cashier labour	25,459	16,974
Stationery and consumables for billing	3,980	5,652
Bill mailing, envelopes and postage	19,724	24,228
Billing Administration	3,094	101,928
Building	14,400	34,212
Human Resources	21,613	1,018
IT Labour	10,090	2,039
SAP Expenses	20,871	18,356
SAP Capital	55,402	62,244
Work Stations and Communications Equipment	1,520	2,277
Warehouse Service	2,800	9,584
Vehicle Usage	50,176	85,675
Shared Employees	116,490	172,057
TOTAL	**550,091**	**797,714**

4.0 - VECC 39 - Affiliate Loans

Reference: Exhibit 1, Tab 2, Schedule 8 – Attachment 1 /Exhibit 4, Tab 5, Schedule 1, Attachment 2

a) For each affiliate please identify whether letters of credit or other loan guarantees are provided; the maximum exposure of the facility and the amount of compensation received by BWP annually for providing this service.

Bluewater Power has letters of credit aggregating $50,000 in favour of Bluewater Power Services Corporation and Electek Power Services Inc. Bluewater Power is also a guarantor of a $500,000 credit facility for Bluewater Power Services Corporation. See Exh 1-3-1, Attachment 1, Note #8. Bluewater Power receives no annual compensation for providing this service.

Please also refer to Exh 1-2-8, Attachment #1, page 6 of 9.

b) Please provide the price and cost for all services listed under section 4.4 “Finance” of the BDO study

For the 2013 test year, both the price and cost is $76,455. This amount can also be found in the response to 4-VECC-38. The $66,803 is ‘Finance excluding payroll’ and the $9,652 is ‘payroll’, totalling $76,455.

4.0 - VECC 40 - Affiliate Loan Rate

Reference: Exhibit 1, Tab 2, Schedule 8 – Attachment 1 /Exhibit 4, Tab 5, Schedule 1, Attachment 2

Please provide evidence that the loans provided to each affiliate were at a rate which was competitive with what that affiliate may have acquired on a stand-alone basis.

There are no loans between Bluewater Power and its affiliates for 2013. The loan identified by the OEB Compliance Office and discussed in the Audit Review of Compliance dated August 2012 (Ex. 1-2-8, Attachment 1) was retired on December 31, 2012. Therefore, there are no affiliate loans relevant to this 2013 Rebasing Application.

We note that the loan identified by OEB Staff as non-compliant was addressed in the Management Response (at page 5 of 9) as follows “The interest rate selected was marginally less favourable to the affiliate than the interest rate applicable at the time so the utility and its customers were protected at all times.” Therefore, while technically a non-compliance existed, the evidence that was produced demonstrated that the affiliate did not receive an advantage at the expense of the distribution company.

4.0 - VECC 41 - Affiliate Insurance policies

Reference: Exhibit 1, Tab 2, Schedule 8 – Attachment 1/Exhibit 4, Tab 5, Schedule 1, Attachment 2, section 4.5 pg. 15. -BDR Study of Affiliate Services.

a) Please provide a list of insurance policies acquired by BWP Distribution which also cover any affiliate, the annual premiums paid by BWP and the amount of annual premium contributions paid by the affiliate (i.e. all costs referred to in Section 4.5 of the BDR Study).

Bluewater Power and all of its affiliates receive Comprehensive Commercial Liability from MEARIE (Electek joined MEARIE in 2012 for the first time). The premiums paid are based on a rate set by MEARIE multiplied by the company's forecast revenue, with a $1,000 minimum charge. The rate charged by MEARIE to Bluewater Power and its affiliates is the same rate, except to the extent that any premium reduction offered by MEARIE (as discussed in response to VECC IR #32) is applied to Bluewater Power's premium only. It is the Premium Reduction in 2012 that explains the variance with 2013.

As explained in the BDR Study, the premiums applicable to each affiliate are separately identified by MEARIE in its invoice. As a result, except for the decision to allocate the premium reduction entirely to Bluewater Power, the costs of this coverage as set out in the invoice was directly assigned to the affiliates.

Comprehensive Commercial Liability Insurance for:	2012	2013
Bluewater Power	$57,176	$76,466
BPSC	$2,538	$1,551
GenCo	$1,000	$1,000

RenewCo	$1,000	$1,000
Electek	$2,059	$1,701

Vehicle insurance coverage is obtained jointly for Bluewater Power, BPSC, and RenewCo. Electek's vehicles are insured under a separate policy directly between Electek and a local brokerage. GenCo does not have any vehicles. The premiums are based on vehicle count and are allocated to each company based on the same premium per vehicle for Bluewater Power and each of its affiliates. The figures paid by each company for 2012 and 2013 are as follows.

Vehicle Insurance for:	2012	2013
Bluewater Power	$23,669	$25,567
BPSC	$6,365	$5,583
RenewCo	$539	$539

4.0 - VECC 42 - Streetlighting mark-up

Reference: Exhibit 4, Tab 5, Schedule 1, pg.11

a) The evidence states that pass-through billing for BPSC street lighting work is performed with "no mark-up". The evidence also states that costs in this area are 80k in 2013. Why does BWP provide this service without a mark-up?

Bluewater Power incurs very minimal costs to provide the billing service. There is only one invoice received from the Services affiliate once the streetlight installation work is done in a new subdivision. This invoice is then added to Bluewater Power's invoice for its installation of the distribution plant for the new subdivision. The developer then only receives one invoice from Bluewater Power with the two amounts clearly indicated. The total of all invoices from the Services affiliate in the 2013 test year is the $80K referred to in this question. This might only represent 3 or 4 new subdivisions depending on their size.

The costs for this billing service forms part of the 'Management Services' cost allocation, as per Exh 4-5-1 page 6, that is passed on to the Services affiliates. To impose a mark-up to the developer would result in Bluewater Power double recovering for its costs.

b) Please also explain if developers interact directly with BPSC for streetlight installation or only with BWP employees.

A developer signs a contract with Bluewater Power's Design Services manager with respect to the installation of distribution plant in a new subdivision. At that time, the developer is also provided with a quote by the manager who coordinates any possible streetlight installation work on behalf of the Services affiliate. The developer always has the right to hire someone else to do this work. Similar to part (a) above, the cost of this Bluewater Power manager is captured under the 'Management Services' cost allocation.

If the developer chooses to have the Services affiliate perform the streetlight installation work, most interactions are conducted with the Bluewater Power Design Services manager. However, at times, there will be some interactions with the employees from the Services affiliate once work begins in the field. For the most part, the developer will coordinate any changes or requests through their engineering consultant for the development who will then interact with Bluewater Power's Design Services manager.

4.0 - VECC 43 - Water Billing Services

Reference: Exhibit 4, Tab 5, Schedule 1, Attachment 1

a) In 2013 the price and cost of water billing services to BPSC are forecast at $123,885. In 2009 the price and cost of this service was $668,022 and $459,979 respectively. Please explain the reason for the significant lowering of both costs and price.

In 2009, water billing services were performed by Bluewater Power directly for the City of Sarnia and the Town of Petrolia. The costs referenced above for 2009 are the total of all costs incurred by Bluewater Power and allocated to non-utility accounts. The contract with the municipalities expired in 2011 and a new contract entered into between BPSC with the City of Sarnia and the Town of Petrolia. At that time, a water billing clerk was transferred from Bluewater Power to BPSC, thereby reducing the costs incurred within Bluewater Power related to water billing. Until 2012, when Smart Meters were introduced, the costs associated with the equivalent of 2 FTEs and associated equipment for meter reading continued to be incurred within Bluewater Power, but were allocated to BPSC for meter reading. In 2012 on the introduction of Smart Meters for electricity, the meter readers and equipment related to the reading of non-Smart Meters were transferred permanently to BPSC. As a result, no costs related to the reading of water meters are now incurred within Bluewater Power.

The variance in the numbers reflected in the question reflects the change in the structure of the relationship. The price and costs in 2009 include all revenues and costs, whereas to the price and the cost in 2013 as incurred and charged by Bluewater Power exclude the costs of the water billing and metering resources that now reside in BPSC. Bluewater Power continues to provide certain services to BPSC to support water billing (ie shared billing system, shared Customer Service Representatives, shared postage and envelopes, etc.). These costs and their recovery through charges to BPSC are the amounts shown for 2013.

For clarity, in 2013, the costs of BPSC to provide water billing services include the charges from Bluewater Power as well as costs incurred directly by BPSC. The costs directly incurred by BPSC include a Billing Representative, meter readers, vehicles and equipment. In computing the total cost of water billing services, BPSC also allocates a portion of the administrator (a BPSC employee), and of the management services charge allocated to BPSC by Bluewater Power. These allocations are mentioned here to complete the explanation of the relationship between the figures referred to in the question.

4.0 - VECC 44 - Executive and Management Time on Affiliates

Reference: Exhibit 4, Tab 5, Schedule 1, Attachment 2 – BDR Study of Affiliate Services.

a) Section 4.2 states that the executive group estimated that they spend 200 hours annually on affiliate activities (pg. 12). Please confirm that this amount is 200 hours in aggregate for the 9 executive positions or whether this is meant as 200 hours per executive.

The 200 hours is in aggregate for day-to-day activities, but this allocation is not for the 9 members of the executive. The 200 hour aggregate amount is for the five members of the executive who do not have direct management responsibilities (i.e. CEO, Finance, Legal, HR and IT). These are the positions referred to as "Executive" and discussed in Section 4.2 of the BDR Study. Another 500 hours is allocated for day-to-day activities for the other four members of the executive with more direct management responsibility for operational groups within the affiliates. These are discussed in Section 4.3 of the BDR Study as "Functional Management".

A further allocation of 100 hours has been budgeted in 2013 as the estimate for "project work" that is in addition to day-to-day work for these five executives and four functional managers, and that will be determined on an actual basis by a time log.

b) What is the basis for allocating Management time to affiliates (see section 4.3 pg. 13-14). Why does Bluewater not use time logs for management activity related to affiliates? Is it planning to use time logs in 2013?

Section 4.3 of the BDR study addresses allocation of the time for the 4 members of the executive team who spend direct management time for the affiliates. The approach taken is the same approach as described in part (a) for the 5 executives whose work for affiliates is indirect. The total allocation consists of a day-to-day component, which is estimated separately for each executive, and a special project component, which has been budgeted for 2013 but which will be determined on an actual basis through a time log. The methodology is therefore a combination of estimation (for the functions that are routine and, on average, predictable) and time tracking (for special initiatives that are less predictable and vary from year to year as to magnitude).

Therefore the answer is yes, Bluewater Power does plan to use time logs in 2013, but only for the component of their work for affiliates that for each year is a unique portfolio of special projects. For the day-to-day responsibilities of management, Bluewater Power proposes to use an allocation based on the estimate of time spent annually on these tasks. The basis for this decision is that this component of work, while variable from day to day or week to week, is in aggregate consistent and predictable from year to year. The related activities are carried out in a series of short time intervals (phone call, email, short meeting), carried out as needed and interrupted frequently. Therefore a requirement to maintain a detailed log of this time would impose a very high administrative burden relative to what, in Bluewater Power’s view, would be the improvement in accuracy of the allocation.

On page 12 of the Study of Affiliate Service Cost and Cost Allocations it is noted:

> “*The brevity, variety and fragmentation of executive and management activities has been documented extensively in the field of behavioural and management science.*

BDR therefore accepts that the nature of the activities caused BPDC management difficulty in identifying specific hours with specific activities and affiliates, particularly in regard to recurring management activities. Management judgement has therefore been applied, with a provision to record time for special non-recurring projects. A high level estimate has been used to budget time spent for the affiliates as a group. Since the costs could not be specifically identified with individual affiliate companies, management selected operating expenses as a measure of the level of activity in each company to be managed, and used it to allocate recurring functions among the companies other than BPDC,

In the absence of more specific data, it is BDR's view that management judgement is a reasonable basis of allocation of costs between BPDC and its affiliates as a group, and is consistent with accepted principles of cost allocation".

c) How many of the 8 management staff partake in affiliate activities? What was the total number of hours they allocated to affiliate activities in 2012?

All of the 9 executive and management staff whose activities are discussed in Sections 4.2 and 4.3 of the BDR Study are involved with the management of the affiliates, and the allocation of costs related to their involvement for 2013 is elaborated in the answer to (a) and (b) above. For the year 2012, the costs that are allocated to affiliates was based on a budgeted amount, but actual dockets were not kept for the reasons set out in the answer to (b) above. As noted in response to 4-VECC-38, the allocation of management-related costs from Bluewater Power to affiliates has increased by 47% in the 2013 Test Year.

4.0 - VECC 45 - SAP and water billing

Reference: Exhibit 4, Tab 5, Schedule 1, Attachment 2 – BDR Study of Affiliate Services?

Please confirm that none of the SAP capital investments made in 2010 through 2013 were unrelated to water billing. If this is not the case please explain what costs related to SAP changes/upgrades have been allocated to an affiliate in 2012 and 2013.

The relevant time period for this question is, in fact, broader than the dates requested by this Interrogatory. On that issue, the Transfer Pricing Study at Exhibit 4-5-1, Attachment #2, page 22, states:

"*The SAP system is depreciated on a straight-line basis over a five-year period, so that any capital expenditures incurred prior to 2009 would be fully depreciated by the Test Year (2013) and was therefore ignored for the analysis. Therefore, only capital projects between 2009 and 2013 were examined*."

In the period from 2009 to 2013, Bluewater Power has undertaken five projects in SAP that were determined to impact on Water Billing. Those projects can be described as follows:

1. 2009 - Technical Upgrade at a cost of approximately $170,000. The Technical Upgrade involved bringing the installed SAP software up to the latest version of the code. While there were no functional changes implemented in this project, there were base code changes that required testing and addressing where there was business process impact.
2. 2009 - Unicode Upgrade at a cost of approximately $210,000. This project converted the current installed SAP code to a Unicode standard. Unicode became an international standard in software code. It was necessary to move to this in order to implement SAP CRM, which was developed in the Unicode standard.

3. 2010 - CRM Upgrade at a cost of approximately $800,000. This project included the implementation of SAP's CRM Web-IC, which is the current version of the Customer Service software solution.
4. 2010 - Dunning Upgrade at a cost of approximately $526,000. This was the implementation of SAP's Flexible Dunning, which was a complete overhaul of the credit and collections functions.
5. 2010 - UCES (My Account) enhancement at a cost of approximately $250,000. Utility Customer Electronic Services was implemented as a customer facing online services portal.
6. 2012 - SAP Patching Project at a cost of approximately $25,000. This project was to implement the latest software and security patches to SAP.
7. 2012 and 2013 – Customer Service & On-line Bill Presentment enhancement at a cost of approximately $350,000. As an extension of the initial customer online portal, this project will enhance online customer services with a focus on a paperless billing offering to customers.

A portion of capital for each project was allocated to Water Billing based on the appropriate allocator to determine the cumulative capital investment for the 2013 Test Year. The Return of Invested Capital (ROIC) for that investment, as well as the depreciation on the investment was allocated to the ServCo affiliate providing Water Billing. The total allocation in 2013 was determined to be $55,402.

4.0 - VECC 46 - Valuation of storage for streetlighting inventory

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Reference: Exhibit 4, Tab 5, Schedule 1, Attachment 2 – BDR Study of Affiliate Services?

a) Please provide evidence that $4 per square foot is a competitive value for storage for affiliate street lighting and water meter inventory?

The rent for storage space on a square foot basis was based on knowledge of the local market.

4.0 - VECC 47 - Vehicle rental and hours for streetlighting services

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Reference: Exhibit 4, Tab 5, Schedule 1, Attachment 2 – BDR Study of Affiliate Services?

a) Please provide the type and number of hours for vehicle rentals affiliates in 2012. Please distinguish as between specialized vehicles (bucket truck etc.) and all other types of vehicles (i.e. car, SUV or pick-up truck).

Bluewater Power rents both ‘large’ trucks and ‘light’ trucks to its Services affiliate who carries out streetlighting services. Large trucks would include bucket, RBD and Digger-Derrick trucks. Light trucks include pick-ups and vans. No other types of vehicles are rented. Streetlighting service is comprised of both streetlight maintenance on an on-going basis, as well as installation of new streetlights on an as-needed basis.

In 2012, the total number of vehicle hours rented by the Services affiliate for their streetlighting services include 563 hours for bucket trucks, 24 hours for a digger-derrick truck, and 111 hours for a RBD truck. It also includes 45 hours for pickups and vans.

b) Please provide the number of hours charged out for street lighting services from BPD to affiliates in 2011 and 2012. How many employees at BPSC work on servicing street lighting?

The Services affiliate employs two full time employees who are dedicated to streetlighting services 100% of the time. The Services affiliate also has other employees who can assist during periods of high volume of street lighting work. As a result, it would not usually be the case that Bluewater Power employees would be called on to perform streetlighting services. No Bluewater Power employees charged out to the Services affiliate for streetlighting services in either 2011 or 2012.

4.0 - VECC 48 - Complaints in regard to alternative providers and subdivisions

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Reference: Exhibit 4, Tab 5, Schedule 1, Attachment 2 – BDR Study of Affiliate Services, pg. 26

a) Has Bluewater received any complaints over the last 4 years, or is aware of any complaints received by the Ontario Energy Board from alternative providers of street lighting or new subdivision customer connection work? If yes please provide details as to the nature of the complaint and how it was resolved.

We have not received directly, nor are we aware of complaints received by the OEB from alternate providers of street lighting or new subdivision customer connection work.

b) From 2009 to 2012 how many subdivision connections have been completed by BPSC and how many from alternative providers?

During the period from 2009 to 2012, BPSC completed 14 subdivision installations in the Bluewater Power distribution territory. During that same time period, the contestable portion of the subdivision installations was performed by an alternative provider on 2 subdivisions in the Bluewater Power distribution territory.

4.0 - VECC 49 - Electricity Meter reading by affiliate

Reference: Exhibit 4, Tab 5, Schedule 1, Attachment 2 – BDR Study of Affiliate Services, pg. 26-27

a) How many electricity meters are forecast to be read by the affiliate BPSC in 2013?

BPSC reads the monthly electric demand meters for Bluewater Power. There are approximately 430 reads each month, or 5,160 reads per year. This pertains to the GS>50 rate category only.

b) What is the cost per meter of reading?

These meters are not read in a sequential route as the neighbouring meters that are not demand meters are read on a bi-monthly basis or read electronically if they are Smart Meters. Therefore, the costs for reading these types of meters are substantially more per meter than historical meter reading when the efficiencies of sequential reading could be obtained. As an example, in Bluewater Power Distribution’s service territory, BPS must now drive approximately 40 minutes to obtain 6 reads that used to be incorporated within a route containing 700 additional meter readings for residential and small commercial customers prior to the installation of Smart Meters. The forecast cost per meter to read for the 430 monthly demand meters is approximately $6.78 per meter. Bluewater Power will undertake a cost benefit analysis for converting these demand meters to electronically read Sensus demand meters when the technology becomes available.

c) What was the cost per meter of reading in 2009 and before the installation of smart meters?

The cost per meter of reading these 430 meters in 2009 was approximately $1.80. This cost was achievable due to the ability to obtain reads in route order sequentially and by reading both water and electric meters simultaneously thereby providing the best possible efficiency in "foot" reading.

The cost per meter of reading before the installation of smart meters was approximately $1.90 in 2011, as we were still able to gain the best possible efficiency in "foot" reading by reading both electric and water meters simultaneously and in route order.

4.0 - VECC 50 - Electek jobs

Reference: Exhibit 4, Tab 5, Schedule 1, Attachment 2 – BDR Study of Affiliate Services, pg. 28.

a) Please provide the number and price of the contracts awarded to Electek in 2012?

There were 48 jobs completed by Electek for Bluewater Power in 2012. Only one contract was over the $10,000 criterion at a cost of $15,771.68. The 26 jobs can be broken into the following categories:

Table 1

Types of Work	Cost
Storm Restoration Work	$13,813.00
Watford Substation Capital Project	$42,254.00
Transformer Maintenance, Refurbishment and Capital Work	$37,676.00
Substation Maintenance, Refurbishment and Capital Work	$64,165.00
Breaker/Arc Flash Work	$16,200.00
Miscellaneous	$20,102.00
Total	**$194,210.00**

b) For all sole source contracts over $10,000 please provide the written explanation as to why sole sourcing is to occur (as per section 2.4.4. of the Procurement Policy).

The Watford Distribution Station Upgrade was sole sourced to Electek Power in the amount of $15,771.68. In accordance with Bluewater Power's Purchasing Policy section 2.4.4 Single Source Solicitations clause:

> *"When failure to receive the material or service by the required date will prolong an unsafe condition; adversely affect operation; cause a work stoppage; hardship to customers or additional financial costs."*

Bluewater Power single sourced Electek to perform work for the Watford Distribution Substation Upgrade in order to mitigate risk of adversely affecting operation that in turn would cause hardship to customers and additional financial costs. The service completed by Electek at the Watford DS was decommissioning and commissioning. Of the contractors potentially available to perform the work, only Electek was known by Bluewater Power to have personnel with significant knowledge of the legacy equipment at that DS. Being able to contract the work to staff already familiar with the equipment, and completing the administration related to the contract quickly, minimized risk and delay, and resulted in successful completion of the job in a timely manner.

1.0 - SEC 6 - Affiliate Transactions

[I/1/14] With respect to the accounting treatment of transactions with affiliates:

a. Please provide a table showing all amounts or value flowing to or from the Applicant from (or to) affiliates or shareholders (including shareholders of the parent company), and showing how each amount or value is being accounted for with respect to the Test Year. For any year prior to the Test Year in which the method of accounting for any part of the table is different, please provide a new table for that year, with the amounts or values for that year, and an explanation of the change from that prior year to the Test Year.

With respect to amounts flowing from the affiliates to Bluewater Power, please refer to the Table provided in response to SEC IR #13 which classifies the services consistent with the “Nature of Services” described in Table ES-1 of the Transfer Pricing Study. The table represents the same as the information presented in response to VECC IR #38, but further details the information by providing the costs broken down by affiliate.

With respect to the request to identify the changes in methodology for the Test Year and any year prior to the Test Year, we can confirm that no change in methodology has occurred, other than those addressed in the response to Board Staff IR #36. All other changes in allocations are driven by changes in structure (see discussion in VECC IR #43) or are driven by demand for the service required.

With respect to amounts flowing to the affiliates from Bluewater Power, we can refer to Appendix 2-N (Exhibit 4, Tab 5, Schedule 1, Attachment 1), which was updated to reflect 2012 (draft) Actuals for the response to SEC IR #13(a). In addition, we can refer to Table 1 in Exhibit

4, Tab 5, Schedule 1, which shows the 2013 Test Year compared to the 2009 Board Approved and the 2011 Actuals.

With respect to the request to identify the changes in methodology for the Test Year and any year prior to the Test Year, we can confirm that there were no material changes in methodology. The primary driver of any variance is the demand for the services. In that regard, we can refer to the note regarding the assumptions for the data presented for the 2013 Test Year that *"all charges from affiliates to Bluewater Power shown in Table 1 and Appendix 2-N, the amounts for 2013 Test Year have been set as reasonable estimates."* (Exhibit 4, Tab 5, Schedule 1, page 4). That is to say that Bluewater Power does not forecast capital work to be performed by affiliates for DistCo; the level of work performed by affiliates depends upon demand and availability. Accordingly, the amounts included as financial transaction between DistCo and affiliates during the Test Year include reasonable estimates of capital work rather than a specific forecast.

b. Please provide a fuller explanation, with numerical examples, of the "streetlight flow-throughs".

Before providing a more fulsome example as requested, it may be helpful to provide context on subdivision development in Sarnia-Lambton. We are a slow growth area and, therefore, the typical subdivision in our distribution territory is 20 lots along a single street. If the street is part of a larger development, the overall subdivision design is approved by the municipality and approved for development in phases.

The Developer would engage with Bluewater Power at the detailed design stage when a given phase is ready to be released for development. Bluewater Power's Engineering Department meets with the developer and the other utilities servicing the subdivision (municipality, Union Gas, Cogeco, and Bell) and services are typically installed in a joint-trench, with each utility ensuring its interests are protected. Bluewater Power prepares an Offer to Connect to the Developer, which includes an estimated cost for the electrical connection to be performed by

Bluewater Power and the estimated cost for the civil work (trenching, laying wires and installing but not connecting streetlights) to be carried out by the affiliate (BPSC).

If a developer does not select a third-party provider for the contestable work, then payment is received by Bluewater Power along with the requisite deposits. BPSC carries out the civil work under the supervision of Bluewater Power's Engineering Department and Bluewater Power makes all electrical connections. BPSC issues an invoice for its services to Bluewater Power and the utility includes that invoice without mark-up for recovery from the Developer. Bluewater Power is also compensated for its engineering time, including supervision of construction, and the cost of carrying out the electrical connections.

On a twenty lot subdivision, the total cost would be approximately $78,000 to install the distribution plant and streetlights. Of that amount, BPSC would typically charge $20,000 for civil work and $18,000 for the installation of streetlights. Bluewater Power would be compensated for its internal costs which would typically represent $2,000 for engineering and $38,000 for the distribution plant installed and for carrying out the electrical connections.

1.0 - SEC 13 - Affiliate Invoices

[1/2/8] With respect to each of the affiliates from or to which the Applicant receives or provides goods or services, or with whom the Applicant shares costs, please provide:

a. The last twelve monthly invoices from the Applicant.

b. The last twelve monthly invoices to the Applicant.

The information requested by Interrogatories 13(a) and (b) would result in a substantial number of individual invoices being placed before the OEB. More meaningful and material information can be provided that is consistent with the level of detail provided in Appendix 2-N. An updated Appendix 2-N that reflects 2012 Draft Actuals is found in Attachment #1 to this interrogatory.

c. A detailed reconciliation of the amounts forecast to be paid, received or shared with respect to the affiliate, to the schedule of the Cost Sharing or Management agreement that sets out the fees and charges.

The amount received or shared between Bluewater Power and its affiliates that is included in the 2013 Test Year is based on the amounts set out in the Cost Sharing Agreements and Management Services Agreements disclosed in the pre-filed evidence. Therefore, there should be no reconciliation required. In making that statement, we note that the agreements include fixed amounts based on management judgment of appropriate cost sharing for those costs expected to be consistent year-over-year, which were reviewed as part of the Transfer Pricing Study. Those will not vary, however, the agreements also contain variable amounts that fluctuate with the demand from the affiliate for the particular service (includes services as the Project Management Services, Warehouse Services, Vehicle Usage and Shared Employees).

The Table provided below is based on the functional breakdown provided in response to VECC IR #38, but further broken down by affiliate.

Table ES:1 - Services Provided by BPDC to Affiliates

Nature of Service	2013	BPSC	Electek	BPGC	BPREI
Executive	24,805	12,399	10,576	1,026	804
Functional Management	53,975	27,186	18,190	-	8,599
Finance services other than payroll	66,803	46,914	17,169	1,360	1,360
Payroll	9,652	4,826	4,826		
Call centre labour	49,237	49,237			
Meter Reading					
Cashier labour	25,459	25,459			
Stationery and consumables for billing	3,980	3,980			
Bill mailing, envelopes and postage	19,724	19,724			
Billing Administration	3,094	3,094			
Building	14,400	14,400			
Human Resources	21,613	14,146	7,467		
IT Labour	10,090	3,153	3,784	-	3,153
SAP Expenses	20,871	20,871			
SAP Capital	55,402	55,402			
Work Stations and Communications Equipment	1,520	1,520			
Warehouse Service	2,800	2,800			
Vehicle Usage	50,176	50,176			
Shared Employees	116,490	76,816	5,106	-	34,568
	550,091	432,103	67,118	2,386	48,484

d. The Cost Sharing, Management Services, or other cost-sharing or services agreement immediately preceding the one included in Schedule 8.

The Agreements requested date to 2009 and were provided to the OEB as part of the pre-filed evidence in the 2009 Rebasing Application, a link is attached for ease of reference. The service agreements start at page 665 of the following:

http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/81037/view/Bluewater_2009EDR_Application_20080908.PDF

The Cost Sharing Agreement between Bluewater Power and BPSC was amended in 2010 to account for the transfer of employees as required for BPSC to provide the water billing function for Sarnia and Petrolia. A redlined version compared to the original filed with the OEB in 2009 is provided for convenience as Attachment #2 to this response.

Attachment 1 of 2

1.0 - SEC 13 - Revised Appendix 2-N with 2012 Draft Actual Results

File Number: EB-2012-0107
Exhibit:
Tab:
Schedule:
Page:

Date: 04-Feb-13

Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: **2012 - Draft Actual**

Shared Services

Name of Company		**Service Offered**	**Pricing Methodology**	**Price for the Service**	**Cost for the Service**
From	**To**			**$**	**$**
Distco	*BPREI*	management services	fully allocated cost	3,600	3,600
Distco	*BPSC*	management services	fully allocated cost	59,274	59,274
Distco	*Genco*	management services	fully allocated cost		
Distco	*Electek*	management services	fully allocated cost	42,966	42,966
Genco	*Distco*	management services	fully allocated cost		
			Sub-Total	**105,840**	**105,840**
Distco	*Genco*	building rent	market value		
Distco	*BPREI*	building rent	market value		
Distco	*BPSC*	building rent	market value	22,800	22,800
			Sub-Total	**22,800**	**22,800**
Distco	*BPSC*	vehicle rental	market value	34,102	34,102
Distco	*Electek*	vehicle rental	market value		
			Sub-Total	**34,102**	**34,102**
Distco	*Genco*	Interest on Advances	market value	-	
Distco	*BPREI*	Interest on Advances	market value	-	
Distco	*BPSC*	Interest on Advances	market value	-	
			Sub-Total	**-**	**-**
Distco	*BPSC*	Water ROIC	fully allocated cost	56,077	56,077
Distco	*Affiliates*	Water Billing costs	fully allocated cost	200,587	200,587
			Sub-Total	**256,664**	**256,664**
Distco	*BPSC*	Capital Work	fully allocated cost		
Distco	*BPREI*	Capital Work	fully allocated cost		
			Sub-Total	**-**	**-**
Distco	*BPSC*	Repair & Maintenance Work	fully allocated cost	-	
Distco	*Electek*	Repair & Maintenance Work	fully allocated cost		
			Sub-Total	**-**	**-**
Distco	*BPSC*	3rd Party Billable	fully allocated cost	13,215	13,215
Distco	*Electek*	3rd Party Billable	fully allocated cost	5,720	5,720
Distco	*Genco*	3rd Party Billable	fully allocated cost		
			Sub-Total	**18,935**	**18,935**
Distco	*BPSC*	Asset sales-vehicle & stock	market value	-	-
Distco	*BPSC*	Shared Staff	fully allocated cost	43,704	43,704
Distco	*Electek*	Shared Staff	fully allocated cost	2,325	2,325
Distco	*BPREI*	Shared Staff	fully allocated cost		
Distco	*Genco*	3rd Party Billable	fully allocated cost		
			Sub-Total	**46,029**	**46,029**
Total				**484,370**	**484,370**
BPSC	Distco	Capital	market value	261,160	261,160
BPSC	Distco	Repair & Maintenance Work	market value	205,385	205,385
BPSC	Distco	HyrdoVac	market value		
BPSC	Distco	Pass Through -Streetlight Install	market value	34,700	34,700
BPSC	Distco - OPA	OPA programs	market value	414,082	414,082
BPSC	Distco	3rd Party Billable	market value	21,526	21,526
BPSC	Distco	commercial meter reading	fully allocated cost	2,301	2,301
BPSC	Distco	Shared Staff	fully allocated cost		
			Sub-Total	**939,154**	**939,154**
Electek	Distco	building rent	market value		
Electek	Distco	Capital	market value	13,813	13,813
Electek	Distco	Repair & Maintenance Work	market value	180,397	180,397
Electek	Distco	3rd Party Billable	market value		
			Sub-Total	**194,210**	**194,210**
				1,617,734	**1,617,734**

Corporate Cost Allocation

Name of Company		**Service Offered**	**Pricing Methodology**	**% of Corporate Costs Allocated**	**Amount Allocated**
From	**To**				
				%	**$**
Distco	*Genco*	Board of Directors			-
Distco	*BPREI*	Board of Directors			-
Distco	*BPSC*	Board of Directors			-
Distco	*Electek*	Board of Directors			-
				Total	-

Note:

1 **This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years.**

2 Distco = Bluewater Power Distribution Corporation
BPSC = Bluewater Power Distribution Corporation
Electek = Electek Power Services Inc.
Genco = Bluewater Power Generation Corporation
BPREI = Bluewater Power Renewable Energy Inc.
Distco - OPA = non-utility OPA program costs

Attachment 2 of 2

1.0 - SEC 13 - Cost Sharing Agreement between BWP and BPSC (November 2010)

COST SHARING AGREEMENT

THIS AGREEMENT made as of the 1st day of January, 2009 (as amended November 30, 2010 to be effective April 1, 2011),

BETWEEN:

BLUEWATER POWER SERVICES CORPORATION,
an Ontario corporation
(“**BPSC**”)

and

BLUEWATER POWER DISTRIBUTION CORPORATION,
an Ontario corporation
(“**BWP Distribution**”)

WHEREAS:

A. 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;

B. BPSC carries on the business of water meter billing, water meter installation and maintenance, street light installation and maintenance, traffic light installation and maintenance and miscellaneous on demand line work, as well as civil work and ad hoc maintenance services;

C. BPSC requires, from time to time, the services of additional persons, use of certain equipment and use of certain physical space; and

D. BWP Distribution has agreed to make available to BPSC certain of its linemen and its equipment and other resources 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

In this Agreement and in the schedules, the following terms and expressions will have the following meanings:

(a) “Agreement” means this 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) "Default" has the meaning ascribed to it in Section 8.1;

(e) "Defaulting Party" has the meaning ascribed to it in Section 8.1;

(f) "Effective Date" means January 1, 2009;

(g) "Event of Default" has the meaning ascribed to it in Section 8.1;

(h) "Equipment" has the meaning ascribed to it in Section 3.2;

(i) "Force Majeure Event" has the meaning ascribed to it in Section 11.1;

(j) "Law" means any law, rule, regulation, code, order, writ, judgement, decree or other legal or regulatory determination by a court, regulatory agency or governmental authority of competent jurisdiction;

(k) "Leased Premises" has the meaning ascribed to it in Section 3.3;

(l) "Party" means a party to this Agreement and "Parties" refers to both BPSC and BWP Distribution collectively;

(m) "Person" means an individual, corporation, partnership, joint venture, association, trust, pension fund, union, governmental agency, official, board, tribunal, ministry, commission or department;

(n) "Personnel" has the meaning ascribed to it in Section 3.1; and

(o) "Term" has the meaning ascribed to it in Section 2.1 of 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, 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. Thereafter, the term shall be automatically renewed for further successive periods of one (1) year each unless a Party gives notice in writing that the Agreement is not to be extended on a date which is at least ninety (90) days prior to the end of the initial five (5) year term, or the end of any renewal term, as the case may be.

ARTICLE 3
SERVICES, EQUIPMENT, LEASED PREMISES AND COVENANTS

3.1 Personnel Services

Subject to the terms, covenants and conditions contained in this Agreement, upon request, BWP Distribution will provide, or cause to be provided, to BPSC the services of employees listed by title under the heading "Services" in Schedule "A" employed by BWP Distribution ("Personnel").

3.2 Equipment

Subject to the terms, covenants and conditions contained in this Agreement, BWP Distribution will also provide to BPSC certain equipment owned by BWP Distribution ("Equipment") for use by BPSC.

3.3 Use of Premises

BWP Distribution will permit BPSC exclusive use of such portion of the property known as "Main Substation No. 1" as may, from time to time, be agreed by BWP Distribution and BPSC for storage, office space and change-room facilities. BWP Distribution will also permit BPSC exclusive use of such portion of the property municipally known as 855 Confederation Street, Sarnia, Ontario as may, from time to time, be agreed by BWP Distribution and BPSC for storage of inventory owned by BPSC. In addition, BWP Distribution will also permit BPSC access to common areas of Main Substation No. 1 and 855 Confederation Street, Sarnia, including washrooms, cafeteria, parking, meeting rooms and change rooms. The portion of Main Substation No. 1 and 855 Confederation Street, Sarnia, used by BPSC, together with the common areas to which BPSC is given access, are collectively referred to as the "Leased Premises".

3.4 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 BPSC with adequate evidence of its compliance with this Section 3.4.

(b) BWP Distribution's Personnel shall, while providing services to BPSC, comply with all the rules and regulations of BPSC from time to time in force, which are brought to their notice or of which they should reasonably be aware.

(c) BWP Distribution shall pay for and maintain for the benefit of BWP Distribution and BPSC appropriate insurance concerning the operations and liabilities of BWP Distribution relevant to this Agreement including, without limiting the generality of the foregoing, workplace safety 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 BPSC Covenants

(a) BPSC shall be responsible for obtaining all necessary licences and permits and for complying with all applicable federal, provincial and municipal laws, codes and regulations required to conduct its business and to use the Equipment and the Leased Premises.

(b) BPSC shall not, without BWP Distribution's prior consent, make any alternations, additions or improvements to the Equipment and shall, while using the Equipment, use reasonable care and skill.

(c) Notwithstanding any other provision of this Agreement, BPSC shall be fully responsible for any damage to or loss of any of the Equipment or any portion thereof while the Equipment is in its possession, reasonable wear and tear excepted.

(d) BPSC shall not part with possession of, sell, assign, lease, sublease, rent or otherwise transfer any of the Equipment or any portion of the Leased Premises.

(e) BPSC shall, while utilizing any portion of the Leased Premises, comply with all rules and regulations of BWP Distribution from time to time in force, which are brought to its notice or of which it should reasonably be aware, and shall be responsible for any damage or loss of the Leased Premises or any portion thereof.

(f) BPSC shall use the Leased Premises solely for the purposes described in Section 3.3 above and shall not make or cause to be made any alterations, additions or improvements or erect or cause to be erected any partitions or install or cause to be installed any trade fixtures, signs, floor covering, interior or exterior lighting, plumbing fixtures, apparatus for air-conditioning, cooling, heating, illuminating, refrigerating, or ventilating in the Leased Premises, or make any changes to the Leased Premises without first obtaining BWP Distribution's written approval thereto.

