Exhibit 4:

OPERATING COSTS

Exhibit 4: Operating Costs

Tab 1 (of 8): Summary of Operating costs

MANAGER'S SUMMARY

The 2013 Rebasing Application represents an increase of $2.05M in OM&A (including taxes other than income taxes) over the last year of actual financial results, being the 2011 Actuals. This increase is the result of the change in accounting method from CGAAP to MIFRS and certain one-time costs, as well as normal increases in Bluewater Power's base costs during the two years from 2011 to 2013. Adjusting for the changes in accounting method and one-time costs, the increase in OM&A proposed for the 2013 Test Year represents a 1.5% annual increase over 2011 Actuals.

1.0 Background:

A fundamental goal of a Cost of Service application is to provide an opportunity for a regulated utility to demonstrate that the operating costs that it is seeking to recover in rates are prudently incurred and are necessary for providing safe, reliable service to its customers while meeting all of its business, regulatory and legislated obligations. Although there is no guarantee that a utility will recover all of the costs claimed, the integrity of the regulatory process requires that each utility be provided the opportunity through a Cost of Service application to establish rates that reflect all of its costs of doing business.

In fact, when the OEB carried out a review of the natural gas industry in 2005, the Board concluded that a Cost of Service Application plays a valuable role in an Incentive Rate Making environment. At page 25 of the Board Report entitled "Natural Gas Regulation in Ontario: A Renewed Policy Framework", dated March 30, 2005 the Board concluded *"Each IR Plan must begin with a robust set of cost-based rates, based on a thorough and transparent review".* A Cost of Service review following an IR Plan is valuable to ensure customers receive the benefit of efficiencies realized during the IRM period, but it is also valuable to utilities that their Cost of Service rates going into an IR plan properly and accurately capture the cost of doing business.

This Manager's Summary provides the context for the amount of OM&A claimed for recovery through this 2013 Rebasing Application.

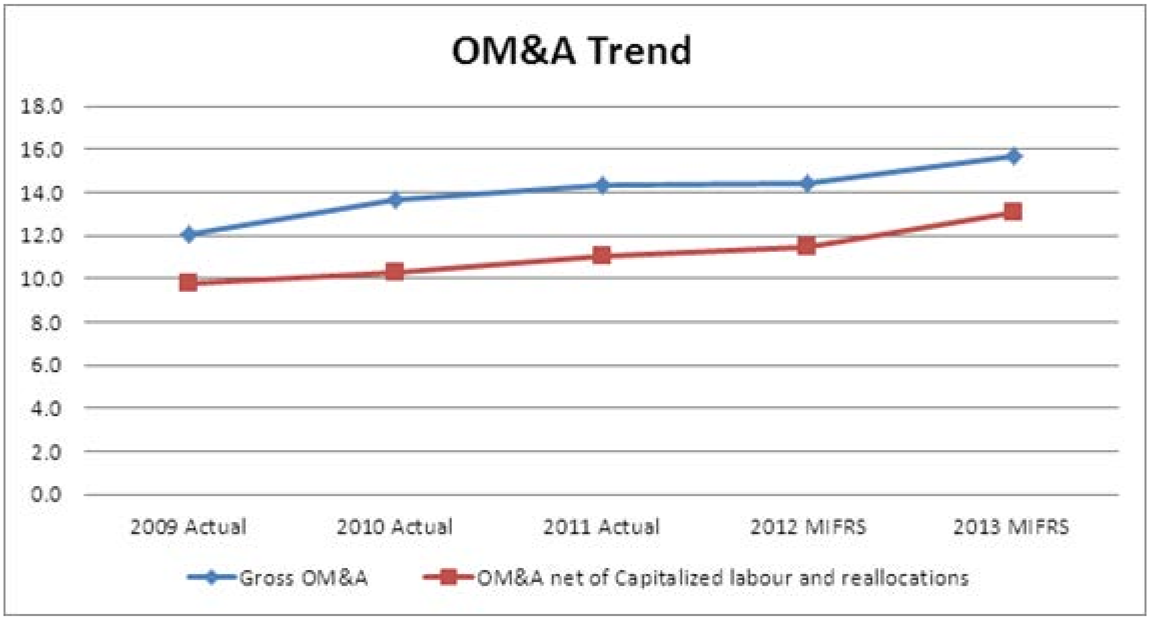
2.0 OM&A Test Year Levels

Many LDCs in Ontario work to realize economies of scope through activities permitted within the distribution company (OPA C&DM programs and billable work on distribution assets paid directly by customers) and by sharing employees and assets with affiliates. The result is that the Gross OM&A claimed for recovery is reduced to a net amount remaining to be collected from customers through distribution rates. Attached as Exhibit 4, Tab 1, Schedule 1, Attachment 1 is a table entitled “Total Recoverable Expenses” showing the forecast total OM&A, including taxes other than income taxes, that is proposed for the 2013 Test Year for recovery through rates.

The total net amount claimed for OM&A in the 2013 Test Year is $13.302M. The amount claimed in the Test Year does not include an assumed across-the-board inflation factor. The salaries and wages 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. The same 3% increase has been assumed for all non-union employees. All other remaining costs have been budgeted based on individual consideration of each budget item and forecast increases and decreases. That principle of forecasting cost changes applies to progression increases in pay for staff, contracted services, fuel, energy, insurance costs, software maintenance fees, etc.

The overall trend in OM&A is presented in the graph below labeled as “Table 1 - OM&A Trend”. We note that the graph has been presented with 2009, 2010 and 2011 on a CGAAP basis and 2012 and 2013 on an MIFRS basis. The difference from an OM&A perspective between CGAAP and MIFRS is that overhead is not permitted to be capitalized under MIFRS, which drives OM&A higher.

Table 1



The graph demonstrates a smooth and gradual increase in both gross and net OM&A from 2009 Actual to the 2013 Test Year. The difference between Gross OM&A and Net OM&A is the removal of Capitalized Labour, reallocation of costs to non-utility accounts and reallocation of costs to affiliates through Management Services Agreements or Costs Sharing Agreements (see discussion in Exhibit 4, Tab 5, Schedule 1). Net of these items, one arrives at the Net OM&A claimed for recovery through distribution rates.

A primary driver of the variance in any given year relates to the level of costs capitalized or reallocated. The influence of these factors is evident in the individual OM&A Variance Analyses included as Exhibit 4, Tab 3, Schedule 1. In the interest of providing maximum clarity to the influence of these factors on net OM&A, we have produced Table 2 entitled “Capitalization and Re-Allocation to Produce Net OM&A”. The table provides the Gross OM&A starting point and the factors that contribute to reduce those costs to arrive at the Net OM&A that is included for recovery through rates.

Table 2- Capitalization and Re-Allocations to Produce Net OM&A

	2013 MIFRS	2012 MIFRS	2012 CGAAP	2011 CGAAP	2010 CGAAP	2009 CGAAP
Gross OM&A	15,724,099	14,438,654	14,438,654	14,322,274	13,634,580	12,008,204
Reallocation to Affiliates	-435,368	-392,786	-392,786	-541,277	-538,018	-557,724
Reallocation OPA	-93,234	-111,004	-112,088	-118,925	-97,195	-56,748
Capitalized internal	-1,885,900	-1,794,670	-1,794,670	-1,179,969	-1,138,338	-905,826
Smart Meter	0	-364,078	-364,078	-437,088	-240,673	-15,159
Billable	-165,229	-227,815	-227,815	-289,520	-486,436	-203,766
Overhead	-65,541	-90,364	-1,350,608	-692,035	-879,100	-496,797
Net OM&A	**13,078,827**	**11,457,937**	**10,196,610**	**11,063,459**	**10,254,821**	**9,772,184**

In effect, therefore, the level of capitalization and re-allocation of costs is a significant and material contributor to cost efficiencies for Bluewater Power. One of the purposes of an IRM Regime is to encourage LDCs to realize savings during the IRM period with the consequence that the Board will, then, build those savings into the COS Rates that follow to the extent the efficiencies are sustainable.

It is important, therefore, to include a discussion of the efficiencies that have been realized in recent years and are therefore embedded in Bluewater Power's 2013 Test Year which can be described as follows:

- **Economies of Scope**: Certain Bluewater Power staff members have responsibilities for both distribution and non-core distribution activities. When those staff members are doing work other than distribution, their costs are reallocated to either non-utility accounts or allocated to affiliates. For example:
    - The amount of $93,234 has been removed from OM&A in the 2013 Test Year assuming those costs will be charged to the Ontario Power Authority for overseeing and implementing OPA C&DM programs.

- The amount of $435,368 has been removed from OM&A in the 2013 Test Year assuming those costs will be allocated to affiliates (Note: the revenue offsets also include revenue from affiliates in the amount of $122,778). Both items are discussed in detail in the schedule entitled Shared Services and Corporate Cost Allocations (Exhibit 4, Tab 5, Schedule 1), which includes OEB Appendix 2-N (Exhibit 4, Tab 5, Schedule 1, Attachment 1).

- **Focus on 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.

In submitting the level of OM&A included in the 2013 Test Year, Bluewater Power has included efficiencies that we intend to demonstrate are sustainable. The ability to sustain those efficiencies depends upon several factors, some of which are outside of the control of the utility. First, the approval of the 2013 Capital Budget submitted with this application, which includes the level of Capitalized Labour shown in Table 2 above. Second, the ability to demonstrate that the increased level of capital proposed in 2012 and 2013 can be achieved by the utility with the proposed staff levels. Third, the level of activity and the relationship between Bluewater Power and its affiliates continues as proposed in this application. Finally, that the current suite of OPA C&DM programs continue in 2013. In the event of a change to any of these assumptions in the Test year that are known prior to, or as part of this approval, then the consequence may be an increase in the level of OM&A to be claimed for recovery through rates.