(g) BPSC shall not do or permit to be done or omitted anything which could damage the Leased Premises or injure or impede the business of BWP Distribution conducted from the balance of Main Substation #1 and/or 855 Confederation Street, Sarnia, Ontario (collectively, the "Properties") or which shall or might result in any nuisance in or about the Properties, whether to BWP Distribution, any tenant of the Properties, or any other party, the whole as determined by BWP Distribution, acting reasonably. In any of the foregoing events, BPSC shall forthwith remedy the same and if such thing or condition shall not be so remedied, BWP Distribution may, after such notice, if any, as BWP Distribution may deem appropriate in the circumstances, correct such situation at the expense of BPSC and BPSC shall pay such expense to BWP Distribution.

(h) BPSC shall keep the Leased Premises in a neat, clean and sanitary condition and shall not allow any refuse, garbage or other loose or objectionable or waste material to accumulate in or about such Leased Premises.

(i) BPSC shall permit BWP Distribution access, upon request at any time during the term hereof, to the Leased Premises.

3.6 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 the other Party, except for purposes related to the provision of 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 BPSC of any changes or prospective changes in circumstances that would materially affect the resources required for the Personnel, Equipment or Leased Premises provided to BPSC, including any anticipated material change in the nature or level of business of BWP Distribution, the number of employees of BWP Distribution, the equipment 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 BPSC, and BPSC 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 BPSC (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

As consideration for the Personnel, Equipment and Leased Premises provided, BPSC shall pay to BWP Distribution the fees and charges set out in Schedule "A". BWP Distribution shall render a monthly invoice for all Personnel and Equipment provided to BPSC, as well as for the pro-rata monthly share of annual fees for use of the Leased Premises and Water Billing related fees, during the preceding month, which invoice shall be due and payable within thirty (30) days of receipt.

5.2 Out of Pocket and Third Party Expenses

BWP Distribution shall be reimbursed for all out-of-pocket expenses actually and properly incurred by BWP Distribution in connection with the provision of Personnel, Equipement and/or the Leased Premises.

5.3 Taxes

BPSC shall pay to BWP Distribution any and all goods and services taxes, sales taxes, value-added taxes and/or any other taxes (excluding income taxes) properly eligible on the supply of Personnel, Equipment and/or Leased Premises provided under this Agreement and on any other amounts payable hereunder.

ARTICLE 6
REPRESENTATIONS AND WARRANTIES

6.1 Representations and Warranties of BWP Distribution

BWP Distribution represents and warrants to BPSC as follows and acknowledges that BPSC is relying on such representations and warranties:

(a) BWP Distribution is a corporation duly incorporated and validly existing under the laws of the Province of Ontario and 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 BPSC in accordance with its terms except as may be limited by bankruptcy, insolvency and other laws affecting the rights of creditors generally and except that equitable remedies may be granted only in the discretion of a court of competent jurisdiction; and

(d) BWP Distribution has the necessary resources and expertise to acquire or perform the Services.

6.2 Representations and Warranties of BPSC

BPSC represents and warrants to BWP Distribution as follows and acknowledges that BWP Distribution is relying on such representations and warranties:

(a) BPSC is a corporation duly incorporated and validly existing under the laws of the Province of Ontario and 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 BPSC, enforceable against BPSC by BWP Distribution in accordance with its terms except as may be limited by bankruptcy, insolvency and other laws affecting the rights of creditors generally and except that equitable remedies may be granted only in the discretion of a court of competent jurisdiction.

ARTICLE 7
INDEMNIFICATION

7.1 <u>Indemnification</u>

(a) BPSC 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 services of the Personnel provided hereunder, use of the Equipment by BPSC and/or possession, occupation and/or use of the Leased Premises by BPSC.

(b) BWP Distribution shall be deemed to hold the provisions of Section 7.1(a) that are for the benefit of BWP Distribution Indemnitees that are not party to this Agreement in trust for such persons as third party beneficiaries under this Agreement.

7.2 <u>Limit of Liability</u>

(a) Should BWP Distribution be held liable by a court of law for any reason outside of the Indemnity under Section 7.1 (a), BPSC agrees that BWP Distribution's liability to BPSC 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 Personnel, Equipment and/or the Leased Premises, 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 Personnel, Equipment and/or the Leased Premises and shall not exceed an amount equal to the total amount paid by BPSC to BWP Distribution under this Agreement for Personnel, Equipment and Leased Premises over the twelve month period immediately 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 Personnel, Equipment or Leased Premises referred to in this Agreement.

7.3 Fines, Etc.

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 BPSC, and BPSC 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 (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; or

(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 BPSC 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:

(i) such Force Majeure Event continues; and

(ii) 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 the implementation of the cure for the Default under Section 8.1(b) cannot be resolved by negotiation between the Parties, then the dispute shall be referred to one arbitrator agreeable to and appointed by both Parties. 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 of which shall be appointed by BPSC and the third shall be appointed by the two arbitrators selected by BWP Distribution and BPSC. 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 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 Parties.

11.3 Assignment

Neither Party shall, without the written consent of the other Party, 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 BPSC,

P.O. Box 2140
855 Confederation Street
Sarnia, ON N7T 7L6

Attn: Kathy Gadsby
Fax: 519-344-7303

(b) if to BWP Distribution,

P.O. Box 2140
855 Confederation Street
Sarnia, ON N7T 7L6

Attn: Alex Palimaka
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. Either 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 the 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 constitutes the entire Agreement between the Parties with respect to the subject matter hereof, 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.

11.13 Independent Contractors

The Parties are independent contractors and BWP Distribution shall not be considered to be an agent of BPSC. It is further understood and agreed that this Agreement does not constitute a partnership or joint venture agreement between the Parties.

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 SERVICES CORPORATION

Per: ______________________________
Name:
Title:

Per: ______________________________
Name:
Title:
I/we have authority to bind the corporation

BLUEWATER POWER DISTRIBUTION CORPORATION

Per: ____________________________________

Name:
Title:

Per: ____________________________________

Name:
Title:

I/we have authority to bind the corporation

SCHEDULE "A"

Fees & Charges

	SERVICES	FEES	PERIOD OF FEE
1.	**Linemen**	Cost	Monthly
2.	**Administrator**	Cost	Monthly
3.	**Fleet Manager**	Cost	Monthly
4.	**Customer Service Rep**	Cost	Monthly
5.	**Equipment use**	Cost	Monthly
6.	**Use of "Main Substation No. 1"**	$12,000	Annually
7.	**Use of 855 Confederation Street, Sarnia, Ontario**	$3,000	Annually
8.	**Water Billing related uses of SAP Billing system, equipment and premises at 855 Confederation Street, Sarnia, Ontario**	$ 88,351	Annually
9.	**Water Billing shared costs for Market and Billing Services Personnel**	$238,251	Annually; fee subject to 3% inflationary increase on January 1, 2012 and each year thereafter
10.	**Water Billing share costs for mailing and postage**	$35,458	Annually; fee subject to inflation based on CPI on January 1, 2012 and each year thereafter

Terms & Conditions		
1	Prices	Subject to Applicable Taxes
2	Payment	Monthly invoice, Net 30 days
3	Cost	BWP Distribution's fully allocated cost

1.0 - SEC 14 - Affiliate details of allocations

[1/2/8] Please provide, for each year from 2010 through 2013, a table that shows all shared costs or charges/allocations between the companies in the corporate group, including in each case:

a. The nature of the cost being shared, allocated, or charged.

See Appendix 2-N, as well as in Table 1 of Ex.4-5-1.

b. The entity that initially incurs the cost (usually the Applicant).

See Appendix 2-N, as well as in Table 1 of Ex. 4-5-1.

c. The total amount of the cost before sharing, allocations, or charges.

Appendix 2-N and Table 1 of Ex 4-5-1 generally do not include the total amount of the cost before allocation because the costs are not allocated as a percentage of the total. For example, costs for employees shared with BPSC are based on a fully-allocated hourly charge and it is not relevant to that allocation what the total cost of all linemen is to Bluewater Power.

d. The amounts allocated to, shared by, or charged to each of the other companies, and the basis for the allocation, sharing or charge.

See the *Transfer Pricing Study* (Exhibit 4, Tab 5, Schedule 1, Attachment 2), which contains detailed descriptions of the nature of costs shared and the basis or methodology to determine the allocation of fees and charges.

e. An explanation of any unusual increases or decreases in any of these amounts from the prior year.

As required by the Filing Guidelines, the explanation for variances from 2009 Rebasing to 2011 Actuals and from 2011 Actuals to 2013 Test Year are found in Exhibit 4, Tab 5, Schedule 1. The explanations noted in those variances are reflective of the major changes impacting affiliate fees and charges over the period from 2009 to 2013.

4.0 - SEC 19 - Capitalized Labour

[4/1/1, p. 5] Please explain how an increase in capitalized labour constitutes "improved productivity".

See answer to OEB Staff IR #26(a)

4.0 - SEC 20 - Statement about spending during IRM

[4/1/1, p. 6] Please provide the legal or other basis for the statement “There is an implied prudence to spending by a utility during an IRM period.”

The referenced statement was intended to frame the relevance of the comparison of 2011 Actuals to 2013 Test Year. The pre-filed evidence contains data for Historic Year and the Bridge Year, but the 2011 Actuals present the most accurate and recent data for comparison to the 2013 Test Year. The statement was a further suggestion that the 2011 Actuals can be relied upon as cost incurred in a business environment where cost control is paramount because a utility is incented during the IRM period to control its costs and, thereby, improve profitability for the corporation; hence the name “Incentive Rate Making”. The logic therefore is simply that the incentive to control costs means that the spending is prudent, or at least not imprudent.

4.0 - SEC 26 - Cost borne by Affiliates and basis for allocation

[4/2/4, p. 1] Please advise how much of the $270,000 is being borne by affiliates, and the basis for the allocation.

The costs reference by the question relate to the one-time costs associated with environmental risk assessment at Main Substation #1 (MS#1) in the City of Sarnia. While it is correct that MS#1 is occupied, in part, by BPSC there is no basis to claim the cost of the risk assessment and remediation to the affiliate who is a mere tenant. Therefore, none of the $270,000 cost is proposed to be allocated to BPSC.

4.0 - SEC 27 - increased cash flow

[4/2/5, p. 2] Please recalculate the value of the increased cash flow using the pre-tax weighted average cost of capital.

The interest earned on the increased cash flow for monthly billing has been calculated to be approximately $20,000 using the current interest rate earned at the bank, which is approximately 0.5%. If we were to use the pre-tax WACC currently estimated to be 6.07%, then the interest earned equates to $243,000. We have provided the calculation requested, but we stand-by the original methodology for determining the cash flow benefits of monthly billing.

4.0 - SEC 28 - Materiality Threshold

[4/3/1, p. 2] Please explain the basis for multiplying the Board's materiality threshold by the number of years for any given comparison.

The OEB Filing Guidelines dated June 28, 2012 at page 14 states:

> "The applicant must provide justification for change from year to year to its rate base, capital expenditures, OM&A and other items above a materiality threshold [emphasis added]."

It is clear that the materiality threshold applies to annual variances, so it follows that a comparison covering two years should utilize a materiality threshold twice the annual materiality threshold. Moreover, the Filing Guidelines go on to state:

> "If an applicant believes that an alternative threshold would be appropriate to its specific circumstances, it is free to propose such an alternative, with appropriate justification, in its application."

The justification included at Exhibit 4, Tab 3, Schedule 1 was as follows:

> "The adjustment to the materiality threshold is appropriate to reflect an annual materiality threshold as contemplated by the Filing Guidelines. This treatment creates better consistency with annual variances and makes the analysis more meaningful than a materiality threshold that would require most variances to be explained."

4.0 - SEC 29 - Variance in account 5605

[4/3/1, p. 4] Please recalculate the variance in Account 5605 on the basis that both 2009 and 2013 account for management fees in the same manner.

In 2009, management fees were recorded as revenue and therefore the OM&A accounts were not adjusted. In 2013, management fees are recorded as a reduction to OM&A. The reduction included in Account 5605 for the 2013 test year was $49,663 relating to management fees. Therefore, the variance for this account from 2009 to 2013 would be higher by this amount and would be $536,877.

4.0 - SEC 32 - Age of assets for 5 largest categories

[4/4/1, Attach 2, p. 6] Please provide a vintage table showing the distribution in ages of the existing assets for each of the five largest asset categories by dollars, excluding general plant. If a vintage table or similar document or analysis was prepared for the conversion to IFRS, please provide that table.

Since this question follows the discussion on page 6 regarding electrical infrastructure, general plant and I.T. capital are ignored. The five largest historical cost categories by account for electrical infrastructure are:

Account 1820 – Distribution Station Equipment <50kV
Account 1830 – Poles, Towers & Fixtures
Account 1835 – Overhead Conductors & Devices
Account 1845 – Underground Conductors & Devices
Account 1850 – Line Transformers

Each of these accounts is presented in Attachment #1 to this interrogatory.

Each account shows the export from Bluewater Power's SAP system which presents the 'historical cost' additions for the historical years where applicable. The sum of each account agrees to the 2011 closing balance that is found at Exh 2-3-2 Attachment 2.

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4.0 - SEC 32

Account 1820 - Dist Stn Equip <50kV

Obj. t	Object	Year	Description	Cuml. APC/repl.v
1820	20052/1975	1975	Municipal Dist	1,539,399.74
1820	20053/1976	1976	Municipal Dist	251,560.55
1820	20054/1980	1980	Municipal Dist	14,339.42
1820	20055/1981	1981	Municipal Dist	30,230.50
1820	20056/1982	1982	Municipal Dist	2,305.09
1820	20057/1983	1983	Municipal Dist	20,363.46
1820	20058/1985	1985	Municipal Dist	200,634.73
1820	20059/1986	1986	Municipal Dist	56,951.09
1820	20060/1987	1987	Municipal Dist	34,851.53
1820	20061/1988	1988	Municipal Dist	237,277.35
1820	20062/1989	1989	Municipal Dist	180,780.52
1820	20063/1990	1990	Municipal Dist	42,995.26
1820	20064/1991	1991	Municipal Dist	21,598.94
1820	20065/1992	1992	Municipal Dist	2,072.03
1820	20066/1992	1992	Municipal Dist	48,914.01
1820	20067/1993	1993	Municipal Dist	43,140.36
1820	20068/1994	1994	Municipal Dist	31,213.85
1820	20069/1994	1994	Municipal Dist	47,706.86
1820	20070/1995	1995	Municipal Dist	20,768.00
1820	20071/1996	1996	Municipal Dist	25,151.32
1820	20072/1997	1997	Municipal Dist	44,438.06
1820	20073/1997	1997	Municipal Dist	6,380.56
1820	20074/1998	1998	Municipal Dist	22,288.20
1820	20075/1999	1999	Municipal Dist	46,752.33
1820	20076/2000	2000	Municipal Dist	52,261.51
1820	20077/2001	2001	Municipal Dist	957,047.53
1820	20106/2002	2002	Municipal Dist	57,498.72
1820	20106/2003	2003	Municipal Dist	39,626.43
1820	20106/2004	2004	Municipal Dist	685,191.65
1820	20106/2005	2005	Municipal Dist	267,059.40
1820	20106/2006	2006	Municipal Dist	247,436.70
1820	20106/2007	2007	Municipal Dist	102,745.38
1820	20106/2008	2008	Municipal Dist	167,332.80
1820	20106/2009	2009	Municipal Dist	183,258.11
1820	20106/2010	2010	Municipal Dist	338,057.26
1820	20112/2005	2005	Substation 2 U	36,056.64
1820	20113/2005	2005	Substation 3 U	400.00
1820	20142/2011	2011	Substation - B	34,264.57
1820	20138/2011	2011	Sub station Tr	152,900.81
1820	20139/2011	2011	Dist Stn Equip	4,745.46
1820	20140/2011	2011	Sub Station Eq	68,300.23
1820	20120/2011	2011	Substation 1	16,358.75
1820	20121/2011	2011	Distribution S	27,743.13
1820	20141/2011	2011	Substation - B	1,326.08
1820	20143/2011	2011	Substation - P	43,856.96
				6,455,581.88

Account 1830 - Poles, Towers & Fixtures

Obj. t	Object	Year	Description	Cuml. APC/repl.v
1830	20110/2005	2005	Poles - New &	103,113.67
1830	20110/2006	2006	Poles,Towers,F	203,424.46
1830	20110/2007	2007	Poles,Towers,F	384,496.45
1830	20110/2008	2008	Poles - New &	244,814.67
1830	20110/2009	2009	Poles - New &	304,726.40
1830	20110/2010	2010	Poles - New &	541,411.91
1830	20117/2011	2011	Wood Pole Full	475,690.34
				2,257,677.90

Prior to 2005, the capital additions were recorded in Account 1835.

Account 1835 - OH Conductors & Devices

Obj. t	Object	Year	Description	Cuml. APC/repl.v
1835	20028/1980	1980	Distribution l	34,000.00
1835	20029/1979	1979	Distribution l	1,477,799.52
1835	20030/1982	1982	Distribution l	666,950.02
1835	20031/1981	1981	Distribution l	285,163.00
1835	20032/1984	1984	Distribution l	303,233.54
1835	20033/1985	1985	Distribution l	486,458.58
1835	20034/1986	1986	Distribution l	472,347.05
1835	20035/1987	1987	Distribution l	438,144.27
1835	20036/1988	1988	Distribution l	473,566.00
1835	20037/1989	1989	Distribution l	600,742.34
1835	20038/1990	1990	Distribution l	717,690.14
1835	20039/1991	1991	Distribution l	720,826.99
1835	20040/1991	1991	Distribution l	2,253,035.00
1835	20041/1992	1992	Distribution l	833,260.83
1835	20042/1993	1993	Distribution l	1,021,368.25
1835	20043/1993	1993	Distribution l	10,122.00
1835	20044/1994	1994	Distribution l	1,141,234.71
1835	20045/1995	1995	Distribution l	993,593.83
1835	20046/1996	1996	Distribution l	907,501.32
1835	20047/1997	1997	Distribution l	1,054,731.61
1835	20048/1998	1998	Distribution l	1,202,355.19
1835	20049/1999	1999	Distribution l	1,645,364.57
1835	20050/2000	2000	Distribution l	1,766,154.76
1835	20051/2001	2001	Distribution l	1,258,635.62
1835	20102/1981	1981	Distribution l	341,414.03
1835	20105/2002	2002	DISTRIBUTION L	553,337.61
1835	20105/2003	2003	DISTRIBUTION L	576,144.31
1835	20105/2004	2004	DISTRIBUTION L	587,060.09
1835	20105/2005	2005	Dist'n Lines &	784,809.80
1835	20105/2006	2006	Dist'n Lines &	778,195.92
1835	20105/2007	2007	Dist'n Lines &	650,518.21
1835	20105/2008	2008	OVERHEAD DISTR	610,595.04
1835	20105/2009	2009	DIST'N LINES &	791,178.56
1835	20105/2010	2010	DIST'N LINES &	588,524.32
1835	20111/2005	2005	27.6kV Load Br	50,621.91
1835	20134/2011	2011	OH Conductors	99,505.16
1835	20127/2011	2011	Overhead Secon	43,170.86
1835	20122/2011	2011	OH Conductors/	196,411.59
1835	20123/2011	2011	OH Conductors	70,168.48
				27,485,935.03

Account 1845 - UG Conductors & Devices

Obj. t	Object	Year	Description	Cuml. APC/repl.v
1845	20000/1979	1979	Distribution L	1,920,024.63
1845	20001/1978	1978	Distribution L	452,071.13
1845	20002/1980	1980	Distribution L	144,281.39
1845	20003/1980	1980	Distribution L	5,065.34
1845	20004/1981	1981	Distribution L	139,642.58
1845	20005/1981	1981	Distribution L	7,678.05
1845	20006/1982	1982	Distribution L	75,998.19
1845	20007/1982	1982	Distribution L	6,859.53
1845	20008/1983	1983	Distribution L	275,266.72
1845	20009/1984	1984	Distribution L	253,891.25
1845	20010/1985	1985	Distribution L	115,627.48
1845	20011/1986	1986	Distribution L	134,935.50
1845	20012/1987	1987	Distribution L	138,637.91
1845	20013/1988	1988	Distribution L	262,762.74
1845	20014/1989	1989	Distribution L	254,774.55
1845	20015/1990	1990	Distribution L	116,551.05
1845	20016/1991	1991	Distribution L	301,432.73
1845	20017/1991	1991	Distribution L	1,537,593.00
1845	20018/1992	1992	Distribution L	398,665.56
1845	20019/1993	1993	Distribution L	386,802.07
1845	20020/1994	1994	Distribution L	827,820.59
1845	20021/1995	1995	Distribution L	730,349.21
1845	20022/1996	1996	Distribution L	445,793.92
1845	20023/1997	1997	Distribution L	682,208.70
1845	20024/1998	1998	Distribution L	1,376,589.97
1845	20025/1999	1999	Distribution L	892,716.70
1845	20026/2000	2000	Distribution L	1,432,258.67
1845	20027/2001	2001	Distribution L	1,162,701.98
1845	20104/2002	2002	Distribution L	741,602.14
1845	20104/2003	2003	Distribution L	730,215.20
1845	20104/2004	2004	Distribution L	632,344.15
1845	20104/2005	2005	Dist'n Lines &	829,735.80
1845	20104/2006	2006	Dist'n Lines &	359,864.95
1845	20104/2007	2007	Distribution L	575,044.69
1845	20104/2008	2008	Ungd - Distrib	439,029.89
1845	20104/2009	2009	Dist'n Lines &	587,305.25
1845	20104/2010	2010	Distribution L	253,575.51
1845	20118/2011	2011	UG Primary Con	501,345.45
1845	20144/2011	2011	UG Primary Con	41,953.86
1845	20132/2011	2011	UG Conductors	17,416.08
1845	20116/2010	2010	Fully Amortiz	76,601.16
1845	20116/2011	2011	Fully Amortiz	23,997.75
1845	20131/2011	2011	UG Conductors	11,026.34
				20,300,059.36

Account 1850 - Line Transformers

Obj. t	Object	Year	Description	Cuml. APC/repl.v
1850	20078/1975	1975	Distribution T	769,532.61
1850	20079/1980	1980	Distribution T	246,121.20
1850	20080/1981	1981	Distribution T	89,244.70
1850	20081/1982	1982	Distribution T	47,325.34
1850	20082/1983	1983	Distribution T	55,796.57
1850	20083/1984	1984	Distribution T	117,666.79
1850	20084/1985	1985	Distribution T	93,729.41
1850	20085/1986	1986	Distribution T	108,211.97
1850	20086/1987	1987	Distribution T	111,287.02
1850	20087/1988	1988	Distribution T	185,768.90
1850	20088/1989	1989	Distribution T	271,390.29
1850	20089/1990	1990	Distribution T	268,777.50
1850	20090/1991	1991	Distribution T	292,430.24
1850	20091/1991	1991	Distribution T	2,329,756.00
1850	20092/1992	1992	Distribution T	229,196.75
1850	20093/1993	1993	Distribution T	338,159.60
1850	20094/1994	1994	Distribution T	316,929.13
1850	20095/1995	1995	Distribution T	488,890.77
1850	20096/1996	1996	Distribution T	520,532.24
1850	20097/1997	1997	Distribution T	457,439.33
1850	20098/1998	1998	Distribution T	256,962.70
1850	20099/1999	1999	Distribution T	182,288.11
1850	20100/2000	2000	Distribution T	1,127,533.74
1850	20101/2001	2001	Distribution T	611,833.72
1850	20103/2002	2002	Distribution T	577,539.16
1850	20103/2003	2003	Distribution T	225,035.95
1850	20103/2004	2004	Distribution T	390,094.06
1850	20103/2005	2005	Distribution T	516,156.82
1850	20103/2006	2006	Distribution T	665,389.32
1850	20103/2007	2007	Distribution T	803,622.12
1850	20103/2008	2008	Distribution T	544,291.91
1850	20103/2009	2009	Distribution T	497,351.01
1850	20103/2010	2010	Distribution T	907,897.24
1850	20119/2011	2011	Overhead Trans	110,412.39
1850	20125/2011	2011	Transformers -	205,950.27
1850	20130/2011	2011	OH Transformer	12,904.09
1850	20124/2011	2011	Transformers -	251,275.00
1850	20126/2011	2011	Transformer -	124,385.97
1850	20137/2011	2011	UG Transformer	18,432.68
				15,367,542.62

4.0 - SEC 34 - Hourly charge for vehicles

[4/5/1, p. 6] Please provide the standard hourly charge for vehicles for each of the years 2009-2013, and the calculation of that charge including all assumptions used.

The standard hourly cost rates are presented in the following table. Light vehicles include passenger cars and vans, as well as pickup trucks. Heavy vehicles are bucket trucks, etc.

	2009	2010	2011	2012	2013
Light	$ 5.39	$ 5.39	$ 5.78	$ 6.68	$ 7.50
Heavy	$ 22.27	$ 21.40	$ 30.76	$ 31.68	$ 39.61

The hourly costing rate is calculated by an estimate of the total costs for all vehicles in each category divided by the total estimated use in hours for all vehicles in that category.

Total costs include all operating costs such as fuel, maintenance, license, insurance, etc, plus depreciation plus an estimate for the 'weighted average cost of capital'.

Total estimated use in hours is primarily based on the prior year's total actual usage with possible adjustments for forecasted changes in use. Total actual usage relates to all hours used for maintenance, capital, billable and affiliates. Forecasted change is use could include known additions or disposals of vehicles, or the change in use for a particular vehicle.

4.0 - SEC 35 - Details of review

[4/5/1, Attach 2, p. 8] Please provide details of all “issues raised in the course of this review”, together with copies of all reports, presentations, memos or other documents from the consultant dealing with those issues.

See response to OEB Staff IR#36.

4.0 - SEC 36 - Related Overheads

[4/5/1, Attach 2, p. 12] Please explain by “related overheads” are not included.

The question refers to the description offered in Section 4.2 of the Transfer Pricing Study for the Management Fees applicable to the Executive group, which was based on estimated hours multiplied by an hourly rate “costed at a weighted average hourly rate for the group, including salary and all benefits (but not related overheads)”. The “related overheads” meant by this statement include the costs of building and facilities, human resources and information technology, workstations, furniture, etc. that support each employee.

When this section of the Transfer Pricing Study was initially drafted, the approach to allocation of such “overheads” had not yet been developed. Through the course of the Transfer Pricing Study an approach was developed and is described in Section 4.1 of the Study. The last sentence from Section 4.1 states “All references to labour costs in the following sections therefore include salaries and wages, benefits and a surcharge for enabler resources.” is accurate, and applies to the allocation of labour costs of the Executive group, as well as to all other employees who perform services for affiliates. The wording in Section 4.2 excluding “related overheads” is not accurate, but was inadvertently not updated in finalizing the Transfer Pricing Study.

For the sake of clarity, the hourly rate charged to affiliates for the work of the Executive group does include an allocation of “related overheads” as described in Section 4.1 of the Transfer Pricing Study.

File Number: EB-2012-0107

Date Filed: February 4, 2013

BLUEWATER POWER DISTRIBUTION CORPORATION

Tab 7 of 11

Exhibit 5 - Capital Structure and Cost of Capital

5.0-Staff-40 - Promissory Note Date

Ref: Exh 5-1-1

Bluewater Power's debt instruments include promissory notes to shareholders and third party borrowing with Infrastructure Ontario. At page 2 it states that the first debenture with Infrastructure Ontario was set as a 10 year debenture at 3.37% as of September 15, 2010. The summary provided as Appendix 2-OB lists a date of September 15, 2011. Please explain the difference.

There is a typographical error on page 2 of Ex. 5-1-1. It should state "September 15, 2011" which would then agree to Appendix 2-OB. This can also be verified by referring to Note 15 in the 2011 audited financial statements found at Exh 1-3-1 Appendix 1.

5.0 - EP 30 - Infrastructure Ontario

Ref: Exhibit 5, Tab 1, Schedule 1

a) Please reconcile the date of September 15, 2010 shown at line 15 of page 2 with the date of September 15, 2011 shown in Appendix 2-OB for 2013.

The following is the same response to OEB Staff IR# “5-Staff-40”:

There is a typographical error on page 2 of Exh 5-1-1. It should state “September 15, 2011” which would then agree to Appendix 2-OB. This can also be verified by referring to Note 15 in the 2011 audited financial statements found at Exh 1-3-1 Appendix 1.

b) Please explain why there is no Advance from Infrastructure Ontario shown for 2013, as there was in previous years, at a variable rate in those years of 1.75%.

All financing from Infrastructure Ontario relates solely to Bluewater Power’s smart meter project. This project was completed in 2012. The final advance ‘draws’ took place in 2012. These final advance ‘draws’ in 2012 resulted in the total previously approved $9.3 million of total financing being reached.

Please also refer to Note 15 in the 2011 audited financial statements found at Exh 1-3-1 Appendix 1.

c) What is the amount of the advance in 2013 from Infrastructure Ontario prior to its conversion to a fixed rate debenture as of September 15, 2013? What is the current and forecasted rate for this debt for the beginning of 2013 up to the conversion date?

At the time of preparing the 2013 COS rate application, it was forecasted that the remaining $2.2 million of advances ($9.3 million total approved financing less $7.1 million debenture) would be converted to a second debenture in September, 2013. At the November 2012 board of director's meeting for Bluewater Power, it was decided to fully repay the $2.2 million of advances and not take out the second debenture.

As a result of the $2.2 million repayment, the interest income that was forecasted for the 2013 test year is incorrect. As per Exh 3-2-1, Table 10 on page 11, the interest income of $43,610 will be reduced by $10,000 to account for an approximate reduction of $2.2 million of cash at an approximate interest rate of 0.5%. This change has been reflected in Table 1 in the response to Energy Probe #16a and 3-VECC #22c – specifically the line labelled "Investment Income".

As a result of the $2.2 million repayment, the deemed weighted average interest rate applied to the deemed long-term debt has been changed from 4.18% to 4.24%. Therefore, this has adjusted the total amount of deemed interest included in the revenue requirement.

Bluewater Power has incorporated these two updates into the revised revenue requirement, into the RRWF and the bill impacts presented in the response to these interrogatories.

d) What is the current Infrastructure Ontario rate for a 10 year term, as proposed by Bluewater Power?

Not applicable. See response to part (c) above.

e) Please provide a copy of all loan/debenture agreements with Infrastructure Ontario.

The only financing agreement that Bluewater Power has with Infrastructure Ontario relates to the overall $9.3 total smart meter financing and is found in Attachment 1 to this interrogatory.

The only debenture that Bluewater Power has with Infrastructure Ontario is for $7.1 million and is found in Attachment 2 to this interrogatory.

Attachment 1 of 2

Energy Probe 30 (e) - Financing Agreement

Infrastructure Ontario

777 Bay Street, 9th Floor
Toronto, Ontario M5G 2C8
Tel.: 416 212-7289
Fax: 416 325-4646

Infrastructure Ontario

777, rue Bay, 9e étage
Toronto, Ontario M5G 2C8
Tél. : 416 212-7289
Téléc. : 416 325-4646

Ontario
Infrastructure Ontario

October 06, 2010

VIA COURIER

Mark Hutson
Controller
BLUEWATER POWER DISTRIBUTION CORPORATION
855 Confederation StreetP.O. Box 2140,
Sarnia, ON N7T 7L6

Dear Mark Hutson,

Please find enclosed a fully executed copy of Financing Agreement #10Blu9041510027FAfor your files. To enquire about short-term advances or debentures, please feel free to contact Judy Lam at (416) 326-7812 at your convenience.

We thank you for considering the Infrastructure Ontario's Loan Program for your infrastructure project. If you have any questions or concerns, please do not hesitate to call us.

Best Regards,

Steve Rohacek
Vice President, Business Development
& Customer Relations

Encl.

Financing Agreement No. **10Blu9041510027FA**
Program year: 2010/2011
Short and Long Term

FINANCING AGREEMENT

THIS AGREEMENT (the "Agreement"), made in duplicate, dated and effective as of the 20th day of September, 2010 (the "Effective Date")

BETWEEN:

ONTARIO INFRASTRUCTURE PROJECTS CORPORATION
(herein after referred to as "OIPC");

and

BLUEWATER POWER DISTRIBUTION CORPORATION
(an Ontario corporation created under the *Business Corporations Act* (Ontario) herein after referred to as the "Borrower")

WHEREAS:

OIPC has advised the Borrower that its loan application number 10027, (the "Application") has been approved;

OIPC agrees to make financing available to the Borrower up to a maximum aggregate principal amount of $9,300,000.00 (NINE MILLION, THREE HUNDRED THOUSAND DOLLARS) (the "Committed Amount") for the projects listed in the Application and more particularly described in Schedule "A" hereto (the "Project"), subject to the terms and conditions set out in this Agreement.

NOW THEREFORE in consideration of the covenants of each of the parties contained herein and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged by the parties, the Borrower and OIPC hereby agree as follows:

1. Definitions

In this Agreement:

(a) **"Acquired Assets"** means any assets, rights or properties, of any nature or kind, acquired, constructed or improved by the Borrower or any Related Entity after the date of this Agreement and, for greater certainty, shall include any buildings or other fixtures, acquired, constructed or improved by the Borrower after the date of this Agreement.

(b) "**Advance**" means a short-term loan made by OIPC to the Borrower in Canadian dollars pursuant to the terms and conditions of this Agreement.

(c) "**Advance Date**" has the meaning given to it in paragraph 6(a) hereof.

(d) "**Advance Interest Rate**" has the meaning given to it in paragraph 9(a) hereof.

(e) "**Agreement**" means the agreement constituted by this agreement including all attached schedules and referenced documents including the debenture(s) and the general security agreement and the respective terms and conditions thereunder, as the same may be amended, restated, modified or replaced from time to time. Terms such as "hereof", "herein" and "hereto" refer to this Agreement.

(f) "**Applicable Law**" means, in respect of any Person, property, transaction or event, all present or future applicable laws, statutes, regulations, treaties, judgments and decrees and all present or future applicable published directives, rules, policy statements, instruments and orders of any Public Authority and all applicable orders and decrees of courts and arbitrators of like application.

(g) "**Application**" has the meaning given to it in the first recital hereof.

(h) "**Authorized Officer**" means with respect to the Borrower, the Chairman of the Board of Directors, or any Executive Director or any other officer or Person designated from time to time by a resolution of the Board of Directors of the Borrower.

(i) "**Business Day**" means a day on which banking institutions in Toronto, Ontario, Canada are not authorized or obligated by law or executive order to be closed, other than Saturday or Sunday.

(j) "**Capital Lease Obligation**" means, in respect of any Person, the obligation of such Person, as lessee, to pay rent or other payment amounts under a lease of real or personal property which is required to be classified and accounted for as a capital lease or liability of such Person, in accordance with GAAP.

(k) "**Committed Amount**" has the meaning given to it in the second recital hereof.

(l) **"Current Ratio"** means current assets divided by current liabilities, where current assets shall exclude all accounts receivables due from affiliated entities or Persons that have no fixed terms of repayment.

(m) **"Debt Service Coverage Ratio"** means, in respect of the Borrower, on a consolidated basis, at any time, the amount determined in accordance with the formula: earnings before interest, taxes, depreciation and amortization (EBITDA) excluding extraordinary items divided by the sum of the principal and interest payments made on all interest-bearing loans, plus 75% of Unfinanced Net Capital Expenditures plus the dividends paid during the fiscal year where:

(i) **"Unfinanced Net Capital Expenditures"** means the capital expenditures in the period less the proceeds from sale of property, plant and equipment and other fixed assets during the normal course of business, and less the amount of such capital expenditures financed by (i) contributed shareholder or other third party entities, and (ii) the principal portion of term debt and capital lease Indebtedness.

(n) **"Debt to Capital Ratio"** means Debt divided by total Capital where:

(i)"**Debt**' means all short-term and long-term interest-bearing loans; and

(i)"**Capital**" means Debt plus Shareholder's net worth which is defined as the sum of share capital, preferred shares and retained earnings minus advances and/or investments to/in affiliated or related companies or third party entities minus goodwill and other intangible assets.

(o) "**Debentures**" means secured debentures of the Borrower issued from time to time pursuant to the terms and conditions of this Agreement.

(p) "**Debenture Interest Rate**" has the meaning given to it in paragraph 11(e) hereof.

(q) "**Debenture Purchase Certificate**" means a certificate substantially in the form as provided by OIPC to the Borrower.

(r) "**Debenture Purchase Date**" has the meaning given to it in paragraph 10(a) hereof.

(s) "**Drawdown Certificate**" means a certificate substantially in the form as provided by OIPC to the Borrower.

(t) **"Eligible Borrower"** means a public body that is eligible to borrow from OIPC pursuant to the *Ontario Infrastructure Projects Corporation Act, 2006* (Ontario).

(u) **"Equity"** means, on a consolidated basis, the book value, preferred and common shares, contributed surpluses and retained earnings of the Borrower.

(v) "**Event of Default**" means any of the events described in paragraph 13(c).

(w) "**Facility Termination Date**" means the earlier of 20th day of September, 2012 and the date on which the obligations of OIPC hereunder have been terminated pursuant to paragraphs 13(b) or 13(c) hereof.

(x) "**Financial Instrument Obligations**" means all obligations and liabilities of the Borrower or a Related Entity under or in respect of any interest or currency rate swap, forward agreement or other instrument which is a financial derivative.

(y) **"Fiscal Year"** means the fiscal year of the Borrower ending on December 31st in each calendar year.

(z) "**GAAP**" means the generally accepted accounting principles stated from time to time in the Handbook of the Canadian Institute of Chartered Accountants.

(aa) "**Indebtedness**" means, at any time and in respect of any Person, without duplication:

- (i) all obligations of such Person for money borrowed including:
    - (A) obligations with respect to bankers' acceptances;
    - (B) contingent reimbursement obligations with respect to letters of credit and other financial instruments; and
    - (C) all Purchase Money Obligations which would be indebtedness under GAAP but excluding, for greater certainty, trade indebtedness accounted for as accounts payable, accrued expenses and other similar current liabilities incurred in the ordinary course of operations determined in accordance with GAAP;
- (ii) any Capital Lease Obligation of such Person; and
- (iii) all undertakings of such Person in respect of obligations of any Person of the type described in (i) which such Person has guaranteed, directly or indirectly, or the holder of which such Person has otherwise assured against loss thereon.

(bb) "**Interest Period**" for an Advance means: (i) initially, the period from and including the date of the Advance to but excluding the next following Reset Date; and (ii) subsequently, each period from and including a Reset Date to but excluding the next following Reset Date.

(cc) "**Issue Date**" for a Debenture means the date on which the Debenture is issued.

(dd) "**Lien**" means any mortgage, hypothec, lien, pledge, assignment, charge, security interest, title retention agreement intended as security, or other similar encumbrance and any other arrangement which has the effect of granting security.

(ee) "**Limited Recourse Debt**" means Indebtedness, under which recourse in respect of a default in the repayment of such Indebtedness is limited to the asset or assets acquired with such Indebtedness by the Borrower or any Related Entity.

(ff) **"Material Related Entity"** means, at any relevant time, any Related Entity, the book value of whose assets, rights and properties constitutes in excess of 10% of the book value of the assets, rights and properties of the Borrower and all its Related Entities, considered as a whole.

(gg) "**Maturity Date**" has the meaning given to it in paragraph 11(a) hereof.

(hh) "**Obligations**" means the amount of all Advances provided to the Borrower pursuant to this Agreement and any unpaid interest thereon.

(ii) "**Officer's Certificate**" means a certificate of the Borrower that has been signed by an Authorized Officer.

(jj) **"Operating Line of Credit"** means a credit facility funding the day-to-day operating requirements of the Borrower and does not include use for long-term capital investments.

(kk) "**Permitted Liens**" means and refers to:

(i) Liens to which any Acquired Assets are subject at the time such Acquired Assets are acquired by the Borrower or any Related Entity provided that such Lien is limited to the Acquired Assets and such Lien has not been created or incurred in anticipation of such acquisition;

(ii) any Lien on or against cash or marketable debt securities to secure Financial Instrument Obligations incurred by the Borrower or any Related Entity in the course of its operations and not for speculative purposes;

(iii) any Lien in respect of a Purchase Money Obligation, Capital Lease Obligation or Limited Recourse Debt incurred in connection with or within 180 days of the acquisition, construction or improvement of any Acquired Assets and which secures the purchase price of such asset or the cost of acquiring, constructing or improving such asset provided that the amount secured by such Lien does not exceed the purchase price or cost of acquiring, constructing or improving such asset (including any applicable interest and/or lease payments to be paid);

(iv) any Liens to which assets acquired or which are deemed to have been acquired by the Borrower or any Related Entity pursuant to a merger or other combination with any other entity are subject at the time of such merger or other combination;

(v) Liens for Taxes, utility charges, levies, assessments or governmental charges:

  (A) not at such time past due; or

  (B) the validity of which are being contested in good faith and by appropriate proceedings;

(vi) the Lien of any judgment rendered, or claim filed, which is being contested in good faith and by appropriate proceedings;

(vii) undetermined or inchoate Liens and charges incidental to, purchases of goods, construction, maintenance or current operations which have not at such time been filed or registered pursuant to law, which relate to obligations which are at such time not past due or which, if filed or registered, are being contested in good faith and by appropriate proceedings;

(viii) easements, rights-of-way, servitudes or other similar rights in property (including rights-of-way and servitudes for railways, sewers, drains, gas and oil pipe lines, gas and water mains, electric light and power and telephone or telegraph or cable television conduits, poles, wires and cables) granted to or reserved or taken by other Persons;

(ix) security given to a public utility or any municipality or governmental or other public authority when and to the extent required by such utility or municipality or other authority in the ordinary course of operations of the Borrower or any Related Entity and not in connection with the borrowing of money or obtaining of credit by the Borrower or any Related Entity;

(x) the right reserved to or vested in any municipality or governmental or other public authority by the terms of any lease, license, franchise, grant or permit, or by any statutory provision, to terminate any such lease, license, franchise, grant or permit, or to require annual or other periodic payments as a condition of the continuance thereof;

(xi) the reservation in any original grant from the Crown of any land or interests therein and statutory exceptions to title;

(xii) Liens created or assumed by the Borrower or any Related Entity if an Authorized Officer has certified to OIPC that such Liens secure amounts which are not material having regard to the then current market value of the assets, rights and properties of the Borrower and its Related Entities, considered as a whole;

(xiii) any renewal, replacement or temporal extension (or successive renewals, replacements or extensions) in whole or in part of any Permitted Lien so long as the principal amount secured by such Permitted Lien does not exceed the principal amount secured by the Permitted Lien immediately prior to such extension;

(xiv) any and all Liens, whether direct or indirect, contingent or otherwise, to which any of the assets, rights and properties of the Borrower and its Related Entities are subject on the date of this Agreement; and

(xv) Liens or any rights of distress reserved in or exercisable under any lease for rent and for compliance with the terms of such lease.

(ll) "**Person**" includes an individual, firm, partnership, trust, trustee, executor, administrator, legal personal representative, government, governmental body or authority, corporation or other incorporated or unincorporated entity.

(mm) "**Prime Rate**" means, on any day, the annual rate of interest which is the arithmetic mean of the prime rates announced from time to time by the Reference Banks as their reference rates in effect on such day for Canadian dollar commercial loans made in Canada. If fewer than five of the Reference Banks quote a prime rate on such days, the "Prime Rate" shall be the arithmetic mean of the rates quoted by the remaining Reference Banks.

(nn) "**Principal Amount**" of an interest-bearing Debenture means the amount stated to be payable at maturity, exclusive of any interest.

(oo) "**Project**" has the meaning given to it in the second recital hereof.

(pp) "**Public Authority**" means any governmental, regional, municipal or local body having authority over either of the parties.

(qq) "**Purchase Money Obligation**" means any unpaid part of, or indebtedness incurred or assumed for the purpose of acquiring, a particular asset, right or property, the repayment of which is secured by recourse against such asset, right or property.

(rr) "**Reference Banks**" means, collectively, The Toronto-Dominion Bank, Bank of Nova Scotia, Bank of Montreal, Royal Bank of Canada and Canadian Imperial Bank of Commerce.

(ss) "**Related Entity**" means any company, corporation, partnership or other entity which is controlled by the Borrower either through the ownership of voting securities, by contract or otherwise.

(tt) "**Reset Date**" has the meaning given to it in paragraph 9(a) hereof.

(uu) "**Substantial Completion**" means the time at which the Project is ready for use or is being used for the purpose intended and is so certified by the architect, the engineer or entity licensed to practice in the province.

(vv) "**Successor Entity**" has the meaning given to it in paragraph 14 hereof.

(ww) "**Taxes**" means any present or future income, excise, stamp, capital, goods and services, property or other taxes, levies or withholding imposed by any taxing authority.

2. Representations and Warranties

The Borrower represents and warrants to OIPC that:

(a) the information contained in the Application, to the extent that it relates to the Borrower or the Project, is true and correct in all material respects as of the date of this Agreement;

(b) the Borrower has been duly incorporated pursuant to Section 142 of the *Electricity Act,* 1998 (Ontario) as amended, all of the shares of the Borrower are held by one or more municipal corporations and the Borrower is in the business of generating, transmitting, distributing, or retailing electricity and has the corporate power and capacity to:

  (i) own, lease and operate its properties and assets and to carry on its activities as a generator, transmitter, distributor or retailer of electricity;

  (ii) to borrow money;

  (iii) to enter into and complete the Project; and

  (iv) to execute and deliver this Agreement and to perform its obligations hereunder;

(c) the Borrower has taken all necessary corporate action to authorize the execution, delivery and performance of this Agreement;

(d) the Agreement has been duly authorized, executed and delivered by the Borrower and constitutes a valid and legally binding obligation, enforceable against the Borrower in accordance with its respective terms, subject to applicable bankruptcy, insolvency and other laws affecting the enforcement of creditors' rights generally;

(e) the execution and delivery by the Borrower of this Agreement and the performance by the Borrower of its obligations hereunder do not violate, result in a breach of, or constitute a default under:

(i) any of the terms, conditions or provisions of its constating documents or by-laws of the Borrower;

(ii) any resolution of the board of directors or any financial plan, budget, borrowing strategy or investment strategy of the Borrower; or

(iii) any statute, regulation or other law applicable to the Borrower;

(f) the Borrower is not currently in default under any Indebtedness and undertakes to immediately inform OIPC if it is in default under any Indebtedness at any time; and

(g) subject only to minor title defects not individually or in the aggregate material nor materially and adversely affecting the use thereof and subject to any security granted to OIPC pursuant to the provisions hereof, the Borrower has good and marketable title to its real and personal properties.

The representations and warranties set out in this paragraph 2 shall survive the execution and delivery of this Agreement and the making of any Advances to the Borrower, notwithstanding any investigations or examinations which may be made by OIPC or any counsel to it.

3. Covenants

The Borrower covenants and agrees with OIPC that:

(a) the proceeds of all Advances provided by OIPC to the Borrower shall be applied only to capital expenditures in respect of hard and soft capital costs actually incurred or to be incurred by the Borrower, if such costs and expenditures are directly related to the Project and not for any other purpose;

(b) the proceeds of each Debenture shall be applied only to either:

(i) repayment of Advances, as more particularly set out in paragraph 11 below; or

(ii) capital expenditures in respect of hard and soft capital costs actually incurred or to be incurred if OIPC in its sole discretion has agreed to purchase a Debenture prior to making any Advance or prior to the expenditure of all or any portion of the Committed Amount on the Project, by the Borrower, if such costs and expenditures are directly related to the Project in respect of which the Debenture is being issued; or

(iii) legal costs and expenses directly related to the issue of such Debenture;

and not for any other purpose;

(c) the Borrower shall duly and punctually pay or cause to be paid when due and payable the principal of and interest on all Advances and all other amounts owing in respect of all Advances, in conformity with the terms of this Agreement, and it shall faithfully observe and perform all the conditions, covenants and requirements of this Agreement;

(d) the Borrower will not, nor will it permit any Material Related Entity to, create, assume or suffer to exist any Lien upon the whole or any part of its assets, rights or properties (both real and personal, including licences, franchises, permits and leasehold interests) whether now owned or hereafter acquired if such Lien secures Indebtedness and is a Lien for the benefit of any Person other than OIPC unless such Lien is a Permitted Lien;

(e) the Borrower will not, nor will it permit any Material Related Entity to, sell, assign or otherwise dispose of any of its assets, rights and properties whether in a single transaction or a series of transactions, other than to the Borrower, unless:

 (i) such sale, assignment or other disposition is not material having regard to the assets, rights and properties of the Borrower and the Material Related Entities, taken as a whole or effected in the ordinary course of operations of the Borrower or the Material Related Entities, as applicable;

 (ii) the Borrower, concurrent with the completion of such sale, assignment or other disposition, provides OIPC with a certificate of an Authorized Officer to the effect that such Authorized Officer has no reason to believe that, after giving effect to such sale, assignment or other disposition, the Borrower will not be able to meet all of its financial obligations in accordance with their terms; including its obligation to pay principal and interest on the Advances; or

 (iii) in the case of a disposition of all or substantially all of its assets, the Borrower complies with paragraph 14 of this Agreement;

(f) the Borrower shall as soon as practicable following the approval thereof by the Borrower and, in any event, within one hundred and twenty (120) days after the end of each Fiscal Year of the Borrower, furnish OIPC with such number of copies as OIPC may reasonably request of an annual balance sheet, statement of revenue and expense, statement of changes in net assets, statement of cash flows, prepared in accordance with GAAP as applied to the presentation of financial information of the Borrower and reported on by an independent accountant and independent auditor, as well as a detailed calculation of required financial ratios pursuant to this Agreement; OIPC agrees to revise the required financial ratios should the difference between the current GAAP rules and the adoption of International Financial Reporting Standards have a material impact on the

Borrower's financial ratios. The revision shall be based on the original intent of the required ratios in this Financing Agreement but allow for reconciliation of the current GAAP rules and the International Financial Reporting Standards.

(g) the Borrower shall as soon as practicable following the approval thereof by the Borrower and, in any event within one hundred and twenty (120) days after the end of each Fiscal Year of the Borrower, furnish OIPC with the next Fiscal Year's operating and capital budget;

(h) the Borrower shall provide notice to OIPC within five (5) Business Days if the Borrower changes it operating bank, which is currently CIBC, and the Borrower shall provide OIPC with a copy of the term sheet issued by the Borrower's new operating bank with regard to any new Operating Line of Credit;

(i) the Borrower shall provide notice to OIPC within five (5) Business Days on the occurrence of any request for amendment or demand for payment of its promissory notes;

(j) the Borrower shall furnish OIPC as soon as practicable with any other financial reporting information that OIPC may require at its discretion and at any time prepared in accordance with GAAP;

(k) the Borrower shall furnish OIPC as soon as practicable with any other reports relevant to the business and financial fundamentals of the Borrower, including without limitation, proof of tax payments and statutory deductions, notification of applications or filings submitted to the OEB, IESO or any other regulatory body;

(l) the Borrower will at all times maintain its existence as a body corporate with all necessary approvals to carry on its operations as a municipal corporation that generates, transmits, distributes, or retails electricity under Applicable Law and conduct its operations in a proper and efficient manner, and will keep or cause to be kept proper books of account and will take all necessary steps to ensure that its Material Related Entities conduct their operations in a proper and efficient manner and keep or cause to be kept proper books of account;

(m) the Borrower shall maintain in force with reputable insurers insurance with respect to losses of or damage to its assets from such risks, casualties and contingencies and of such types and in such amounts and subject to such deductible amounts as are customary in the case of prudent persons of established reputation engaged in the same or similar businesses with similar assets, and any other form(s) of appropriate insurance that a prudent person in the business of operating a municipal corporation for the purposes of generating, transmitting, distributing or retailing electricity under Applicable Law would maintain. The Borrower's insurance carriers and policy provisions must be acceptable to OIPC and must remain in effect for the duration of this Agreement. OIPC shall be named as an additional insured and loss payee on all such insurance policies. The Borrower shall submit certificates of insurance as evidence of the above required insurance to OIPC prior to any Advances pursuant to this Agreement. Subsequent to Project completion, the Borrower shall maintain adequate liability, machinery replacement insurance naming OIPC as an additional insured on said insurance policies. The Borrower shall provide OIPC with a copy of its latest certificates of insurance or insurance policies with one hundred and twenty (120) days after the end of each Fiscal Year;

(n) since the date of incorporation of the Borrower, there has been no development materially adversely affecting the business or financial condition or position of the Borrower or its ability to carry on business as presently conducted or as contemplated hereunder to be conducted;

(o) the Borrower shall submit project management reports to OIPC for the Project (the "Reports") pursuant to the attached Schedule "D" to this Agreement; such Reports to be completed to the satisfaction of OIPC;

(p) the Borrower shall maintain a Debt Service Coverage Ratio of 1 to 1 or higher for the term of this Agreement, such ratio will otherwise be tested and calculated as of the end of each Fiscal Year as applicable;

(q) the Borrower shall maintain a Debt to Capital Ratio at 65% or lower for the term of this Agreement, such ratio will otherwise be tested and calculated as of the end of each Fiscal Year as applicable;

(r) the Borrower shall maintain its Current Ratio at 1.1:1 or higher for the term of this Agreement, such ratio will otherwise be tested and calculated as of the end of each Fiscal Year as applicable;

(s) the Borrower shall notify OIPC as soon as practicable after becoming aware of the occurrence of any Event of Default or of the occurrence of any event or circumstance which, after notice or lapse of time, would become an Event of Default;

(t) the Borrower shall and shall cause its subsidiaries to carry on its operations under Applicable laws, regulations, directives and market rules as established by the Independent Electricity System Operator (the "IESO"), the Ontario Energy Board and/or any other regulatory body at all times;

(u) the Borrower shall and shall cause its subsidiaries to conduct its operations in a proper and efficient manner, and will keep or cause to be kept proper books of account at all times;

(v) the Borrower shall and shall cause its subsidiaries to make payments on all required taxes including income and property taxes, statutory dues and levies and all other applicable fees; the Borrower shall notify OIPC immediately of any failure of making such payments when due;

(w) the Borrower shall not, without prior written consent of OIPC, make loans to, invest in, or make guarantees for any affiliated or unaffiliated companies or Persons in aggregate amounts exceeding 5.0% of its total assets;

(x) the Borrower shall not, without prior written consent of OIPC, distribute to shareholders in the form of dividends and/or share redemption, or make principal and interest payments on any promissory notes issued to the shareholders including the note of $139,981 to the Corporation of the Village of Alvinston, the note of $1,430,914 to the Corporation of the Town of Petrolia, the note of $655,187 to the Corporation of the Village of Point Edward, the note of $16,729,636 to the Corporation of Sarnia and the note of $421,886 to the Corporation of the Township of Warwick that will cause a monetary default or a breach of covenants including financial ratios required herein;

(y) the Borrower shall not, without prior written consent of OIPC, sell assets outside the ordinary course of business in an aggregate amount that exceeds 2.5% of its total assets, except that in the course of leading up to such sale, the Borrower or its subsidiaries has required replacement assets for the value no less than the assets being sold;

For greater certainty, OIPC is not responsible for ensuring that the proceeds of Advances and Debentures provided to the Borrower are in fact used in the manner specified in paragraphs 3(a) and 3(b) above.

4. Project Expenditure Requirements

The Borrower shall not request an Advance in respect of the Project hereunder unless expenditures in an amount no less than the amount of the Advance to be allocated to the Project have actually been incurred by the Borrower prior to the date of such request subject to the right of OIPC to waive this requirement at its sole discretion.

5. Evidence of Advances

OIPC shall open and maintain in accordance with its usual practice books of account evidencing all Advances and all other amounts owing by the Borrower to OIPC. OIPC shall enter in the foregoing accounts details of each Advance and of all amounts from time to time owing or paid by the Borrower to OIPC hereunder, the amounts of principal, interest and fees payable from time to time hereunder. The information entered in the foregoing accounts shall constitute, in the absence of manifest error, *prima facie* evidence of the obligations of the Borrower to OIPC hereunder, the date OIPC made each Advance available to the Borrower and the amounts the Borrower has paid from time to time on account of the principal of, interest on and fees related to the Advances.

6. Procedure for Obtaining Advances

(a) The Borrower may request an Advance to be made on either the 1st or the 15th day of any calendar month or the first Business Day following such date if such date is not a Business Day (either of which is defined as the "Advance Date") by delivering to OIPC at the address shown on Schedule "B" hereto no later than five (5) Business Days prior to the Advance Date on which the Advance is required, by courier or fax, an irrevocable Drawdown Certificate.

(b) The principal amount of all Advances will be tendered to the Borrower by electronic transfer of funds to an account of the Borrower maintained with a deposit-taking institution, such account to be designated by notice in writing to OIPC by the execution and delivery of the attached Schedule "C" to this Agreement and the Borrower undertakes to notify OIPC immediately in writing of any changes in its designated account for the purposes of such deposit.

7. Conditions Precedent to Advances

OIPC shall not make any Advance until each of the following conditions precedent has been satisfied:

(a) OIPC shall have received a Drawdown Certificate in respect of the Advance requested;

(b) at OIPC's discretion, if any issues that were raised in any audit conducted under paragraph 18(a) have been resolved to OIPC's satisfaction and/or OIPC has neither required an audit under paragraph 18(a) nor is such an audit ongoing;

(c) the amount of the requested Advance when added to the aggregate amount of Advances then outstanding in respect of the Project does not exceed the Committed Amount for the Project;

(d) the representations and warranties of the Borrower set out in paragraph 2 hereof shall be true and correct as at the date of the Advance, as evidenced by a Drawdown Certificate;

(e) the Borrower shall not be in material default of any of its obligations under this Agreement as at the date of the Advance, as evidenced by a Drawdown Certificate;

(f) no Event of Default shall have occurred and be continuing;

(g) the Borrower shall have executed, delivered to OIPC and registered as applicable, all Security documents as described in paragraph 12 (a);

(h) expenditures on the Project shall have been incurred subject to paragraph 4, as evidenced by a Drawdown Certificate;

(i) a legal opinion from the Borrower's external legal counsel addressed to OIPC and in the form and substance satisfactory to OIPC shall have been delivered to OIPC on or prior to the first Advance made by OIPC;

(j) at OIPC's discretion, the requested Advance when added to the aggregate amount of all Advances then outstanding does not exceed the Advance requests as noted in Schedule "A" hereto;

(k) OIPC shall have received evidence in the form of valid certificates of insurance from the Borrower that OIPC has been named as an additional insured on all insurance policies in association with the construction of the Project by the entity that is responsible for the development of the Project and that has been retained by the Borrower;

(l) OIPC shall have either been named as a dual obligee on any surety bonds (e.g., performance and labour and materials bond) issued to the Borrower by the surety or the Borrower shall have ensured that a dual obligee rider (naming OIPC as a obligee) has been inserted into any surety bond issued to the Borrower by the surety; and

(m) the Borrower shall have provided OIPC with copies of any powers of attorney which accompany any surety bonds issued to it as evidence of authorization from the surety company;

8. Conditions Precedent to Debenture Purchases

OIPC shall not purchase any Debenture until each of the following conditions precedent, has been satisfied, subject also to paragraphs 10 and 11:

(a) OIPC shall have received a Debenture Purchase Certificate;

(b) the amount from the proceeds of the Debenture purchase when added to the aggregate amount of Debentures then outstanding in respect of the Project does not exceed the Committed Amount;

(c) the representations and warranties of the Borrower set out in paragraph 2 hereof shall be true and correct as at the date of the Debenture purchase, as evidenced by a Debenture Purchase Certificate;

(d) the Borrower shall not be in material default of any of its obligations under this Agreement as at the date of the Debenture purchase, as evidenced by a Debenture Purchase Certificate;

(e) at OIPC's discretion, if any issues that were raised in any audit conducted under paragraph 18(a) have been resolved to OIPC's satisfaction and/or OIPC has neither required an audit under paragraph 18(a) nor is such an audit ongoing;

(f) no Event of Default shall have occurred and be continuing;

(g) the Borrower shall have executed, delivered to OIPC and registered as applicable, all Security documents as described in paragraph 12 (a);

(h) a legal opinion from the Borrower's external legal counsel addressed to OIPC and in the form and substance satisfactory to OIPC shall have been delivered to OIPC;

(i) expenditures on the Project shall have been incurred or will be incurred if OIPC in its sole discretion has agreed to purchase a Debenture prior to making any Advance or prior to the expenditure of all or any portion of the Committed Amount on the Project, as evidenced by a Debenture Purchase Certificate;

(j) OIPC shall have received evidence in the form of valid certificates of insurance from the Borrower that OIPC has been added as a named insured on all insurance policies in association with the construction of the Project by the entity that is responsible for the development of the Project and that has been retained by the Borrower;

(k) OIPC shall have either been named as a dual obligee on any surety bonds (e.g., performance and labour and materials bond) issued to the Borrower by the surety or the Borrower shall have ensured that a dual obligee rider (naming OIPC as a obligee) has been inserted into any surety bond issued to the Borrower by the surety; and

(l) the Borrower shall have provided OIPC with copies of any powers of attorney which accompany any surety bonds issued to it as evidence of authorization from the surety company;

9. Interest on Advances

(a) Each Advance shall bear interest at a floating rate per annum as determined by OIPC based on OIPC's cost of funds plus OIPC's prevailing spread assigned to the borrower sector for program delivery costs and risks (the "Advance Interest Rate"). The Advance Interest Rate for an Advance for the initial Interest Period shall be set by OIPC based on OIPC's cost of funds plus OIPC's prevailing spread assigned to the borrower sector for program delivery costs and risks and will be effective on the date of the Advance. The Advance Interest Rate for each subsequent Interest Period shall be reset on the first Business Day of each calendar month (each such Business Day, a "Reset Date") for the following Interest Period as set by OIPC at its discretion and will be effective on the Reset Date, which Advance Interest Rate as so reset shall apply to the Advance for such Interest Period until reset again.

(b) Interest accrued during an Interest Period on the principal balance of an Advance outstanding during such Interest Period shall be payable in arrears on the first Business Day of the calendar month following the Interest Period in an amount equal to the product of the Advance Interest Rate in effect during such Interest Period and the principal balance of the Advance outstanding as at the Reset Date for such Interest Period, or in the case of an initial Interest Period the principal balance outstanding on the date of the Advance, multiplied by a fraction, the numerator of which is the number of days in the Interest Period and the denominator of which is 365.

(c) Payments of interest due by the Borrower for any Advance, and any other payments due under this Agreement, shall be made by pre-authorized debit from an account of the Borrower maintained with a deposit-taking institution, such account to be designated by notice in writing to OIPC by the execution and delivery of the attached Schedule "C" to this Agreement which Schedule forms part of this Agreement, together with such other authorizations, voided cheques and other documentation as the deposit-taking institution and the rules of the Canadian Payments Association may require for such pre-authorized debit, and the Borrower undertakes to notify OIPC immediately in writing of any changes in its designated account for the purposes of pre-authorized debits.

(d) The Borrower shall pay interest to OIPC on any overdue amount of principal or interest in respect of any Advance, both before and after demand, default, maturity and judgment, at a rate per annum equal to the Prime Rate plus 200 basis points, calculated on a daily basis from the date such amount becomes overdue for so long as such amount remains overdue, and the Borrower shall pay to OIPC any and all costs and losses incurred by OIPC as a result of the payment having been overdue.

(e) For purposes of disclosure pursuant to the *Interest Act* (Canada), the yearly rate of interest which is equivalent to a rate of interest payable in respect of the principal amount of any Advance for any period of less than a year may be determined by multiplying the rate of interest for such period by a fraction, the numerator of which is the actual number of days in a year commencing on and including the first day in such period and ending on but excluding the corresponding day in the next calendar year and the denominator of which is the actual number of days in such period.

10. Purchase of Debentures

(a) Provided that the Borrower is not in default under this Agreement, that all of the conditions precedent listed in paragraph 8 have been satisfied and that none of the events specified in paragraph 13(c) shall have occurred and be continuing, and upon satisfaction of such other usual and customary conditions precedent as OIPC and its legal counsel may reasonably require, and subject to paragraph 11 hereof, OIPC agrees to purchase Debentures from the Borrower on the 1st or 15th of the calendar month next following the debenture purchase date(s) as noted on the attached Schedule "A" and as determined in the sole discretion of OIPC ("Debenture Purchase Date") and/or at a time or times to be determined at the sole discretion of OIPC, on or prior to the Facility Termination Date in an aggregate Principal Amount not to exceed the Committed Amount and subject to the detailed Debenture purchase process to be provided to the Borrower.

(b) Notwithstanding anything in this Agreement, the Borrower hereby irrevocably offers to issue Debentures in the amount of the Obligations subject to the terms and conditions as described herein within one hundred and twenty (120) days of Substantial Completion of the Project. OIPC's acceptance of this offer will constitute an irrevocable agreement between the Borrower and OIPC for the Borrower to issue and offer to sell to OIPC such Debentures on the terms and conditions hereof. In the event that the Borrower fails to complete the issuance of Debentures on the terms as described herein within one hundred and twenty (120) days of Substantial Completion, thereafter the Debenture Interest Rate shall increase to the Prime Rate.

(c) The purchase price for any Debenture issued in accordance with paragraph 10(a) shall be satisfied by virtue of and to the extent of the satisfaction of the Obligations effected by such issuance pursuant to paragraph 11(d). Satisfaction of such purchase price by such means shall be deemed to be equivalent for all purposes, to the receipt by the Borrower from OIPC of a sum of money equal to the amount of the Obligations so satisfied. If such purchase price exceeds the amount of the Obligations so satisfied, OIPC shall pay such excess to the Borrower in immediately available funds upon the issue of the Debentures.

(d) If OIPC agrees to purchase a Debenture(s) from the Borrower prior to making any Advance or prior to the expenditure of all or any portion of the Committed Amount on the Project, the Borrower agrees that it will submit an annual report to OIPC, in the form to be provided by OIPC, verifying that all proceeds of such Debenture(s) have been used exclusively for the financing of the Project during the relevant period. The first such report shall be due on the first anniversary of the purchase of the Debenture(s) by OIPC and subsequent reports shall be due annually thereafter on subsequent anniversaries until such time as all the proceeds of such Debenture(s) have been expended.

(e) The purchase price for Debentures, in excess of the principal amount of any outstanding Obligations, will be tendered to the Borrower by electronic transfer of funds to an account of the Borrower maintained with a deposit-taking institution, such account to be designated by notice in writing to OIPC by the execution and delivery of the attached Schedule "C" to this Agreement and the Borrower undertakes to notify OIPC immediately in writing of any changes in its designated account for the purposes of such deposit.

11. Issue of Debentures and Repayment of Advances

(a) Each Advance shall be due and payable in full on the earlier of the Facility Termination Date or the Debenture Purchase Date for the Project for which the Advance was made (the "Maturity Date"), subject to OIPC's right to extend the Maturity Date in its sole discretion. The Borrower shall repay the Advance on the Maturity Date by:

(i) paying an amount equal to the Advance to OIPC in immediately available funds;

(ii) converting the Advance into long term financing by issuing to OIPC one or more Debentures in a principal amount at least equal to the Advance to be repaid; or

(iii) any combination of (i) and (ii).

(b) The Borrower shall notify OIPC at least sixty (60) days in advance of the Debenture Purchase Date as noted on Schedule "A" hereto if the Debenture(s) will not be offered for purchase on such date and the Borrower shall propose another Debenture Purchase Date subject to OIPC's rights under paragraph 10(a) and subject to OIPC's right to reject the new Debenture Purchase Date.

(c) An Advance may be repaid at any time prior to its Maturity Date at the discretion of OIPC and subject to such terms and conditions as may be imposed at OIPC's discretion. The principal amount of any such repaid Advance cannot be subsequently borrowed by the Borrower.

(d) The issuance of Debentures shall satisfy the Obligations then outstanding to the extent of the aggregate Principal Amount of such issuance with the exception that any amount owing for interest on the Obligations on the Issue Date will be payable on the next following Reset Date and will not be added to the aggregate Principal Amount of such issuance. If such aggregate Principal Amount is less than the total amount of the Obligations, then the principal owing on the balance of the Obligations shall be repaid on the Issue Date to the extent of such aggregate Principal Amount and the interest owing on such balance on the Issue Date will be payable on the next following Reset Date, subject to the right of OIPC to permit the Borrower to satisfy the said balance of the Obligations at a later date.

(e) The interest rate for each Debenture (the "Debenture Interest Rate") shall be fixed by OIPC based on OIPC's cost of funds plus OIPC's prevailing spread assigned to the borrower sector for program delivery costs and risks. A rate confirmation letter will be sent to the Borrower by OIPC confirming the interest rate to be offered for the Debenture and the Borrower's acceptance of such rate shall be conclusive proof of acceptance of the rate offered.

(f) Payments of principal and interest due on each Debenture, and any other payments due under this Agreement, shall be made by pre-authorized debit from an account of the Borrower maintained with a deposit-taking institution, such account to be designated by notice in writing to OIPC by the execution and delivery of the attached Schedule "C" to this Agreement, together with such other authorizations, voided cheques and other documentation as the deposit-taking institution and the rules of the Canadian Payments Association may require for such pre-authorized debit, and the Borrower undertakes to notify OIPC immediately in writing of any changes in its designated account for the purposes of pre-authorized debits.

12. Security and Standby Fees

(a) As continuing collateral security for the payment by the Borrower to OIPC under the terms of this Agreement and for performance by the Borrower of its obligations hereunder, the Borrower acknowledges and agrees that OIPC is to have the benefit of:

(i) the general security agreement as more particularly described in Schedule "E" hereto, ranking in second priority behind the general security agreement registered in favour of the Canadian Imperial Bank of Commerce;

(ii) an acknowledgement and consent from the Canadian Imperial Bank of Commerce in the form attached as Schedule "F" hereto; and

(iii) all insurance as required by this Agreement with loss payable to OIPC as loss payee on insurance policies covering physical loss or damage to the Project and an assignment of insurance proceeds to OIPC.

(b) The Borrower shall pay OIPC a standby fee (the "Standby Fee") calculated at the rate of 25 basis points (0.25% per annum) on the unadvanced balance of the Committed Amount should the Borrower fail to draw any funds pursuant to this Agreement from OIPC during any period of twelve (12) consecutive months commencing initially from the Effective Date of this Agreement and subsequently from the date of the draw of any such funds until the earlier of the Facility Termination Date or the full advance of the Committed Amount. The Standby Fee shall be calculated daily on the basis of a calendar year of 365 or 366 days, as the case may be, and shall be due and payable by the Borrower monthly in arrears on the last Business Day of each month in accordance with the pre-authorized debit procedure outlined in paragraphs 9(c) and 11(f) above.

13. Term, Termination and Default

(a) This Agreement shall terminate ten (10) Business Days following the date on which the last Obligations outstanding hereunder are paid in full or following the last payment made by the Borrower to OIPC as specified on the Debenture(s) and or general security agreement pursuant to this Agreement unless earlier terminated in accordance with paragraphs (b) or (c) below.

(b) OIPC may terminate its obligations under this Agreement on thirty (30) days prior notice in writing to the Borrower if in the reasonable opinion of OIPC the Borrower is in material default under this Agreement, other than for any cause enumerated in (c) below or if OIPC rejects a new Debenture Purchase Date pursuant to section 11(b).

(c) OIPC may terminate any or all of its obligations under this Agreement immediately, subject to paragraph (d) below,

(i) if the Borrower:

(A) fails to make one or more payments of principal or interest in respect of any Advance or Debenture within five (5) Business Days after the same becomes due and payable;

(B) reaches or exceeds any updated debt and financial obligation limit imposed by its by-laws or any resolution of the Board of Directors of the Borrower;

(C) has failed to pay principal of or interest on any Indebtedness other than the Advances or Debentures issued under this Agreement when due and such default continues for five (5) Business Days;

(D) has failed to meet and pay any of its liabilities and obligations other than Indebtedness when due and default in payment is occasioned from financial difficulties affecting the Borrower;

(E) has or may become involved in financial difficulties such that default or unusual difficulty in meeting debts or obligations or in providing adequate funds to meet current expenditures may ensue;

(F) uses any Advance or the proceeds of any Debenture financing provided by OIPC for any purpose other than financing the Project;

(G) takes any action to authorize the termination of the existence of the Borrower or a resolution is passed authorizing the termination of the existence of the Borrower, unless such action or resolution is being pursued by the Borrower on the basis that it has made provision for payment of all of its Indebtedness including all of the Advances and Debentures issued under this Agreement, that no court proceedings are pending against it and that it has obtained the approval of its creditors to a plan for the rateable distribution of all of its property; or

(H) is subject to any proceeding whereby such proceeding shall be instituted against the Borrower or applying to a substantial part of its property or assets seeking to adjudicate it a bankrupt or insolvent, or seeking liquidation, dissolution, winding-up, reorganization, arrangement, adjustment, protection, relief or composition of it or any substantial part of its property or debt under any law relating to bankruptcy, insolvency or reorganization or relief of debts, or seeking an order for relief or the appointment of a receiver, trustee or other similar official for it or for any substantial part of its property and such proceeding shall have continued undismissed or unstayed for sixty (60) days, or a creditor or creditors of the Borrower shall privately appoint a receiver, trustee or similar official for any substantial part of the property of the Borrower and, if the Borrower shall be contesting such appointment in good faith, such appointment shall continue for ninety (90) days; or any such action or proceeding shall have been consented to or not expeditiously opposed by the Borrower;

(ii) if the Borrower shall fail to observe or perform any covenant or condition contained herein and the Borrower shall not make good such default within a period of thirty (30) days after written notice has been given to the Borrower by OIPC;

(iii) if the representations and warranties made by the Borrower in this Agreement and/or the Application, or in any certificate or other document delivered hereunder shall be incorrect in any material respect when made and, if such incorrect representation or warranty is curable, the Borrower shall fail to make good such default within a period of thirty (30) days after notice in writing has been given to the Borrower by OIPC;

(iv) if issues raised in an audit required under paragraph 18(a) have not been resolved to OIPC's satisfaction within a reasonable time after the Borrower has been notified of such issues;

(v) if the report of the auditors on any annual financial statements delivered pursuant to paragraph 3(f) or any other financial information requested by OIPC delivered pursuant to paragraph 3(g) or 3(j) hereof shall be qualified in any way which OIPC acting reasonably deems to be materially adverse or if the Borrower should fail to supply any documents requested pursuant to paragraphs 3(f), (g) and (j);

(vi) if any final judgment is obtained against the Borrower for an amount in excess of $100,000 and, within 10 days of the obtaining thereof, such judgment has not been discharged or execution thereunder stayed; or

(vii) if at any time any licence or approvals required by the Borrower by any Applicable Law or Public Authority to carry on the business of a municipal corporation for the purposes of generating, transmitting, distributing or retailing electricity has been assigned, cancelled or suspended;

(viii) if the Borrower shall fail to have obtained the consent required under paragraph 14(i);

(ix) if the Borrower shall enter into any Indebtedness which is senior to any Indebtedness to OIPC, other than pursuant to this Agreement, subsequent to the date of this Agreement without the prior written consent of OIPC or

(x) if the shares of the Borrower are no longer held exclusively by one or more municipal corporations as further described in paragraph 2(b) above.

(d) If OIPC elects to terminate its obligations under this Agreement pursuant to paragraph 13(c) hereof, it shall give notice in writing of such termination to the Borrower, specifying the reason for such termination. Upon delivery of such notice OIPC shall have no further obligation to make any Advances or to purchase any Debentures hereunder. In such notice OIPC may also declare all Obligations and Debentures outstanding hereunder to be immediately due and payable, whereupon such Obligations and Debentures shall become immediately due and payable pursuant to paragraph 11(f) in addition to any other rights or remedies that OIPC may have at law or in equity to enforce such Obligations and Debentures.

(e) No delay on the part of OIPC in exercising any remedy and no waiver by OIPC of any of its rights against the Borrower shall operate as a waiver of any other rights nor shall any single or partial exercise of any remedy against the Borrower restrict other or further exercises of such remedy, all remedies being cumulative and not exclusive.

(f) If OIPC elects to terminate its obligations under this Agreement in accordance with paragraphs 13(b) or (c) above, OIPC, at its discretion, shall assess any losses that it may incur as a result of the early termination as follows: if on the date of termination the outstanding principal balance on the Debenture is less than the net present value of the Debenture, the Borrower shall pay the difference between these two amounts to OIPC. Net present value will be calculated based on the following formulae: For Bullet Debenture – [(principal) / (1+(r/2))^n] + [(interest payment /(r/2))*(1-(1/(1+(r/2))^n)] or for Serial Debenture – [(principal) / (1+(r/2))^n] + [(interest payment /(r/2))*(1-(1/(1+(r/2))^n)] for each remaining serial principal repayment or for Amortizing Debenture – [(loan payment /(r/2))*(1-1/(1+(r/2))^n)], where "r" is the prevailing lending rate less an appropriate basis point deduction for costs incurred and "n" is the number of semi-annual periods to maturity.