3.0 The Increase in OM&A from 2011 Historic Year to 2013 Test Year

In assessing the reasonableness and prudency of a utility's OM&A claim, it is instructive to compare the Test Year to the most recent year of actuals. There is an implied prudence to spending by a utility during an IRM period.

This 2013 COS Application will capture efficiencies realized by the utility since 2009, but it must also ensure that the costs claimed are sustainable. In addition, the amount claimed must account for new obligations imposed upon the utility and those costs beyond the control of utility management. If a blanket inflation factor were to be applied, without consideration of new cost drivers, the resulting rate might hinder the ability of a utility to maintain its system and provide the level of service required by the OEB and expected by its customers.

With that context in mind, the OM&A for the 2013 Test Year can be described as being based on the Net OM&A for 2011 Actuals (CGAAP) of $11.252M (per Exhibit 4, Tab 1, Schedule 1, Attachment 1) plus the following extraordinary cost items:

- An adjustment to OM&A is required to the 2013 MIFRS amount to recognize the overhead amount that would have otherwise been capitalized under CGAAP in 2013 of $957k (see Exhibit 10, Tab 1, Schedule 1, Attachment 1)

- One proposed enhancement to service for the 2013 Test Year which is a move from Bi-monthly Billing to Monthly Billing at an incremental cost of $322k (see Exhibit 4, Tab 2, Schedule 5)

- Extraordinary increases in OMERS rates that are beyond the control of management, representing a $159k increase over the period from 2011 to 2013 (see Exhibit 4, Tab 2, Schedule 2, Attachment 1)

- One-Time Costs for environmental issues to be recovered as $67k per year (see Exhibit 4, Tab 2, Schedule 4)

- Net Incremental OM&A related to Smart Meters (incremental cost of automated meter reads and software maintenance fees, less savings from eliminating manual meter reads) of $191k (see Exhibit 2, Tab 4, Schedule 4)

Accounting for these extraordinary items, the remaining increase of $354k represents approximately a 1.5% annual increase (3.1% over two years). Bluewater Power respectfully submits that the adjustments set out above are essential to accommodate any comparison of the 2011 Actuals to the 2013 Test Year. Bluewater Power further submits that the increase of approximately 1.5% annually from 2011 to 2013 is appropriate and is representative of the fiscally restrained nature of this 2013 COS Application.

If one seeks to look to the increase in OM&A for the 2013 Test Year compared to the 2009 Board Approved amount, the increase is approximately $3.05M or a 29.7% increase. Of course, this comparison ought to be adjusted for the extraordinary cost items noted above so that it becomes a $1.35M increase, which equates to a 13.1% increase (3.2% on a compounded annual basis).

4.0 Staffing Levels

The explanation of staffing levels and compensation of employees is provided in detail through OEB Appendix 2-K, which is included as Exhibit 4, Tab 4, Schedule 1, Attachment 1. For ease of reference, the sections of Appendix 2-K dealing with number of employees has been reproduced below as Table 2 – FTE Counts by Year.

Table 2 – FTE Counts by Year

	2009	2009	2010	2011	2012	2013
	LRY - Board Approved	LRY - Actual	Historical Year 2	Historical Year 1	Bridge Year	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	50.16	52.97	51.34	53.13	51.00	56.17
Contract	0.88	3.29	6.21	6.58	3.92	2.00
Students = FTE	3.67	5.67	5.44	6.33	5.67	5.33
Total	97.67	105.26	111.32	116.54	111.58	114.50

As explained in the detailed discussion of Appendix 2-K included in Exhibit 4, Tab 4, Schedule 1 entitled “Staffing and Compensation Levels”, the FTE counts are presented on a Gross Basis. Some of the efficiencies achieved by Bluewater Power include the ability to allocate staff costs to non-core distribution activities and/or affiliates. Accordingly, although the increase in the proposed FTEs for 2013 Test Year represents a 17% increase from the 2009 Approved levels, the impact on ratepayers through recoverable OM&A is minimized. Further, we note much of the growth in FTEs during the period between 2009 and 2013 was in the area of contract employees; Bluewater Power utilized contract employees to “flex” its workforce in order to respond to industry demands.

These and related issues are discussed in detail in the Human Resources Strategy included as Exhibit 4, Tab 4, Schedule 1, Attachment 2.

5.0 Business Environment Changes

Since the transition from a public utility commission to a private company operating in a deregulated electricity environment, Bluewater Power has been subject to significant and consistent change. This section will introduce four major drivers of change to our current business environment, namely MIFRS, Monthly Billing, Smart Meters, and Industry Renewal.

The single biggest challenge to OM&A is due to the change from CGAAP to MIFRS. The inability to capitalize overhead is the largest driver of the variance in financial results from 2011 (and prior) to the 2013 Test Year. The impact on OM&A, as well as the impact on Rate Base, Depreciation, and Payments in Lieu of Taxes, are addressed in Exhibit 10 of this Application and an overall summary is provided in the Manager’s Summary to that exhibit at Exhibit 10, Tab 1, Schedule 1.

Smart Meters represented the single biggest capital project in the history of Bluewater Power and placed significant demands on the utility’s resources and employees. The capitalization of labour for Smart Meters has artificially lowered the net OM&A in 2011 and 2012 because the level of effort required of employees during the transition to Smart

Meters was simply not sustainable. On an ongoing basis, the impact of Smart Meters on OM&A in the 2013 Test Year is a net increase in OM&A of $191k; as discussed at Exhibit 2, Tab 4, Schedule 4, Bluewater Power already enjoyed efficiencies with its meter reading as the resource was shared with the water billing function prior to the introduction of Smart Meters.

In the 2013 Test Year, Bluewater Power has proposed to enhance its service offering to customers by moving from Bi-Monthly to Monthly Billing. This has impacted OM&A in the 2013 Test Year and will represent a transition for both customers and staff. The move to monthly billing is partly driven by the desire to get Smart Meter consumption information to customers as quickly as possible and to provide more frequent billing to assist customers to manage their household budgets.

Finally, we have faced numerous challenges leading up to the 2013 Test Year including the *Green Energy and Green Economy Act*, ESA regulation, and Smart Meters. The new challenges expected in the future include renewal in two forms. First, regulatory industry reform anticipated due to the Renewed Regulatory Framework for Electricity and the recommendations of the Distribution Sector Review Panel. Second, renewal of distribution infrastructure as we focus as a utility on the Asset Management Plan developed over the past two years.

6.0 Materiality Threshold

Section 2.4.4 of the Filing Guidelines indicate that the materiality threshold will be *"0.5% of distribution revenue requirement for a distributor with a distribution revenue requirement greater than $10 million and less than or equal to $200 million."* Accordingly, Bluewater Power's materiality threshold is $114,785.

7.0 Other Matters

Other matters addressed in this Exhibit on Operating Expenses include the following:

- Exhibit 4, Tab 6 contains the discussion of purchases from non-affiliated companies, and includes a copy of Bluewater Power's purchasing policy.

- Exhibit 4, Tab 7 contains a discussion of Depreciation and Amortization, wherein Bluewater Power confirms we are within the range of the useful lives contained in the Kinetrics Study.

- Exhibit 4, Tab 8 contains the discussion of Payments in Lieu of Taxes (PILs) and Capital Taxes, including an overview of the provision for PILs.

Total Recoverable Expenses

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 CGAAP	2012 MIFRS	2013 Test Year
Operations	$ 3,126,141	$ 2,926,385	$ 3,135,697	$ 3,177,397	$ 2,964,970	$ 3,102,525	$ 3,467,004
Maintenance	$ 139,393	$ 162,468	$ 175,850	$ 157,217	$ 138,100	$ 138,100	$ 142,600
Billing and Collecting	$ 1,324,117	$ 1,357,619	$ 1,732,894	$ 1,481,275	$ 1,454,659	$ 1,467,712	$ 2,055,877
Community Relations	$ 191,769	$ 213,194	$ 191,747	$ 256,299	$ 237,181	$ 270,425	$ 258,483
Administrative and General	$ 5,209,999	$ 5,161,300	$ 5,073,080	$ 6,021,899	$ 5,401,700	$ 6,479,176	$ 7,154,864
Total	**$ 9,991,419**	**$ 9,820,966**	**$ 10,309,268**	**$ 11,094,087**	**$ 10,196,610**	**$ 11,457,938**	**$ 13,078,828**
Less: donations	$ -	$ (48,784)	$ (54,448)	$ (30,629)	$ -	$ -	$ -
Total OM&A Expenses	**$ 9,991,419**	**$ 9,772,182**	**$ 10,254,820**	**$ 11,063,458**	**$ 10,196,610**	**$ 11,457,938**	**$ 13,078,828**
Taxes Other Than Income Taxes	262,750	247,231	180,940	189,527	194,128	194,128	223,914
Total Recoverable Expenses	**10,254,169**	**10,019,413**	**10,435,760**	**11,252,985**	**10,390,738**	**11,652,066**	**13,302,742**

Exhibit 4: Operating Costs

Tab 2 (of 8): Detailed Analysis of Operating Costs

OM&A EXPENSE TABLES AND EXPLANATIONS

This whole of Exhibit 4 contains thorough qualitative analyses of the proposed OM&A spending for the 2013 Test Year, as well as details related to variances from the 2009 Board Approved values through to the 2013 Test Year. The OEB Filing Guidelines require the presentation of numerous quantitative analyses and three of the Appendices required by the Filing Guidelines are included as attachment to this Schedule. They are described as follows.

OEB Appendix 2-I Summary of OM&A Expenses

Included as Exhibit 4, Tab 2, Schedule 1, Attachment 1 is the quantitative analysis of recoverable OM&A. The variance between these amounts and the amounts reflected in Exhibit 4, Tab 1, Schedule 1, Attachment 1 is that “Taxes other than Income Tax” is not included OEB Appendix 2-I. Taxes other than Income Tax are not considered OM&A, although it is included in the amount recovered through rates.