14. Successor Corporations

The Borrower may:

(a) amalgamate, merge, consolidate or otherwise combine pursuant to statute or by private agreement with any other Person, or

(b) sell, lease or otherwise dispose of all or substantially all of its assets, rights and properties, whether in a single transaction or a series of related transactions, to any other Person;

provided, in either case that:

(i) the prior written consent of OIPC is obtained;

(ii) the resulting or acquiring entity (the "Successor Entity") is a body corporate existing and organized under the laws of Canada or any province or territory thereof;

(iii) the Successor Entity is an Eligible Borrower;

(iv) the Successor Entity expressly assumes the due and punctual payment of the principal of, and all interest on all Advances and all other amounts owing hereunder and the performance and observance of all of the covenants and conditions of this Agreement on the part of the Borrower to be performed;

(v) the Successor Entity delivers an opinion acceptable to counsel for OIPC, acting reasonably, to the effect that the Successor Entity has validly assumed such obligations; and

(vi) no Event of Default shall have occurred or be continuing as of the effective date of each such transaction or shall arise as of the effective date of each such transaction and as a result thereof and the Borrower shall have provided OIPC with an Officer's Certificate to such effect.

15. Communications Requirements

(a) OIPC and the Borrower will work together to ensure that OIPC financing of the Project receives recognition and prominence through agreed upon communications activities. An example of such activity could include signage at the project site signifying Government of Ontario project financing.

(b) OIPC reserves the right to undertake its own communications activities in relation to OIPC financing of the Project at anytime in its sole discretion and at its expense.

(c) All joint communications activities between the Borrower and OIPC must comply with the Government of Ontario's Visual Identity Directive and guidelines.

16. Project Management Requirements

(a) (a) As a condition of OIPC making financing available to the Borrower as further described in the second recital hereof, the Borrower shall: (1) be required to have a qualified project manager in place for the Project subject to OIPC approval; (2) comply with OIPC's project management reporting requirements for the Project; and (3) shall submit the Reports to OIPC pursuant to and as further described in the attached Schedule "D" to this Agreement.

(b) Reports submitted by the Borrower to OIPC are for OIPC's reference only and in no way shall OIPC, its officers, directors, agents, subcontractors, or employees be held responsible or liable at law for: (a) any claim, demand or action brought forward by any party, including third parties, against OIPC; and (b) direct or indirect consequential damages, including bodily injury, death or property damages, arising out of or in any way related to the Reports, this Agreement or the Project.

17. Indemnity

To the fullest extent permitted by law, the Borrower shall indemnify and hold harmless OIPC, its officers, directors, employees and agents (the "Indemnified

Parties") from and against all (a) claims and causes of action, pending or threatened, of any kind (whether based in contract, tort or otherwise) by third parties or by whomever made related to or arising out of or in any way related to the Reports, this Agreement or the Project and (b) liabilities, losses, damages, costs and expenses (including, without limitation, legal fees and disbursements) suffered or incurred by any of the Indemnified Parties in connection with any claims or causes of action described in (a) above. The obligations contained in this paragraph shall survive the termination or expiry of this Agreement.

18. General Provisions

(a) OIPC reserves the right to audit compliance with this Agreement at any time. Such right will survive any termination of this Agreement. The cost of any such audit will be at OIPC's or the Borrower's expense at OIPC's discretion. The Borrower is required to keep any supporting documents required for any such audit for a minimum of seven (7) years.

(b) No amendment, supplement, restatement or termination of any provision of this Agreement is binding unless it is in writing and signed by each party.

(c) The Borrower may not assign its rights or transfer its obligations under this Agreement without the prior written consent of OIPC. OIPC may assign its rights or transfer its obligations under this Agreement without the prior written consent of the Borrower by giving thirty (30) days notice of such assignment or transfer to the Borrower. This Agreement enures to the benefit of and binds the parties and their respective successors and permitted assigns.

(d) This Agreement, together with the Schedules, the Application, the Drawdown Certificate, the Debenture Purchase Certificate, the Officer's Certificates delivered hereunder, the annual report provided for in paragraph 10(c) hereof, the Debenture(s) and the general security agreement and their respective terms and conditions delivered hereunder constitute the entire agreement between the parties with respect to the subject matter referenced in those documents and supersedes all prior agreements, negotiations, discussions, undertakings, representations, warranties and understandings, whether written or oral.

(e) Each party shall from time to time promptly execute and deliver all further documents and take all further action reasonably necessary or appropriate to give effect to the provisions and intent of this Agreement.

(f) This Agreement is governed by, and is to be construed and interpreted in accordance with, the laws of the Province of Ontario and the federal laws of Canada applicable in the Province of Ontario.

(g) This Agreement and any amendment, supplement, restatement or termination of any provision of this Agreement may be executed and delivered in any number of counterparts, each of which when executed and delivered is an original but all of which taken together constitute one and the same instrument.

(h) Either party may deliver an executed copy of this Agreement by fax but that party shall immediately deliver to the other party an original executed copy of this Agreement.

(i) Unless otherwise specified, each notice to a party must be given in writing and delivered personally or by courier, sent by prepaid registered mail or transmitted by fax to the address or fax number set out in Schedule "B".

(j) If any provision of this Agreement is or becomes illegal, invalid or unenforceable in any jurisdiction, the illegality, invalidity or unenforceability of that provision will not affect:

- (i) the legality, validity or enforceability of the remaining provisions of this Agreement; or
- (ii) the legality, validity or enforceability of that provision in any other jurisdiction.

(k) All covenants, agreements, representations and warranties made herein or in any document delivered pursuant to the provisions hereof are material, shall be deemed to have been relied upon by each party hereto and, notwithstanding any investigation heretofore or hereafter made by such party shall survive the execution and delivery of this Agreement until all amounts owing pursuant to the provisions hereof have been paid in full.

(l) Words importing the singular include the plural and vice versa.

IN WITNESS WHEREOF the parties hereto have executed this Agreement effective as of the date first above written.

ONTARIO INFRASTRUCTURE PROJECTS CORPORATION

By:

Name: Bill Ralph

Title: Senior Vice President, Infrastructure Lending and Chief Risk Officer

I have authority to bind the Corporation.

BLUEWATER POWER DISTRIBUTION CORPORATION

By: J McMichael-Denn

Name: Janice L. McMichael-Dennis
Title: President & Chief Executive Officer

By:

Name: G. Firman Bentley
Title: Chairman of the Board

We have authority to bind the Corporation.

Mark Hut

NAME: MARK HUTSON
TITLE: CHIEF FINANCIAL OFFICER
BLUEWATER POWER
DISTRIBUTION CORPORATION

[Affix Corporate Seal]

SCHEDULE "A"

FINANCING SCHEDULE

Print Form Submit by Email

ONTARIO INFRASTRUCTURE PROJECTS CORPORATION

Financing Schedule

Program Year: **2010/2011**

Date: **Jul 26, 2010**

Organization Name: **Bluewater Power Distribution**

Approved Loan Amount: **$9,300,000.00**

Please review, complete areas where indicated, sign, date and return the form to OIPC. The following information will be incorporated into the OIPC Financing Agreement.

The following lists the project information outlined in your application. Please verify that the project details are correct. You may amend the project completion dates or the total project cost if this information has changed since the application was submitted. Transfers between projects or categories are at OIPC's discretion and require pre-approval.

A Project Details

	Project Information						Financing Information					
App ID	**Project Name**	**Category**	**Start Date (mm/dd/yyyy)**	**Completion Date (mm/dd/yyyy)**	**Total Project Cost**	**OIPC Loan Amount**	**Project ID**	**Term**	**Type**	**Amount**	**Application Request Date * (mm/dd/yyyy)**	**Revised Request Date (mm/dd/yyyy)**
1002 7	Smart Meter Project	MCOther	5/31/2010	5/31/2010	$9,300,000.00	$9,300,000.00	6611	10 y	Amortizing	$9,300,000.00	6/30/2010	
					$9,300,000.00	**$9,300,000.00**				**$9,300,000.00**		

* **Please note, debentures are to be purchased after expenditures have been incurred. Please review and adjust the Application Debenture Purchase Date if required ensuring adequate time for the debenture purchase. For further clarifications or questions, please contact Debbie Chen-yin, Loan Operations, Community Loans Management at 416-326-1149.**

ONTARIO INFRASTRUCTURE PROJECTS CORPORATION

Financing Schedule

Program Year: **2010/2011**

Date: **Sept. 23, 2010**

Organization Name: **Bluewater Power Distribution**

Approved Loan Amount: **$9,300,000.00**

B Construction Financing Quarterly Forecast

If you wish to participate in the construction loan program, please indicate the amount of construction financing you require per fiscal quarter and per debenture. A reminder that OIPC provides construction advances based on incurred project expenditures, unless prior approval has been sought.

Project ID	JUL-SEP 2010	OCT-DEC 2010	JAN-MAR 2011	APR-JUN 2011	JUL-SEP 2011	OCT-DEC 2011	JAN-MAR 2012	APR-JUN 2012	JUL-SEP 2012	OCT-DEC 2012
6611	$ 0	$5,300,000	$1,000,000	$1,500,000	$1,000,000	$ 500,000				

Project ID	JAN-MAR 2013	APR-JUN 2013	JUL-SEP 2013	OCT-DEC 2013	JAN-MAR 2014	APR-JUN 2014	JUL-SEP 2014	OCT-DEC 2014	JAN-MAR 2015	APR-JUN 2015
6611										

ONTARIO INFRASTRUCTURE PROJECTS CORPORATION

Financing Schedule

Program Year: **2010/2011**

Date: **Jul 26, 2010**

Organization Name: **Bluewater Power Distribution**

Approved Loan Amount: **$9,300,000.00**

C Authorization

I agree that these are the terms for the OIPC loan. I understand that OIPC will use this information to draft the Financing Agreement.

Mark Hutson

Chief Financial Officer
PRINT NAME

Signature

Sept 27, 2010

Date

DIRECTIONS: Please mail or courier the original signed Financing Schedule to OIPC, 777 Bay Street, 9th Floor, Toronto, ON M5G 2C8

SCHEDULE "B"

ADDRESSES FOR NOTICE

Ontario Infrastructure Projects Corporation
777 Bay Street, 9th Floor
Toronto, Ontario M5G 2C8

Attn: Director, Loans Operations
Tel.: 416-326-1149
Fax: 416-263-5900

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

Attn: Christina McCready, Executive Admin.
Tel.: 519-337-8201 ext. 263
Fax: 519-344-6094

SCHEDULE "C"

PRE-AUTHORIZED DEBIT ("PAD") AND ACCOUNT FOR DEPOSIT

BLUEWATER POWER DISTRIBUTION CORPORATION

(1) Account Holder Information

Full Legal Name: Bluewater Power Distribution Corporation

Exact account name: Bluewater Power Distribution Corp.

Address: 855 Confederation Street City: Sarnia

Province: ON Postal Code: N7T 7L6 Phone #: 519-337-8201

(2) Financial Institution Information **(Note: Please attach VOID cheque)**

(i) Inflow of Deposits

Name of Financial Institution: CIBC

Address: 1170 London Road City: Sarnia

Province: ON Postal Code: N7S 1P6 Phone #: 519-337-0373

Transit #: 04382 Institution #: 010 Account #: 92 97316

(ii) Outflow of Pre-Authorized Debit

☒ Same as above

☐ If different from above fill out banking information below

Name of Financial Institution: ______

Address: ______ City: ______

Province: ______ Postal Code: ______ Phone #: ______

Transit #: ______ Institution #: ______ Account #: ______

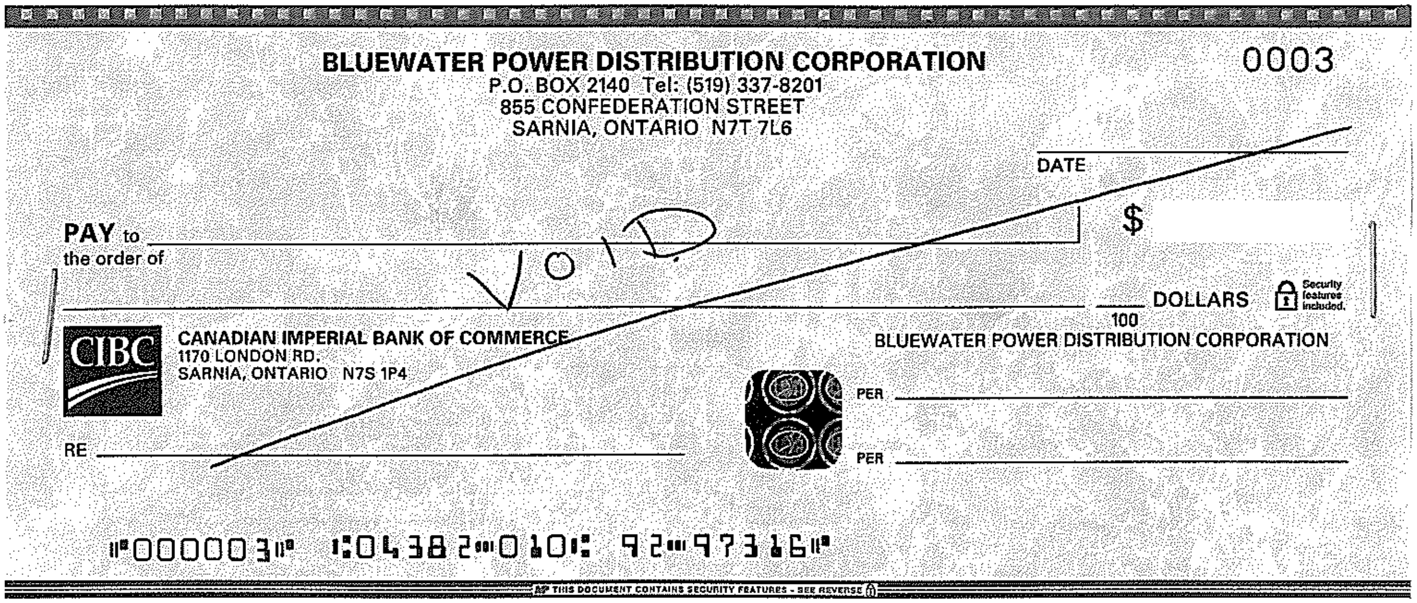
Sample of the numbering at the bottom of a cheque

001234	01234 - 001		111-222-3
⇩ Cheque #	⇙ Transit #	⇘ Institution #	⇩ Account #

PRE-AUTHORIZED DEBIT ("PAD") AND ACCOUNT FOR DEPOSIT

BLUEWATER POWER DISTRIBUTION CORPORATION

Attach VOID Cheque Here:



BLUEWATER POWER DISTRIBUTION CORPORATION
P.O. BOX 2140 Tel: (519) 337-8201
855 CONFEDERATION STREET
SARNIA, ONTARIO N7T 7L6

0003

DATE

PAY to the order of

$

VOID

DOLLARS
100

CIBC
CANADIAN IMPERIAL BANK OF COMMERCE
1170 LONDON RD.
SARNIA, ONTARIO N7S 1P4

BLUEWATER POWER DISTRIBUTION CORPORATION

PER

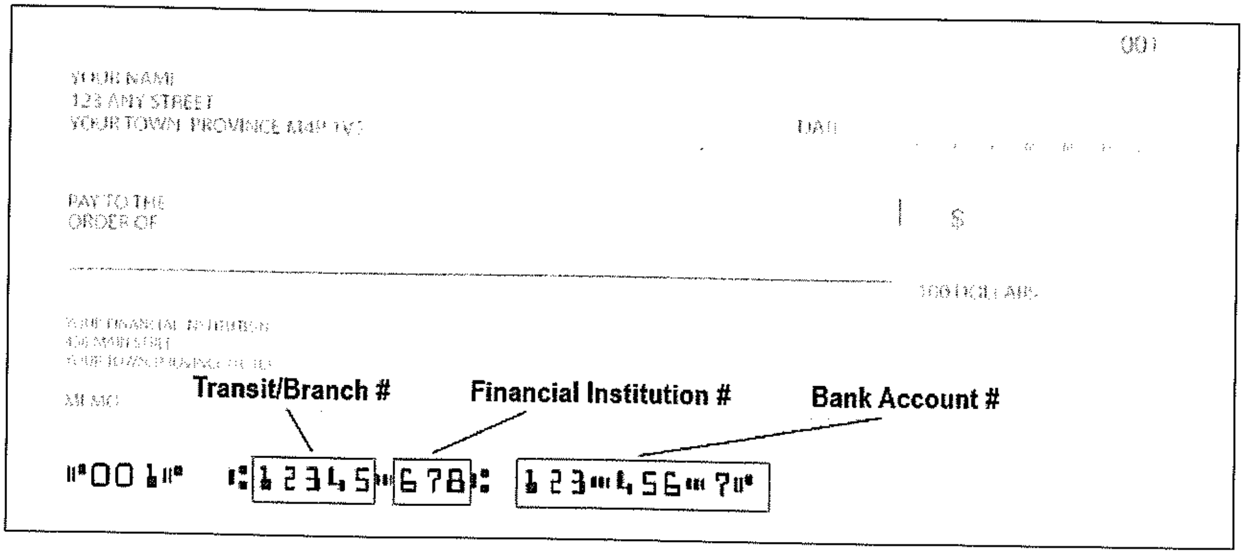
PER

RE

⑈000003⑈ ⑆04382⑉010⑆ 92⑉97316⑈

THIS DOCUMENT CONTAINS SECURITY FEATURES - SEE REVERSE

Sample:



001

YOUR NAME
123 ANY STREET
YOUR TOWN PROVINCE [illegible]

DATE

PAY TO THE
ORDER OF

$

100 DOLLARS

YOUR FINANCIAL INSTITUTION
456 MAIN STREET
YOUR TOWN PROVINCE [illegible]

MEMO

Transit/Branch #

Financial Institution #

Bank Account #

⑈001⑈ ⑆12345⑉678⑆ 123⑉456⑉7⑈

1. Purpose of Debits

[X] Business PAD

2. Pre Notification of Amounts

Fixed Amounts: The Company will provide written notice of the amount to be debited and the date of the debit at least ten (10) calendar days before the date of the first debit and every time there is a change in the amount or payment date.

Variable Amounts: The Company will provide written notice of each amount to be debited and the date of the debit at least ten (10) calendar days before the date of each debit.

The Customer and Company agree to waive the above pre notification requirements.

Authorized Signature of Customer: ______________________
BLUEWATER POWER DISTRIBUTION CORPORATION

Authorized Signature of Customer: L McMichael-Dennis
BLUEWATER POWER DISTRIBUTION CORPORATION

Authorized Signature of Company: ______________________
OIPC

3. Rights of Dispute

The Customer may dispute a debit under the following conditions: (i) the debit was not drawn in accordance with this Authorization; (ii) this Authorization was revoked or cancelled; or (iii) prenotification (as set out in paragraph 2 above) was not received.

In order to be reimbursed, the Customer must complete a Declaration Form at the above indicated branch of the Bank up to and including ten (10) calendar days, after the date on which the debit in dispute was posted to the Customer's account.

The Customer acknowledges that disputes after the above noted time limitations are matters to be resolved solely between the Company and Customer.

4. Terms of Authorization to Debit the Above Account

The Customer authorizes the Company to debit the above account(s) in the amount of $_______(intentionally left blank)_______ for payments payable to the Company in respect of its indebtedness to OIPC as further identified in the Financing Agreement between the Company and the Customer.

The Bank is not required to verify that any debits drawn by the Company are in accordance with this Authorization or the agreement made between the Customer and the Company.

This authorization is to remain in effect until the Company has received written notification from the Customer of its change or termination. This notification must be received at least thirty (30) days before the next scheduled debit by the Company from the account(s) noted above. The Customer may obtain a sample cancellation form, or more information on the right to cancel a PAD Agreement by visiting www.cdnpay.ca. This Authorization applies only to a method of payment and cancellation of this Authorization does not mean that the Customer's contractual obligations to the Company are ended.

The Customer will notify the Company promptly in writing if there is any change in the above account information.

Ontario Infrastructure Projects Corporation
777 Bay Street, 9th Floor
Toronto, ON M5G 2C8
Attention: Loan Operations Manager

The Customer has certain recourse rights if any debit does not comply with this agreement. For example, the Customer has the right to receive reimbursement for any PAD that is not authorized or is not consistent with this PAD. To obtain more information on the Customer's recourse rights, the Customer can visit www.cdnpay.ca.

Any delivery of this Authorization to the Company constitutes delivery by the Customer to the Bank. It is warranted by the Customer that all persons whose signatures are required to sign on the above account have signed this Authorization. The Customer acknowledges receipt of a signed copy of this Authorization.

____
Signature(s) or Authorized Signature(s) of Account Holder(s) **(Date)**

McMichael-Denn
____
Signature(s) or Authorized Signature(s) of Account Holder(s) **(Date)**

SCHEDULE "D"

ONTARIO INFRASTRUCTURE PROJECTS CORPORATION PROJECT MANAGEMENT AND BEST PRACTICES REPORTING REQUIREMENTS

Construction Reporting

To help ensure effective and efficient delivery of projects financed (in whole or in part) with funds from the Infrastructure Ontario Loan Program, Ontario Infrastructure Projects Corporation (Infrastructure Ontario) has introduced reporting requirements for all **capital construction projects**. Borrowers are responsible to submit project reports according to the Estimated Project Start Date as indicated in their online application.

Depending on the size of the project, borrowers will be subject to the following requirements.

For projects under $10,000,000, borrowers will:

- Be required to have a qualified project manager in place for the Project subject to OIPC approval
- Submit standard **quarterly** project management report(s)
- For projects three months in duration or less, only a **final** report is required

For projects over $10,000,000, borrowers will:

- Be required to have a qualified project manager in place for the Project subject to OIPC approval
- Submit **monthly** project management reports using the Infrastructure Ontario template prior to the end of the second week of each month (for the preceding month)
- The final project management report shall be submitted to Infrastructure Ontario one month after the Project is completed in accordance with subsection 2(3) of the *Construction Lien Act* (Ontario)

Please forward all reports to:
Mail: Customer Relations Coordinator
Infrastructure Ontario
777 Bay St., 9th Fl.
Toronto, Ontario M5G 2C8

Email: Customer.Relations@infrastructureontario.ca
Fax: (416) 263-5900

For more details on Project Management and Best Practices Reporting, please visit www.infrastructureontario.ca/private/pmr/index.asp.

SCHEDULE "E"
GENERAL SECURITY AGREEMENT

For valuable consideration the undersigned (the "Borrower") agrees with Ontario Infrastructure Projects Corporation ("OIPC") as follows:

1. GRANT OF SECURITY INTEREST

As general and continuing security for the payment and performance when due of all Obligations, the Borrower hereby mortgages, charges and assigns to OIPC, and grants to OIPC, and OIPC takes, a Security Interest in the property, whether now owned or hereafter acquired directly or indirectly by the Borrower, described in the following paragraphs of this section, and in all property described in any schedules, documents or listings that the Borrower may from time to time sign and provide to OIPC in connection with this Agreement, and in all present and future Accessions to, and all Proceeds of, any such property (collectively, the "Collateral") as a general and continuing collateral security for the due payment of the obligations payable under the Financing Agreement (the "Financing Agreement") dated and effective as of the 20th day of September, 2010 and made between the Borrower and Ontario Infrastructure Projects Corporation:

(a) **Accounts Receivable.** All debts, book debts, accounts, claims, demands, money and choses in action, including without limitation, all claims against Her Majesty the Queen in right of Canada or any Province (other than Ontario) or Territory and all claims and benefits under any insurance policies;

(b) **Inventory.** All inventory, including, without limitation, all goods, merchandise, raw materials, goods in process, finished goods and other tangible personal property now or hereafter held for sale, lease or resale or that are to be furnished or have been furnished under a contract of service or that are used or consumed in the business of the Borrower;

(c) **Equipment**. All goods which are not inventory or consumer goods, including, without limitation, all fixtures, equipment, machinery, vehicles and other tangible personal property;

(d) **Chattel Paper, Instruments, Securities etc.** All chattel paper, instruments, warehouse receipts, bills of lading and other documents of title, whether negotiable or non-negotiable, shares, stock, warrants, bonds, debentures, debenture stock and other securities;

(e) **Intangibles.** All intangibles, including, without limitation, all contractual rights, goodwill, patents, trade-marks, copyrights, industrial designs and other industrial or intellectual property or rights therein;

(f) **Books and Accounts, etc.** All books, accounts, invoices, letters, papers, writings, certificates, receipts, documents and other records and data in any form or medium evidencing, representing, creating, giving rise to any rights in respect of or otherwise relating to the property described in paragraphs (a) to (e) inclusive;

(g) **Real Property.** All real and immovable property, wherever situate, and all buildings, structures, fixtures, hereditaments and appurtenances thereon or relating thereto; and

(h) **Proceeds.** All property in any form derived directly or indirectly from any dealing with any undertaking or property subject to the Security Interest or that indemnifies or compensates for such undertaking or property being destroyed, damaged, expropriated, stolen or lost and proceeds or proceeds whether of the same type or kind as the original proceeds.

2. GOVERNING LAW

This Agreement is governed by the laws of Ontario.

BLUEWATER POWER DISTRIBUTION CORPORATION

By:

Name: Janice L. McMichael-Dennis
Title: President & Chief Executive Officer

By:
Name: G. Firman Bentley
Title: Chairman of the Board

c/s

We have authority to bind the Corporation.

ADDITIONAL TERMS AND CONDITIONS. THE ADDITIONAL TERMS AND CONDITIONS (INCLUDING ANY SCHEDULES) ON THE FOLLOWING PAGES FORM PART OF THIS AGREEMENT.

The Borrower has signed this Agreement on September 20, 2010.

GENERAL SECURITY AGREEMENT ADDITIONAL TERMS AND CONDITIONS

3. FINANCING AGREEMENT

Reference is hereby expressly made to the Financing Agreement and all instruments supplemental thereto for a statement and description of, among other things, the liability of the Borrower for payment of the Obligations, the terms, conditions, covenants and warranties upon which the Obligations are issued and held, and the rights and remedies of OIPC, all to the same effect as if the provisions of the Financing Agreement were herein set out.

4. PLACES OF BUSINESS

The Borrower represents and warrants that the locations of all existing Places of Business are specified in Schedule AA. The Borrower will promptly notify OIPC in writing of any additional Places of Business as soon as they are established. Subject to Section 5, the Collateral will at all times be kept at the Places of Business and will not be removed without OIPC's prior written consent.

5. COLLATERAL FREE OF CHARGES

The Borrower represents and warrants that the Collateral is, and agrees that the Collateral will at all times be free, of any Charge or trust except in favour of OIPC or incurred with OIPC's prior written consent. OIPC may, but will not have to, pay any amount or take any action required to remove or redeem any unauthorized Charge. The Borrower will immediately reimburse OIPC for any amount so paid and will indemnify OIPC in respect of any action so taken.

6. USE OF COLLATERAL

The Borrower will not, without OIPC's prior written consent, sell, lease or otherwise dispose of any of the Collateral (other than Inventory, which may be sold, leased or otherwise disposed of in the ordinary course of the Borrower's business). All Proceeds of the Collateral (including among other things received in respect of Receivables), whether or not arising in the ordinary course of the Borrower's business, will be received by the Borrower as trustee for OIPC and will be immediately paid to OIPC.

7. INSURANCE

The Borrower will keep the Collateral insured to its full insurable value against loss or damage by fire and such other risks as are customarily insured for property similar to the Collateral (and against such other risks as OIPC may reasonably require). At OIPC's request, all policies in respect of such insurance will contain a loss payable clause in favour of OIPC and in any event the Borrower assigns all proceeds of insurance on the Collateral to OIPC. The Borrower will, from time to time at OIPC's request, deliver such policies (or satisfactory evidence of such policies) to OIPC. If the Borrower does not obtain or maintain such insurance, OIPC may, but will not have to, do so. The Borrower will immediately reimburse OIPC for any amount so paid. The Borrower will promptly give OIPC written notice of any loss or damage to all or any part of the Collateral.

8. INFORMATION AND INSPECTION

The Borrower will from time to time immediately give OIPC in writing all information requested by OIPC relating to the Collateral, the Places of Business, and the Borrower's financial or business affairs. The Borrower will promptly advise OIPC of the Serial Number, model year, make and model of each Serial Number Good at any time included in the Collateral that is held as Equipment, including in circumstances where the Borrower ceases holding such Serial Number Good as Inventory and begins holding it as Equipment. OIPC may from time to time inspect any Books and Records and any Collateral, wherever located. For that purpose OIPC may, without charge, have access to each Place of Business and to all mechanical or electronic equipment, devices and processes where any of them may be stored or from which any of them may be retrieved. The Borrower authorizes any Person holding any Books and Records to make them available to OIPC, in a readable form upon request by OIPC.

9. RECEIVABLES

If the Collateral includes Receivables, OIPC may advise any Person who is liable to make any payment to the Borrower of the existence of this Agreement. OIPC may from time to time confirm with such Persons the existence and the amount of the Receivables. Upon an Event of Default, OIPC may collect and otherwise deal with the Receivables in such manner and upon such terms, as OIPC considers appropriate.

10. RECEIPTS PRIOR TO DEFAULT

Until an Event of Default, all amounts received by OIPC as Proceeds of the Collateral will be applied on account of the Obligations in such manner and at such times as OIPC may consider appropriate or, at OIPC's option, may be held unappropriated in a collateral account or released to the Borrower.

11. DEFAULT

(1) **Events of Default**. "Event of Default" means any of the events described in paragraph 13(c) of the Financing Agreement. In case an Event of Default shall occur and be continuing, the full unpaid principal amount together with interest accrued thereon of any obligations outstanding payable under the Financing Agreement at the time of the occurrence, may become or be declared due before stated maturity by OIPC.

(2) **Additional Rights upon Default**. Upon the occurrence of any Event of Default, OIPC and a Receiver, as applicable, will to the extent permitted by law have the following additional rights:

(a) <u>Appointment of Receiver</u>. OIPC may by instrument in writing appoint any Person as a Receiver of all or any part of the Collateral. OIPC may from time to time remove or replace a Receiver, or make application to any court of competent jurisdiction for the appointment of a Receiver. Any Receiver appointed by OIPC will (for purposes relating to responsibility for the Receiver's acts or omissions) be considered to be the Borrower's agent. OIPC may from time to time fix the Receiver's remuneration and the Borrower will pay OIPC the amount of such remuneration. OIPC will not be liable to the Borrower or any other Person in connection with appointing or not appointing a Receiver or in connection with the Receiver's actions or omissions.

(b) Dealings with the Collateral. OIPC or a Receiver may take possession of all or any part of the Collateral and retain it for as long as OIPC or the Receiver considers appropriate, receive any rents and profits from the Collateral, carry on (or concur in carrying on) all or any part of the Borrower's business or refrain from doing so, borrow on the security of the Collateral, repair the Collateral, process the Collateral, prepare the Collateral for sale, lease or other disposition, and sell or lease (or concur in selling or leasing) or otherwise dispose of the Collateral on such terms and conditions (including among other things by arrangement providing for deferred payment) as OIPC or the Receiver considers appropriate. OIPC or the Receiver may (without charge and to the exclusion of all other Persons including the Borrower), enter upon any Place of Business.

(c) Realization. OIPC or a Receiver may use, collect, sell, lease or otherwise dispose of, realize upon, release to the Borrower or other Persons and otherwise deal with, the Collateral in such manner, upon such terms (including among other things by arrangement providing for deferred payment) and at such times as OIPC or the Receiver considers appropriate. OIPC or the Receiver may make any sale, lease or other disposition of the Collateral in the name of and on behalf of the Borrower or otherwise.

(d) Application of Proceeds After Default. All Proceeds of Collateral received by OIPC or a Receiver may be applied to discharge or satisfy any expenses (including among other things the Receiver's remuneration and other expenses of enforcing OIPC's rights under this Agreement), Charges, borrowings, taxes and other outgoings affecting the Collateral or which are considered advisable by OIPC or the Receiver to preserve, repair, process, maintain or enhance the Collateral or prepare it for sale, lease or other disposition, or to sell, lease or otherwise dispose of the Collateral. The balance of such Proceeds will be applied to the Obligations in such manner and at such times as OIPC considers appropriate and thereafter will be accounted for as required by law.

(e) Other Legal Rights. Before and After Default. OIPC will have in addition to the rights specifically provided in this Agreement, the rights of a secured party under the PPSA, as well as the rights recognized at law and in equity. No right will be exclusive of or dependent upon or merge in any other right, and one or more of such rights may be exercised independently or in combination from time to time.

(f) Deficiency. The Borrower will remain liable to OIPC for payment of any obligations under the Financing Agreement that are outstanding following realization of all or any part of the Collateral.

12. OIPC NOT LIABLE

OIPC will not be liable to the Borrower or any other Person for any failure or delay in exercising any of its rights under this Agreement (including among other things any failure to take possession of, collect, or sell, lease or otherwise dispose of any Collateral). None of OIPC, a Receiver or any agent of OIPC is required to take, or will have any liability for any failure to take or delay in taking, any steps necessary or advisable to preserve rights against other Persons under any Chattel Paper, Securities or Instrument in possession of OIPC, a Receiver or OIPC's agent.

13. CHARGES AND EXPENSES

The Borrower agrees to pay on demand all costs and expenses incurred (including among other things legal fees on a solicitor and client basis) and fees charged by OIPC in connection with obtaining or discharging this Agreement or establishing or confirming the priority of the Charges created by this Agreement or by law, compliance with any demand by any Person under the PPSA to amend or discharge any registration relating to this Agreement, and by OIPC or any Receiver in exercising any remedy under this Agreement (including among other things, repairing, processing, preparing for disposition and disposing of the Collateral by sale, lease or otherwise) and in carrying on the Borrower's business. All such amounts will bear interest from time to time at the highest interest rate then applicable to any of the Obligations, and the Borrower will reimburse OIPC upon demand for any amount so paid.

14. FURTHER ASSURANCES

The Borrower will from time to time immediately upon request by OIPC take such action (including among other things the signing and delivery of financing statements and financing change statements, other schedules, documents or listings describing property included in the Collateral, further assignments and other documents, and the registration of this Agreement) as OIPC may require in connection with the Collateral or as OIPC may consider necessary to give effect to this Agreement. If permitted by law, the Borrower waives the right to sign or receive a copy of any financing statement or financing change statement, or any statement issued by any registry that confirms any registration of a financing statement or financing change statement, relating to this Agreement. The Borrower irrevocably appoints the Senior Vice President, Infrastructure Lending and Chief Financial Officer of OIPC as the Borrower's attorney (with full powers of substitution and delegation) to sign, upon an Event of Default, all documents required to give effect to this section. Nothing in this section affects the right of OIPC as secured party, or any other Person on OIPC's behalf, to sign and file or deliver (as applicable) all such financing statements, financing change statements, notices, verification agreements and other documents relating to the Collateral and this Agreement as OIPC or such other Person considers appropriate.

15. DEALINGS BY OIPC

OIPC may from time to time increase, reduce, discontinue or otherwise vary the Borrower's credit facilities, grant extensions of time and other indulgences, take and give up any Charge, abstain from taking, perfecting or registering any Charge, accept compositions, grant releases and discharges and otherwise deal with the Borrower, Borrowers of the Borrower, guarantors and others, and with the Collateral and any Charges held by OIPC, as OIPC considers appropriate without affecting the Borrowers obligations to OIPC or OIPC's rights under this Agreement.

16. DEFINITIONS IN THIS AGREEMENT

"**Accessions**", "**Account**", "**Chattel Paper**", "**Collateral**", "**Document of Title**", '"**Equipment**", "**Goods**", "**Instrument**", "**Intangible**", "**Inventory**", "**Proceeds**", "**Purchase-Money Security Interest**" and "**Security Interest**" have the respective meanings given to them in the PPSA.
"**Books and Records**" means all books, records, files, papers, disks, documents and other repositories of data recording, evidencing or relating to the Collateral to which the Borrower (or any Person on the Borrower's behalf) has access.

"**Charge**" means any mortgage, charge, pledge, hypothecation, lien (statutory or otherwise), assignment, financial lease, title retention-agreement or arrangement, security interest or other encumbrance of any nature however arising, or any other security agreement or arrangement creating in favour of any creditor a right in respect of a particular property that is or could be prior to the right of any other creditor in respect of such property.

"**Consumer Goods**" has the meaning given to it in the PPSA.

"**Event of Default**" has the meaning set out in subsection 11(1).

"**Obligations**" means all present and future indebtedness and liability of every kind, nature and description (whether direct or indirect, joint or several, absolute or contingent, matured or unmatured) of the Borrower to OIPC, wherever and however incurred and any unpaid balance thereof, including, without limitation, under or in respect of the Financing Agreement.

"**Money**" has the meaning given to it in the PPSA or, if there is no such definition, means a medium of exchange authorized or adopted by the Parliament of Canada as part of the currency of Canada, or by a foreign government as part of its currency

"**Person**" means any natural person or artificial body (including among others any firm, corporation or government).

"**Personal Property**" means personal property and includes among other things Inventory, Equipment, Receivables, Books and Records, Chattel Paper, Goods, Documents of Title, Instruments, Intangibles (including intellectual property), Money and Securities, and includes all Accessions to such property.

"**Place of Business**" means a location where the Borrower carries on business or where any of the Collateral is located (including any location described in Schedule AA).

"**PPSA**" means the *Personal Property Security Act, 1990* (Ontario), as such legislation may be amended, renamed or replaced from time to time (and includes all regulations from time to time made under such legislation).

"**Receivables**" means all debts, claims and choses in action (including among other things Accounts and Chattel Paper) - now or in the future due or owing to or owned by the Borrower.

"**Receiver**" means a receiver or a receiver and manager.

"**Securities**" has the meaning given to it in the PPSA or, if there is no such definition and the PPSA defines "security" instead, it means the plural of that term.

"**Serial Number**" means the number that the Person who manufactured or constructed a Serial Number Good permanently marked or attached to it for identification purposes or, if applicable such other number as the PPSA stipulates as the serial number or vehicle information number to be used for registration purposes of such Serial Number Good.

"**Serial Number Good**" means a motor vehicle, trailer, mobile home, aircraft airframe, aircraft engine or aircraft propeller, boat or an outboard motor for a boat.

17. GENERAL

(a) Reservation of the Last Day of any Lease. The Charges created by this Agreement do not extend to the last day of the term of any lease or agreement for lease; however, the Borrower will hold such last day in trust for OIPC and, upon the exercise by OIPC of any of its rights under this Agreement following Default, will assign such last day as directed by OIPC.

(b) Attachment of Security Interest. The Security Interests created by this Agreement are intended to attach (i) to existing Collateral when the Borrower signs this Agreement, and (ii) to Collateral subsequently acquired by the Borrower, immediately upon the Borrower acquiring any rights in such Collateral. The parties do not intend to postpone the attachment of any Security Interest created by this Agreement.

(c) Purchase-Money Security Interest. If OIPC gives value for the purpose of enabling the Borrower to acquire rights in or to any of the Collateral, the Borrower will in fact apply such value to acquire those rights (and will provide OIPC with such evidence in this regard as OIPC may require), and the Borrower grants to OIPC, and OIPC takes, a Purchase-Money Security Interest in such Collateral to the extent that the value is applied to acquire such rights. A certificate or affidavit of any of OIPC's authorized representatives is admissible in evidence to establish the amount of any such value.

(d) Entire Agreement. OIPC has not made any representation or undertaken any obligation in connection with the subject matter of this Agreement other than as specifically set out in this Agreement, and in particular nothing contained in this

Agreement will require OIPC to make, renew or extend the time for payment of any loan or other credit accommodation to the Borrower or any other Person.

(e) Additional Security. The Charges created by this Agreement are in addition and without prejudice to any other Charge now or later held by OIPC. No Charge held by OIPC will be exclusive of or dependent upon or merge in any other Charge, and OIPC may exercise its rights under such Charges independently or in combination.

(f) Severability: Headings. Any provision of this Agreement that is void or unenforceable in any jurisdiction is, as to that jurisdiction, ineffective to that extent without invalidating the remaining provisions of this Agreement. The headings in this Agreement are for convenience only and do not limit or extend the provisions of this Agreement.

(g) Interpretation. When the context so requires, the singular will be read as the plural, and vice versa.

(h) Copy of Agreement. The Borrower acknowledges receipt of a copy of this Agreement.

(i) Notice. OIPC may send to the Borrower, by prepaid regular mail addressed to the Borrower at the Borrower's address last known to OIPC, copies of any document required by the PPSA to be delivered by OIPC to the Borrower. Any document mailed in this manner will be deemed to have been received by the Borrower upon the earlier of actual receipt by the Borrower and the expiry of 10 days after the mailing date. A certificate or affidavit of any of OIPC's authorized representatives is admissible in evidence to establish the mailing date.

(j) Enurement; Assignment. This Agreement will enure to the benefit of and be binding upon (i) OIPC, its successors and assigns, and (ii) the Borrower and the Borrower's heirs, executors, administrators, successors and permitted assigns. The Borrower will not assign this Agreement without OIPC's prior written consent.

Schedule "AA"

The following are the Places of Business:

1. 855 Confederation Street, Sarnia, Ontario N7T 7L6

SCHEDULE "F"

ACKNOWLEDGEMENT AND CONSENT

TO: Ontario Infrastructure Projects Corporation ("OIPC")

RE: Bluewater Power Distribution Corporation (the "Debtor")

We are the secured party under certain personal property security registrations made against the Debtor under the *Personal Property Security Act* (Ontario), including those listed in Schedule "A" (the "Registrations").

We understand that OIPC proposes to establish certain credit facilities in favour of the Debtor pursuant to a Financing Agreement dated September 20, 2010 (the "Financing Agreement"), and that OIPC requires this Acknowledgement and Consent as a condition to the establishment of such credit facilities. To induce OIPC to establish such credit facilities, in consideration of it doing so and for other good and valuable consideration, the receipt and sufficiency of which is acknowledged, we confirm and agree as follows:

1. We will only use our first-ranking general security agreement to secure the present operating line of credit for $7,100,000.00, and standby letters of credit for $6,281,038.00; such operating line of credit shall not exceed a principal amount of $7,100,000.00 without prior written consent of OIPC; and such standby letters of credit may be increased to an aggregate principal amount of $6,281,038 provided that the standby letters of credit are for the exclusive purpose of providing required prudential support for the Borrower's electricity purchases through the Independent Electricity System Operator (the "IESO"), such increase is required by the IESO and the Borrower provides prior written notice to OIPC.

2. We consent to the Debtor granting a second-ranking general security agreement in favour of OIPC under the Financing Agreement.

3. We confirm that we have not assigned any of the Registrations or the related security or any interest therein. We agree that we will not assign or otherwise transfer any of the Registrations or the related security or any interest therein without obtaining from the assignee an agreement in your favour to be bound by this Acknowledgement and Consent.

4. This Acknowledgement and Consent may be relied upon by OIPC, and its successors and assigns, and shall be binding upon us and our successors and assigns.

DATED this __ day of September, 2010.

THE CANADIAN IMPERIAL BANK OF COMMERCE

By:

Name:
Title:

I have authority to bind the Corporation.

SCHEDULE "A"

Secured Party	Canadian Imperial Bank of Commerce
Date of Registration	September 25, 2003
Registration Number	20030925 1033 7034 1149
Reference File Number	898555293
Registration Period	September 25, 2013
Collateral Classification	IEAO
General Collateral Description	N/A

File Number:EB-2012-0107

Tab:	7
Schedule:	2

Date Filed:February 4, 2013

Attachment 2 of 2

Energy Probe 30 (e) - Debenture

DEBENTURE

UNLESS PERMITTED UNDER SECURITIES LEGISLATION, THE HOLDER OF THIS DEBENTURE MUST NOT TRADE THE DEBENTURE BEFORE THE DATE THAT IS 4 MONTHS AND A DAY AFTER THE LATER OF (I) SEPTEMBER 15, 2011, AND (II) THE DATE THE ISSUER BECAME A REPORTING ISSUER IN ANY PROVINCE OR TERRITORY.

BLUEWATER POWER DISTRIBUTION CORPORATION

SECURED DEBENTURE DUE SEPTEMBER 15, 2021

No. 09-15-2011

Cdn.$7,100,000.00

Bluewater Power Distribution Corporation (hereinafter referred to in such capacity as the "Borrower"), for value received, hereby acknowledges itself liable and indebted and promises to pay to ONTARIO INFRASTRUCTURE AND LANDS CORPORATION or its registered assigns by September 15, 2021 the principal sum of Seven Million One Hundred Thousand Dollars ($7,100,000.00) in lawful money of Canada by semi-annual payments on the 15th day of March and the 15th day of September in each of the years 2012 to 2021, both inclusive, in the amounts set forth in the attached Schedule A which forms part of this Debenture (the "Payment Schedule") and to pay interest on the said principal sum from time to time outstanding from the date hereof, or from the last interest payment date to which interest shall have been paid or made available for payment on this Debenture, whichever is later, at a rate of interest set forth in the Payment Schedule in arrears on the 15th day of March and the 15th day of September in each of the years 2012 to 2021 (each a "Payment Date") with the first payment due on March 15, 2012. Upon default interest shall be paid at the rate specified in the attached Schedule B which forms part of this Debenture. The applicable rate of interest, the payment of principal and interest and the principal balance outstanding under this Debenture in each year are shown in the Payment Schedule.

This Debenture is one of the Borrower's Secured Debentures originally authorized in the aggregate principal amount of Cdn.$7,100,000.00 pursuant to the financing agreement dated as of September 20, 2010 (the "Financing Agreement") and made between the Borrower and Ontario Infrastructure and Lands Corporation (herein called "OILC"). Capitalized terms not defined herein shall have the meanings assigned to them in the Financing Agreement.

For the purposes of disclosure pursuant to the *Interest Act* (Canada), the yearly rate of interest which is equivalent to a rate of interest payable in respect of the principal for any period of less than a year may be determined by multiplying the rate of interest for such period by a fraction, the numerator of which is the actual number of days in a year commencing on and including the first day in such period and ending on but excluding the corresponding day in the next calendar year and the denominator of which is the actual number of days in such period.

Reference is hereby expressly made to the Financing Agreement and all instruments supplemental thereto for a statement and description of, among other things, the liability of the Borrower for payment of the Debenture, the terms, conditions, covenants and warranties upon which the Debenture is issued and held, and the rights and remedies of the holder of the Debenture issued thereunder and of the Borrower in respect thereof, all to the same effect as if the provisions of the Financing Agreement were herein set out, to all of which provisions the holder hereof by acceptance hereof assents.

The undersigned authorizes the registered holder of this Debenture to record on the reverse of this Debenture or on any attachment to this Debenture all repayments of principal and interest and the unpaid balance of principal from time to time. The undersigned agrees that in the absence of manifest error the record kept by the registered holder on this Debenture or any attachment shall be conclusive evidence of the matters recorded, provided that the failure of the registered holder to record or correctly record any amount or date shall not affect the obligation of the undersigned to pay the outstanding principal amount and interest.

In case an Event of Default (as defined in the Financing Agreement) shall occur and be continuing, the full unpaid principal amount of this Debenture, together with interest accrued thereon, may become or be declared due before stated maturity by the registered holder of this Debenture in its sole discretion.

This Debenture is also subject to the conditions set forth in the attached Schedule B.

This Debenture shall be construed in accordance with the laws of the Province of Ontario and the federal laws of Canada applicable therein.

The parties hereto have declared that they have required that these presents and all other documents related hereto be in the English language.

Les parties aux présentes ont déclaré qu'elles ont exigé que le présent certificat, de même que tous les documents s'y rapportant, soient rédigés en anglais.

IN WITNESS HEREOF the Borrower has caused this Debenture to be executed and delivered as of the 15th day of September 2011.

BLUEWATER POWER DISTRIBUTION CORPORATION

By: ______________________________

Name: Mark Hutson
Title: Chief Financial Officer

By: JLMcMichael-Dennis

Name: Janice L. McMichael-Dennis
Title: President & Chief Executive Officer

SCHEDULE A

Amortizing Debenture Schedule

Organization Name	**Bluewater Power Distribution Corporation**
Principal Amount	**$7,100,000.00**
Annual Interest Rate	**3.3700%**
Loan Term (Year)	**10**
Debenture Date (m/d/yyyy)	**9/15/2011**
Maturity Date (m/d/yyyy)	**9/15/2021**
Payment Frequency	**Semi Annual**
Loan Type	**Amortizing**

Payment Date	Total Payment	Principal Amount	Interest Amount	Principal Balance
3/15/2012	$421,125.62	$301,490.62	$119,635.00	$6,798,509.38
9/17/2012	$421,125.62	$306,570.74	$114,554.88	$6,491,938.64
3/15/2013	$421,125.62	$311,736.45	$109,389.17	$6,180,202.19
9/16/2013	$421,125.62	$316,989.21	$104,136.41	$5,863,212.98
3/17/2014	$421,125.62	$322,330.48	$98,795.14	$5,540,882.50
9/15/2014	$421,125.62	$327,761.75	$93,363.87	$5,213,120.75
3/16/2015	$421,125.62	$333,284.54	$87,841.08	$4,879,836.21
9/15/2015	$421,125.62	$338,900.38	$82,225.24	$4,540,935.83
3/15/2016	$421,125.62	$344,610.85	$76,514.77	$4,196,324.98
9/15/2016	$421,125.62	$350,417.54	$70,708.08	$3,845,907.44
3/15/2017	$421,125.62	$356,322.08	$64,803.54	$3,489,585.36
9/15/2017	$421,125.62	$362,326.11	$58,799.51	$3,127,259.25
3/15/2018	$421,125.62	$368,431.30	$52,694.32	$2,758,827.95
9/17/2018	$421,125.62	$374,639.37	$46,486.25	$2,384,188.58
3/15/2019	$421,125.62	$380,952.04	$40,173.58	$2,003,236.54
9/16/2019	$421,125.62	$387,371.08	$33,754.54	$1,615,865.46
3/16/2020	$421,125.62	$393,898.29	$27,227.33	$1,221,967.17
9/15/2020	$421,125.62	$400,535.47	$20,590.15	$821,431.70
3/15/2021	$421,125.62	$407,284.50	$13,841.12	$414,147.20
9/15/2021	$421,125.58	$414,147.20	$6,978.38	$0.00
Total	**$8,422,512.36**	**$7,100,000.00**	**$1,322,512.36**	

CONDITIONS AND DEFINITIONS

Schedule B to the Secured Debenture dated as of September 15, 2011 issued by the Borrower in favour of Ontario Infrastructure and Lands Corporation

1. Definitions

"**Net Present Value**" will be calculated based on the following formulae: For Amortizing Debenture – [loan payment /(r/2))*(1-1/(1+(r/2))^n)], where "r" is the prevailing lending rate less an appropriate basis point deduction for costs incurred and "n" is the number of semi-annual periods to maturity.

"**Prime Rate**" means, on any day, the annual rate of interest which is the arithmetic mean of the prime rates announced from time to time by the five major Canadian Schedule I banks, as of the issue date of this Debenture, Royal Bank of Canada, Canadian Imperial Bank of Commerce, The Bank of Nova Scotia, Bank of Montreal and The Toronto-Dominion Bank (the "Reference Banks") as their reference rates in effect on such day for Canadian dollar commercial loans made in Canada. If fewer than five of the Reference Banks quote a prime rate on such days, the "Prime Rate" shall be the arithmetic mean of the rates quoted by the remaining Reference Banks.

2. Form and Registration of the Debenture

(a) The Debenture is a direct and secured obligation of the Borrower and shall have priority over all unsecured senior debt obligations of the Borrower.

(b) The Borrower shall maintain at its designated office a register in respect of the Debenture in which shall be recorded the names and addresses of the registered holders and in which particulars of the cancellation, exchanges, substitutions and transfers of the Debenture, may be recorded and the Borrower is authorized to use electronic, magnetic or other media for records of or related to the Debenture or for copies of them.

3. Title

The Borrower shall not be bound to see to the execution of any trust affecting the ownership of this Debenture or be affected by notice of any equity that may be subsisting in respect thereof. The Borrower shall deem and treat the registered holder of this Debenture as the absolute owner thereof for all purposes whatsoever notwithstanding any notice to the contrary and all payments to or to the order of the registered holder shall be valid and effectual to discharge the liability of the Borrower on the Debenture to the extent of the sum or sums so paid. Where a Debenture is registered in more than one name, the principal of and interest from time to time payable on such Debenture shall be paid to or to the order of all the joint registered holders thereof, failing written instructions to the contrary from all such joint registered holders, and such payment shall constitute a valid discharge to the Borrower. In the case of the death of one or more joint registered holders, despite the foregoing provisions of this section, the principal of and interest on the Debenture registered in their names may be paid to the survivor or survivors of such holders and such payment shall constitute a valid discharge to the Borrower.

4. Payments of Principal and Interest

(a) The record date for purposes of payment of principal of and interest on the Debenture is as of 5:00 p.m. on the sixteenth calendar day preceding any Payment Date including a maturity date. Principal of and interest on the Debenture are payable by the Borrower to the persons registered as holders in the register on the relevant record date. The Borrower shall not be required to register any transfer, exchange or substitution of the Debenture during the period from any record date to the corresponding Payment Date.

(b) The Borrower shall make all payments in respect of semi-annual combined principal and interest on the Debenture on each Payment Date commencing on March 15, 2012 (other than in respect of the final payment of principal and outstanding interest which the Borrower shall pay on the final maturity date upon presentation and surrender of this Debenture) in lawful money of Canada by pre-authorized debit in respect of such interest and principal to the credit of the registered holder on such terms as to which the registered holder and the Borrower may agree.

(c) The Borrower shall pay to the registered holder interest on any overdue amount of principal or interest in respect of any Debenture, both before and after default and judgment, at a rate per annum equal to the greater of the rate specified on the Payment Schedule for such amount plus 200 basis points or Prime Rate plus 200 basis points, calculated on a daily basis from the date such amount becomes overdue for so long as such amount remains overdue and the Borrower shall pay to the registered holder any and all costs incurred by the registered holder as a result of the overdue payment.

(d) Whenever it is necessary to compute any amount of interest in respect of the Debenture for a period of less than one full year, other than with respect to regular semi-annual interest payments, such interest shall be calculated on the basis of the actual number of days in the period and a year of 365 days.

(e) Delivery of payments in respect of principal of and interest on the Debenture as provided on the Payment Schedule shall be made only on a day on which banking institutions in Toronto, Ontario, are not authorized or obligated by law or executive order to be closed (a "Toronto Business Day"), and if any date for delivery of payment is not a Toronto Business Day, payment as specified on the Payment Schedule shall be made on the next following Toronto Business Day.

(f) The Debenture is transferable or exchangeable at the office of the Treasurer of the Borrower upon presentation for such purpose accompanied by an instrument of transfer or exchange in a form approved by the Borrower and which form is in accordance with the prevailing Canadian transfer legislation and practices, executed by the registered holder thereof or such holder's duly authorized attorney or legal personal representative, whereupon and upon registration of such transfer or exchange and cancellation of the Debenture, a new Debenture will be delivered as directed by the transferee, in the case of a transfer or as directed by the registered holder in the case of an exchange.

(g) The Borrower shall issue and deliver a new Debenture in exchange or substitution for the Debenture outstanding on the register with the same maturity and of like form which has become lost, stolen, mutilated, defaced or destroyed, provided that the applicant therefor shall have: (i) paid such costs as may have been incurred in connection therewith; (ii) (in the case of a lost, stolen or destroyed Debenture) furnished the Borrower with such evidence (including evidence as to the certificate number of the Debenture in question) and indemnity in respect thereof satisfactory to the Borrower in its discretion; and (iii) surrendered to the Borrower any mutilated or defaced Debenture in respect of which the new Debenture is to be issued in substitution.

(h) The Debenture(s) issued upon any registration of transfer or exchange or in substitution for the Debenture(s) or part thereof shall carry all the rights to interest if any, accrued and unpaid which were carried by such Debenture(s) or part thereof and shall be so dated and shall bear the same maturity date and shall be subject to the same terms and conditions as the Debenture(s) in respect of which the transfer, exchange or substitution is effected.

(i) The cost of all transfers and exchanges, including the printing of authorized denominations of the new Debenture(s), shall be borne by the Borrower. When the Debenture is surrendered for transfer or exchange the Treasurer of the Borrower shall: (i) in the case of an exchange, cancel and destroy the Debenture surrendered for exchange; (ii) in the case of an exchange, certify the cancellation and destruction in the register; and (iii) enter in the register particulars of the new Debenture issued in exchange.

(j) Reasonable fees for the substitution of a new Debenture for the Debenture that is lost, stolen, mutilated, defaced or destroyed may be imposed by the Borrower. Where new Debentures are issued in substitution in these circumstances the Borrower shall: (i) treat as cancelled and destroyed the Debentures in respect of which new Debentures will be issued in substitution; (ii) certify the deemed cancellation and destruction in the register; (iii) enter in the register particulars of the new Debentures issued in substitution; and (iv) make a notation of any indemnities provided.

5. Notices

Except as otherwise expressly provided herein, any notice required to be given to a registered holder of the Debenture will be sufficiently given if a copy of such notice is mailed or otherwise delivered to the registered address of such registered holder. If the Borrower or any registered holder is required to give any notice in connection with the Debenture on or before any day and that day is not a Toronto Business Day then such notice may be given on the next following Toronto Business Day.

6. Time

Unless otherwise expressly provided herein, any reference herein to a time shall be considered to be a reference to Toronto time.

7. **Assignment and Benefit of Debenture**

The Borrower may not assign its rights or transfer its obligations under this Debenture without the prior written consent of the registered holder of the Debenture. The registered holder of this Debenture may assign or transfer its rights under this Debenture without the prior written consent of the Borrower by giving thirty (30) days notice of such assignment or transfer to the Borrower. This Debenture enures to the benefit of and binds the Borrower and the registered holder of the Debenture and their respective successors and permitted assigns.

8. **Amendment**

Any amendment to this Debenture shall be in writing signed by each of the Borrower and the registered holder of the Debenture except that any waiver of any provision of this Debenture or consent to any departure by the Borrower herefrom, shall be effective if the same is in writing and signed by the registered holder of the Debenture.

9. No Waiver

No failure on the part of the registered holder to exercise, and no delay in exercising, any right under the Debenture shall operate as a waiver thereof; nor shall any single or partial exercise of any right under the Debenture preclude any other or further exercise thereof or the exercise of any other right. The remedies herein provided are cumulative and not exclusive of any remedies provided by law.

10. Waiver of Protest

The Borrower waives diligence, demand, presentment, protest and notice of any kind and agrees that it will not be necessary for the registered holder to first initiate suit in order to enforce payment of this Debenture pursuant to the terms and conditions of this Debenture.

11. Termination of Financing Agreement

If OILC elects to terminate its obligations under the financing agreement entered into between the parties, OILC, at its discretion, shall assess any losses that it may incur as a result of the termination as follows: if on the date of termination the outstanding principal balance on the Debenture is less than the Net Present Value of the Debenture, the Borrower shall pay the difference between these two amounts to OILC.

DEBENTURE PURCHASE CERTIFICATE

TO: **Ontario Infrastructure and Lands Corporation**
777 Bay Street, 9th Floor
Toronto, Ontario M5G 2C8
Attention: Loan Operations Manager

This Debenture Purchase Certificate is delivered pursuant to the financing agreement dated as of September 20, 2010 (the "Financing Agreement") made between Ontario Infrastructure and Lands Corporation ("OILC") and Bluewater Power Distribution Corporation ("Borrower"). Capitalized terms used but not otherwise defined herein shall have the meanings given to them in the Financing Agreement.

I, Mark Hutson, Chief Financial Officer of the Borrower, hereby certify pursuant to paragraph 8 of the Financing Agreement, for and on behalf of the Borrower, and not in my personal capacity, to the best of my knowledge, information and belief, that:

i. the amount from the proceeds of the Debenture purchase when added to the aggregate amount of Debentures outstanding in respect of a Project does not exceed the Committed Amount for that Project;

ii. the representations and warranties of the Borrower set out in paragraph 2 of the Financing Agreement are true and correct as at the date hereof;

iii. the Borrower is not in material default of any of its obligations under the Financing Agreement as at the date hereof;

iv. no Event of Default has occurred and is continuing, nor will any such event occur as a result of the Debenture issuance or the application of proceeds therefrom; and

v. the Borrower has incurred expenditures on the Project(s) in an amount equal to or greater than the proceeds from the Debenture purchase;

vi. In accordance with the Financing Agreement (including Schedule "A" of the Financing Agreement), the Borrower will issue a Debenture to OIPC on September 15, 2011. The proceeds from the issuance of the Debenture shall be used for:

    (a) Repayment of $7,100,000.00 the amount of Advance outstanding under the Financing Agreement.

DATED this 15th day of September, 2011

BLUEWATER POWER DISTRIBUTION CORPORATION

By

Name: Mark Hutson

Title: Chief Financial Officer

[Please Affix Seal]

BRING FORWARD CERTIFICATE

TO: **Ontario Infrastructure and Lands Corporation ("Infrastructure Ontario")**

IN THE MATTER OF a financing agreement between Bluewater Power Distribution Corporation and Infrastructure Ontario dated 20th September, 2010 in the aggregate principal amount of $9,300,000.00.

I, Janice L. McMichael-Dennis refer to my Officer's Certificate in respect of the above-referenced matter executed on 3rd day of August, 2010. I hereby certify that all statements and certifications contained in such Officer's Certificate are true and correct as at the date hereof.

DATED at Sarnia, Ontario, September 15, 2011.

BLUEWATER POWER DISTRIBUTION CORPORATION

By: JL McMichael-Denni

Name: Janice L. McMichael-Dennis
Title: President & Chief Executive Officer

[Affix Corporate Seal]

Sent via
Courier
Sept 2/11
-AS

Ontario Infrastructure and Lands Corporation

Debenture Worksheet

Please complete and return to OILC with the debenture documentation

Organization Name: **Bluewater Power Distribution Corporation**

Date: **August 24, 2011**

Program Year: **2010**

FA Number: **10Blu9041510027FA**

Debenture Funding Details

Category	Project Name	Loan Amount	Outstanding Advances	Remaining Amount	New Funds	Conversion	Debenture Amount
MCOther	Smart Meter Project	$9,300,000.00	$7,141,290.85	$2,158,709.15		$7,100,000.00	$7,100,000.00
	Total	**$9,300,000.00**	**$7,141,290.85**	**$2,158,709.15**		**$7,100,000.00**	**$7,100,000.00**

Terms for the Debenture

Principal amount of the debenture **$7,100,000.00**

Term **10 years**

Type **Amortizing**

Frequency **Semi Annual**

Interest rate **To Be Determined**

Closing Date **September 15, 2011**

Council/Board Meeting *Date* ____________

I confirm that these are the Terms for the Debenture to be issued by Bluewater Power Distribution Corporation to OILC.

Treasurer , CFO

Date Sept 15, 2011

Infrastructure Ontario

777 Bay Street
9th Floor
Toronto, Ontario M5G 2C8
Phone: 416-212-7289
Fax: 416 263-5900

OILC DEBENTURE TERM SHEET

Bluewater Power Distribution Corporation

Principal amount of the debenture	**$7,100,000.00**
Term	**10 years**
Type	**Amortizing**
Interest Rate	**3.37%**
Closing Date	**September 15, 2011**

We confirm that these are the Terms for the Debenture to be issued by Bluewater Power Distribution Corporation to OILC.

Mark Hunt

J L McMichael-Dennis

Date Sept 1, 2011

PLEASE FAX THIS TO OILC at (416) 263-5900 BY 3PM, IN ORDER TO CONFIRM YOUR ACCEPTANCE OF THIS OFFER.

Sent via
courier
Sept. 2/11
-LS

7. The persons named below are duly appointed officers of the Company holding the offices set forth below opposite their respective names and the signatures appearing opposite their respective names are the genuine signatures of such persons:

Name	**Office Held**	**Specimen Signature**
Janice L. McMichael-Dennis	President & CEO	JLMcMichael-Dennis
Mark Hutson	Chief Financial Officer	Mark
Alex Palimaka	Vice President Corporate Services and General Counsel	

8. OILC is authorized to act upon any instructions received from any of these persons from time to time, whose instructions shall be binding upon the Borrower, until the Borrower provides written revocation of such authority to OILC and OILC has had a reasonable period of time to change its internal controls to give effect to such revocation.

9. The Corporation's principal place of business and its chief executive office and principal place of residence is located in the Province of Ontario.

DATED at Sarnia, Ontario this 12 day of September, 2011.

JLMcMichael-Dennis

Name: Janice L. McMichael-Dennis
Title: President & Chief Executive Officer

I, Alex Palimaka, Vice President Corporate Services and General Counsel of Bluewater Power Distribution Corporation, hereby certify for and on behalf of the Borrower, and not in my personal capacity, that Janice McMichael-Dennis is President & Chief Executive Officer of the Borrower and that the signature appearing above is her genuine signature.

DATED at Sarnia, Ontario this 12th day of September, 2011.

Name: Alex Palimaka
Title: Vice President Corporate Services and General Counsel

5.0 - VECC 51 - Actual and deemed ROE for 2009-2012

Reference: Exhibit 5, Tab 1, Schedule 1

a) Please provide the actual and Board deemed return on equity for each of the years 2009 through 2012 (estimated).

Return on Equity	Actual	Actual	Actual	Draft
	2009	2010	2011	2012
Deemed per OEB	12.52%	10.98%	9.17%	11.23%
Actual per Financials	13.40%	14.97%	9.99%	10.70%

The ‘Deemed per OEB’ percentages for 2010 and 2011 are from Section 2.1.5 of the RRR filing. The amount indicated for 2009 and 2012 have been calculated using the OEB prescribed methodology introduced for the 2011 reporting year.

The ‘Actual per Financials’ percentages are calculated by taking the net income after tax divided by total shareholders’ equity as found in the financial statements.

5.0 - VECC 52 - Actual D/E ratio for 2013

Reference: Exhibit 5, Tab 1, Schedule 1

a) Please provide Bluewater's actual debt/equity ratio forecast for 2013.

Bluewater Power's forecasted total debt at the end of 2013 is $25,240,817. This amount consists of the promissory notes to shareholders plus the debenture owing to Infrastructure Ontario. This amount excludes the second debenture with Infrastructure Ontario (see response to Energy Probe #30c). There is no short term debt forecasted.

Bluewater Power's forecasted total equity at the end of 2013 is $23,791,643. This amount is calculated by taking the 2011 audited shareholders' equity and adding the forecasted net income and dividends for 2012 and 2013.

Therefore, the forecasted actual debt/equity ratio at the end of 2013 is 1.06. Or in comparable terms with the OEB deemed structure, 0% short term debt, 51% long term debt, and 49% equity.

5.0 - VECC 53 - Unfunded Debt

Reference: Exhibit 5, Tab 1, Schedule 1

a) Why has Bluewater included the unfunded deemed portion of debt at a rate of 4.41% in its calculation of the appropriate rate to charge long term debt.

The OEB has implemented a deemed equity structure born out of the desire for regulatory efficiency. Bluewater Power has less debt than the deemed level and we submit that the debt is required to be at the deemed interest rate as dictated by a strict reading of the rules and as required by fairness in balancing the interests of ratepayers and shareholders.

With respect to the rules, the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* dated December 11, 2009 states at page 54 "*The deemed long-term debt rate will be used where an electricity distribution utility has no actual debt*." The statement is clear in our view that the unfunded debt, whether whole or part, should be set at the deemed rate. In fact, previous OEB decisions (including Bluewater Power's 2009 Rebasing Application) have approved of the unfunded portion being funded at the deemed interest rate whether a utility has partial or no debt. It would be illogical that a utility can set the unfunded portion of its debt at the deemed rate, but the moment a utility borrows any amount from a third-party, the blended rate would be applied.

With respect to the issue of fairness, we note that the deemed debt rate is intended to be an approximation of the market rate so there should be no significant difference between the deemed rate and third-party debt. To the extent there is a difference (the Application was filed with a deemed rate of 4.41% versus a rate of 3.37% with Infrastructure Ontario), then the OEB ought to conclude that the rate of borrowing with Infrastructure Ontario is not a market rate. This is more compelling in light of one of the Distribution Sector Review Panel's findings that:

> ***"Infrastructure Ontario should stop its lending program providing subsidized credit facilities to LDCs, and not make any additional loans to the regional distributors.*** *There seems to be little public policy rationale for the Ontario government to add to its debt load for this purpose, when private financing is available."*

One purpose of the debt calculation should be to ensure the debt funded through rates reflects a market rate. The other purpose is to ensure that, if the utility were to borrow funds from the market for the unfunded portion, that sufficient recovery is included in rates to cover the financing cost. For either purpose, it is essential that the rate for the unfunded portion be set at the best possible estimate of market rate and we submit that the deemed debt rate set by the OEB through its Costs of Capital Parameter update is the most appropriate estimate of market rate. To the extent the blended rate (as requested in VECC IR#53(b) below) includes Infrastructure Ontario borrowing which may not be a market rate and which may not be available to utilities in the future, it ought not to be relied upon for rate making purposes.

Accordingly, we submit that the rules require the unfunded portion of debt to be set at the OEB deemed rate. The result of that interpretation is that the unfunded debt is set at a rate of interest that the OEB has determined is the best estimate of the market rate.

Finally, we note that the financial consequence of the varying interpretation appears to be less significant based on the OEB's most recent update of the Cost of Capital Parameters dated November 15, 2012 which sets the deemed debt rate at 4.03% (compared to the Infrastructure Ontario debt rate of 3.37%). However, the principle behind our position remains the same that unfunded debt should be set at the deemed rate. We have not updated the calculations below for the revised debt rate of 4.03% because the Cost of Capital Parameters will be further updated prior to final approval of this application.

b) Please recalculate the cost of long-term debt by removing this factor (that is by using the funded rate average applied to the unfunded portion).

Table 1 – Calculation of Funded Debt Rate

Description	**Amount**	**Interest Rate** (a)	Weighted Amount	Weighted debt
Village of Point Edward	655,187	4.41%	28,894	
Town of Petrolia	1,430,914	4.41%	63,103	
Village of Alvinston	139,981	4.41%	6,173	
Township of Warwick	421,886	4.41%	18,605	
City of Sarnia	16,729,636	4.41%	737,777	
Infrastructure Ontario 7.1M deb	6,177,576	3.37%	208,184	
Total	25,555,180		1,062,737	4.16%

Table 2 – Application of Funded Debt Rate to Unfunded Portion

Description	**Amount**	**Interest Rate** (a)	Weighted Amount	Weighted debt
Village of Point Edward	655,187	4.41%	28,894	
Town of Petrolia	1,430,914	4.41%	63,103	
Village of Alvinston	139,981	4.41%	6,173	
Township of Warwick	421,886	4.41%	18,605	
City of Sarnia	16,729,636	4.41%	737,777	
Infrastructure Ontario 7.1M deb	6,177,576	3.37%	208,184	
Remaining deemed debt	11,768,019	4.16%	489,384	
Total	37,323,199		1,552,121	4.16%

Table 3 – Resulting Weighted Average Cost of Capital

	Deemed Portion	***Effective Rate***	***Return Amount***
Short-Term Debt	4.00%	2.08%	
Long-Term Debt	56.00%	4.16%	
Total Equity	40.00%	9.12%	
Regulated Rate of Return	**100.00%**	**6.07%**	
Rate Base			66,648,570
Regulated Return on Capital			**4,038,912**
IFRS Adjustment			0
Deemed Interest Expense			*1,607,573*
Deemed Return on Equity			*2,431,340*

5.0 - VECC 54 - Status of IO debenture

Reference: Exhibit 5, Tab 1, Schedule 1, pg. 1

a) Please update the status of the debenture with infrastructure Ontario including the most current estimate of the interest rate and start date for this debenture.

This second debenture will not be taken out. The remaining $2.2 million in advances owing to Infrastructure Ontario were repaid at the end of 2012. Please see response to Energy Probe #30c.

b) Please recalculate the long-term debt rate by prorating the most current estimate of the interest rate and start date of this debenture for 2013.

Not applicable as per part (a) above.

File Number: EB-2012-0107

Date Filed: February 4, 2013

Tab 8 of 11

Exhibit 6

File Number: EB-2012-0107

Date Filed: February 4, 2013

BLUEWATER POWER DISTRIBUTION CORPORATION

Tab 9 of 11

Exhibit 7 - Cost Allocation

7.0-Staff-41 - Revenue Cost Ratio

Ref: Exh 7-1-1 and Appendix 2-P

Ref: Decision EB-2011-0153

The Board approved a revenue to cost ratio of 1.03 for the GS<50 kW class in proceeding EB-2011-0153. This ratio is summarized in the evidence at page 2 of Ex. 7-1-1 in the current proceeding. Please explain why the current revenue to cost ratio for the GS<50 kW class is shown as 1.05 in Appendix 2-P.

The current revenue to cost ratio for the GS<50 kW class should be 1.03, not 1.05. An updated Appendix 2-P is attached.

File Number:EB-2012-0107

Tab:	9
Schedule:	1

Date Filed:February 4, 2013

Attachment 1 of 1

Updated Appendix 2-P

File Number: EB-2012-0107
Exhibit: 7
Tab: 1
Schedule: 1
Attachment: 3

Date: February 4, 2013

Appendix 2-P
Cost Allocation

Please complete the following four tables.

A) Allocated Costs

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$ 8,989,144	52.47%	$ 13,718,684	59.76%
GS < 50 kW	$ 2,768,342	16.16%	$ 2,868,271	12.49%
GS > 50 -999 kW	$ 2,690,185	15.70%	$ 2,981,166	12.99%
GS >1000-4999 kW	$ 729,118	4.26%	$ 1,014,089	4.42%
Large User	$ 1,075,451	6.28%	$ 1,296,326	5.65%
Street Lighting	$ 664,099	3.88%	$ 912,638	3.98%
Sentinel Lighting	$ 59,797	0.35%	$ 58,839	0.26%
Unmetered Scattered Load (USL)	$ 157,338	0.92%	$ 106,926	0.47%
		0.00%		0.00%
		0.00%		0.00%
Embedded distributor class		0.00%		0.00%
Total	$ 17,133,474	100.00%	$ 22,956,939	100.00%

Notes

1 Customer Classification - If proposed rate classes differ from those in place in the previous Cost Allocation study, modify the rate classes to match the current application as closely as possible.

2 Host Distributors - Provide information on embedded distributor(s) as a separate class, if applicable. If embedded distributor(s) are billed as customers in a General Service class, include the allocated cost and revenue of the embedded distributor(s) in the applicable class. Also complete Appendix 2-Q.

3 Class Revenue Requirements - If using the Board-issued model, in column 7A enter the results from Worksheet O-1, Revenue Requirement (row 40 in the 2013 model). This excludes costs in deferral and variance accounts. Note to Embedded Distributor(s), it also does not include Account 4750 - Low Voltage (LV) Costs.

B) Calculated Class Revenues

Classes (same as previous table)	Column 7B	Column 7C	Column 7D	Column 7E
	Load Forecast (LF) X current	L.F. X current approved rates X	LF X proposed rates	Miscellaneous Revenue
Residential	$ 10,126,325	$ 12,026,197	$ 12,026,198	$ 714,812
GS < 50 kW	$ 2,625,746	$ 3,118,381	$ 3,118,381	$ 116,462
GS > 50 -999 kW	$ 2,905,671	$ 3,450,825	$ 3,450,825	$ 102,760
GS >1000-4999 kW	$ 693,814	$ 823,985	$ 871,604	$ 38,755
Large User	$ 1,213,404	$ 1,441,059	$ 1,441,059	$ 53,021
Street Lighting	$ 660,223	$ 784,092	$ 784,092	$ 46,630
Sentinel Lighting	$ 51,175	$ 60,778	$ 60,776	$ 2,970
Unmetered Scattered Load (USL)	$ 144,300	$ 171,373	$ 123,755	$ 4,839
0				
Embedded distributor class				
Total	$ 18,420,658	$ 21,876,690	$ 21,876,690	$ 1,080,249

Notes:

1 Columns 7B to 7D - LF means Load Forecast of Annual Billing Quantities (i.e. customers or connections X 12, (kWh or kW, as applicable). Revenue Quantities should be net of Transfomrer Ownership Allowance. Exclude revenue from rate adders and rate

2 Columns 7C and 7D - Column total in each column should equal the Base Revenue Requirement

3 Columns 7C - The Board cost allocation model calculates "1+d" in worksheet O-1, cell C21. "d" is defined as Revenue Deficiency/ Revenue at Current Rates.

4 Columns 7E - If using the Board-issued Cost Allocation model, enter Miscellaneous Revenue as it appears in Worksheet O-1, row 19.