OEB Appendix 2-G Detailed, Account by Account OM&A Expenses

Included as Exhibit 4, Tab 2, Schedule 1, Attachment 2 is the quantitative analysis of OM&A expense broken down by OEB Account. As Bluewater Power is adopting MIFRS on January 1, 2013, Appendix 2-G has been completed with 2012 on both a CGAAP and on a MIFRS basis. The difference between those two figures is $1,261,328 which is overhead that is not capitalized under MIFRS.

OEB Appendix 2-L OM&A per Customer and per FTEE

Included as Exhibit 4, Tab 2, Schedule 1, Attachment 3 is the quantitative analysis of OM&A per customer and per FTEE.

The customer numbers included in Appendix 2-L are the number of customers, not the number of connections. The numbers of customers correspond to the number of customers presented in the load forecast and represent the average number of customers in the year.

The FTEE counts were taken from Appendix 2-K, but we have removed directors from that count as they are not directly involved in the delivery of service. We note that Bluewater Power is relatively stagnant in its customer count and the employee FTEEs continue to increase over time. The FTEEs is not driven by increases in demands 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. These factors are independent of customer growth.

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Appendix 2-I
Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2009 BA)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
Operations	$ 3,126,141	$ 2,926,385	$ 3,135,697	$ 3,177,397	$ 3,102,525	$ 3,467,004
Maintenance	$ 139,393	$ 162,468	$ 175,850	$ 157,217	$ 138,100	$ 142,600
SubTotal	**$ 3,265,535**	**$ 3,088,853**	**$ 3,311,547**	**$ 3,334,614**	**$ 3,240,625**	**$ 3,609,604**
%Change (year over year)			7.2%	0.7%	-2.8%	11.4%
%Change (Test Year vs Last Rebasing Year - Actual)						16.9%
Billing and Collecting	$ 1,324,117	$ 1,357,619	$ 1,732,894	$ 1,481,275	$ 1,467,712	$ 2,083,111
Community Relations	$ 191,769	$ 213,194	$ 191,747	$ 256,299	$ 270,425	$ 258,483
Administrative and General	$ 5,209,999	$ 5,112,516	$ 5,018,632	$ 5,991,270	$ 6,479,176	$ 7,127,630
SubTotal	**$ 6,725,884**	**$ 6,683,329**	**$ 6,943,273**	**$ 7,728,844**	**$ 8,217,313**	**$ 9,469,224**
%Change (year over year)			3.9%	11.3%	6.3%	15.2%
%Change (Test Year vs Last Rebasing Year - Actual)						41.7%
Total	**$ 9,991,419**	**$ 9,772,182**	**$ 10,254,820**	**$ 11,063,458**	**$ 11,457,938**	**$ 13,078,828**
%Change (year over year)			4.9%	7.9%	3.6%	14.1%

	Last Rebasing Year (2009 BA)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Operations	$ 3,126,141	$ 2,926,385	$ 3,135,697	$ 3,177,397	$ 3,102,525	$ 3,467,004
Maintenance	$ 139,393	$ 162,468	$ 175,850	$ 157,217	$ 138,100	$ 142,600
Billing and Collecting	$ 1,324,117	$ 1,357,619	$ 1,732,894	$ 1,481,275	$ 1,467,712	$ 2,083,111
Community Relations	$ 191,769	$ 213,194	$ 191,747	$ 256,299	$ 270,425	$ 258,483
Administrative and General	$ 5,209,999	$ 5,112,516	$ 5,018,632	$ 5,991,270	$ 6,479,176	$ 7,127,630
Total	**$ 9,991,419**	**$ 9,772,182**	**$ 10,254,820**	**$ 11,063,458**	**$ 11,457,938**	**$ 13,078,828**
%Change (year over year)			4.9%	7.9%	3.6%	14.1%

	Last Rebasing Year (2009 BA)	Last Rebasing Year (2009 Actuals)	Variance 2009 BA – 2009 Actuals	2010 Actuals	Variance 2010 Actuals vs. 2009 Actuals	2011 Actuals	Variance 2011 Actuals vs. 2010 Actuals	2012 Bridge Year	Variance 2012 Bridge vs. 2011 Actuals	2013 Test Year	Variance 2013 Test vs. 2012 Bridge
Operations	$ 3,126,141	$ 2,926,385	$ 199,756	$ 3,135,697	$ 209,312	$ 3,177,397	$ 41,700	$ 3,102,525	-$ 74,872	$ 3,467,004	$ 364,479
Maintenance	$ 139,393	$ 162,468	-$ 23,075	$ 175,850	$ 13,382	$ 157,217	-$ 18,633	$ 138,100	-$ 19,117	$ 142,600	$ 4,500
Billing and Collecting	$ 1,324,117	$ 1,357,619	-$ 33,502	$ 1,732,894	$ 375,275	$ 1,481,275	-$ 251,619	$ 1,467,712	-$ 13,563	$ 2,083,111	$ 615,399
Community Relations	$ 191,769	$ 213,194	-$ 21,425	$ 191,747	-$ 21,447	$ 256,299	$ 64,552	$ 270,425	$ 14,126	$ 258,483	-$ 11,942
Administrative and General	$ 5,209,999	$ 5,112,516	-$ 97,483	$ 5,018,632	-$ 93,884	$ 5,991,270	$ 972,638	$ 6,479,176	$ 487,906	$ 7,127,630	$ 648,454
Total OM&A Expenses	$ 9,991,419	$ 9,772,182	$ 219,237	$ 10,254,820	$ 482,638	$ 11,063,458	$ 808,638	$ 11,457,938	$ 394,480	$ 13,078,828	$ 1,620,890
Variance from previous year				$ 482,638		$ 808,638		$ 394,480		$ 1,620,890	
Percent change (year over year)				5%		8%		4%		14%	
Percent Change: Test year vs. Most Current Actual						18.22%					
Simple average of % variance for all years						33.84%					8%
Compound Annual Growth Rate for all years											6.0%
Compound Growth Rate (2011 Actuals vs. 2009 Actuals)						13.21%					

Note:

1 "BA" = Board-Approved

2 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.

3 Recoverable OM&A that is included on these tables should be identical to the recoverable OM&A that is shown for the corresponding periods on Appendix 2-H.

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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]	Bridge Year 2012[3]	Test Year 2013
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**
Operations							
5005 Operation Supervision and Engineering	835,073	$ 626,703	$ 888,541	$ 814,674	$ 728,594	$ 763,498	$ 792,514
5010 Load Dispatching	184,799	$ 187,893	$ 215,197	$ 212,873	$ 210,731	$ 215,812	$ 221,350
5012 Station Buildings and Fixtures Expense	88	$ 53,112	$ 17,440	$ 1,917			$ 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	$ 26,600	$ 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	$ 256,298	$ 289,300
5030 Overhead Sub-transmission Feeders - Operation	-						
5035 Overhead Distribution Transformers - Operation	1,738	$ 342	$ 241	$ 1,878			
5040 Underground Distribution Lines and Feeders - Operation Labour	795,488	$ 741,539	$ 831,743	$ 995,046	$ 866,141	$ 961,197	$ 1,089,225
5045 Underground Distribution Lines and Feeders - Operation Supplies and Expenses	270,909	$ 337,253	$ 167,941	$ 120,553	$ 90,808	$ 90,808	$ 124,669
5050 Underground Sub-transmission Feeders - Operation	-						
5055 Underground Distribution Transformers - Operation	-	$ -	$ -	$ 1,122	$ -	$ -	$ -
5060 Street Lighting and Signal System Expense	-	$ 392	$ -	$ -	$ -	$ -	$ -
5065 Meter Expense	386,874	$ 335,735	$ 355,175	$ 359,545	$ 395,202	$ 397,503	$ 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	$ 363,809	$ 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	$ 27,000	$ 35,500
5096 Other Rent	-						
Total - Operations	$ 3,126,141	$ 2,926,385	$ 3,135,697	$ 3,177,397	$ 2,964,970	$ 3,102,525	$ 3,467,004
Account Description	**2009 Board Approved**	**Last Rebasing Year (2009 Actuals)**	**2010 Actual**	**2011 Actual[2]**	**Bridge Year 2012[3]**	**Bridge Year 2012[3]**	**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	$ 18,000	$ 18,000
5120 Maintenance of Poles, Towers and Fixtures	12,645	$ 11,295	$ 4,881	$ 4,986	$ 8,000	$ 8,000	$ 9,000
5125 Maintenance of Overhead Conductors and Devices	73,853	$ 79,516	$ 54,937	$ 64,602	$ 64,000	$ 64,000	$ 68,000
5130 Maintenance of Overhead Services	-						
5135 Overhead Distribution Lines and Feeders - Right of Way	-						
5145 Maintenance of Underground Conduit	-	$ 48	$ 10	$ 14	$ -	$ -	$ -
5150 Maintenance of Underground Conductors and Devices	14,944	$ 21,071	$ 19,139	$ 25,926	$ 19,200	$ 19,200	$ 19,200
5155 Maintenance of Underground Services	4,549	$ 5,650	$ 3,637	$ 775	$ 400	$ 400	$ 400
5160 Maintenance of Line Transformers	22,991	$ 14,829	$ 23,761	$ 30,102	$ 27,500	$ 27,500	$ 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	$ 1,000	$ 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	$ 138,100	$ 142,600
Account Description	**2009 Board Approved**	**Last Rebasing Year (2009 Actuals)**	**2010 Actual**	**2011 Actual[2]**	**Bridge Year 2012[3]**	**Bridge Year 2012[3]**	**Test Year 2013**
Billing and Collecting							
5305 Supervision	110,356	$ 122,263	$ 170,710	$ 208,714	$ 214,677	$ 214,997	$ 230,451
5310 Meter Reading Expense	130,998	$ 126,551	$ 110,314	$ 55,952	$ 161,099	$ 161,099	$ 241,109
5315 Customer Billing	784,936	$ 791,098	$ 768,194	$ 818,456	$ 790,720	$ 797,284	$ 1,179,268
5320 Collecting	206,153	$ 214,394	$ 193,454	$ 191,529	$ 185,763	$ 191,932	$ 242,549
5325 Collecting - Cash Over and Short	-	$ 104	-$ 84	$ 120	$ -	$ -	$ 100
5330 Collection Charges	697	$ 440	$ 162	$ 309	$ 400	$ 400	$ 400
5335 Bad Debt Expense	90,976	$ 102,769	$ 490,144	$ 206,195	$ 102,000	$ 102,000	$ 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	$ 1,467,712	$ 2,083,111
Account Description	**2009 Board Approved**	**Last Rebasing Year (2009 Actuals)**	**2010 Actual**	**2011 Actual[2]**	**Bridge Year 2012[3]**	**Bridge Year 2012[3]**	**Test Year 2013**
Community Relations							
5405 Supervision	-						
5410 Community Relations - Sundry	45,981	$ 43,958	$ 44,624	$ 106,039	$ 115,867	$ 115,867	$ 95,900
5415 Energy Conservation	40,269	$ 49,799	$ 33,708	$ 27,391	$ 20,882	$ 26,966	$ 39,342
5420 Community Safety Program	105,519	$ 119,437	$ 113,415	$ 122,273	$ 100,432	$ 127,592	$ 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	$ 270,425	$ 258,483