C) Rebalancing Revenue-to-Cost (R/C) Ratios

Class	Previously Approved Ratios Most Recent Year: 2012 IRM	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	103.00	92.87	92.87	85 - 115
GS < 50 kW	103.00	112.78	112.78	80 - 120
GS > 50 -999 kW	90.00	119.20	119.20	80 - 120
GS >1000-4999 kW	101.00	85.08	89.77	80 - 120
Large User	103.00	115.25	115.25	85 - 115
Street Lighting	85.00	91.02	91.02	70 - 120
Sentinel Lighting	85.00	108.34	108.34	80 - 120
Unmetered Scattered Load (USL)	85.00	164.80	120.26	80 - 120
0				
Embedded distributor class				▨

Notes

1 Previously Approved Revenue-to-Cost Ratios - For most applicants, Most Recent Year would be the third year of the IRM 3 period, e.g. if the applicant rebased in 2009 with further adjustments over 2 years, the Most recent year is 2011. For applicants that have had rates adjusted only under IRM 2, the Most Recent Year is 2006, and the applicant should enter the ratios from their Informational Filing.

2 Status Quo Ratios - The Board's updated Cost Allocation Model yields the Status Quo Ratios in Worksheet O-1. Status Quo means "Before Rebalancing".

D) Proposed Revenue-to-Cost Ratios

Class	Proposed Revenue-to-Cost Ratios			Policy Range
	2013	2014	2015	
	%	%	%	%
Residential	92.87			85 - 115
GS < 50 kW	112.78			80 - 120
GS > 50 -999 kW	119.20			80 - 120
GS >1000-4999 kW	89.77			80 - 120
Large User	115.25			85 - 115
Street Lighting	91.02			70 - 120
Sentinel Lighting	108.34			80 - 120
Unmetered Scattered Load (USL)	120.26			80 - 120
0				0
				0
Embedded distributor class				▨

Note

1 The applicant should complete Table D if it is applying for approval of a revenue to cost ratio in 2012 that is outside the Board's policy range for any customer class. Table (d) will show the information that the distributor would likely enter in the IRM model) in 2013. In 2013 Table (d), enter the planned ratios for the classes that will be 'Change' and 'No Change' in 2013 (in the current Revenue Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision – Cost Revenue Adjustment', column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

7.0-Staff-42 - Weighting Factor for Services

Ref: Exh 7-1-1

At page 4 of the reference, Bluewater Power states that its policy "is to charge customers other than residential customers for the cost of their service such that there are no service costs being booked to account 1855 for non-residential customers." Bluewater Power has proposed 2013 services weighting factors of "0" for all customer classes except residential. Please confirm whether the policy stated on page 4 of the reference refers to capital contributions as well as any subsequent related OM&A expenses.

The policy stated on page 4 does not refer to capital contribution. Typically a single residential customer does not pay capital contribution for a service, unless a system expansion is required.

The only costs being booked to account 1855 relate to new residential services. Once the service is installed there are no further costs being booked to account 1855. Therefore this policy would not apply in the case of any further OM&A expenses.

7.0-Staff-43 - Weighting Factors for Billing and Collection

Ref: Exh 7-1-1

At page 7, Bluewater Power states that it could not justify the disparity of the classes to the extent that the Board's default weighting factors identified for billing and collecting. The Report of the Board – *Review of Electricity Distribution Cost Allocation Policy* (March 31, 2011) states that a factor affecting the level of effort in billing and collecting is the complexity of the bill. The report also states that billing software costs are a component of billing costs. Please explain how these factors were considered in the determination of the weighting factors listed on page 8 of the evidence and used in the cost allocation model.

In order to calculate weighting factors for billing and collection, Bluewater Power analyzed the 'complexity of a bill' as the main criteria for determining the weighting factors. This was completed by assessing the level of effort required to 'manually' calculate a bill in each rate class. The effort required to manually calculate a bill would factor in all the different components such as whether a rate class utilized interval data or demand data or TOU data and any other distinguishing factors between rate classes. By using the manual calculation of a residential bill as the base (ie. Factor of 1.0), we were able to weight each rate class against each of the other rate classes. This approach was deemed to be a fair way determine relative 'complexity of a bill' for the different customer classes in order to complete the analysis.

For example, the sentinel lighting rate class was deemed to have the lowest factor of 0.06 relative to a residential factor of 1.0 because there is very little complexity to calculating a sentinel bill given that there is no smart meter, no interval meter, or demand to measure because it is an unmetered account. Conversely, the calculation of a large use bill is the most complex, given the manual calculation of the peak demand factors and the global adjustment and is therefore assessed a weighting of 1.14.

In regard to billing software costs, Bluewater Power did not include this cost in the weighting factor analysis. Billing software costs are lumpy in nature, and have at least a five year life cycle. The most recent billing software expenditure related to the implementation of TOU pricing after the installation of smart meters. All of the billing related software specific to the TOU implementation was allocated to the residential and GS<50 rate class customers in accordance with cost causality and Bluewater Power has received approval of the disposition of these costs. Furthermore, the cost allocation model utilizes 2013 Test Year data, not historical data and there is no planned 'billing' software projects projected for 2013.

7.0 - SEC 38 - GS>50 R/C Ratio

[7/1/1, Attach 1, p. 11] Please provide a summary of the main reasons why the revenue to cost ratio for GS>50 class increased from 88.47% in 2009 to 119.20% in 2013.

The movement in the revenue to cost ratios is the result of changes to the cost allocation model input data. The current cost allocation model incorporates updated (ie. 2013 forward test year) data, as well as the introduction of Bluewater-specific weighting factors for 'Services' and for 'Billing and Collecting'. The sensitivities below indicate the change related to moving away from the OEB's default weighting factors in accordance with the filing guidelines. Each change is isolated and the impact on the R/C ratio is provided.

Table 1 - Base Case – as provided in the Application

	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
Weighting Factor for Services	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Weighting Factor for Billing and Collecting	1.00	0.89	0.14	0.86	1.14	1.00	0.06	1.06
Revenue to Cost Ratio in Application	92.87%	112.78%	119.20%	85.08%	115.25%	91.02%	108.34%	164.80%

Table 2 – Changing the Weighting Factor for 'Services' back to OEB default values

	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
Previous OEB default values - SERVICES	1.0	2.0	10.0	10.0	30.0	1.0	1.0	1.0
Resulting R/C Ratio	93.26%	111.96%	118.71%	85.08%	115.25%	88.95%	105.98%	163.62%

Table 3 – Changing the 'Billing & Collecting' Weighting Factor to OEB default values

	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
Previous OEB default values - BILLING AND COLLECTING	1.0	2.0	7.0	7.0	15.0	1.0	0.1	5.0
Resulting R/C Ratio	98.66%	105.03%	103.83%	84.22%	114.72%	91.06%	107.83%	72.89%

Table 4 – Changing both factors to OEB default values

	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
Previous OEB default values - SERVICES	1.0	2.0	10.0	10.0	30.0	1.0	1.0	1.0
Previous OEB default values - BILLING AND COLLECTING	1.0	2.0	7.0	7.0	15.0	1.0	0.1	5.0
Resulting R/C Ratio	99.10%	104.32%	103.46%	84.22%	114.72%	88.99%	105.49%	72.66%

The tables above indicate that approximately 16% of the change to the R/C ratio for the GS>50 rate class relates to the change in the factors, with the majority (approximately 15%) being attributable to the change to the Billing and Collecting weighting factor. As the evidence indicates, Bluewater Power made reasonable efforts to adjust the billing factors to ones that more adequately represented the complexity in billing and collecting components between rate classes.

As mentioned above, the input data is based on 2013 forward test year data. The result is an increase in number of customers and load forecast for the GS>50 rate class in 2013 over the 2009 cost allocation model, whereby the 2009 model was based on 2004 data. Table 5 below details some of the components that have changed between the models which indicate that the revenue has increased for this class at a greater pace than the costs.

Table 5 – Data from 2009 Cost Allocation Model compared to 2013 Model

Rate Class	Data	# customers	kW	Revenue	Costs
GS>50	2009 (based on 2004 data)	360	467,580	2,345,236	2,690,185
	2013	438	627,074	3,553,585	2,981,166
	% change	21.7%	34.1%	51.5%	10.8%

7.0 - AMPCO 12 - R/C Ratio's

Interrogatory #12

Reference: Exhibit 7, Tab1, Schedule 1, Page 7, Table 6

Preamble: Table 6 shows proposed 2013 proposed revenue to cost ratios.

a) Please provide a table with the revenue to cost ratios for the years 2009 to 2012.

Table 1 – Revenue to Cost Ratio's 2009 – 2013

	2009 Board Approved	2010 IRM	2011 IRM	2012 IRM	2013 Initial Results	2013 Proposed
Residential	1.03	1.03	1.03	1.03	0.93	0.93
General Service < 50 kW	1.10	1.07	1.05	1.03	1.13	1.13
General Service > 50 to 999 kW	0.90	0.90	0.90	0.90	1.19	1.19
General Service 1000 to 4999 kW	1.01	1.01	1.01	1.01	0.85	0.90
Large Use	1.07	1.07	1.05	1.03	1.15	1.15
Unmetered Scattered Load	0.70	0.75	0.80	0.85	1.65	1.20
Sentinel Lighting	0.47	0.60	0.72	0.85	1.08	1.08
Street Lighting	0.56	0.66	0.75	0.85	0.91	0.91

b) Please provide the rationale in moving the revenue to cost ratios for some classes away from unity.

Bluewater Power did not move the revenue to cost ratios away from unity by proposing rate changes that vary from the average increase required for the company to recover its proposed revenue requirement. Rather the revenue to cost ratio changes are the result of changes to the cost allocation model input data.

The current cost allocation model incorporates updated (i.e., 2013 forward test year) data, including the introduction for the first time of Bluewater-specific weighting factors, in accordance with Board Report - Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219). A natural outcome of this update is that the revenue to cost ratios have been changed from those in the 2009 model. With one exception, the movement in the ratios between 2009 and the 2013 initial results (Ex. 7-1-1, Table 5) is a consequence of the updated data and LDC specific weighting factors. The only proposed change to the revenue to cost ratios that results from a variance from an across the board rate increase was detailed in (Ex. 7-1-1, Table 6) whereby the ratio for the USL class was moved towards unity.

c) Please explain why Bluewater Power is proposing to move the revenue to cost ratio for the Large User class from the previously approved ratio of 103% in 2012 IRM to 115% in 2013.

Please see response to part (b) above.

The factor of 1.15 for the large use class was the outcome of the cost allocation model when utilizing the 2013 forward test year data. Bluewater Power did not make any further adjustments to the revenue to cost ratio for the large use rate class. The change from the result in the 2012 IRM application to the 2013 test year is a result of the full update of the model using forward test year data.

d) Please discuss why Bluewater Power does not propose phased movement towards unity in the IRM years.

All of the proposed revenue to cost ratio's for 2013 are within the OEB floor and ceiling targets. The OEB did not provide any guidelines to indicate that distributors should further adjust ratio's that are within the target ranges in order to move towards unity, thus Bluewater Power does not seek to do so.

e) Please provide Bluewater Power's perspective on the accuracy of the data and its level of modeling experience related to its updated cost allocation study filed in this application.

Bluewater Power's cost allocation model was prepared and filed consistent with the OEB's Cost Allocation guidelines. Demand allocators for all classes were updated to reflect the best available data. This includes a full update to intermediate and large use load profiles to reflect 2011 actual meter data, and all classes were further scaled to 2013 forecasted energy. This captures both the most accurate available non-coincident demand for each rate class, as well as providing for an updated forecast of system peak, and updated coincident demand allocators. The methodology fully satisfies current OEB requirements, and can be expected to produce results at least as accurate as those typically used by LDCs.

7.0 - AMPCO 13 - Large Use

Interrogatory #13

Reference: Exhibit 7, Tab1, Schedule 1, Attachment 2

a) Please discuss if Bluewater Power consulted with its Large User class in allocating costs and expenses to the Large User class in completing its 2013 cost allocation study.

No, Bluewater Power did not consult with the customers in the Large Use class in updating the cost allocation study.

i) If yes, please summarize the results of those consultations.

N/A.

ii) If not, why not.

The inputs to the cost allocation model include items such as trial balance data, load data, meter reading and meter cost data, whether customers are served off the primary or secondary system, and revenue data. Bluewater Power has all the information necessary to update the cost allocation model, and individual customers would not provide any additional input that would aid the completion or the results of the model.

7.0 - VECC 62 - Cost Allocation and weighting factors

Reference: Exhibit 7, Tab 1, Schedule 1, pages 4-6

a) Does Bluewater's policy with respect to Services also apply to USL customers such as phone booths, etc.?

Yes, the policy applies to all non-residential customers, in that no service costs would be booked to account 1855 for non-residential customers.

b) Does the use of demand billing and the resulting introduction of an additional billing determinant for the GS>50 and GS 1,000-4,999 classes introduce additional complexities and costs into the billing process? If not, why not? If yes, how have these additional costs been recognized in the Billing & Collecting Weighting factor.

Demand is a factor, which is used as a billing determinant, is not unlike any other billing factor whether that is hourly data, monthly data, TOU data, etc. Demand in itself does not make billing more complex, rather it makes calculation of a bill different than a rate class that does not have demand. As indicated in response to Board Staff IR #43, Bluewater Power used the manual calculation of a bill as the main method to compare 'complexity' among the rate classes. A customer in the GS>50 rate class with a regular demand meter is a very straight forward bill to calculate, thus has been weighted lightly when compared to a residential bill that now has TOU data added to the complexity.

For the intermediate rate class, we have assessed a higher weighting than the GS>50 class given that these customers all have interval meters, thus more data to compile and analyze. In addition the customers in the Intermediate rate class have primary meter discounts and transformer allowances added to the calculation.

c) Please explain why the Billing & Collecting Weighting factor for Residential is higher than that for any of the GS classes.

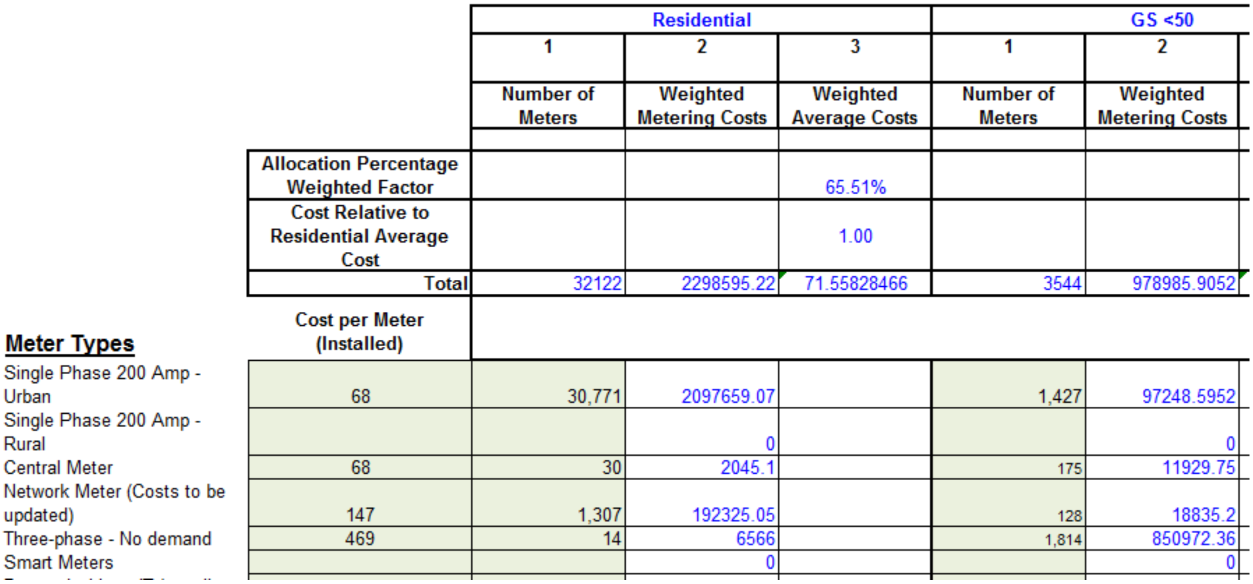
The billing and collecting weighting factor for residential is higher than the general service classes mainly due to the added complexity of Time-of-Use ("TOU") billing. The TOU bill for residential and GS<50 classes now requires the collection and aggregation of hourly data, then allocating the data into the relevant TOU periods which vary depending on the day and the season. The residential rate class is then weighted slightly higher than the GS<50 class due to the additional collections issues associated with this rate class, and extra weighting for call centre given that the majority of the call centre effort is related to the residential rate class.

In addition, approximately 90% of customers that have signed with retailers are in the residential rate class, which entails more time to process transactions through the EBT Hub, and increased call volumes related to high bills and global adjustment. Therefore the residential class is weighted heavier than the GS<50 even though both classes are billed on a TOU basis.

The billing and collecting for the GS>50 rate class is the most straight forward billing at this point, with the majority of the GS>50 meters being standard consumption meters with a demand register. There is less weighting for call centre and collections for this rate class as well.

d) Why are there no "smart meters" include in the CA Model SheetI7.1 for either the Residential or GS<50 class?

The excerpt below is from Sheet I7.1 of the cost allocation model. All the meters for the residential and GS<50 rate classes are smart meters. We used the appropriate meter type in order to separate out the different types of smart meters, rather than using the 'smart meter' row in this sheet. For example the ‘Single phase 200 Amp – Urban meters’ are smart meters for an installed cost of $68.



		Residential			GS <50	
		1	2	3	1	2
		Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs
	Allocation Percentage Weighted Factor			65.51%		
	Cost Relative to Residential Average Cost			1.00		
	Total	32122	2298595.22	71.55828466	3544	978985.9052
Meter Types	Cost per Meter (Installed)					
Single Phase 200 Amp - Urban	68	30,771	2097659.07		1,427	97248.5952
Single Phase 200 Amp - Rural			0			0
Central Meter	68	30	2045.1		175	11929.75
Network Meter (Costs to be updated)	147	1,307	192325.05		128	18835.2
Three-phase - No demand	469	14	6566		1,814	850972.36
Smart Meters			0			0

File Number: EB-2012-0107

Date Filed: February 4, 2013

Tab 10 of 11

Exhibit 8 - Rate Design

8.0-Staff-44 - Fixed Revenue Component

Ref: Exh 8-2-1 Tables 5, 6 and 8, Appendix 2-V

A transformer ownership allowance credit applies to the GS>50 to 999 kW, GS>1000 to 4999 kW and Large Use customer classes. Board staff notes that the fixed revenue component for these three classes differs in Tables 5, 6 and 8. Please review and make appropriate corrections. Please confirm whether the corrected data in this exhibit is consistent with the revenue reconciliation presented in Appendix 2-V.

Tables 5 through 9 in Ex. 8-2-1 detail the progression through the rate design process required in order to develop the final proposed rates. The fixed revenue component in Table 5 is the initial calculation, but the evidence at page 4 indicates that the "*initial fixed charges were higher than the ceiling based on the Minimum system with PLCC adjustment from the cost allocation model for the following rate classes: General Service>50 kW, General Service 1000 to 4999 kW, and Large Use. Bluewater accordingly reduced the amount of the fixed charge to the current level as highlighted in Table 6*." (underline added)

In order to maintain the ceiling as the 'current fixed charge', more revenue requirement was allocated to the variable rate thereby changing the proportion of revenue realized from the fixed component vs. the variable component. For example, Table 5 indicates the fixed component for the GS>50kW class based on existing fixed/variable proportions at 25.69% which derives a fixed rate of $168.84. Bluewater Power then reduced the fixed rate to the current level of $142.00 which reduced the fixed revenue proportion in Table 8 to 21.63%.

In summary, there are no corrections required, and Appendix 2-V is correct.

8.0-Staff-45 - UTR Rates

<u>Ref: Exh 8-3-1</u>

On December 20, 2012, the Board issued updated Uniform Transmission Rates that are effective January 1, 2013. Please file a revised RTSR workform that reflects the new UTR.

Bluewater Power has updated the OEB's RTSR Workform with the Hydro One Transmission Rates, and Sub-Transmission rates both effective January 1, 2013. The resulting updated RTSR Network and RTSR Connection rates are displayed in Table 1 below. Bluewater Power has incorporated the updated rates into the revised revenue requirement, the RRWF and bill impacts presented in response to these interrogatories.

<u>Table 1 – Updated RTSR Rates based on Hydro One Rates of January 1, 2013</u>

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	$ 0.0064	$ 0.0054
General Service Less Than 50 kW	kWh	$ 0.0060	$ 0.0047
General Service 50 to 999 kW	kW	$ 2.4271	$ 1.8963
General Service 1,000 to 4,999 kW	kW	$ 2.5778	$ 2.0788
Large Use	kW	$ 2.8543	$ 2.3772
Unmetered Scattered Load	kWh	$ 0.0060	$ 0.0047
Sentinel Lighting	kW	$ 1.8397	$ 1.4966
Street Lighting	kW	$ 1.8304	$ 1.4660

File Number:EB-2012-0107

Tab: 10
Schedule: 2

Date Filed:February 4, 2013

Attachment 1 of 1

8.0 - Staff 45 - Updated RTSR Model

v 3.0

RTSR Workform for Electricity Distributors (2013 Filers)

Utility Name	Bluewater Power Distribution Corp.
Assigned EB Number	EB-2012-0107
Name and Title	Leslie Dugas, Manager of Regulatory Affairs
Phone Number	519-337-8201 Ext 2255
Email Address	ldugas@bluewaterpower.com
Date	Updated January 30, 2013
Last COS Re-based Year	**2009**

Note: Drop-down lists are shaded blue; Input cells are shaded green.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

RTSR Workform for Electricity Distributors (2013 Filers)

RTSR Workform for Electricity Distributors (2013 Filers)

1. Select the appropriate rate classes that appear on your most recent Board-Approved Tariff of Rates and Charges.
2. Enter the RTS Network and Connection Rate as it appears on the Tariff of Rates and Charges

Rate Class	Unit	RTSR-Network	RTSR-Connection
Residential	kWh	$ 0.0068	$ 0.0057
General Service Less Than 50 kW	kWh	$ 0.0063	$ 0.0050
General Service 50 to 999 kW	kW	$ 2.5648	$ 1.9998
General Service 1,000 to 4,999 kW	kW	$ 2.7241	$ 2.1923
Large Use	kW	$ 3.0162	$ 2.5070
Unmetered Scattered Load	kWh	$ 0.0063	$ 0.0050
Sentinel Lighting	kW	$ 1.9441	$ 1.5783
Street Lighting	kW	$ 1.9342	$ 1.5461
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			

RTSR Workform for Electricity Distributors (2013 Filers)

In the green shaded cells, enter the most recent reported RRR billing determinants. Please ensure that billing determinants are non-loss adjusted.

Rate Class	Unit	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor	Load Factor	Loss Adjusted Billed kWh	Billed kW
Residential	**kWh**	262,832,708		1.0356		272,189,552	-
General Service Less Than 50 kW	**kWh**	108,173,255		1.0356		112,024,223	-
General Service 50 to 999 kW	**kW**	225,654,890	617,147		**50.12%**	225,654,890	617,147
General Service 1,000 to 4,999 kW	**kW**	163,185,559	342,743		**65.26%**	163,185,559	342,743
Large Use	**kW**	253,616,043	401,335		**86.61%**	253,616,043	401,335
Unmetered Scattered Load	**kWh**	2,176,365		1.0356		2,253,844	-
Sentinel Lighting	**kW**	608,868	1,430		**58.36%**	608,868	1,430
Street Lighting	**kW**	9,005,139	24,131		**51.15%**	9,005,139	24,131

RTSR Workform for Electricity Distributors (2013 Filers)

Uniform Transmission Rates	Unit	Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.22	$ 3.57	$ 3.63
Line Connection Service Rate	kW	$ 0.79	$ 0.80	$ 0.75
Transformation Connection Service Rate	kW	$ 1.77	$ 1.86	$ 1.85

Hydro One Sub-Transmission Rates	Unit	Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 2.65	$ 2.65	$ 3.18
Line Connection Service Rate	kW	$ 0.64	$ 0.64	$ 0.70
Transformation Connection Service Rate	kW	$ 1.50	$ 1.50	$ 1.63
Both Line and Transformation Connection Service Rate	kW	$ 2.14	$ 2.14	$ 2.33

Hydro One Sub-Transmission Rate Rider 6A	Unit	Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013
Rate Description		**Rate**	**Rate**	**Rate**
RSVA Transmission network – 4714 – which affects 1584	kW	$ 0.0470	$ -	$ -
RSVA Transmission connection – 4716 – which affects 1586	kW	-$ 0.0250	$ -	$ -
RSVA LV – 4750 – which affects 1550	kW	$ 0.0580	$ -	$ -
RARA 1 – 2252 – which affects 1590	kW	-$ 0.0750	$ -	$ -
Hydro One Sub-Transmission Rate Rider 6A	kW	$ 0.0050	$ -	$ -

RTSR Workform for Electricity Distributors (2013 Filers)

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Sheet "4. RRR Data". For Hydro One Sub-transmission Rates, if you are charged a *combined* Line and Transformer connection rate, please ensure that both the line connection and transformer connection columns are completed.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	137,672	$3.22	$ 443,304	140,483	$0.79	$ 110,982	140,483	$1.77	$ 248,655	$ 359,636
February	141,720	$3.22	$ 456,338	141,720	$0.79	$ 111,959	141,720	$1.77	$ 250,844	$ 362,803
March	125,938	$3.22	$ 405,520	134,327	$0.79	$ 106,118	134,327	$1.77	$ 237,759	$ 343,877
April	100,555	$3.22	$ 323,787	120,588	$0.79	$ 95,265	120,588	$1.77	$ 213,441	$ 308,705
May	113,349	$3.22	$ 364,984	143,773	$0.79	$ 113,581	143,773	$1.77	$ 254,478	$ 368,059
June	128,122	$3.22	$ 412,553	158,673	$0.79	$ 125,352	158,673	$1.77	$ 280,851	$ 406,203
July	138,620	$3.22	$ 446,356	178,027	$0.79	$ 140,641	178,027	$1.77	$ 315,108	$ 455,749
August	130,247	$3.22	$ 419,395	158,653	$0.79	$ 125,336	158,653	$1.77	$ 280,816	$ 406,152
September	136,358	$3.22	$ 439,073	165,303	$0.79	$ 130,589	165,303	$1.77	$ 292,586	$ 423,176
October	112,271	$3.22	$ 361,513	122,696	$0.79	$ 96,930	122,696	$1.77	$ 217,172	$ 314,102
November	129,664	$3.22	$ 417,518	134,964	$0.79	$ 106,622	134,964	$1.77	$ 238,886	$ 345,508
December	132,455	$3.22	$ 426,505	149,858	$0.79	$ 118,388	149,858	$1.77	$ 265,249	$ 383,636
Total	1,526,971	$ 3.22	$ 4,916,847	1,749,065	$ 0.79	$ 1,381,761	1,749,065	$ 1.77	$ 3,095,845	$ 4,477,606

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	11,115	$2.65	$ 29,455	11,115	$0.64	$ 7,114	11,115	$1.50	$ 16,673	$ 23,786
February	11,243	$2.65	$ 29,794	11,243	$0.64	$ 7,196	11,243	$1.50	$ 16,865	$ 24,060
March	11,161	$2.65	$ 29,577	11,161	$0.64	$ 7,143	11,161	$1.50	$ 16,742	$ 23,885
April	9,788	$2.65	$ 25,938	9,788	$0.64	$ 6,264	9,788	$1.50	$ 14,682	$ 20,946
May	12,618	$2.65	$ 33,438	12,618	$0.64	$ 8,076	12,618	$1.50	$ 18,927	$ 27,003
June	15,062	$2.65	$ 39,914	15,062	$0.64	$ 9,640	15,062	$1.50	$ 22,593	$ 32,233
July	15,332	$2.65	$ 40,630	15,332	$0.64	$ 9,812	15,332	$1.50	$ 22,998	$ 32,810
August	12,796	$2.65	$ 33,909	12,796	$0.64	$ 8,189	12,796	$1.50	$ 19,194	$ 27,383
September	13,457	$2.65	$ 35,661	13,457	$0.64	$ 8,612	13,457	$1.50	$ 20,186	$ 28,798
October	10,386	$2.65	$ 27,523	10,386	$0.64	$ 6,647	10,386	$1.50	$ 15,579	$ 22,226
November	10,415	$2.65	$ 27,600	10,415	$0.64	$ 6,666	10,415	$1.50	$ 15,623	$ 22,288
December	12,426	$2.65	$ 32,929	12,426	$0.64	$ 7,953	12,426	$1.50	$ 18,639	$ 26,592
Total	145,799	$ 2.65	$ 386,367	145,799	$ 0.64	$ 93,311	145,799	$ 1.50	$ 218,699	$ 312,010

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	148,787	$3.18	$ 472,759	151,598	$0.78	$ 118,095	151,598	$1.75	$ 265,327	$ 383,423
February	152,963	$3.18	$ 486,132	152,963	$0.78	$ 119,154	152,963	$1.75	$ 267,709	$ 386,863
March	137,099	$3.17	$ 435,097	145,488	$0.78	$ 113,261	145,488	$1.75	$ 254,500	$ 367,762
April	110,343	$3.17	$ 349,725	130,376	$0.78	$ 101,529	130,376	$1.75	$ 228,123	$ 329,652
May	125,967	$3.16	$ 398,421	156,391	$0.78	$ 121,656	156,391	$1.75	$ 273,405	$ 395,061
June	143,184	$3.16	$ 452,467	173,735	$0.78	$ 134,991	173,735	$1.75	$ 303,444	$ 438,436
July	153,952	$3.16	$ 486,986	193,359	$0.78	$ 150,454	193,359	$1.75	$ 338,106	$ 488,560
August	143,043	$3.17	$ 453,305	171,449	$0.78	$ 133,525	171,449	$1.75	$ 300,010	$ 433,535
September	149,815	$3.17	$ 474,734	178,760	$0.78	$ 139,202	178,760	$1.75	$ 312,772	$ 451,974
October	122,657	$3.17	$ 389,036	133,082	$0.78	$ 103,577	133,082	$1.75	$ 232,751	$ 336,328
November	140,079	$3.18	$ 445,118	145,379	$0.78	$ 113,287	145,379	$1.75	$ 254,509	$ 367,796
December	144,881	$3.17	$ 459,434	162,284	$0.78	$ 126,340	162,284	$1.75	$ 283,888	$ 410,228
Total	1,672,770	$ 3.17	$ 5,303,214	1,894,864	$ 0.78	$ 1,475,073	1,894,864	$ 1.75	$ 3,314,544	$ 4,789,616

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to calculate the expected billing when current 2012 Uniform Transmission Rates are applied against historical 2011 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	137,672	$ 3.5700	$ 491,489	140,483	$ 0.8000	$ 112,386	140,483	$ 1.8600	$ 261,298	$ 373,685
February	141,720	$ 3.5700	$ 505,940	141,720	$ 0.8000	$ 113,376	141,720	$ 1.8600	$ 263,599	$ 376,975
March	125,938	$ 3.5700	$ 449,599	134,327	$ 0.8000	$ 107,462	134,327	$ 1.8600	$ 249,848	$ 357,310
April	100,555	$ 3.5700	$ 358,981	120,588	$ 0.8000	$ 96,470	120,588	$ 1.8600	$ 224,294	$ 320,764
May	113,349	$ 3.5700	$ 404,656	143,773	$ 0.8000	$ 115,018	143,773	$ 1.8600	$ 267,418	$ 382,436
June	128,122	$ 3.5700	$ 457,396	158,673	$ 0.8000	$ 126,938	158,673	$ 1.8600	$ 295,132	$ 422,070
July	138,620	$ 3.5700	$ 494,873	178,027	$ 0.8000	$ 142,422	178,027	$ 1.8600	$ 331,130	$ 473,552
August	130,247	$ 3.5700	$ 464,982	158,653	$ 0.8000	$ 126,922	158,653	$ 1.8600	$ 295,095	$ 422,017
September	136,358	$ 3.5700	$ 486,798	165,303	$ 0.8000	$ 132,242	165,303	$ 1.8600	$ 307,464	$ 439,706
October	112,271	$ 3.5700	$ 400,807	122,696	$ 0.8000	$ 98,157	122,696	$ 1.8600	$ 228,215	$ 326,371
November	129,664	$ 3.5700	$ 462,900	134,964	$ 0.8000	$ 107,971	134,964	$ 1.8600	$ 251,033	$ 359,004
December	132,455	$ 3.5700	$ 472,864	149,858	$ 0.8000	$ 119,886	149,858	$ 1.8600	$ 278,736	$ 398,622
Total	1,526,971	$ 3.57	$ 5,451,286	1,749,065	$ 0.80	$ 1,399,252	1,749,065	$ 1.86	$ 3,253,261	$ 4,652,513

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	11,115	$ 2.6500	$ 29,455	11,115	$ 0.6400	$ 7,114	11,115	$ 1.5000	$ 16,673	$ 23,786
February	11,243	$ 2.6500	$ 29,794	11,243	$ 0.6400	$ 7,196	11,243	$ 1.5000	$ 16,865	$ 24,060
March	11,161	$ 2.6500	$ 29,577	11,161	$ 0.6400	$ 7,143	11,161	$ 1.5000	$ 16,742	$ 23,885
April	9,788	$ 2.6500	$ 25,938	9,788	$ 0.6400	$ 6,264	9,788	$ 1.5000	$ 14,682	$ 20,946
May	12,618	$ 2.6500	$ 33,438	12,618	$ 0.6400	$ 8,076	12,618	$ 1.5000	$ 18,927	$ 27,003
June	15,062	$ 2.6500	$ 39,914	15,062	$ 0.6400	$ 9,640	15,062	$ 1.5000	$ 22,593	$ 32,233
July	15,332	$ 2.6500	$ 40,630	15,332	$ 0.6400	$ 9,812	15,332	$ 1.5000	$ 22,998	$ 32,810
August	12,796	$ 2.6500	$ 33,909	12,796	$ 0.6400	$ 8,189	12,796	$ 1.5000	$ 19,194	$ 27,383
September	13,457	$ 2.6500	$ 35,661	13,457	$ 0.6400	$ 8,612	13,457	$ 1.5000	$ 20,186	$ 28,798
October	10,386	$ 2.6500	$ 27,523	10,386	$ 0.6400	$ 6,647	10,386	$ 1.5000	$ 15,579	$ 22,226
November	10,415	$ 2.6500	$ 27,600	10,415	$ 0.6400	$ 6,666	10,415	$ 1.5000	$ 15,623	$ 22,288
December	12,426	$ 2.6500	$ 32,929	12,426	$ 0.6400	$ 7,953	12,426	$ 1.5000	$ 18,639	$ 26,592
Total	145,799	$ 2.65	$ 386,367	145,799	$ 0.64	$ 93,311	145,799	$ 1.50	$ 218,699	$ 312,010

Total	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	148,787	$ 3.50	$ 520,944	151,598	$ 0.79	$ 119,500	151,598	$ 1.83	$ 277,971	$ 397,471
February	152,963	$ 3.50	$ 535,734	152,963	$ 0.79	$ 120,572	152,963	$ 1.83	$ 280,464	$ 401,035
March	137,099	$ 3.50	$ 479,175	145,488	$ 0.79	$ 114,605	145,488	$ 1.83	$ 266,590	$ 381,194
April	110,343	$ 3.49	$ 384,920	130,376	$ 0.79	$ 102,735	130,376	$ 1.83	$ 238,976	$ 341,710
May	125,967	$ 3.48	$ 438,094	156,391	$ 0.79	$ 123,094	156,391	$ 1.83	$ 286,345	$ 409,439
June	143,184	$ 3.47	$ 497,310	173,735	$ 0.79	$ 136,578	173,735	$ 1.83	$ 317,725	$ 454,303
July	153,952	$ 3.48	$ 535,503	193,359	$ 0.79	$ 152,234	193,359	$ 1.83	$ 354,128	$ 506,362
August	143,043	$ 3.49	$ 498,891	171,449	$ 0.79	$ 135,112	171,449	$ 1.83	$ 314,289	$ 449,400
September	149,815	$ 3.49	$ 522,459	178,760	$ 0.79	$ 140,855	178,760	$ 1.83	$ 327,649	$ 468,504
October	122,657	$ 3.49	$ 428,330	133,082	$ 0.79	$ 104,804	133,082	$ 1.83	$ 243,794	$ 348,597
November	140,079	$ 3.50	$ 490,500	145,379	$ 0.79	$ 114,637	145,379	$ 1.83	$ 266,656	$ 381,292
December	144,881	$ 3.49	$ 505,793	162,284	$ 0.79	$ 127,839	162,284	$ 1.83	$ 297,375	$ 425,214
Total	1,672,770	$ 3.49	$ 5,837,654	1,894,864	$ 0.79	$ 1,492,563	1,894,864	$ 1.83	$ 3,471,959	$ 4,964,523

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to calculate the expected billing when forecasted 2013 Uniform Transmission Rates are applied against historical 2011 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	137,672	$ 3.6300	$ 499,749	140,483	$ 0.7500	$ 105,362	140,483	$ 1.8500	$ 259,894	$ 365,256
February	141,720	$ 3.6300	$ 514,444	141,720	$ 0.7500	$ 106,290	141,720	$ 1.8500	$ 262,182	$ 368,472
March	125,938	$ 3.6300	$ 457,155	134,327	$ 0.7500	$ 100,745	134,327	$ 1.8500	$ 248,505	$ 349,250
April	100,555	$ 3.6300	$ 365,015	120,588	$ 0.7500	$ 90,441	120,588	$ 1.8500	$ 223,088	$ 313,529
May	113,349	$ 3.6300	$ 411,457	143,773	$ 0.7500	$ 107,830	143,773	$ 1.8500	$ 265,980	$ 373,810
June	128,122	$ 3.6300	$ 465,083	158,673	$ 0.7500	$ 119,005	158,673	$ 1.8500	$ 293,545	$ 412,550
July	138,620	$ 3.6300	$ 503,191	178,027	$ 0.7500	$ 133,520	178,027	$ 1.8500	$ 329,350	$ 462,870
August	130,247	$ 3.6300	$ 472,797	158,653	$ 0.7500	$ 118,990	158,653	$ 1.8500	$ 293,508	$ 412,498
September	136,358	$ 3.6300	$ 494,980	165,303	$ 0.7500	$ 123,977	165,303	$ 1.8500	$ 305,811	$ 429,788
October	112,271	$ 3.6300	$ 407,544	122,696	$ 0.7500	$ 92,022	122,696	$ 1.8500	$ 226,988	$ 319,010
November	129,664	$ 3.6300	$ 470,680	134,964	$ 0.7500	$ 101,223	134,964	$ 1.8500	$ 249,683	$ 350,906
December	132,455	$ 3.6300	$ 480,812	149,858	$ 0.7500	$ 112,394	149,858	$ 1.8500	$ 277,237	$ 389,631
Total	1,526,971	$ 3.63	$ 5,542,905	1,749,065	$ 0.75	$ 1,311,799	1,749,065	$ 1.85	$ 3,235,770	$ 4,547,569

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	11,115	$ 3.1800	$ 35,346	11,115	$ 0.7000	$ 7,781	11,115	$ 1.6300	$ 18,117	$ 25,898
February	11,243	$ 3.1800	$ 35,753	11,243	$ 0.7000	$ 7,870	11,243	$ 1.6300	$ 18,326	$ 26,196
March	11,161	$ 3.1800	$ 35,492	11,161	$ 0.7000	$ 7,813	11,161	$ 1.6300	$ 18,192	$ 26,005
April	9,788	$ 3.1800	$ 31,126	9,788	$ 0.7000	$ 6,852	9,788	$ 1.6300	$ 15,954	$ 22,806
May	12,618	$ 3.1800	$ 40,125	12,618	$ 0.7000	$ 8,833	12,618	$ 1.6300	$ 20,567	$ 29,400
June	15,062	$ 3.1800	$ 47,897	15,062	$ 0.7000	$ 10,543	15,062	$ 1.6300	$ 24,551	$ 35,094
July	15,332	$ 3.1800	$ 48,756	15,332	$ 0.7000	$ 10,732	15,332	$ 1.6300	$ 24,991	$ 35,724
August	12,796	$ 3.1800	$ 40,691	12,796	$ 0.7000	$ 8,957	12,796	$ 1.6300	$ 20,857	$ 29,815
September	13,457	$ 3.1800	$ 42,793	13,457	$ 0.7000	$ 9,420	13,457	$ 1.6300	$ 21,935	$ 31,355
October	10,386	$ 3.1800	$ 33,027	10,386	$ 0.7000	$ 7,270	10,386	$ 1.6300	$ 16,929	$ 24,199
November	10,415	$ 3.1800	$ 33,120	10,415	$ 0.7000	$ 7,291	10,415	$ 1.6300	$ 16,976	$ 24,267
December	12,426	$ 3.1800	$ 39,515	12,426	$ 0.7000	$ 8,698	12,426	$ 1.6300	$ 20,254	$ 28,953
Total	145,799	$ 3.18	$ 463,641	145,799	$ 0.70	$ 102,059	145,799	$ 1.63	$ 237,652	$ 339,712

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	148,787	$ 3.60	$ 535,095	151,598	$ 0.75	$ 113,143	151,598	$ 1.83	$ 278,011	$ 391,154
February	152,963	$ 3.60	$ 550,196	152,963	$ 0.75	$ 114,160	152,963	$ 1.83	$ 280,508	$ 394,668
March	137,099	$ 3.59	$ 492,647	145,488	$ 0.75	$ 108,558	145,488	$ 1.83	$ 266,697	$ 375,255
April	110,343	$ 3.59	$ 396,140	130,376	$ 0.75	$ 97,293	130,376	$ 1.83	$ 239,042	$ 336,335
May	125,967	$ 3.58	$ 451,582	156,391	$ 0.75	$ 116,662	156,391	$ 1.83	$ 286,547	$ 403,210
June	143,184	$ 3.58	$ 512,980	173,735	$ 0.75	$ 129,548	173,735	$ 1.83	$ 318,096	$ 447,644
July	153,952	$ 3.59	$ 551,946	193,359	$ 0.75	$ 144,253	193,359	$ 1.83	$ 354,341	$ 498,594
August	143,043	$ 3.59	$ 513,488	171,449	$ 0.75	$ 127,947	171,449	$ 1.83	$ 314,366	$ 442,312
September	149,815	$ 3.59	$ 537,773	178,760	$ 0.75	$ 133,397	178,760	$ 1.83	$ 327,745	$ 461,143
October	122,657	$ 3.59	$ 440,571	133,082	$ 0.75	$ 99,292	133,082	$ 1.83	$ 243,917	$ 343,209
November	140,079	$ 3.60	$ 503,800	145,379	$ 0.75	$ 108,514	145,379	$ 1.83	$ 266,660	$ 375,173
December	144,881	$ 3.59	$ 520,326	162,284	$ 0.75	$ 121,092	162,284	$ 1.83	$ 297,492	$ 418,583
Total	1,672,770	$ 3.59	$ 6,006,546	1,894,864	$ 0.75	$ 1,413,858	1,894,864	$ 1.83	$ 3,473,423	$ 4,887,281

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to re-align the current RTS Network Rates to recover current wholesale network costs.