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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]	Bridge Year 2012[3]	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	$ 1,324,165	$ 1,338,330
5610 Management Salaries and Expenses	184,825	$ 67,390	$ 68,523	$ 74,042	$ 64,195	$ 81,726	$ 85,356
5615 General Administrative Salaries and Expenses	1,515,325	$ 972,326	$ 992,791	$ 1,352,575	$ 1,147,418	$ 1,470,414	$ 1,591,130
5620 Office Supplies and Expenses	2,529	$ 2,637	$ 5,919	$ 5,269	$ 3,476	$ 4,646	$ 4,569
5625 Administrative Expense Transferred - Credit	- 543,487						
5630 Outside Services Employed	157,994	$ 273,402	$ 267,635	$ 281,162	$ 243,132	$ 306,658	$ 389,845
5635 Property Insurance	146,853	$ 160,266	$ 110,030	$ 127,829	$ 116,570	$ 144,964	$ 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	$ 1,818,515	$ 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	$ 359,330	$ 374,545
5660 General Advertising Expenses	18,569	$ 10,237	$ 8,491	$ 39,301	$ 6,800	$ 6,800	$ 7,000
5665 Miscellaneous General Expenses	640,900	$ 682,251	$ 647,754	$ 719,664	$ 657,773	$ 817,641	$ 947,730
5670 Rent	-						
5672 Lease Payment Charge	-						
5675 Maintenance of General Plant	91,788	$ 114,991	$ 103,430	$ 146,944	$ 111,677	$ 144,317	$ 166,023
5680 Electrical Safety Authority Fees	-	$ -	$ 26	$ 714			
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	$ 6,479,176	$ 7,127,630
Total OM&A	$ 9,991,419	$ 9,820,966	$ 10,309,268	$ 11,094,087	$ 10,196,610	$ 11,457,938	$ 13,078,828
Adjustments for non-recoverable items							
5681 Special Purpose Charge Expense							
6205 Donations[1]		$ 48,784	$ 54,448	$ 30,629			
Total Recoverable OM&A	$ 9,991,419	$ 9,772,182	$ 10,254,820	$ 11,063,458	$ 10,196,610	$ 11,457,938	$ 13,078,828
					a	b	

c = b - a = overhead = $ 1,261,328

$ 11,457,938

[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.

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Appendix 2-L
Recoverable OM&A Cost per Customer and per FTEE

	Last Rebasing Year (2009 Board-Approved)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
Number of Customers	36,326	35,825	35,934	36,178	36,376	36,578
Total Recoverable OM&A from Appendix 2-I	$ 9,991,419	$ 9,772,182	$ 10,254,820	$ 11,063,458	$ 11,457,938	$ 13,078,828
OM&A cost per customer	$ 275.05	$ 272.78	$ 285.38	$ 305.81	$ 314.99	$ 357.56
Number of FTEEs	91.7	99.3	105.3	110.5	105.6	108.5
Customers/FTEEs	396.3	360.9	341.2	327.3	344.5	337.1
OM&A Cost per FTEE	108,993	98,450	97,368	100,086	108,524	120,542

Notes:

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 The method of calculating the number of customers must be identified.
3 The method of calculating the number of FTEEs must be identified. See also Appendix 2-K
4 The number of customers and the number of FTEEs should correspond to mid-year or average of January 1 and December 31 figures.

Bluewater Power Notes
1. The number of customers is reported on the number of customers, not the number of connections. The number of customers correspond to the number of customers reported in the load forecast and is the average number of customers in the year.
2. The number of FTEE does not include the Directors.

COST DRIVERS

Bluewater Power is providing the following analysis related to OEB Appendix 2-J – OM&A Cost Driver Table at Exhibit 4, Tab 2, Schedule 2, Attachment 1. The drivers are presented below with all annual variances shown. The presentation of cost drivers is sorted by the highest contribution to the variance in the 2013 Test Year. The qualitative explanations of the drivers of the variance are provided below each table.

1. Allocation of Costs to Smart Meter Project

OM&A	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Allocation of Costs to Smart Meter Project		(225,000)	(196,000)	73,000	364,000

Throughout the Smart Meter project, incremental labour and capital labour associated with the deployment of Smart Meters were allocated to the Smart Meter deferral accounts. With the near completion of the Smart Meter project in the first quarter of 2012, the labour that was formerly reallocated to the Smart Meter project now remains in the regular OM&A. There is a reduction in allocations for 2012, driving a positive variance in OM&A of $73,000, and there is a further reduction in allocations for 2013, driving the $364,000 variance in OM&A for the 2013 Test Year.

2. Progression and Cost of Living Changes

OM&A	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Progression and Cost of Living changes	56,000	342,000	279,000	290,000	344,000

The variance of $56,000 shown for 2009 Actuals is not truly a progression or cost of living increase over the 2009 Board Approved, it reflects the fact that the reduction to labour as a result of the settlement for the 2009 COS Application could not actually be achieved in 2009. The variance simply demonstrates that the amount spent on payroll was greater than the amount built into rates as a result of the settlement. All other variances demonstrate relative consistency from year to year.

3. Monthly Billing

OM&A	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Monthly Billing					322,000

The variance in the 2013 Test Year relates to the proposed new service offering of Monthly Billing which is discussed at Exhibit 4, Tab 2, Schedule 5.

4. Net Smart Metering Incremental OM&A

OM&A	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Net Smart Metering Incremental OM&A				66,000	125,000

The total incremental cost of Smart Meters is $191,000 as discussed in Exhibit 2, Tab 4, Schedule 4. Of the net increase, $66,000 is experienced in 2012 representing eight months of AMI fees, Sensus Network fees and ODS fees, less the savings in manual meter reads ($96,000 of costs for eight months - $30,000 in savings). The 2013 variance represents the remaining four months, plus $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.

5. Net Change in FTE's

OM&A	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Net Change in FTE's	(57,000)	396,000	202,000	121,000	102,000

There are numerous movements of staff that are discussed in detail in the Staffing and Compensation Levels (Exhibit 4, Tab 4, Schedule 1), but this summary of the cost driver speaks to the high level changes in FTEs. In addition, variances related to net changes in FTEs are discussed in greater detail in both the OM&A Variance Analysis (Exhibit 4, Tab 3, Schedule 1).

The increase in 2010 was driven primarily by an increase in management and non-union positions intended to enhance leadership in operational areas, as well as to respond to pressures imposed by the *Green Energy Act* and the focus on asset management planning. For the year 2011, the variance is driven by an executive position being filled that was vacant until 2011, as well as two new union position. The remaining increase in 2012 and 2013 relate to the addition of union positions as Bluewater Power works to respond to increased workload and demands on its union staff.

6. Benefit Increases attributed to payroll changes

OM&A	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Benefit Increases attributed to payroll changes		102,000	59,000	55,000	89,000

This variance represents the increase in benefits that are attributable to the increases explained above for Net Change in FTEs (#5 Cost Driver) and the Progression and Cost of Living Increases (#2 Cost Driver). The explanation for this variance is that any increase in payroll leads to a corresponding increase in benefits apart from any change in rates for benefits. This variance does not reflect any change to the rates paid for benefits, although the issue of managing benefit costs is discussed in the Human Resources Strategy included as Exhibit 4, Tab 4, Schedule 1, Attachment 2.

7. Bad Debt Expense

OM&A	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Bad Debt Expense		387,375	(283,949)	(104,195)	87,000

In early 2011, a customer in the Intermediate rate class went into receivership which caused a significant increase in the amount of bad debt expense reflected in the year 2010 financial statements. The negative variance in 2011 reflects a return to more normal levels of bad debt, although there was bad debt in 2011 attributable to the same intermediate customer.

In 2012, we are seeing an increase in the level of bad debt expense and have therefore increased the level of bad debt projected for 2013. This is partially driven by economic conditions; Bluewater Power has been experiencing an increase in the number of personal bankruptcies filed by consumers that has led to an increase in unrecoverable bad debt. However, the increase in bad debt is also attributed to by changes to the

Distribution System Code, Retail Settlement Code and the Standard Supply Code as it relates to customer service rules and low income customer service rules. The changes affected the following:

i) Bill Issuance and Payment
ii) Arrears Management Programs
iii) Opening and Closing of Accounts
iv) Use of Load Limiter Devices
v) Disconnection of Service
vi) Equal Billing Plans

Throughout 2009 and 2010, Bluewater Power met with various social service agencies within our service territory to provide awareness of the changes to customer service rules. As such, Bluewater Power has received on file a total of approximately 1,000 low income certifications for consumers in our territory. Upon receipt of the certifications, the consumer account is reviewed and any deposit on hand is returned, or in the case of a new customer, the deposit requirement is waived. In November 2010, Bluewater Power held approximately $770,000 of residential deposits on hand, which was representative of the average annual historic level. As of July 2012 Bluewater Power held only $425,000 of residential deposits on hand. This increases the risk to Bluewater Power in a material way as the foregone deposits typically relate to high-risk customers.

8. OMERS Rate Increase

OM&A	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
OMERS Rate Increase			118,000	74,000	85,000

Starting in the year 2011, every company participating in the OMERS pension plan has seen contribution rates increase steadily. These costs are beyond the control of Bluewater Power management and are discussed in greater detail in the Human Resources Strategy included as Exhibit 4, Tab 4, Schedule 1, Attachment 2.

9. Allocation to Billable Work

OM&A	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Allocation of Costs to Billable Work		(283,000)	197,000	62,000	63,000

As discussed in the Manager's Summary (Exhibit 4, Tab 1, Schedule 1), Bluewater Power achieves efficiencies through the allocation of OM&A to Billable Work (among other things). This work fluctuates depending upon demand which is largely outside of the control of management. The variances reflect the fact that 2010 was a high demand year, primarily driven by work undertaken to connect eight 10 MW solar farms under the OPA's RESOP program. Demand for billable work has declined since that time reflecting, in part, the fact that the market in southwestern Ontario is saturated for large renewable energy projects.

10. Change to capitalization of overhead

OM&A	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Change to capitalization of overhead		(382,000)	187,000	602,000	25,000

Bluewater Power's policy for the capitalization of overhead is discussed in detail in Exhibit 2, Tab 2, Schedule 2 and the changes in methodology are summarized in Exhibit 1, Tab 2, Schedule 4. The variance in the level of capitalized overhead is partially driven by changes in the rate of overhead calculated for a given year. For example, the variance in 2011 is primarily driven by the increase in the capitalization rate from 10% to 12% of capital. However, the primary driver is typically the level of capital activity to which the overhead rate is applied. Accordingly, the negative variance in 2010 of $382,000 represents an increase in the amount of overhead capitalized related to the significant level of capital projects undertaken in 2012 ($8.1M) compared to 2011 ($5.4M).

The 2012 Bridge Year is reported in this analysis on a MIFRS based, so the explanation for the variance in 2012 relates to the transition to MIFRS. As discussed throughout this application, the most significant consequence of the change to MIFRS for OM&A is the fact that overhead is not permitted to be capitalized. The variance of $602,000 represents the fact that capitalization of overhead in 2011 was $602,000 whereas that amount in 2012 is $0 under MIFRS. The amount of that variance is not to be confused with the variance discussed elsewhere in this application as a variance of $1.26M between 2012 CGAAP and 2012 MIFRS; that variance reflects the amount of overhead capitalized in 2012 under CGAAP versus $0 under MIFRS.

11. Employee Future Benefit Obligation

OM&A	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Employee Future Benefit Obligation	(226,000)	162,000	(41,000)	(20,000)	(11,000)

The variances from year-to-year in the Employee Future Benefit Obligation reflect changes in FTEs, benefits program and discount rates employed by the actuary. The downward trend in recent years reflects the efforts by management to reduce the retiree group benefits as discussed in Exhibit 4, Tab 4, Schedule 1, as shown in the retiree benefits summary attached to that schedule.

12. Allocation of labour and costs to Capital Projects

OM&A	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Allocation of Costs to Capital Projects		(233,000)	(42,000)	(615,000)	(91,000)

As discussed in the Manager’s Summary (Exhibit 4, Tab 1, Schedule 1), Bluewater Power achieves efficiencies over its Gross OM&A through the capitalization of labour otherwise included in the gross amount. The level of capitalized labour fluctuates with the level of Capital in a given year and the nature of the capital work to be undertaken.

The negative variance above reflects the fact that 2010 was a high demand year for capital, driving $233,000 more out of OM&A than the prior year due to capitalized labour. The table reveals that the level of capitalized labour has increased steadily over all years of this analysis. The significant increase in the 2012 Bridge Year reflects the renewed focus on the asset management planning process and additions to the management team in the operation groups to reinforce leadership in those important areas. This represents an intentional effort to improve output toward capital improvements. These issues are discussed further in the Manager’s Summary (Exhibit 4, Tab 1, Schedule 1) and the Human Resources Strategy (Exhibit 4, Tab 4, Schedule 1, Attachment 2).

13. Decline in Overtime

OM&A	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Decline in Overtime				(130,000)	

Overtime is a function of workload and the number of employees available to achieve the given amount of work. There are certain types of overtime that cannot be avoided, such as storm response or work that must be scheduled after hours to reduce customer inconvenience. However, the reduction in 2012 Bridge Year represents the forecast reduction in overtime attributable to the increase in FTEs in the operational areas.

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Appendix 2-J
OM&A Cost Driver Table

OM&A	**Last Rebasing Year (2009 Actuals)**	**2010 Actuals**	**2011 Actuals**	**2012 Bridge Year**	**2013 Test Year**
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**
Opening Balance	$ 9,991,419	$ 9,772,182	$ 10,254,820	$ 11,063,458	$ 11,457,938
Allocation to Smart Meter Project		$ (225,000)	$ (196,000)	$ 73,000	$ 364,000
Progression and Cost of Living changes	$ 56,000	$ 342,000	$ 279,000	$ 290,000	$ 344,000
Monthly Billing					$ 322,000
Net Smart Metering Incremental OM&A				$ 66,000	$ 125,000
Net Change in FTE's	$ (57,000)	$ 396,000	$ 202,000	$ 121,000	$ 102,000
Benefit Increases attributed to payroll changes		$ 102,000	$ 59,000	$ 55,000	$ 89,000
Bad Debt Expense		$ 387,375	$ (283,949)	$ (104,195)	$ 87,000
OMERS Rate Increase			$ 118,000	$ 74,000	$ 85,000
Allocation to Billable Work		$ (283,000)	$ 197,000	$ 62,000	$ 63,000
Change to capitalization of overhead		$ (382,000)	$ 187,000	$ 602,000	$ 25,000
Employee Future Benefit Obligation	$ (226,000)	$ 162,000	$ (41,000)	$ (20,000)	$ (11,000)
Allocation of labour and costs to Capital Projects		$ (233,000)	$ (42,000)	$ (615,000)	$ (91,000)
Decline in Overtime				$ (130,000)	
Other	$ 7,763	$ 216,263	$ 329,587	$ (79,325)	$ 116,890
Closing Balance	$ 9,772,182	$ 10,254,820	$ 11,063,458	$ 11,457,938	$ 13,078,828

Notes:

1 For each year, a detailed explanation for each cost driver and associated amount is required.

2 The closing balance for each year becomes the opening balance for the next year.

3 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

4 Opening Balance for "Last Rebasing Year" (cell B15) should be equal to the Board-Approved amount.

REGULATORY COSTS

The 2013 Rebasing Costs forecast to be spent in 2012 and 2013 total $400,800 as set out in Table 1 below. This amount represents a 1.9% increase over the 2009 Rebasing Costs of $393,214. Although there are more studies required for the 2013 COS Application as compared to the requirements that were in place in 2009, Bluewater Power has managed to offset the extra costs of these studies by reducing its reliance on consultants and outside legal services. Bluewater Power gained valuable experience through the 2009 rebasing process and has been able to apply that experience to the 2013 process.

Attachment 1 to this schedule is the OEB Appendix 2-M Regulatory Costs which includes the breakdown of the regulatory costs. The results are reproduced for ease of reference in Table 1 below.

Table 1 – Historical and Projected Rate Application Costs

		2009 Rebasing Costs	2012 Bridge Year	2013 Test Year	Total Incremental Rebasing Costs for 2013 (2012 + 2013)
4	Expert Witness costs for regulatory matters		$ -	$ -	$ -
6a	Consultants' costs for regulatory matters	$ 132,373	$ 88,000	$ 42,000	$ 182,000
5a	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	$ 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

The 2013 Rebasing Cost of $400,800 is considered a ‘one-time’ cost to be amortized over the IRM period. Therefore, one-fourth of the total 2013 Rebasing Costs (being $100,200) are included in Regulatory Costs for 2013 and beyond.

Account 5655 is utilized by Bluewater Power to record all Regulatory Costs. The account includes the amortized Rebasing Costs, as well as the following items:

- Salary and associated employee expenses for the Regulatory Manager
- OEB Assessment Fees, OEB License Fees, and OEB Cost Awards for OEB initiated applications
- Electrical Safety Authority Annual Audit Fees
- LEAP funding
- Annual (non-rebasing) consulting and legal fees

As set-out in Appendix 2-M, which is included as Exhibit 4, Tab 2, Schedule 3, Attachment 1, the on-going expense forecast for 2013 is $292,859. This compares to the 2011 Actual expense of $276,734. This represents a $16,000 increase which equates to 5.8% over 2 years (2.9% annual increase). The primary driver of the $16,000 increase is the increase in OEB Assessment costs from $122,592 to $132,190.

Appendix 2-M includes a sub-total for one-time costs as they are incurred. As discussed above, however, those one-time costs are amortized evenly over the IRM Period. The OEB Approved Regulatory costs from the 2009 Rebasing Application were amortized over four years at $98,304. The projected costs for the 2013 Rebasing Application are proposed to be amortized over four years at $100,200.

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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%	$ 95,169	5.16%
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%	$ 292,859	4.77%
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%	$ 520,859	15.15%

[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 between one-time and ongoing costs.
[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**

ONE-TIME COSTS

Rate Applications based on a forecast Test Year typically include consideration of extraordinary circumstances that occur during the Test Year. First, there are extraordinary circumstances that relate to matters that impact the Test Year with new costs or material cost increases. These extraordinary circumstances are typically explored in the context of a variance analysis of OM&A.