Rate Class	Unit	Current RTSR-Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR Network
Residential	kWh	$ 0.0068	272,189,552	-	$ 1,850,889	29.2%	$ 1,702,268	$ 0.0063
General Service Less Than 50 kW	kWh	$ 0.0063	112,024,223	-	$ 705,753	11.1%	$ 649,083	$ 0.0058
General Service 50 to 999 kW	kW	$ 2.5648	225,654,890	617,147	$ 1,582,859	24.9%	$ 1,455,759	$ 2.3589
General Service 1,000 to 4,999 kW	kW	$ 2.7241	163,185,559	342,743	$ 933,666	14.7%	$ 858,695	$ 2.5054
Large Use	kW	$ 3.0162	253,616,043	401,335	$ 1,210,507	19.1%	$ 1,113,306	$ 2.7740
Unmetered Scattered Load	kWh	$ 0.0063	2,253,844	-	$ 14,199	0.2%	$ 13,059	$ 0.0058
Sentinel Lighting	kW	$ 1.9441	608,868	1,430	$ 2,780	0.0%	$ 2,557	$ 1.7880
Street Lighting	kW	$ 1.9342	9,005,139	24,131	$ 46,674	0.7%	$ 42,926	$ 1.7789
					$ 6,347,326			

RTSR Workform for Electricity Distributors (2013 Filers)

re-align the current RTS Connection Rates to recover current wholesale connection costs.

Unit	Current RTSR-Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR Connection
kWh	$ 0.0057	272,189,552	-	$ 1,551,480	30.1%	$ 1,494,400	$ 0.0055
kWh	$ 0.0050	112,024,223	-	$ 560,121	10.9%	$ 539,514	$ 0.0048
kW	$ 1.9998	225,654,890	617,147	$ 1,234,171	23.9%	$ 1,188,764	$ 1.9262
kW	$ 2.1923	163,185,559	342,743	$ 751,395	14.6%	$ 723,751	$ 2.1116
kW	$ 2.5070	253,616,043	401,335	$ 1,006,147	19.5%	$ 969,130	$ 2.4148
kWh	$ 0.0050	2,253,844	-	$ 11,269	0.2%	$ 10,855	$ 0.0048
kW	$ 1.5783	608,868	1,430	$ 2,257	0.0%	$ 2,174	$ 1.5202
kW	$ 1.5461	9,005,139	24,131	$ 37,309	0.7%	$ 35,936	$ 1.4892
				$ 5,154,150			

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to update the re-align RTS Network Rates to recover forecast wholesale network costs.

Rate Class	Unit	Adjusted RTSR-Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Network
Residential	kWh	$ 0.0063	272,189,552	-	$ 1,702,268	29.2%	$ 1,751,517	$ 0.0064
General Service Less Than 50 kW	kWh	$ 0.0058	112,024,223	-	$ 649,083	11.1%	$ 667,862	$ 0.0060
General Service 50 to 999 kW	kW	$ 2.3589	225,654,890	617,147	$ 1,455,759	24.9%	$ 1,497,877	$ 2.4271
General Service 1,000 to 4,999 kW	kW	$ 2.5054	163,185,559	342,743	$ 858,695	14.7%	$ 883,539	$ 2.5778
Large Use	kW	$ 2.7740	253,616,043	401,335	$ 1,113,306	19.1%	$ 1,145,516	$ 2.8543
Unmetered Scattered Load	kWh	$ 0.0058	2,253,844	-	$ 13,059	0.2%	$ 13,437	$ 0.0060
Sentinel Lighting	kW	$ 1.7880	608,868	1,430	$ 2,557	0.0%	$ 2,631	$ 1.8397
Street Lighting	kW	$ 1.7789	9,005,139	24,131	$ 42,926	0.7%	$ 44,168	$ 1.8304
					$ 5,837,654			

RTSR Workform for Electricity Distributors (2013 Filers)

e the re-aligned RTS Connection Rates to recover forecast wholesale connection costs.

Unit	Adjusted RTSR-Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Connection
kWh	$ 0.0055	272,189,552	-	$ 1,494,400	30.1%	$ 1,471,149	$ 0.0054
kWh	$ 0.0048	112,024,223	-	$ 539,514	10.9%	$ 531,119	$ 0.0047
kW	$ 1.9262	225,654,890	617,147	$ 1,188,764	23.9%	$ 1,170,268	$ 1.8963
kW	$ 2.1116	163,185,559	342,743	$ 723,751	14.6%	$ 712,490	$ 2.0788
kW	$ 2.4148	253,616,043	401,335	$ 969,130	19.5%	$ 954,051	$ 2.3772
kWh	$ 0.0048	2,253,844	-	$ 10,855	0.2%	$ 10,686	$ 0.0047
kW	$ 1.5202	608,868	1,430	$ 2,174	0.0%	$ 2,140	$ 1.4966
kW	$ 1.4892	9,005,139	24,131	$ 35,936	0.7%	$ 35,377	$ 1.4660
				$ 4,964,523			

RTSR Workform for Electricity Distributors (2013 Filers)

For Cost of Service Applicants, please enter the following Proposed RTS rates into your rates model.

For IRM applicants, please enter these rates into the 2013 IRM Rate Generator, Sheet 11 "Proposed Rates", column I. Please note that the rate description for the RTSRs has been transfered to Sheet 11, Column A from Sheet 4.

Rate Class	Unit	Proposed RTSR Network		Proposed RTSR Connection	
Residential	**kWh**	**$**	**0.0064**	**$**	**0.0054**
General Service Less Than 50 kW	**kWh**	**$**	**0.0060**	**$**	**0.0047**
General Service 50 to 999 kW	**kW**	**$**	**2.4271**	**$**	**1.8963**
General Service 1,000 to 4,999 kW	**kW**	**$**	**2.5778**	**$**	**2.0788**
Large Use	**kW**	**$**	**2.8543**	**$**	**2.3772**
Unmetered Scattered Load	**kWh**	**$**	**0.0060**	**$**	**0.0047**
Sentinel Lighting	**kW**	**$**	**1.8397**	**$**	**1.4966**
Street Lighting	**kW**	**$**	**1.8304**	**$**	**1.4660**

8.0 - VECC 55 - Updated RTSR rates

Reference: Exhibit 8, Tab 3, Schedule 1

a) Please update the RTSRs to reflect the recently approved 2013 UTRs.

Please see response to Board Staff #45.

8.0 - VECC 56 - Account History Charge and Meter Dispute Charge

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Reference: Exhibit 8, Tab 3, Schedule 4, pages 1-2

a) With respect to the Account History charge and residential landlords, please confirm that the charge is billed to the landlord.

The account history charge is levied to the account holder requesting the document. In the case of residential landlords requesting the information in order to provide it to potential tenants, the charge is levied to the landlord.

b) With respect to the Meter Dispute charge, is Bluewater verifying the meter reading or the accuracy of the meter? Please explain more clearly the circumstances under which such a charge would be levied.

The meter dispute charge would be applied in a case where a customer believes the meter is inaccurate. In this case, Bluewater Power will work with the customer to demonstrate that the meter is working correctly. This could include one or all of the following things. First, we may temporarily install a dual meter base which is a device that would allow a second meter to measure the same load as the customer's meter and allows them to see that both register the same energy usage. Secondly, we may install an electronic analyser which measures energy usage and tracks demand over time. This again allows the customer to see another device measuring the same energy consumption as the meter on their house, and also helps them to see when energy is being used to assist them in identifying what is driving their bill. Thirdly, we can test the meter in our shop to verify its accuracy. If those things fail to satisfy the customer, then we would involve Measurement Canada. It would be in this case that the meter dispute charge could apply. The meter would be shipped to their facility in London for verification. If

Measurement Canada finds fault with the meter, the customer would not be charged the fee, but if Measurement Canada verifies the meter is correct, the charge would apply. The charge is mainly to cover the costs of time and shipping to send the meter to Measurement Canada.

8.0-Staff-46 - Retail Service Charges

Ref: Exh 8-3-2

Bluewater Power charges retailers for services related to the supply of competitive electricity to consumers.

a) Please confirm whether or not the applicant has followed Article 490, Retail Services and Settlement Variances of the Accounting Procedures Handbook for Account 1518 and Account 1548. Please explain if the applicant has not followed Article 490. In other words, please confirm that the higher of, the relevant revenues (i.e. account 4082, Retail Services Revenue and/or account 4084, STR Revenue) and the incremental expenses in the associated expense accounts (i.e. account 5315, Customer Billing, and possibly 5305, Supervision and 5340, Miscellaneous Customer Accounts Expenses) is reduced (i.e. revenues debited or expenses credited) at the end of each period, with an offsetting entry to the variance account. Please explain if the applicant has not followed Article 490, and if so, please quantify the variance.

Prior to 2013, Bluewater Power has not followed Article 490 with respect to Account 1518 and 1548. In the past, Bluewater Power has compared high level cost estimates with the amount of revenues collected from retailers. Since the variance was normally immaterial, no adjustments were made to reallocate revenues and costs to these two accounts.

Starting January 1, 2013, Bluewater Power will follow Article 490 with respect to Account 1518 and 1548.

b) Please confirm that all costs incorporated into the variances reported in Account 1518 and Account 1548 are incremental costs of providing retail services.

See response to part (a) above.

8.0-Staff-47 - LV Costs

Ref: Exh 8-3-5

Bluewater Power has projected 2013 LV costs based on the actual demand for each of the six Hydro One delivery points. The proposed rates in the Hydro One proceeding EB-2012-0136 were applied to estimate the 2013 LV costs. Please update the 2013 LV costs based on the Sub-Transmission rates found in the rate order issued on December 20, 2012.

Bluewater Power has updated the proposed LV rates to reflect the Hydro One actual rates effective January 1, 2013. The original filing proposed LV costs of $189,083, and the revised LV cost estimate based on actual Hydro One rates is $189,412. The revised rates required to recover the LV costs are presented in Table 1 below. Bluewater Power has incorporated the updated LV rates into the revised revenue requirement, the RRWF and bill impacts presented in response to these interrogatories.

Table 1 – Updated LV Proposed Rates

	2013 Projected Transmission Connection Rate $/kWh or kW	2013 forecast kWh (uplifted)	2013 forecast kW	Billed Transmission connection ($)	% Allocation	Proposed LV Recovery ($)	2013 forecast kWh (non-uplifted)	Proposed Rate $	Unit of Measure
Residential	0.0054	266,451,788	-	1,438,840	30.0%	56,910	255,687,351	0.0002	$/kWh
GS<50	0.0047	101,536,145	-	477,220	10.0%	18,875	97,434,167	0.0002	$/kWh
GS>50	1.8963	231,248,216	627,074	1,189,120	24.8%	47,033	627,074	0.0750	$/kW
Intermediate	2.0788	161,652,837	337,859	702,341	14.7%	27,779	337,859	0.0822	$/kW
Large	2.3772	249,249,951	392,393	932,797	19.5%	36,895	392,393	0.0940	$/kW
USL	0.0047	2,333,194		10,966	0.2%	434	2,238,935	0.0002	$/kWh
Sentinel	1.4966	654,099	1,452	2,173	0.0%	86	1,452	0.0592	$/kW
Streetlighting	1.4660	9,369,836	24,157	35,414	0.7%	1,401	24,157	0.0580	$/kW
		1,022,496,067	1,382,935	4,788,871	100.0%	189,412			

The current rates as compared to the proposed rates are detailed in Table 2

Table 2 – Proposed LV rate compared to Current LV rate

	Proposed Rate $	Current LV Rates $	Unit of Measure
Residential	0.0002	0.0002	$/kWh
GS<50	0.0002	0.0002	$/kWh
GS>50	0.0750	0.0722	$/kW
Intermediate	0.0822	0.0792	$/kW
Large	0.0940	0.0905	$/kW
USL	0.0002	0.0002	$/kWh
Sentinel	0.0592	0.057	$/kW
Streetlighting	0.0580	0.0558	$/kW
Amount to recover	189,412	189,602	

8.0 - VECC 57 - Updated LV costs and power purchases

Reference: Exhibit 8, Tab 3, Schedule 5

a) Please update the 2013 forecast LV cost for Hydro One's recently approved 2013 distribution rates.

Please see response to Board Staff #47.

b) Please provide a schedule that compares Bluewater's actual 2011 power purchases with its forecast 2013 power purchases.

The 2011 wholesale power purchased for 2011 was 1,051,339,006 kWh. Bluewater Power did not forecast power purchases for 2013 as the load forecast was derived using monthly class specific retail data to generate a weather normal load forecast (where applicable), not by forecasting power purchases. Although there is a correlation between the power purchases and the load forecast it is difficult to translate the load forecast into a power purchase forecast in order to respond to this question. The power purchased is a measurement of the load that comes into our system, and the load forecast measures the retail sales at the meter. Furthermore, the 2011 power purchased value quoted above is an actual value, not weather normalized.

8.0-Staff-48 - Loss Factor

Ref: Exh 8-3-6 Table 2

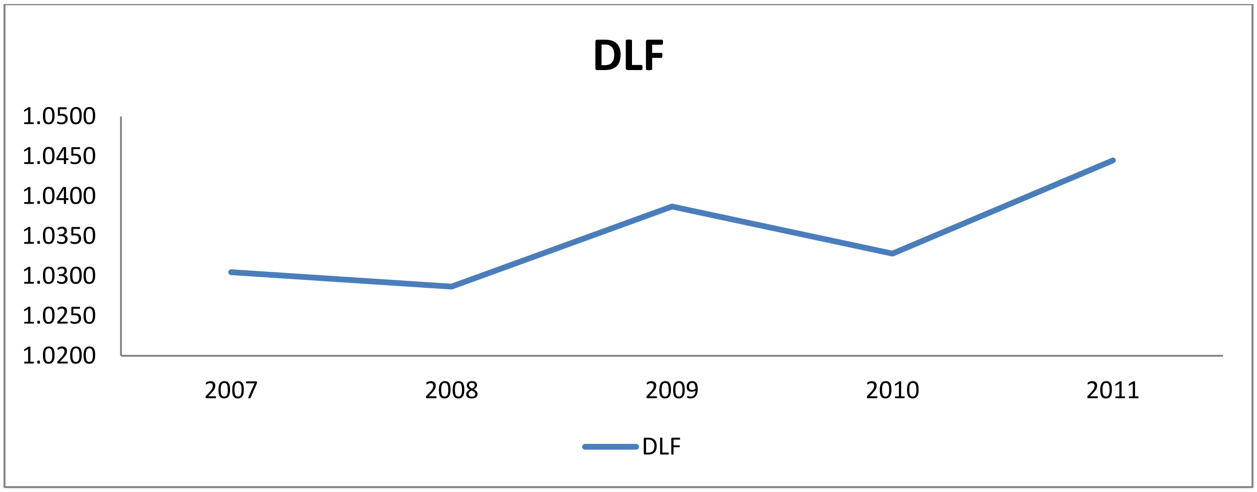
The distribution loss factors ("DLF"), and the supporting data, for the period 2007 to 2011 are summarized in Table 2. The amount of distributed generation has increased significantly in the 5 year period. Bluewater Power's distribution losses are less than 5%, however, there is a trend of increasing DLF in the 5 year period. Please explain the factors that are contributing to the trend, particularly as the amount of distributed generation is increasing each year.

The majority of the distributed generation (99.41%) is from large generation facilities. Bluewater Power is host to eight 10MW solar farms and two large Biomass generation facilities. Given the close proximity of the generation facilities to the transmission station, along with the lack of consuming loads between these two points, the majority of electricity generated is arriving back at our transmission station and is either being re-distributed through the TS, or returned into the IESO controlled transmission system outside of our service territory. If the generation facilities were more centrally located within our service territory one might expect to see a decrease in the DLF given that the generated load may be consumed by local customers, thus avoiding longer distances between supply and delivery point. Given the nature of facilities in our territory, distribution losses are not reduced as might otherwise be anticipated.

Since Micro-FIT generation accounts for only 0.59% of total generation, and the fact that there were no MicroFIT installations in our area until May 2010, there is no notable impact on our DLF from this type of distributed generation.

Although the trendline may appear to be increasing overall, the DLF has been fluctuating significantly over that period as seen in Table 1 below.

Table 1 – DFL 2007-2011



In general, we can comment that line losses can be attributed to both technical and non-technical issues. Technical losses occur on all parts of the distribution lines, station transformers, distribution transformers and secondary services to customers. Urban areas typically have lower line losses as compared to rural area given the difference in the distances between consuming loads. Bluewater Power has a mix of urban and rural areas which would contribute to more losses than a highly urban distributor.

Losses can also be attributed to theft of power, metering inaccuracies, and unmetered loads. As well, losses may be artificially high or low based on the calculation of the losses. For example, the commodity is not sold to customers on a calendar month basis so when comparing retail sales to the wholesale purchases there may be a mis-match in the timing of the data. Bluewater Power has a query that is used to allocate non-calendar kWh to each calendar month for purposes of calculating losses, and although the query is accurate it is not perfect. The implementation of smart meters should improve the accuracy of loss calculations, as real-time consumption will be available which will correspond more directly to the wholesale purchases.

A report was produced by the OEB's Regulatory Audit Office on June 23, 2008, '*Ontario Electricity Distributor Practices Relating to Management of System Losses*.' The results of the 53 LDCs surveyed showed that the average distribution losses for 2002 were 4.49%, 2003 – 4.15%, 2004 – 4.30%, 2005 – 4.24% and 2006 – 4.32%. This data shows that Bluewater Power is within the average range, with a proposed DLF in 2011 of 4.45%. The report also indicated that "*Over the 5 year period (2002-2006), the reported losses varied considerably from year to year for each distributor with the average minimum value equal to 3.7% and the average maximum equal to 4.9% for a typical distributor. This year over year variability may be attributable to a number of things including temperature and load fluctuations, estimation errors in loss calculations, and reporting errors.*"

In summary, Bluewater Power acknowledges that 2011 has a higher DLF than seen in the previous four years, however it is within range and is supported by the evidence. We are committed to continue to monitor issues related to losses.

8.0 - VECC 58 - DLF increase in 2011

Reference: Exhibit ~~3~~ 8, Tab ~~2~~ 3, Schedule 6, page 2

a) Please explain the increase in DLF for 2011.

Please see response to Board Staff # 48.

8.0 - SEC 39 - Fixed Charge

[8/1/1] Please recalculate the volumetric rate for GS>50 on the basis that the monthly fixed charge is set at Minimum system with PLCC, i.e. $52.46.

By changing the fixed rate to $52.46, the resulting variable rate would be $5.1816/kW.

Table 1 – Impact of changing the Fixed Rate

	Fixed Rate	Fixed %	Variable %	Fixed $	Variable $	Total Revenue	Resulting Variable Rate	
Per Application	$142.00	21.63%	78.37%	$746,352	$2,704,473	$3,450,825	$4.4311	kW
Sensitivity	$52.46	7.99%	92.01%	$275,730	$3,175,095	$3,450,825	$5.1816	kW

8,0 - AMPCO 14 - Large Use scenario

Interrogatory #14

Reference: Exhibit 8, Tab 2, Schedule 1

a) Please recalculate the volumetric rate and the fixed and variable percentages for Large User class if the monthly fixed charge is set at the Minimum System with PLCC, i.e. $3,940.67.

By changing the fixed rate to $3940.67, the resulting variable rate would be $3.9192/kW.

	Fixed Rate	Fixed %	Variable %	Fixed $	Variable $	Total Revenue	Resulting Variable Rate	
Per Application	$24,427.60	61.05%	38.95%	$879,394	$561,079	$1,440,473	$2.0397	kW
Sensitivity	$3,940.67	9.85%	90.15%	$141,864	$1,298,609	$1,440,473	$3.9192	kW

File Number: EB-2012-0107

Date Filed: February 4, 2013

Tab 11 of 11

Exhibit 9 - Deferral and Variance Accounts

9.0-Staff-49 - Account 1572

Ref: Exh 9-1-1
Ref: Exh 9-1-2

As per the settlement agreement for Bluewater Power's 2009 rate application EB-2008-0221, Account 1572 is to record the net distribution revenues from two customers that were known at the time to be closing.

In the current application, Bluewater Power is proposing a refund of the 2012 year-end balance of $355,670 for accounts 1572 Extra-Ordinary Event Costs including a forecast amount in 2012. Bluewater Power states that if the Board requires settlement based on audited amounts, then Bluewater Power will request disposition during the 2014 IRM rate application.

Bluewater Power also indicates that the Group 2 accounts submitted for disposition in this rate application, including 1572, will not continue going forward assuming final disposition. Board staff summarizes the balance for account 1572 in the following table:

	Audited 2011 Balance	**2012 - 7 month revenues based on billings**	**2012 - 5 month revenues forecasted**	**2012 balance requested in this application**
Account 1572	-342,101	-9,499	-4,070	-355,670

Bluewater Power states that the $342,101 of net distribution revenues from these two customers (or locations) is broken down as $273,487 in 2009, $49,615 in 2010 and $18,999 in 2011.

a) Please update 2012 actual and forecast figures using Bluewater Power's billing system if the numbers are different than the proposed ones.

At the time of preparing this IR response, no further estimates for any part of 2012 are needed. It is known with certainty from Bluewater Power's billing system that the 2012 revenue is $15,026 ($9,499 first 7 months plus $5,527 last 5 months).

Similarly, the corresponding carrying charges have been updated to be $5,136 for 2012 and $1,750 for the first four months of 2013.

Therefore, the total claim for Account 1572 has been updated to reflect $357,127 of principal and $15,087 of carrying charges, for a total claim of $372,214. The previously filed total claim was $370,742 principal and carrying charges. Bluewater Power reiterates that if the Board requires settlement based on audited amounts, then Bluewater Power requests disposition during the 2014 IRM rate application.

These changes have been included in the updated EDDVAR model and the bill impacts presented in the response to these interrogatories.

b) Net distribution revenues recorded in account 1572 are $49,615 in 2010 and $18,999 in 2011. Please confirm that the auditor has performed the necessary procedures to confirm the completeness of the net distribution revenues in 2010 and 2011.

Confirmed.

c) Please confirm that there will not be any revenues generated from these two customers (or locations) after 2012. If not, please explain how Bluewater Power proposes to address these future revenues.

The former Royal Polymers location remains shut down. Therefore the 2013 load forecast does not include any load from this location.

The former UBE location has a new business operating from it and their current load has been factored into the 2013 load forecast.

9.0-Staff-50 - Stranded Meters

Ref: Exh 9-1-3

Ref: EB-2012-0263 and EB-2008-0221

At page 3 it states that the net recoverable stranded meter amount from customers at December 31, 2012 is $1,928,303. In response to interrogatories related to Bluewater Power's smart meter application, the NBV of stranded conventional meters was estimated to be $1,897,063. Please explain the difference.

Page 3 of Exh 9-1-3, as well as Appendix 2-S, indicates $1,926,645 as the net recoverable stranded meter amount. This amount is the 2012 CGAAP figure and is also found at Exh 2-1-2 Appendix 2-EB.

The $1,928,303 amount referred to in this question is the 2012 MIFRS figure and is also found at Exh 2-1-2 Appendix 2-EB.

Bluewater Power's claim is based on the CGAAP amount of $1,926,645. The $1,897,063 was an estimated calculation made earlier in 2012 that was not finalized until the preparation of the 2013 COS rate application. The smart meter interrogatory asked for an estimate, not a final balance.

9.0-Staff-51 - Stranded Meter rate rider

Ref: Exh 9-1-3

Bluewater Power has proposed stranded meter rate riders ("SMRR") of $2.25 per month for residential customers and $2.24 per month for GS<50 kW customers applicable for two years. In *Guideline G-2011-0001: Smart Meter Funding and Cost Recovery – Final Disposition* ("Guideline G-2011-0001"), issued December 15, 2011, the Board states its expectation that proposals for the SMRR would reflect an allocation of the stranded meter costs reflecting the net book value of the conventional meters stranded by replacement by smart meters. In Section 3.7, page 22, of Guideline G-2011-0001, the Board states:

> The distributor should determine and support its proposed allocation, based on the principles of cost causality and practicality. The stranded meter NBV should be recovered through rate riders for applicable customer classes. A distributor must outline the manner in which it intends to allocate the stranded meter costs to the applicable customer rate classes and the rationale for the selected approach. If a distributor has recorded the NBV of the stranded meters by customer class, it should propose class-specific rate riders for each applicable class (Residential, GS < 50 kW and any other classes approved by the Board for smart meter deployment). If the NBV is not known on a class-specific basis, a distributor should propose an allocation between the affected metered customer classes and support its proposal.

In sheet 7.1 of the cost allocation model filed with the current application, it indicates that the capital costs of Residential and GS<50 kW smart meters are, respectively, $71.56 and $276.24. In other words, the average cost of a GS<50 kW smart meters is close to four times that of a residential smart meter. Since we are dealing with the net book value of the conventional meters, the capital cost of smart meters is not an appropriate proxy. However, capital cost data from sheet I7.1 of the 2006/7 Cost Allocation Informational Filing would have comparable information on the conventional meters.

a) Please provide a copy of Sheet I7.1 from Bluewater Power's 2006/7 Cost Allocation Informational Filing.

Sheet I7.1 from Bluewater Power's 2006 Cost Allocation study is provided as Attachment 1 to this Interrogatory.

b) Based on the information provided in a), please provide class-specific SMRRs for the Residential and GS<50 kW customer classes. Please adequately document the methodology for allocating the costs between the classes.

Table 1 below utilizes the results from Sheet I7.1 of the 2006 Cost Allocation Study, to determine a weighted average percent allocation to the residential and GS<50 rate classes. Based on this information 58.9% of the conventional meter cost pertained to the residential rate class and 41.1% of the cost pertained to the GS<50 rate class. If we assume this percent allocation applies to the value of the stranded meters removed from service, the results are indicated in Table 2.

Table 1 – Results from Sheet I7.1 of 2006 Cost Allocation Study

	# meters - Residential	# meters - GS<50	Meter Cost	Total Residential Meter Costs	Total GS<50 Meter Costs	Total Meter Costs
Single Phase	28,785	1,754	50	1,439,250	87,700	1,526,950
Network Meter	1,119	-	225	251,775	-	251,775
Three phase	-	1,358	210	-	285,180	285,180
Smart Meters	711	-	300	213,300	-	213,300
Central Meter	33		250	8,250	-	8,250
Demand without IT		177	500		88,500	
Demand with IT		416	2100		873,600	
Total	30,648	3,705		1,912,575	1,334,980	3,247,555
Total Cost Rate Class Allocation				58.9%	41.1%	
Weighted Average price per meter				$ 62.40	$ 360.32	
Factor relative to average residential cost				1	5.77	

Table 2 – Calculation of Class Specific Stranded Meter Rate Rider

	Residential	**GS<50kW**	**Total**
Allocation based on 2006 Cost Allocation	58.9%	41.1%	
NBV of Stranded Meters to be Recovered	$ 1,134,655	$ 791,990	$ 1,926,645
Number of Customers - 2013 Forecast	32,122	3,544	35,666
Rate Rider ($ per customer/month for 2 years)	$ 1.47	$ 9.31	
Rate Rider ($ per customer/month for 4 years)	$ 0.74	$ 4.66	

c) Please indicate Bluewater Power's preference, with reasons, for either a uniform or class-specific SMRR.

It would be fair to allocate a weighted cost to the residential and GS<50 rate classes based on their relative cost of meters. The data presented in Table 1 was in the 2006 (and 2009) Cost Allocation study, thus the heavier allocation of meter costs to the GS<50 rate class was already included in the resulting determination of rates in the prior periods, therefore it would be reasonable to allocate the higher cost of the average GS<50 meters to that rate class.

However, given the resulting rate rider to the GS<50 rate class, Bluewater Power would propose disposing the stranded meter amount over a 4 year period for the GS<50 kW class, and maintain the proposed 2 year disposition for the residential customers. This result would lead to fairly equal bill impacts as a percent of the total bill for both classes as detailed in Table 3.

Table 3 – Bill Impacts of the Stranded Meter Disposition

Customer Class	Volume (kWh)	Current Bill (TOU)	Stranded Meter Rate Rider	Grossed up Rate Rider with tax Less OCEB Credit	Less OCEB Credit	Total Bill Impact	Percent of Current Bill
Residential (2 year disposition)	800	$119.82	$1.47	$1.66	-$0.17	$1.49	1.2%
General Service < 50 kW (4 year disposition)	2000	$275.14	$4.66	$5.27	-$0.53	$4.74	1.7%

Attachment 1 of 1

Board Staff Interrogatory 51 - 2006 Cost Allocation Sheet I7.1

Ontario

2006 COST ALLOCATION INFORMATION FILING

Bluewater Power Distribution Corpora
EB-2005-0340 EB-2007-0001
January-15-07

Sheet I7.1 Meter Capital Worksheet - Second Run

		Residential			GS <50			GS>50-Regular		
		1	2	3	1	2	3	1	2	3
		Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs
	Allocation Percentage Weighted Factor			46.80%			33%			16%
	Cost Relative to Residential Average Cost			1.00			5.77			29.79
	Total	30648	1912575	62.40456147	3705	1334980	360.3184885	360	669200	1858.888889
Meter Types	**Cost per Meter (Installed)**									
Single Phase 200 Amp - Urban	50	28,785	1439250		1,754	87700			0	
Single Phase 200 Amp - Rural	150	0	0		0	0			0	
Central Meter	250	33	8250		0	0		0	0	
Network Meter (Costs to be updated)	225	1,119	251775		0	0		0	0	
Three-phase - No demand	210	0	0		1,358	285180		0	0	
Smart Meters	300	711	213300		0	0		0	0	
Demand without IT (usually three-phase)	500	0	0		177	88500		57	28500	
Demand with IT	2,100		0		416	873600		281	590100	
Demand with IT and Interval Capability - Secondary	2,300		0			0		22	50600	
Demand with IT and Interval Capability - Primary	10,000		0			0			0	
Demand with IT and Interval Capability -Special (WMP)	40,000		0			0		0	0	
LDC Specific 1			0			0		0	0	
LDC Specific 2			0			0		0	0	
LDC Specific 3			0			0		0	0	

GS >50-Intermediate			Large Use >5MW			Street Light			Sentinel		
1	2	3	1	2	3	1	2	3	1	2	3
Number of Meters	**Weighted Metering Costs**	**Weighted Average Costs**	**Number of Meters**	**Weighted Metering Costs**	**Weighted Average Costs**	**Number of Meters**	**Weighted Metering Costs**	**Weighted Average Costs**	**Number of Meters**	**Weighted Metering Costs**	**Weighted Average Costs**
		3%			1%			0%			0%
		160.24			160.24			-			-
12	120000	10000	5	50000	10000	0	0	-	0	0	-

	0			0			0			0	
	0			0			0			0	
	0			0			0			0	
	0			0			0			0	
	0			0			0			0	
	0			0			0			0	
	0			0			0			0	
	0			0			0			0	
0	0			0			0			0	
12	120000		5	50000			0			0	
	0			0			0			0	
	0			0			0			0	
	0			0			0			0	
	0			0			0			0	

Unmetered Scattered Load			TOTAL		
1	2	3	1	2	3
Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs
		0%			100%
		-			1.89
0	0	-	34730	4086755	117.6721854
	0		30,539	1526950	
	0		0	0	
	0		33	8250	
	0		1,119	251775	
	0		1,358	285180	
	0		711	213300	
	0		234	117000	
	0		697	1463700	
	0		22	50600	
	0		17	170000	
	0		0	0	
	0		0	0	
	0		0	0	
	0		0	0	

9.0 - EP 31 - Stranded Meter Rate Rider

Ref: Exhibit 9, Tab 1, Schedule 3

a) Does the Bluewater Power approach to setting a rate rider for the recovery of stranded meter costs implicitly assume that the historical cost of a residential meter is equivalent to that of a GS < 50 meter? If so, does Bluewater Power believe this is a reasonable assumption?

Bluewater Power's original evidence did not include an allocation related to the weighting of the meter costs; however in response to Board Staff Interrogatory 51(c), we have accepted that a weighted allocation is an appropriate result.

b) What were the relative weighted meter costs for the residential and GS < 50 classes in the cost allocation filing used in the 2009 cost of service application?

The weighted meter cost for residential customers was $62.40, and for GS<50 customers was $360.32 in the 2009 cost allocation study.

c) What are the relative weighted meter costs for the residential and GS < 50 classes in the cost allocation filing used in this cost of service application?

The weighted meter cost for residential customers is $71.56, and for GS<50 customers is $276.24 in the 2013 cost allocation study.

9.0 - VECC 59 - Stranded Meter rate rider

Reference: Exhibit 9, Tab 1, Schedule 3, pg. 5.

a) Please explain how the stranded meter rate rider represents the cost causality difference as between residential and general service meters.

Please see response to 9.0 - Board Staff 51.

b) Please comment on why one of the following methodologies employed by other Electricity LDCs is not a better approximation of cost causality and why it is not being proposed by BWP:

- allocation based on revenue requirement;
- allocation based on smart meter installation costs for the class; or,
- allocation based on actual recorded cost for the different rate classes for their stranded meter rate rider.

Bluewater Power has updated the stranded meter rate rider to reflect the cost differential between residential and GS <50 meters. Please see response to 9.0 - Board Staff 51.

9.0-Staff-52 - HST

Ref: Exh 9-1-4
Ref: Filing Requirements for Electricity Transmission and Distribution Applications (last revised on June 28, 2012)
Ref: Accounting Procedures Handbook, FAQ December 2010

Section 2.12.2 of Filling Requirements last revised June 28, 2012 states that

> The applicant must provide an analysis that supports the applicant's conformity with December 2010 APH FAQs, in particular the example shown in FAQ #4.

APH FAQ #3 issued December 2010 indicates that a distributor should not record in the sub-account the incremental HST on items not previously subject to PST, such as natural gas and electricity utility costs that became subject to the HST at 13% but are subject to recaptured ITC requirements, thus nullifying the ITCs.

Bluewater Power states that it disagrees with this direction and records the adjustment in Account 1592 for $11,526 annually for the incremental cost incurred by Bluewater Power due to Restricted ITC. Bluewater Power provides its projected 1592 HST balance as of April 30, 2013 related to OM&A expenses in Table 2 on page 5 of Exh 9-1-4.