The second example of extraordinary circumstances considered in the context of Rate Applications relate to one-time costs that occur during the Test Year only and which are normalized over the Cost of Service Term to avoid over-collection from Ratepayers. The purpose of this type of adjustment is to ensure fair rates for both ratepayers and the utility. One clear example of the OEB practice of allocating one-time costs over the COS period is seen with the treatment of Rebasing Costs. Legal and consulting costs incurred prior to the test year have been permitted to be recovered in order to hold the utility whole; likewise costs incurred during the Test Year (as is common with applications for rate effective May 1st) are not imposed on ratepayers other than through a mechanism to normalize costs. These one-time costs are permitted to be recovered spread evenly over the term of the COS regime and are discussed in Exhibit 4, Tab 2, Schedule 3.

The only costs claimed in this Application as One-Time Costs (other than Rebasing Costs) relate to the forecast environmental costs required to study and remediate a property owned by Bluewater Power and known as Main Substation #1 located on Maxwell Street in Sarnia (“MS#1”). The application includes $67,500 included in the Test Year as the normalized cost of remediation at MS#1 forecast to cost the utility $270,000 during the Test Year.

The Ministry of the Environment identified MS#1 in 1989 as one of several sites located in Ontario known to be contaminated by Coal Tar. The Site was operated by the former Sarnia Gas Works and the property came into the ownership of the former Sarnia Hydro

Commission in 1916. Since 1989, the site has been the subject of regular and ongoing monitoring by Sarnia Hydro and, subsequently, Bluewater Power.

In June of 2012, a tar-like substance was found rising to the surface on the grounds of Centennial Park (located in close vicinity of MS#1). An article published in the Sarnia Observer on June 22, 2012 entitled “Summer Thankfully Not Stuck in Coal Tar” identified the substance as Coal Tar and identified the former Sarnia Gasworks site as the “likely candidate” to be the source of the contaminant. Since that report, Bluewater Power has been engaged in discussions with the City of Sarnia regarding the substance. The City of Sarnia is currently engaged in preliminary testing and is performing environmental audits of Centennial Park. That process is likely to move into a Site Specific Risk Assessment (“SSRA”) and, given the proximity of MS#1 and the current assumption of a link between the two sites, Bluewater Power has forecast that it will either participate in the City’s SSRA process in 2013, or commence a parallel SSRA process concerning the MS#1 site only.

The forecast costs included in the application are beyond the control of Bluewater Power and the timing of the expenditures during the Test Year is dictated by circumstances outside of the utility’s influence. The costs included for recovery represent the most conservative option involving an SSRA, only, with no physical remediation required. Bluewater Power has a high level of confidence that MS#1 is not the source of the contaminant and we have, therefore, only included costs required to move the site through the SSRA process. Any costs beyond a SSRA would be speculative in nature and are best handled at a future time, if necessary, through a request for a deferral account from the OEB for the costs of remediation.

We have estimated the costs of a SSRA to be $270,000 and we have proposed that the costs be recovered at $67,500 per year for the four years of the COS period. In the alternative, we request a deferral account to record all legal, consulting and remediation costs in relation to environmental issues at MS#1. These costs are expense in nature and should be recovered through O&M. While the project may result in physical improvement to the property, these investments will not extend the useful life of the asset or add value to the asset and, therefore, are not capital in nature.

Looking to Historic Years and Bridge Year, the only material one-time cost in distribution expenses in any year was a bad debt expense in 2010. Bluewater Power experienced an Intermediate customer going into receivership at the beginning of 2011, leaving bad debt for the 2010 financial year in the amount of $373,607. Bluewater Power put the Board on notice by letter dated July 14, 2011 that it had experienced a Z-factor event and that it might consider filing a z-factor claim. Bluewater Power has determined, based on previous Board decisions relating to z-factor claims in relation to bad debt, not to file a Z-factor claim with this Application.

MONTHLY BILLING

Bluewater Power currently processes approximately 19,700 consumer bills each month. Approximately 32,000 customers are billed on a bi-monthly basis, resulting in 16,000 bills produced each month for those customers. The remaining 3,700 customers are billed each month.

In the recent past, Bluewater Power had considered moving 100% of customers to monthly billing, but the incremental cost to the corporation could not be justified. Bluewater Power acknowledges that there are benefits to customers by moving to monthly billing. By including the incremental costs of monthly billing in this 2013 Rebasing Application, we believe we achieve the appropriate allocation of the costs to ratepayers who are the beneficiaries of the change in billing practice. In support of that position, we submit that ratepayers benefit from the move to monthly billing based on the following factors:

- A consumer's ability to manage their household budget would be aided by the lower bills that result from more frequent billing. Consumers are interested in these benefits, as seen with the number of inquiries received by Bluewater Power from customers requesting monthly billing.
- The introduction of Smart Meters creates a need to get current information to consumers so that they can better respond to seasonal fluctuations in consumption patterns. We know from experience that only a minority of customers access their billing information online, so the majority of customers are best reached through a move to monthly billing.

Finally, we note that Bluewater Power understands there are discussions regarding the potential for the electricity industry to be mandated to move to monthly billing. With that in mind, and in light of the above considerations, it is appropriate for these costs to be included in the 2013 Rebasing Application.

The incremental cost associated with the transition from Bluewater Power's current practice of bi-monthly billing to monthly billing is shown in Table 1 below. Of the incremental cost of $322,641, approximately 50% of the increased costs are directly related to paper, envelopes and postage costs. The remaining 50% of the increase are costs related to increased staff. It is anticipated that three additional staff members would be required, specifically one mailroom/clerical, one billing representative and one cashier. In proposing these increased staffing levels, Bluewater Power has considered the effect that monthly billing may have for billing, customer service and the credit collections processes. The current duties associated with the production, delivery, customer service and collections are significant. Moreover, there were no staff increases associated with the introduction of Smart Meters even though TOU pricing requires increased interaction for billing purposes with outside agencies, including new agencies such as the MDM/R. Accordingly, while the current staff levels are appropriate any added work leads to the need for staff adds.

When Bluewater Power transitions to monthly billing there will be timing impacts related to the one-time influx of funds from consumers, which will increase the interest income on Bluewater Power's funds. This relates to the fact that customers will be billed 30 days earlier than usual for approximately 50% of their consumption costs. That amounts to approximately $4,000,000 being collected 30 days earlier every other month compared to the bi-monthly billing process. Assuming an annual interest rate of 0.5%, the annual interest income on those funds is approximately $20,000. That amount has been included in Account 4405 as a revenue offset.

Table 1 – Monthly Billing Incremental Costs

Account	Amount $
5315	216,513
5320	51,412
5645	32,621
5665	22,095
Total OM&A	322,641

LOW-INCOME ENERGY ASSISTANCE PROGRAM (LEAP)

In March 2009 the OEB issued its *Report of the Board: Low Income Energy Assistance Program* (the "LEAP Report"), which detailed the level of financial assistance expected to be funded by distributors. The Board determined that "…*the greater of 0.12% of a distributor's Board-approved distribution revenue requirement, or $2,000 is a reasonable commitment by all distributors to emergency financial assistance*."

Based on the calculation of 0.12% of the total distribution revenue requirement, Bluewater Power contributed an amount of $23,267 in 2011, and the same amount in 2012, and has forecast an amount of $24,000 as a contribution to our Social Service Agency for 2013.

CHARGES RELATED TO THE GREEN ENERGY AND GREEN ECONOMY ACT

Bluewater Power has filed a Basic Green Energy Act Plan at Exhibit 2, Tab 7, Schedule 1. Table 1 indicates the proposed OM&A expenditures that are included within the Green Energy Act Plan.

Table 1 – Planned OM&A Expenditures

Smart Grid Customer	2013 ($000)	2014 ($000)	2015 ($000)	2016 ($000)	Total ($000)
Capital	$0	$0	$0	$0	$0
OM&A	$40	$40	$40	$40	$160
Total	**$40**	**$40**	**$40**	**$40**	**$160**

Bluewater Power is not seeking a prudence review of the expenditures at this time. Rather we are providing notice to the OEB of our plans, and the proposed budget. We will be recording the costs to the appropriate deferral account and will likely be seeking disposition during the next rebasing application.

CDM COSTS

Bluewater Power is delivering CDM programs in accordance with '*The Conservation and Demand Management Code'* dated September 16, 2010 which follows from the directive of the Ministry of Energy and Infrastructure that mandates distributors to implement programs in order to achieve certain CDM targets. The OPA will provide approximately $2.1 million between 2011 and 2014 to Bluewater Power in order to fund the administration and delivery of programs.

Bluewater Power is only implementing OPA funded programs and receives no funding through distribution rates nor is proposing to fund any programs through OEB Tier 2 programs at this time.

All revenues and costs related to implementing CDM programs are accounted for separately in USoA accounts 4375 and 4380 – Revenue and Expenses of Non Rate-regulated Utility Operations. Bluewater Power adheres to the fully allocated costing methodology for the purpose of allocating costs to OPA programs, therefore any time or resources that are involved in the delivery of CDM activities are booked to the expense Account 4380. For the 2013 forecast, an amount of $93,234 has been reduced from the Distribution Company's projected OM&A expenses and booked to account 4380 for projected labour costs related to CDM.

Bluewater Power is proposing recovery for lost revenue under the LRAM process for CDM programs implemented in 2011, and for losses as a result of 2006-2010 programs that persisted in 2011. A full discussion and analysis is at Exhibit 9, Tab 3, Schedule 1.

CHARITABLE DONATIONS

Bluewater Power has not included any amounts for charitable donations in its 2013 OM&A, and therefore nothing is included in revenue requirement. This includes political donations.

Historical charitable donations have been recorded to Account 6205 ‘Donations’ and include $48,784 in 2009, $54,448 in 2010 and $30,629 in 2011. These amounts are also disclosed in OEB Appendix 2-G ‘Detailed, Account by Account, OM&A Expense Table’ found in Exhibit 4, Tab 2, Schedule 1, Attachment 2.

Exhibit 4: Operating Costs

Tab 3 (of 8): OM&A Variance Analysis

OM&A VARIANCES

Provided earlier in this Application are the general cost trends found in the Manager's Summary at Exhibit 4, Tab 1, Schedule 1. The OM&A Variance Analyses found in this schedule further detail the changes in operating costs by providing variance explanations for any OEB Account that exceeds the materiality threshold of $114,785 (either positive or negative).

The analysis is provided in two forms. First, we have included OEB Appendix 2-H as Exhibit 4, Tab 3, Schedule 1, Attachment 1; that analysis provides the variance from 2009 Board Approved to 2013 Test Year, as well as from 2011 Actuals to 2013 Test Year. The qualitative explanation of those variances follows in this schedule below. Second, we provide annual variances below starting with 2009 Board Approved to 2009 Actuals, followed by year-over-year analyses from 2009 through to 2013 Test Year.

Before turning to either analysis, it is worth noting that PST is included in PST applicable OM&A accounts in the 2009 and 2010 actuals for expenditures incurred up to and including June 30, 2010. For the remainder of 2010 and 2011, the actuals do not include any PST amounts due to the implementation of HST, however certain restricted HST ITCs were expensed in OM&A. Similarly, the 2012 and 2013 budgeted OM&A amounts are exclusive of HST, but will contain restricted ITCs. Further details are explained in Deferral Account 1592 'PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) found in Exhibit 9, Tab 1, Schedule 4. Although this has not contributed to a material variance in any one account, it is a change worth noting prior to any annual comparisons.

Appendix 2-H Variance Analysis

Provided as Exhibit 4, Tab 3, Schedule 1, Attachment 1 is OEB Appendix 2-H. The appendix provides an account by account variance analysis for the years 2009 Board Approved to 2013 Test Year, as well as for 2011 Actuals to 2013 Test Year.

In completing Appendix 2-H and providing the qualitative explanations below, we have made the following assumptions:

- The Filing Guidelines speak to a materiality threshold for “changes from year to year” that exceed, in the case of Bluewater Power, $114k. The variances discussed below represent four year variances from 2009 to 2013 and two-year variances from 2011 to 2013. Accordingly, the appropriate materiality threshold for qualitative explanations has been set at $456k for variances from 2009 to 2013 and at $228k for variances from 2011 to 2013. 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. We note this “alternative threshold” change in accordance with the Filing Guidelines.
- As discussed elsewhere in this Application, any comparison with 2009 Board Approved presents a challenge because the approved amount was the result of a settlement reached with Intervenors and approved by the Board. The settlement reached required a reduction to capital spending in the Test Year, as well as a reduction to Revenue Requirement. The capital items removed from the Capital Budget in 2013 were specifically identified through the settlement process and the impact on amortization and PILs were flowed through to the Revenue Requirement. However, the further reduction to Revenue Requirement required by the settlement was not specifically addressed through settlement process but was left to the discretion of the utility as a blanket reduction. For the purposes of this analysis, we have assumed that the entire reduction was allocated to OM&A, and prorated on an account by account basis to provide a 2009 Board Approved OM&A Budget.
- 2011 represents actual amounts spent and allocated on an account by account basis.
- 2013 is based on the forecast spending on an account by account basis.

1.1 Appendix 2-H: 2009 Approved to 2013 Test Year

Utilizing a materiality threshold of $456k, as discussed above, the material variances are explained below. In the interest of further transparency, however, where the material variance threshold of $456k does not result in five accounts being explained, we have gone below the materiality threshold in order to identify the top five variances.

- **Account 5625 - Administrative Expense Transferred (variance of $543,487):** This account was utilized in 2009 to record Overhead Capitalization (NOTE: in 2010, 2011 and 2012 capitalized overhead was recorded on a pro-rata basis to the accounts where the costs were deemed to have originated). Under MIFRS, overhead can no longer be capitalized, so the entire variance represents the overhead capitalized in 2009.

- **Account 5605 – Executive Salaries and Expenses (variance of $487,214)**: The primary driver of the variance are reallocations and normal cost drivers as follows:
    - New costs not included in 2009 Approved explain $286,000 of the variance. One such cost is an FTE included as Management in the 2009 COS Application that was reclassified to Executive in 2009 such that those costs are reflected in the Executive account for 2009 Actuals and beyond; accordingly the variance is not an increase in costs but rather a reclassification, with a corresponding decrease in Managerial Salaries and Expense. The second increase reflects the fact that the overall reduction that was applied to all accounts to reflect the settlement reached in the 2009 COS Application could not be absorbed in some accounts, such as the Executive Account.
    - Four years of Cost of Living increases provides for a variance of $113,000
    - Progression and Incentive Increases over the four year period are $157,000, although included in this account is a $50,000 amount budgeted for progressions in all departments.

  - Increases in this Account are offset by a credit of $134,000 representing two things. First, a change is practice to treat management fees as a reduction to OM&A rather than a revenue offset with the same impact on rates (see discussion of Account 4220 in Exhibit 3, Tab 2, Schedule1). Second, there is an increase in quantum of costs moved from executive for Capital Projects and charges to affiliates as management fees.
  - Other increases over the 4 year period approximate $65,214.

- **Account 5315 – Customer Billing (variance of $394,332):** The primary driver of the variance in this account relates to Monthly Billing, with the remainder related to Cost of Living and Progressions as follows:
  - Of the total incremental cost of $322,000 to move from Bi-monthly to Monthly Billing, the costs related to 2 of the 3 FTEs and postage costs are found in Account 5315, contributing $216,000 to the variance.
  - Four Years of Cost of Living is $81,000
  - Progression and Incentive Increase are $34,000
  - Other being $63,332.

- **Account 5645 – Employee Pensions and Benefits (variance of $318,538)**: Benefit costs increase because the total payroll has increased or because the rates on which benefits are based have increased. The variance in Account 5645 is explained as follows:
  - Increase in benefit costs due to Payroll increases over four years (caused by new FTEs, Progressions and Cost of Living increases) accounts for an increase of $437,000 in benefits.
  - OMERS Rate increase accounts for $277,000 above and beyond Payroll increases.
  - Other Benefits rate increases account for $103,000 above and beyond Payroll increases.
  - Accounting changes implemented by Bluewater Power between 2009 and 2013 mean that Account 5645 now includes the credit on benefits included in loaded labour rates charged to capital projects. This amount

and other credits create a negative variance of $336,000 in this account when comparing 2009 to 2013.

- The Employee Future Benefit expense in 2013 is less than the Employee Future Benefit expense in the 2009 Rebasing Application creating a negative variance of $135,000 in this account. The most recent actuarial report reflects the amendments to retiree group benefits discussed in Exhibit 4, Tab 4, Schedule 1, as well as changes in FTEs and the discount rate used in the analysis.
- Other being ($27,462)

- **Account 5665 – Miscellaneous General Expenses (variance of $306,830):** The variance is explained by increases in software maintenance fees, utilities and miscellaneous charges as follows:
  - Increase in software maintenance fees, including $47,000 for Smart Meter software, accounts for $149,000 of the variance.
  - A portion of the incremental costs of Monthly Billing contributes $22,000 of the variance in this account.
  - Increase in utilities, phone and internet for $107,000
  - Other being $28,830

1.2 Appendix 2-H: 2011 Actual to 2013 Test Year

Utilizing a materiality threshold of $228k, as discussed above, the material variances are explained below. In the interest of further transparency, however, where the material variances of $228k does not result in five accounts being explained, we have gone below the materiality threshold in order to identify the top five variances.

We note that the largest single variance was the inability to capitalize overhead under MIFRS; however, unlike in 2009 where the entire amount of capitalized overhead was booked to Account 5625, the capitalized overhead amount in 2011 of $627,000 was spread over 20 different accounts. This creates a $627,000 variance driven by the change in rules under MIFRS and, as will be noted below, contributes to the variances in some of the accounts explained below.

- **Account 5645 – Employee Pensions and Benefits (variance of $367,121)**: Benefits increase because the total payroll has increased or because the rate on which benefits are based has increased. This variance is explained as follows:
    - Increase due to the two year Payroll increase (caused by new FTEs, Progressions and Cost of Living increases) accounts for an increase of $170,000 in benefit costs.
    - OMERS Rate increase accounts for $159,000 above and beyond Payroll increases.
    - Other Benefits rate increases account for $57,000 above and beyond Payroll increases.
    - Other being ($18,879).

- **Account 5315 – Customer Billing (variance of $360,812):** The primary driver of the variance in this account is related to Monthly Billing, with the remainder related to Cost of Living and Progressions as follows:
    - Of the total incremental cost of $322,000 to move from Bi-monthly to Monthly Billing, the costs related to 2 of the 3 FTEs and postage costs are found in Account 5315, contributing $216,000 to the variance.
    - Change in staffing due to retirements in 2011 contributed to a negative variance of $59,000 in this account.
    - The Smart Meter implementation placed demands on Customer Billing in 2011, which resulted in costs being allocated to Smart Meters; that project is complete and the variance of $96,000 represents the fact those costs now remain in Account 5315 in the 2013 Test Year.
    - Two Year Cost of Living is $43,000
    - Progression and Incentive Increase is $70,000
    - Other contributes a negative variance of $5,188.