As per Section 2.12.2 of Filling Requirements and APH FAQs #3, please restate Table 2 without the annual adjustment of $11,526 related to the incremental cost incurred by Bluewater Power.

Table 2 restated:

Table 2: Projected 1592 HST Balance as of April 30, 2013		
	AC# 1592 HST	**AC# 2425**
Description	**100%**	**50%**
Balance June 30, 2010	$ -	$ -
Transactions Jul to Dec 2010	$ 42,956	$ 21,478
Transactions Jan to Dec 2011	$ 85,912	$ 42,956
Transactions Jan to Dec 2012	$ 85,912	$ 42,956
Transactions Jan to Apr 2013	$ 28,637	$ 14,319
Balance April 30, 2013	**$ 243,417**	**$ 121,709**

The updated carrying charges would be $656 to the end of 2011, $1,237 for 2012 and $552 for the first four months of 2013.

9.0-Staff-53 - PST Savings

Ref: Exh 9-1-4

Ref: Filing Requirements for Electricity Transmission and Distribution Applications (last revised on June 28, 2012)

Ref: Accounting Procedures Handbook, FAQ December 2010

Section 2.12.2 of Filling Requirements last revised June 28, 2012 states that

> The applicant must provide an analysis that supports the applicant's conformity with December 2010 APH FAQs, in particular the example shown in FAQ #4.

APH FAQ #4 indicates that for any period before the rebasing that occurs after July 1, 2010, the PST savings would be included in the annual depreciation of the capital items and be recorded in Account 1592 sub-account HST/OVAT Input Tax Credits (ITCs). Bluewater Power disagrees with this assertion.

Bluewater Power states that the 2009 capital assets additions included PST and these test year capital additions formed the basis for the depreciation collected in rates and the depreciation related to the capital costs incurred between January 1, 2010 and April 30, 2013 have not been included in rates until the 2013 rebasing. As a result, there is no incremental savings for 2009 and for 2010 to 2013.

As a result, Bluewater Power has not recorded any amounts related to the PST saving on the depreciation related to capital additions from July 1, 2010 to April 30, 2013 in Account 1592.

a) As per Section 2.12.2 of Filling Requirements, please provide the analysis following the APH FAQ #4, i.e. using 2009 capital additions as proxy to calculate the PST savings on depreciation related to capital additions from July 1, 2010 to April 30, 2013.

Bluewater Power analyzed all of its SAP system capital orders from 2009 which made up the total capital additions of $5,338,678 as per the audited cash flow statement found in Exh 1-3-1 Attachment 3. Per inspection of each individual order, only amounts that were PST applicable were totaled. All other amounts such as capitalized labour, overhead, external services, etc, where no PST was applied, were ignored.

Of the PST applicable amounts, the actual PST cost embedded within was determined. Finally, this resulting PST that was capitalized in each order was divided by the applicable useful life for that asset category. This determined the PST embedded in the annual depreciation.

The total PST for all capital orders embedded in the annual depreciation expense is $16,279. This amount is therefore the annual proxy amount as per FAQ#4. Therefore, the annual proxy amounts for each of 2010 to 2013 are:

	Annual Proxy Calc: PST Savings in Annual Dep'n			
	2010	2011	2012	2013
from 2010 deemed cap additions	16,279	16,279	16,279	16,279
from 2011 deemed cap additions	-	16,279	16,279	16,279
from 2012 deemed cap additions	-	-	16,279	16,279
from 2013 deemed cap additions	-	-	-	16,279
total annual proxies	16,279	32,558	48,837	65,116

Based on the requirements of FAQ#5, the full principal amount (i.e. 100%) would be recorded to a sub-account and a contra sub-account of Account 1592, which offset each other. As per Bluewater Power's OM&A discussion relating to FAQ#5 at Exh 9-1-4, page 4, 50% of the required principal amount would be recorded to a different sub-account of Account 1592 with the offset being recorded against distribution margin.

The 100% principal amount is based on 6 months of 2010, 12 months for 2011 and 2012, and 4 months of 2013. The 100% and 50% amounts are as follows:

Projected 1592 HST Balance as of April 30, 2013

	AC# 1592 HST	AC# 1592 HST
Description	**100%**	**50%**
Balance June 30, 2010	$ -	$ -
Transactions Jul to Dec 2010	$ 8,140	$ 4,070
Transactions Jan to Dec 2011	$ 32,558	$ 16,279
Transactions Jan to Dec 2012	$ 48,837	$ 24,419
Transactions Jan to Apr 2013	$ 21,705	$ 10,852
Balance April 30, 2013	**$ 111,240**	**$ 55,620**

Carrying charges are calculated based on 50% of the liability amount that would be recorded in Account 1592 (excluding contra sub-account). These total $179 for the period to the end of 2011, $464 for 2012 and $239 for the first four months of 2013. The carrying charges would be recorded in a further sub-account of Account 1592.

b) After completing this analysis, please provide an updated balance in Account 1592 PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) and also update any other related evidence where appropriate.

Both OM&A and Capital amounts for Account 1592 would be added together. ‘OM&A’ for Account 1592 would be adjusted per the response to 9-Staff-52. ‘Capital’ for Account 1592 is presented in part (a) of this question. Therefore, the two combined are summarized in the following table:

	AC# 1592 HST	**AC# 1592 HST**
Description	**100%**	**50%**
Balance June 30, 2010	$ -	$ -
Transactions Jul to Dec 2010	$ 51,096	$ 25,548
Transactions Jan to Dec 2011	$ 118,470	$ 59,235
Transactions Jan to Dec 2012	$ 134,749	$ 67,375
Transactions Jan to Apr 2013	$ 50,342	$ 25,171
Balance April 30, 2013	**$ 354,657**	**$ 177,329**

As well, carrying charges for both ‘OM&A’ and ‘Capital’ would be combined. The revised amounts consist of $835 for the period to the end of 2011, $1,701 for 2012 and $791 for the first four months of 2013.

9.0-Staff-54 - Smart Meter Decision

Ref: Exh 9-1-5 Attachment 3
Ref: Exh 8-4-1 Attachment 1
Ref: Exh 8-4-1 Attachment 2

Please update these and any other exhibits to reflect the rate order issued in Bluewater Power smart meter proceeding EB-2012-0263 issued on November 8, 2012.

Bluewater Power's smart meter application EB-2012-0263 was approved with the OEB's Decision and Order dated October 18, 2012. This decision approved Bluewater Power's smart meter capital expenditures in their entirety. This decision resulted in some minor OM&A items that were disallowed.

As a result of the OEB's Decision and Order for EB-2012-0263, there is nothing to update in the 2013 COS rate application.

See also Energy Probe #3 and 2-VECC-11.

9.0-Staff-55 - Deferred IFRS Costs

Ref: Exh 9-2-1

Bluewater Power seeks recovery of $121,683 in 1508 sub-account – Deferred IFRS Transition Costs.

Bluewater Power states that the $121,683 includes an estimated audit fee of $28,500 in 2013. The estimated audit fee relates to the audit of the 2012 opening IFRS balance sheet and the 2012 CGAAP-IFRS conversion audit.

The account balance includes a total of $85,810 professional accounting fees which is related to KPMG's consulting services provided to Bluewater Power for the implementation of the IFRS project. Board staff notes from Appendix 2-U the majority of this cost incurred in 2009.

Bluewater Power states that if the Board requires settlement based on the audited amount of $91,437, Bluewater Power then requests review and disposition of this account in the 2014 IRM proceeding.

In its decision summary issued in September 2012, the Canadian Accounting Standards Board decided to extend the existing deferral of the mandatory IFRS changeover date for entities with qualifying rate-regulated activities by an additional year to January 1, 2014.

a) Please confirm that the estimated audit fee of $28,500 in 2013 will be incurred given the further deferral allowed by Canadian Accounting Standard Board. If not, please update Appendix 2-U.

These audit fees will not be incurred in 2013. Bluewater Power will be taking the additional one year deferral and will therefore adopt IFRS on January 1, 2014 (with 2013 being the new IFRS comparative year).

As a result, Bluewater Power is removing its entire claim of $121,683, including carrying charges, pertaining to Account 1508, Other Regulatory Assets, "Sub-account – Deferred IFRS Transition Costs" from its 2013 COS rate application.

By doing so, Bluewater Power will be adhering to the October 2009 FAQ#1 which states that "In the distributor's next cost of service rate application immediately after the IFRS transition period, the balance in this sub-account *[Account 1508]* should be included for review and disposition."

Since Bluewater Power has not completed its IFRS transition period, this sub-account will be included in the next COS rate application in 2017.

An updated Appendix 2-U with the $28,500 estimated audit fee removed is found in Attachment #1 to this interrogatory.

The removal of the claim for this sub-account of Account 1508, and the elimination of the $28,500 estimated audit fee, has been reflected in the updated EDDVAR model and the bill impacts presented in the response to these interrogatories.

b) For the professional accounting fees of $85,810, please confirm that none of this cost was included in the 2009 base revenue requirement.

Confirmed.

c) The account balance includes $1,611 for professional legal fees related to the Board's section 30 cost awards for consultations on IFRS. Are these costs also included in the regulatory costs summarized in Appendix 2-M?

These costs are not included in Appendix 2-M.

d) The account balance includes $1,775 related to IFRS seminars and courses. Please confirm that these seminars and courses are incremental to Bluewater Power's training budget included in base distribution rates.

Confirmed.

File Number:EB-2012-0107

Tab:	11
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Date Filed:February 4, 2013

Attachment 1 of 1

9.0 - Board Staff 55 - Revised Appendix 2-U

File Number: EB-2012-0107
Exhibit: 9
Tab: 2
Schedule: 1
Attachment: 1

Date: 04-Feb-13 Response to Board Staff 55

Appendix 2-U
One-Time Incremental IFRS Transition Costs

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include one-time incremental IFRS transition costs that are currently included in Account 1508, Other Regulatory Assets, sub-account Deferred IFRS Transition Costs Account, or Account 1508, Other Regulatory Assets, sub-account IFRS Transition Costs Variance Account.

Nature of One-Time Incremental IFRS Transition Costs [1]	Audited Actual Costs Incurred 2009	Audited Actual Costs Incurred 2010	Audited Actual Costs Incurred 2011	Audited Carrying Charges to Dec 31, 2011	Total Audited Actual Costs to Dec 31, 2011	RRR 2.1.7 Balance 31-Dec-11	Variance [2]	Carrying Charges 2012 to Apr 30, 2013	Estimated Costs 2013	Total Costs to Apr 30, 2013	Reasons why the costs recorded meet the criteria of one-time IFRS administrative incremental costs
professional accounting fees	$ 78,625	$ 2,000	$ 5,185	$ 2,305	$ 88,115			$ 1,682		$ 89,797	
professional legal fees	$ 1,537			$ 44	$ 1,581			$ 30		$ 1,611	
salaries, wages and benefits of staff added to support the transition to IFRS					$ -					$ -	
associated staff training and development costs	$ 693	$ 104	$ 916	$ 28	$ 1,741			$ 34		$ 1,775	
costs related to system upgrades, or replacements or changes where IFRS was the major reason for conversion					$ -					$ -	
					$ -					$ -	
estimated audit fees related to the opening IFRS balance sheet audit and the CGAAP-IFRS conversion audit for the 2012 comparative year					$ -				$ -	$ -	
					$ -					$ -	
Insert description of additional item(s) and new rows if needed.					$ -					$ -	
Total	$ 80,855	$ 2,104	$ 6,101	$ 2,377	$ 91,437	$ 645,803	-$ 554,366	$ 1,746	$ -	$ 93,183	

Note:

1 The Deferred IFRS Transition Costs Account and the IFRS Transition Costs Variance Account are exclusively for necessary, incremental transition costs and shall not include ongoing IFRS compliance costs or impacts arising from adopting accounting policy changes that reflect changes in the timing of the recognition of income. The incremental costs in these accounts shall not include costs related to system upgrades, or replacements or changes where IFRS was not the major reason for conversion. In addition, incremental IFRS costs shall not include capital assets or expenditures.

2 Applicants are to provide an explanation of material variances in evidence

9.0-Staff-56 - LRAM

Ref: Exh 9-3-1 Pages 1-3
Ref: Exh 9-3-1 Attachment 2
Ref: Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003), Section 13: LRAM

LRAM for pre-2011 CDM Activities: Bluewater Power has requested recovery of an LRAM amount for persisting lost revenues from 2006 to 2010 CDM programs in 2011 for the total amount of $146,861 not including carrying charges. Bluewater Power has requested recovery over a two-year period.

Bluewater Power has also included a request for approval of $6,356 in carrying charges associated with the entirety of its lost revenue request, inclusive of both LRAM amounts for persisting savings from 2006-2010 CDM programs in 2011 and LRAMVA amounts for 2011 CDM program savings in 2011.

Board staff notes that section 13.6 of the 2012 CDM Guidelines states that it is the Board's expectation that LRAM for pre-2011 CDM activities should have been completed with the 2012 rate applications, outside of persisting historical CDM impacts realized after 2010 for those distributors whose load forecast has not been updated as part of a cost of service application.

a) Please discuss whether Bluewater Power will seek recovery of persisting lost revenues from 2006-2010 CDM programs in 2012 in this application.

Bluewater Power's prefiled evidence did not include a claim for persisting lost revenues from 2006-2010 CDM programs in 2012. This decision was based on precedent from Bluewater Power's 2012 IRM Decision. Page 14 of the OEB Decision EB-2011-0153 dated March 22, 2012 notes that Bluewater Power stated that “*if this proceeding is its last opportunity to recover LRAM from 2006-2010 programs, including persistence in 2011 and 2012, it is appropriate to include 2012 amounts at this time, but only if the Board directs that this is Bluewater Power’s last opportunity to claim these savings*.” Further The Board ordered that it “*will not approve recovery of persistence from 2006 to 2010 programs in 2011 and 2012, as it is premature to do so and inconsistent with the LRAM Guidelines*.” Bluewater Power notes herein that the Board did not express denial of future claims. Bluewater Power further interpreted that it was the Boards direction to claim the last audited years LRAM (being 2010 in the case of the referenced decision) as being appropriate. Hence Bluewater applied for 2011 persistence in this application as 2011 was the last audited year. Bluewater intended to claim 2012 persistence in the subsequent 2014 IRM application to avoid being premature to do so and inconsistent with the LRAM Guidelines.

However, if so allowed, Bluewater will seek recovery of persisting lost revenues from 2006-2010 CDM programs in 2012 in this application. Conversely, if persisting lost revenues in 2012 are denied, Bluewater Power will claim the amount in the 2014 IRM application.

b) If the answer to (a) is yes, please provide supporting evidence for the persisting lost revenues in 2012 from 2006-2010 CDM programs in the same manner as has been provided in the Elenchus LRAM/LRAMVA report for the persisting lost revenues of 2006-2010 CDM programs in 2011.

Please reference Attachment 1 to this response for supporting evidence. Bluewater Power hereby amends its request for recovery of lost revenue from 2006-2010 CDM programs both 2011 and 2012 persistence in this application as follows, excluding 2011 LRAMVA.

2006 to 2010 LRAM (2011/2012 Persistence)

Customer Class	Savings	Amount	Interest *	Total
Residential	15.6 GWh	$ 198,633	$ 5,468	$ 204,101
General Service Less Than 50 kW	4.9 GWh	$ 82,606	$ 2,274	$ 84,880
General Service Greater Than 50 kW	2.6 MW	$ 9,216	$ 254	$ 9,470
Total		**$ 290,455**	**$ 7,995**	**$ 298,451**

* Carrying Costs to April 30, 2013

c) If the answer to (a) is no, please confirm that Bluewater Power foregoes the opportunity to recover the persisting lost revenues from 2006-2010 CDM programs in 2012.

Bluewater Power confirms that it does not intend to forego the opportunity to recover the persisting lost revenues from 2006-2010 CDM programs in 2012.

d) Please recalculate the carrying charges to provide carrying charges specific to only those lost revenues associated with the LRAM amount for persisting 2006-2010 CDM savings in 2011. Do not include any lost revenues associated with 2011 CDM programs in this calculation.

Please reference response b) above.

e) Please provide separate rate riders specific to Bluewater Power's requested LRAM amount for persisting lost revenues from 2006-2010 CDM programs in 2011 (and 2012 if Bluewater Power updates its application based on the interrogatories above). Do not include any LRAMVA amounts associated with 2011 CDM programs in the LRAM rate riders.

2006 - 2010 LRAM Rate Rider Calculation

Effective: May 1, 2013 to April 30, 2015

Rate Class	Total	Billing Determinant		Rate Rider
Residential	$ 204,101	255,687,351	kWh	$ 0.0004
General Service Less Than 50 kW	$ 84,880	97,434,167	kWh	$ 0.0004
General Service Greater Than 50 kW	$ 9,470	627,074	kW	$ 0.0076
Total	**$ 298,451**			

Attachment 1 of 1

Staff 56 - 2011/2012 Persistence

Input Table One
Residential 2006 to 2010 Programs
2011 / 2012 Persistence (Net kWh)

Amount	2011	2012
2006		
Cool & Hot Savings Rebate	89,581	89,581
Every Kilowatt Counts	299,690	299,690
Secondary Refrigerator Retirement Pilot	36,288	
2006 Total	**425,559**	**389,270**
2007		
Cool & Hot Savings Rebate	140,645	133,977
Every Kilowatt Counts	832,777	804,338
Great Refrigerator Roundup	248,981	248,152
Renewable Energy Standard Offer	79,716	79,716
Summer Savings	36,348	36,348
2007 Total	**1,338,466**	**1,302,531**
2008		
Cool Savings Rebate	150,418	150,418
Every Kilowatt Counts Power Savings Event	760,237	645,264
Great Refrigerator Roundup	489,294	488,479
peaksaver®	6,228	6,228
Renewable Energy Standard Offer	33,230	33,230
Summer Sweepstakes	248,000	248,000
2008 Total	**1,687,408**	**1,571,619**
2009		
Cool Savings Rebate	186,626	185,963
Every Kilowatt Counts Power Savings Event	311,049	311,030
Great Refrigerator Roundup	457,202	455,275
peaksaver®	223	223
2009 Total	**955,099**	**952,490**
2010		
Cool Savings Rebate	451,498	451,498
Every Kilowatt Counts Power Savings Event	108,582	105,126
Great Refrigerator Roundup	441,550	441,550
peaksaver®	447	447
2010 Total	**1,002,076**	**998,620**
Grand Total	**5,408,608**	**5,214,531**

Input Table Two
GSLT50 2006 to 2010 Programs
2011 / 2012 Persistence (Net kWh)

Amount		
	2011	**2012**
2008		
High Performance New Construction	2,913	2,913
2008 Total	**2,913**	**2,913**
2009		
High Performance New Construction	85,395	85,395
Power Savings Blitz	1,107,278	1,107,278
2009 Total	**1,192,673**	**1,192,673**
2010		
High Performance New Construction	292,654	292,654
Power Savings Blitz	977,602	977,602
2010 Total	**1,270,256**	**1,270,256**
Grand Total	**2,465,842**	**2,465,842**

Input Table Three
GSGT50 2006 to 2010 Programs
2011 / 2012 Persistence (Net kW)

Amount	**2011**	**2012**
2007		
Social Housing Pilot	108	108
2007 Total	**108**	**108**
2009		
Electricity Retrofit Incentive	483	483
2009 Total	**483**	**483**
2010		
Electricity Retrofit Incentive	563	563
Multi-Family Energy Efficiency Rebates	146	146
2010 Total	**709**	**709**
Grand Total	**1,299**	**1,299**

Output Table One

Bluewater 2010 LRAM

2006 to 2010								
2011 Persistence		Net kWh	2011 Rate	Amount	Total	RES	GSLT 50	GSGT50
	RES	5,408,608	0.0186	$ 100,600		$ 100,600		
	GSLT 50	2,465,842	0.0169	$ 41,673			$ 41,673	
				$ 142,273				
		Net kW	2011 Rate	Amount				
	GSGT50	1,299	3.5306	$ 4,588.00				$ 4,588
	Sub Total				**$ 146,861**	$ 100,600	$ 41,673	$ 4,588
2006 to 2010								
2012 Persistence		Net kWh	2012 Rate	Amount				
	RES	5,214,531	0.0188	$ 98,033		$ 98,033		
	GSLT 50	2,465,842	0.0166	$ 40,933			$ 40,933	
				$ 138,966				
		Net kW	2012 Rate	Amount				
	GSGT50	1,299	3.5617	$ 4,628.42				$ 4,628
	Sub Total				**$ 143,595**	$ 98,033	$ 40,933	$ 4,628
				2011 LRAM	**$ 290,455**	**$ 198,633**	**$ 82,606**	**$ 9,216**

Output Table Two
Calculated Carrying Costs to April 30, 2013

				LRAM LRAMVA			Allocated Carrying Costs		
Month	OEB Prescribed Annual Rate	Days in Month	Monthly Interest Rate	Residential	GS LT 50	GS GT 50	Residential	GS LT 50	GS GT 50
Jan-2011	1.47%	31	0.12%	$ 16,553	$ 6,884	$ 768	$ 20.67	$ 8.59	$ 0.96
Feb-2011	1.47%	28	0.11%	$ 33,106	$ 13,768	$ 1,536	$ 37.33	$ 15.53	$ 1.73
Mar-2011	1.47%	31	0.12%	$ 49,658	$ 20,651	$ 2,304	$ 62.00	$ 25.78	$ 2.88
Apr-2011	1.47%	30	0.12%	$ 66,211	$ 27,535	$ 3,072	$ 80.00	$ 33.27	$ 3.71
May-2011	1.47%	31	0.12%	$ 82,764	$ 34,419	$ 3,840	$ 103.33	$ 42.97	$ 4.79
Jun-2011	1.47%	30	0.12%	$ 99,317	$ 41,303	$ 4,608	$ 120.00	$ 49.90	$ 5.57
Jul-2011	1.47%	31	0.12%	$ 115,869	$ 48,187	$ 5,376	$ 144.66	$ 60.16	$ 6.71
Aug-2011	1.47%	31	0.12%	$ 132,422	$ 55,070	$ 6,144	$ 165.33	$ 68.76	$ 7.67
Sep-2011	1.47%	30	0.12%	$ 148,975	$ 61,954	$ 6,912	$ 179.99	$ 74.85	$ 8.35
Oct-2011	1.47%	31	0.12%	$ 165,528	$ 68,838	$ 7,680	$ 206.66	$ 85.94	$ 9.59
Nov-2011	1.47%	30	0.12%	$ 182,081	$ 75,722	$ 8,448	$ 219.99	$ 91.49	$ 10.21
Dec-2011	1.47%	31	0.12%	$ 198,633	$ 82,606	$ 9,216	$ 247.99	$ 103.13	$ 11.51
Jan-2012	1.47%	31	0.12%	$ 198,633	$ 82,606	$ 9,216	$ 247.31	$ 102.85	$ 11.48
Feb-2012	1.47%	29	0.12%	$ 198,633	$ 82,606	$ 9,216	$ 231.36	$ 96.22	$ 10.73
Mar-2012	1.47%	31	0.12%	$ 198,633	$ 82,606	$ 9,216	$ 247.31	$ 102.85	$ 11.48
Apr-2012	1.47%	30	0.12%	$ 198,633	$ 82,606	$ 9,216	$ 239.34	$ 99.53	$ 11.11
May-2012	1.47%	31	0.12%	$ 198,633	$ 82,606	$ 9,216	$ 247.31	$ 102.85	$ 11.48
Jun-2012	1.47%	30	0.12%	$ 198,633	$ 82,606	$ 9,216	$ 239.34	$ 99.53	$ 11.11
Jul-2012	1.47%	31	0.12%	$ 198,633	$ 82,606	$ 9,216	$ 247.31	$ 102.85	$ 11.48
Aug-2012	1.47%	31	0.12%	$ 198,633	$ 82,606	$ 9,216	$ 247.31	$ 102.85	$ 11.48
Sep-2012	1.47%	30	0.12%	$ 198,633	$ 82,606	$ 9,216	$ 239.34	$ 99.53	$ 11.11
Oct-2012	1.47%	31	0.12%	$ 198,633	$ 82,606	$ 9,216	$ 247.31	$ 102.85	$ 11.48
Nov-2012	1.47%	30	0.12%	$ 198,633	$ 82,606	$ 9,216	$ 239.34	$ 99.53	$ 11.11
Dec-2012	1.47%	31	0.12%	$ 198,633	$ 82,606	$ 9,216	$ 247.31	$ 102.85	$ 11.48
Jan-2013	1.47%	31	0.12%	$ 198,633	$ 82,606	$ 9,216	$ 247.99	$ 103.13	$ 11.51
Feb-2013	1.47%	28	0.11%	$ 198,633	$ 82,606	$ 9,216	$ 223.99	$ 93.15	$ 10.39
Mar-2013	1.47%	31	0.12%	$ 198,633	$ 82,606	$ 9,216	$ 247.99	$ 103.13	$ 11.51
Apr-2013	1.47%	30	0.12%	$ 198,633	$ 82,606	$ 9,216	$ 239.99	$ 99.81	$ 11.14
							$ 5,467.83	$ 2,273.91	$ 253.70

Output Table Three

2006 to 2010 LRAM (2011/2012 Persistence)

Customer Class	Savings	Amount	Interest *	Total
Residential	15.6 GWh	$ 198,633	$ 5,468	$ 204,101
General Service Less Than 50 kW	4.9 GWh	$ 82,606	$ 2,274	$ 84,880
General Service Greater Than 50 kW	2.6 MW	$ 9,216	$ 254	$ 9,470
Total		**$ 290,455**	**$ 7,995**	**$ 298,451**

* Carrying Costs to April 30, 2013

2006 - 2010 LRAM Rate Rider Calculation

Effective: May 1, 2013 to April 30, 2015

Rate Class	Total	Billing Determinant		Rate Rider
Residential	$ 204,101	255,687,351	kWh	$ 0.0004
General Service Less Than 50 kW	$ 84,880	97,434,167	kWh	$ 0.0004
General Service Greater Than 50 kW	$ 9,470	627,074	kW	$ 0.0076
Total	**$ 298,451**			

9.0-Staff-57 - LRAMVA

Ref: Exh 9-3-1 Attachment 2

Ref: Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003), Section 13: LRAM

Ref: Chapter 2 of the Filing Requirements for Electricity Transmission and Distribution Applications, Last Revised on June 28, 2012, Section 2.7.10: CDM Costs

Bluewater Power has requested recovery of an LRAMVA amount for 2011 lost revenues from 2011 CDM programs in the total amount of $84,030, not including carrying charges. Bluewater Power has requested recovery over a two-year period.

Bluewater Power has also included a request for approval of $6,356 in carrying charges associated with the entirety of its lost revenue request, inclusive of both LRAM amounts for persisting savings from 2006-2010 CDM programs and 2011 CDM programs.

a) Please recalculate the carrying charges included in the application for only those lost revenues associated with the LRAMVA amount for 2011 CDM program savings in 2011. Do not include any lost revenues associated with persisting 2006-2010 CDM programs in this calculation.

Please reference Attachment 1 to this response for the detailed calculation. A summary of the results is presented in Table 1 below.

Table 1 – 2011 LRAMVA

2011 LRAMVA

Customer Class	Savings	Amount	Interest *	Total
Residential	1.9 GWh	$ 25,159	$ 693	$ 25,852
General Service Less Than 50 kW	0.6 GWh	$ 9,793	$ 270	$ 10,063
General Service Greater Than 50 kW	13.9 MW	$ 49,078	$ 1,351	$ 50,429
Total		**$ 84,030**	**$ 2,313**	**$ 86,343**

* Carrying Costs to April 30, 2013

b) Please provide separate rate riders for Bluewater Power's requested LRAMVA amount associated with 2011 CDM programs. Do not include any LRAM separate from LRAM amounts for persisting 2006-2010 CDM programs in the LRAMVA rate riders.

Bluewater Power originally requested recovery over a two-year period. With the requested split Bluewater Power now requests recovery over a one year period.

Table 2 – LRAMVA Rate Rider Calculation

2011 LRAMVA Rate Rider Calculation

Effective: May 1, 2013 to April 30, 2014

Rate Class	Total	Billing Determinant		Rate Rider
Residential	$ 25,852	255,687,351	kWh	$ 0.0001
General Service Less Than 50 kW	$ 10,063	97,434,167	kWh	$ 0.0001
General Service Greater Than 50 kW	$ 50,429	627,074	kW	$ 0.0804
Total	**$ 86,343**			

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Attachment 1 of 1

Board Staff 57 - 2011 LRAMVA

Input Table One
2011 Programs
(Net kWh)

	kWh
RES	
Appliance Exchange	3,826
Appliance Retirement	288,762
Bi-Annual Retailer Event	189,856
Conservation Instant Coupon Booklet	121,767
HVAC Incentives	748,429
RES Total	**1,352,640**
GSLT50	
Demand Response 3 (part of the Industrial program schedule)	15,695
Direct Install Lighting	238,084
Efficiency: Equipment Replacement	325,703
GSLT50 Total	**579,482**
Grand Total	**1,932,122**

Input Table Two
2011 Programs
(Net kW)

Rate Class	GSGT50		
	kW	**Months**	**Extended kW**
Demand Response 3	1,686	5	8,428
Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	23	12	279
Electricity Retrofit Incentive Program	432	12	5,187
High Performance New Construction	1	12	8
Grand Total	**2,142**	**10**	**13,901**

Output Table One

Bluewater 2011 LRAMVA

2011 Final								
2011 Programs		Net kWh	2011 Rate	Amount				
	RES	1,352,640	0.0186	$ 25,159		$ 25,159		
	GSLT 50	579,482	0.0169	$ 9,793			$ 9,793	
				$ 34,952				
		Net kW	2011 Rate	Amount				
	GSGT50	13,901	3.5306	$ 49,077.77				$ 49,078
				2011 LRAMVA	**$ 84,030**	$ 25,159	$ 9,793	$ 49,078

Output Table Two
Calculated Carrying Costs to April 30, 2013

				LRAM LRAMVA			Allocated Carrying Costs		
Month	OEB Prescribed Annual Rate	Days in Month	Monthly Interest Rate	Residential	GS LT 50	GS GT 50	Residential	GS LT 50	GS GT 50
Jan-2011	1.47%	31	0.12%	$ 2,097	$ 816	$ 4,090	$ 2.62	$ 1.02	$ 5.11
Feb-2011	1.47%	28	0.11%	$ 4,193	$ 1,632	$ 8,180	$ 4.73	$ 1.84	$ 9.22
Mar-2011	1.47%	31	0.12%	$ 6,290	$ 2,448	$ 12,269	$ 7.85	$ 3.06	$ 15.32
Apr-2011	1.47%	30	0.12%	$ 8,386	$ 3,264	$ 16,359	$ 10.13	$ 3.94	$ 19.77
May-2011	1.47%	31	0.12%	$ 10,483	$ 4,081	$ 20,449	$ 13.09	$ 5.09	$ 25.53
Jun-2011	1.47%	30	0.12%	$ 12,580	$ 4,897	$ 24,539	$ 15.20	$ 5.92	$ 29.65
Jul-2011	1.47%	31	0.12%	$ 14,676	$ 5,713	$ 28,629	$ 18.32	$ 7.13	$ 35.74
Aug-2011	1.47%	31	0.12%	$ 16,773	$ 6,529	$ 32,719	$ 20.94	$ 8.15	$ 40.85
Sep-2011	1.47%	30	0.12%	$ 18,869	$ 7,345	$ 36,808	$ 22.80	$ 8.87	$ 44.47
Oct-2011	1.47%	31	0.12%	$ 20,966	$ 8,161	$ 40,898	$ 26.18	$ 10.19	$ 51.06
Nov-2011	1.47%	30	0.12%	$ 23,063	$ 8,977	$ 44,988	$ 27.86	$ 10.85	$ 54.36
Dec-2011	1.47%	31	0.12%	$ 25,159	$ 9,793	$ 49,078	$ 31.41	$ 12.23	$ 61.27
Jan-2012	1.47%	31	0.12%	$ 25,159	$ 9,793	$ 49,078	$ 31.33	$ 12.19	$ 61.11
Feb-2012	1.47%	29	0.12%	$ 25,159	$ 9,793	$ 49,078	$ 29.30	$ 11.41	$ 57.16
Mar-2012	1.47%	31	0.12%	$ 25,159	$ 9,793	$ 49,078	$ 31.33	$ 12.19	$ 61.11
Apr-2012	1.47%	30	0.12%	$ 25,159	$ 9,793	$ 49,078	$ 30.31	$ 11.80	$ 59.13
May-2012	1.47%	31	0.12%	$ 25,159	$ 9,793	$ 49,078	$ 31.33	$ 12.19	$ 61.11
Jun-2012	1.47%	30	0.12%	$ 25,159	$ 9,793	$ 49,078	$ 30.31	$ 11.80	$ 59.13
Jul-2012	1.47%	31	0.12%	$ 25,159	$ 9,793	$ 49,078	$ 31.33	$ 12.19	$ 61.11
Aug-2012	1.47%	31	0.12%	$ 25,159	$ 9,793	$ 49,078	$ 31.33	$ 12.19	$ 61.11
Sep-2012	1.47%	30	0.12%	$ 25,159	$ 9,793	$ 49,078	$ 30.31	$ 11.80	$ 59.13
Oct-2012	1.47%	31	0.12%	$ 25,159	$ 9,793	$ 49,078	$ 31.33	$ 12.19	$ 61.11
Nov-2012	1.47%	30	0.12%	$ 25,159	$ 9,793	$ 49,078	$ 30.31	$ 11.80	$ 59.13
Dec-2012	1.47%	31	0.12%	$ 25,159	$ 9,793	$ 49,078	$ 31.33	$ 12.19	$ 61.11
Jan-2013	1.47%	31	0.12%	$ 25,159	$ 9,793	$ 49,078	$ 31.41	$ 12.23	$ 61.27
Feb-2013	1.47%	28	0.11%	$ 25,159	$ 9,793	$ 49,078	$ 28.37	$ 11.04	$ 55.34
Mar-2013	1.47%	31	0.12%	$ 25,159	$ 9,793	$ 49,078	$ 31.41	$ 12.23	$ 61.27
Apr-2013	1.47%	30	0.12%	$ 25,159	$ 9,793	$ 49,078	$ 30.40	$ 11.83	$ 59.30
							$ 692.56	$ 269.58	$ 1,350.98

Output Table Three

2011 LRAMVA

Customer Class	Savings	Amount	Interest *	Total
Residential	1.9 GWh	$ 25,159	$ 693	$ 25,852
General Service Less Than 50 kW	0.6 GWh	$ 9,793	$ 270	$ 10,063
General Service Greater Than 50 kW	13.9 MW	$ 49,078	$ 1,351	$ 50,429
Total		**$ 84,030**	**$ 2,313**	**$ 86,343**

* Carrying Costs to April 30, 2013

2011 LRAMVA Rate Rider Calculation

Effective: May 1, 2013 to April 30, 2014

Rate Class	Total	Billing Determinant		Rate Rider
Residential	$ 25,852	255,687,351	kWh	$ 0.0001
General Service Less Than 50 kW	$ 10,063	97,434,167	kWh	$ 0.0001
General Service Greater Than 50 kW	$ 50,429	627,074	kW	$ 0.0804
Total	**$ 86,343**			

9.0 - VECC 60 - LRAM Measure details

REFERENCE: EXHIBIT 9, TAB 3, SCHEDULE 1, ATTACHMENT 2

a) For each measure for the years 2006 through 2010 please provide a table showing:

- Program
- Efficiency Measure
- Number of units (participants)
- Measure Life
- LRAM Free Ridership
- Annual energy savings
- Annual Peak demand savings
- Contribution to LRAM

Please reference response to VECC IR 5a) for Bluewater Power in EB-2011-0153 (hyperlink attached)

Bluewater_IRR_VECC_20111205

Please note that a summary of the 'Contribution to LRAM' as requested in this Interrogatory can be found in response to Board Staff #56.

Below, for reference, is the original interrogatory from Bluewater Power's 2012 IRM application:

VECC Question # 5

Reference: Tab 6, LRAM Support, Burman Energy Consultants Group Inc. Report, September 29, 2011 *a) For each program for each year, at the program/measure level, please confirm the number of units, measure life, LRAM free ridership, annual energy savings (kWh/a), annual peak demand savings (kW/a) and contribution to the LRAM recovery.*

9.0 - VECC 61 - OPA assumptions

REFERENCE: EXHIBIT 9, TAB 3, SCHEDULE 1, ATTACHMENT 2

a) List and confirm OPAs input assumptions for Every Kilowatt Counts 2006 including the measure life and unit kWh savings for Compact Fluorescent Lights and Seasonal Light Emitting Diodes. Confirm some of these assumptions were changed in 2007 and again in 2009 and compare the values.

Please reference response to VECC IR 5b) for Bluewater Power in EB-2011-0153 (hyperlink below)

Bluewater_IRR_VECC_20111205

Below is the interrogatory from the 2012 IRM application.

VECC Question # 5

Reference: *Tab 6, LRAM Support, Burman Energy Consultants Group Inc. Report, September 29, 2011*

b) List and confirm OPA's input assumptions for Every Kilowatt Counts (EKC) 2006 and 2007 separately including the measure life, unit kWh savings and free ridership for Compact Fluorescent Lights (CFLs) and Seasonal Light Emitting Diodes (LED). Confirm some of these assumptions were changed in 2007 and again in 2009 and compare the values.

b) Please confirm that savings from CFLs installed under EKC 2006 expire in 2010.

Please reference response to VECC IR 5c) for Bluewater Power in EB-2011-0153

Bluewater_IRR_VECC_20111205

Below is the interrogatory from the 2012 IRM application.

VECC Question # 5

Reference: *Tab 6, LRAM Support, Burman Energy Consultants Group Inc. Report, September 29, 2011*

c) Demonstrate/confirm that savings for EKC 2006 Mass Market measures 13-15 W Energy Star CFLs & Seasonal LEDs have been removed from the LRAM claim beginning in 2010.

c) Adjust the LRAM claim as necessary to reflect the measure lives (and Unit savings) for any/all measures that have expired starting in 2010.

Please reference response to VECC IR 5d) for Bluewater Power in EB-2011-0153 Bluewater_IRR_VECC_20111205

Below is the interrogatory from the 2012 IRM application.

VECC Question # 5

Reference: *Tab 6, LRAM Support, Burman Energy Consultants Group Inc. Report, September 29, 2011*

d) Adjust the LRAM claim as necessary to reflect the measure lives and unit savings for any/all measures that have expired starting in 2010.