- **Account 5665 – Miscellaneous General Expenses (variance of $228,066):** This variance is explained by increases in software maintenance fees, utilities and miscellaneous charges as follows:
    - Increase in software maintenance fees, including $47,000 for Smart Meter software, accounts for $74,000 of the variance.
    - A portion of the incremental cost of Monthly Billing contributes $22,000 to the variance in this account.
    - Reduction in allocations due to overhead not being capitalized under MIFRS, as well as reductions in allocations and capitalization explains $127,000 of the variance in this account.
    - Other being $5,066

- **Account 5310 – Meter Reading Expenses (variance of $185,157):** The variance in this account is driven by the incremental cost of Smart Meters as discussed in Exhibit 2, Tab 4, Schedule 4.
    - $174,000 of the $191,000 incremental cost is found in Account 5310 and is the primary driver of the variance in this account. This account did not have any labour related to manual meter reading, so the savings are reflected in other accounts.
    - Other being $11,157.

- **Account 5605 – Executive Salaries and Expenses (variance of $125,036)**: The primary driver of the variance relates to changes in allocation of executive costs as:
    - Increase in Reallocation in 2013 of executive costs to Affiliates (through Management Services Agreements) and capital projects through direct capitalization of time accounts for a negative variance of $95,000 as those reallocations reduce the costs remaining in Account 5605.
    - There is an offset to the reduction in allocations due to the fact that overhead costs are not capitalized under MIFRS and this creates a positive variance of $139,000.
    - Two Year Cost of Living increase of $21,000

- o Two year Progression and Incentive Increase of $70,000, although included in this account is a $50,000 amount budgeted for progressions in all departments.
- o Other being a further credit of approximately $9,964.

2.0 Annual Variance Analysis

Provided below are annual variance explanations from 2009 Board Approved to 2009 Actuals, followed by year-over-year variance explanations from 2009 through to the 2013 Test Year. The annual variances set out below are provided on a quantitative basis in the tables provided. The table in respect of each annual variance contains a list of only those accounts with material variances in the year (NOTE: account balances for all years are shown in the Detailed, Account by Account, OM&A Expenses included as Exhibit 4, Tab 2, Schedule 1, Attachment 2). The qualitative explanations of the variance are found below each table, under a heading indicating the account being explained. The explanation provides the drivers of the variance in each account and the entire variance is explained, with smaller contributing variances grouped together under the heading of "other".

2.1 2009 Board Approved to 2009 Actual

It should be noted that the 2009 values as reported in the RRR filing report of May 12, 2010 contained an incorrect classification of a number of accounts related to billable work. Bluewater Power requested a change on December 9, 2010 however the OEB was not able to accommodate the Change Request. However, for purposes of this variance analysis, Bluewater Power has reflected the reallocation entry in order to present a more consistent view of the accounts for a year over year analysis (this issue is discussed in greater detail in Exhibit 1, Tab 3, Schedule 3).

Account	Description	2009 Board Approved	Last Rebasing Year (2009 Actuals)	2009 Actuals versus 2009 Board Approved	
	Reporting Basis	CGAAP	CGAAP	Variance ($)	Percentage Change (%)
Operations					
5005	Operation Supervision and Engineering	$ 835,073	$ 626,703	-$ 208,370	-25.0%
Administrative and General Expenses					
5605	Executive Salaries and Expenses	$ 851,116	$ 1,046,191	$ 195,075	22.9%
5610	Management Salaries and Expenses	$ 184,825	$ 67,390	-$ 117,435	-63.5%
5615	General Administrative Salaries and Expenses	$ 1,515,325	$ 972,326	-$ 542,999	-35.8%
5625	Administrative Expense Transferred - Credit	-$ 543,487	$ -	$ 543,487	-100.0%
5630	Outside Services Employed	$ 157,994	$ 273,402	$ 115,408	73.0%
5645	OMERS Pensions and Benefits	$ 1,756,541	$ 1,495,682	-$ 260,859	-14.9%

5005 Operation Supervision and Engineering

- ($180,000) – Two new positions were included in the 2009 COS Application in this Account, but the positions were unable to be filled until 2010. The positions were a new Lines Supervisor and a replacement Engineer.
- ($28,000) – Other

5605 Executive Salaries and Expenses

- $110,000 – this variance is driven by an employee reallocation issue only as a senior manager was reallocated to this account from Account 5610 ‘Management Salaries and Expenses’ (see below) for the 2009 actuals.
- $56,000 – 2009 COS reflects the 12% reduction related to settlement, and savings could not be achieved in this account.
- $29,000 – Other

5610 Management Salaries and Expenses

- ($110,000) – A senior management employee was reallocated from this account to Account 5605 ‘Executive Salaries and Expenses’ (see above) for the 2009 actuals.
- ($7,000) – Other

5615 General Administrative Salaries and Expenses

- ($303,000) – The 2009 COS Application included the amounts for overhead to be capitalized in Account 5625 'Administrative Expense Transferred – Credit' (see below), but the 2009 actuals included a portion of the reduction for capitalized overhead in Account 5615 and the remainder spread amongst the various labour accounts.
- ($134,000) – There were two positions reflected for the year in the 2009 COS Application that were unfilled for all or part of 2009. The IT Programmer was not filled until 2010 and the Accountant position was not filled until mid-year.
- ($43,000) – Payroll accrual was lower than projected in the 2009 COS Application.
- ($35,000) – Reallocations to affiliates in 2009 Actual was higher than the amount included in the 2009 COS Application.
- ($28,000) – Other

5625 Administrative Expense Transferred – Credit

- $543,487 – The 2009 COS included overhead to be capitalized in this account as a credit. The 2009 actuals included the credit in Account 5615 'General Administrative Salaries and Expenses' (see above). The amount of $543,487 is the exact amount included in the 2009 COS, whereas the amount of $303,000 is the rounded figure representing the actual level of overhead capitalized in 2009 Actuals as they impact Account 5615; the remaining amount is spread amongst other Accounts representing the costs determined to be included in the capitalized overhead.

5630 Outside Services Employed

- $123,000 – The 2009 Actuals included contract labour costs for certain positions that were not included in the 2009 COS Application. These contract costs were incurred on a part-year basis to create a variance of $123,000. This increase in contract costs is balanced by the lower labour costs in various departments (i.e. the Power Specialist hired on contract offsets the Engineer we were unable to hire where the savings is reflected in Account 5005 above).

- ($8,000) – Other

5645 OMERS Pensions and Benefits

- ($226,000) – The 2009 COS Application included the employee future benefit obligation expense which was based on an actuarial report completed in the summer of 2008 which included forecasted amounts for 2009. The 2009 Actual expense was based on an updated actuarial report completed in February 2010 and reflected an increased discount rate which effectively lowered the obligation liability at the end of 2009 and hence lowered the corresponding expense recorded to this account.
- ($35,000) - Other

2.2 2009 Actuals to 2010 Actuals

Account	Description	Last Rebasing Year (2009 Actuals)	2010 Actual	2010 Actuals versus 2009 Actuals	
Reporting Basis		CGAAP	CGAAP	Variance ($)	Percentage Change (%)
Operations					
5005	Operation Supervision and Engineering	$ 626,703	$ 888,541	$ 261,838	41.8%
5045	Underground Distribution Lines and Feede	$ 337,253	$ 167,941	-$ 169,312	-50.2%
Billing and Collecting					
5335	Bad Debt Expense	$ 102,769	$ 490,144	$ 387,375	376.9%
Administrative and General Expenses					
5605	Executive Salaries and Expenses	$ 1,046,191	$ 935,378	-$ 110,813	-10.6%

5005 Operation Supervision and Engineering

- $134,000 – This variance represents the part year impact of two positions. One position was created in 2009 but not filled until 2010 (Lines Supervisor) and the other position was a new position (Design Technologist) to respond to increase workload due to Green Energy Act and increased focus on asset management planning processes.
- $30,000 - Overtime in 2010 exceeds the amount from 2009, driven by workload.
- $46,000 – Cost of living and progressions in 2010.

- $23,000 – 27 pays in 2010 was expensed to this account and the single offsetting payroll accrual reversal representing all company cost centers at the beginning of the year was credited to Account 5615 ‘General Administrative Salaries and Expenses’.
- $29,000 – Other

5045 Underground Distribution Lines and Feeder

- ($94,000) – In 2009 and prior years, capitalized vehicle costs were allocated to labour accounts because that is how our SAP system was originally built to allocate those costs. Upgrades to our SAP system in 2010 now allows capitalized vehicle costs to be recorded to accounts where the costs are originally recorded, being Account 5045. The variance, therefore, represents this change in accounting practice.
- ($35,000) – increased activity in billable has resulted in decreased vehicle costs in Account 5045 as more vehicle costs are allocated to third parties through billable projects in 2010 versus 2009.
- ($40,000) – Other

5335 Bad Debt Expense

- $373,607 - A large customer went into receivership at the beginning of 2011 and the corresponding outstanding receivable at the end of 2010 was recorded to “bad debts expense” in the year 2010.
- $13,768 – General increase in accounts written off over 2009.

5605 Executive Salaries and Expenses

- ($30,000) – the negative variance is created by an increase in direct labour hours capitalized by staff normally reflected in this account to the Smart Meter capital project in 2010.
- ($172,000) – In 2009, overhead was included as part of the capitalized labour rate and recorded as a credit to the applicable labour-related general ledger accounts. In 2010, and subsequent years, overhead was not included in the labour rates, and was

calculated separately on each capital project. As a result, overhead is more accurately credited against the accounts from which the costs were deemed to have originated, such as Account 5605.

- $45,000 – Cost of living annual increases and progressions in 2010
- $31,000 - 27 pays in 2010 was expensed to this account and the single offsetting payroll accrual reversal representing all company cost centers at the beginning of the year was credited to Account 5615 ‘General Administrative Salaries and Expenses’.
- $15,000 – Other

2.3 2010 Actuals to 2011 Actuals

Account	Description	2010 Actual	2011 Actual[2]	2011 Actuals versus 2010 Actuals	
	Reporting Basis	CGAAP	CGAAP	Variance ($)	Percentage Change (%)
Operations					
5040	Underground Distribution Lines and Feeders - Operation Labour	$ 831,743	$ 995,046	$ 163,303	19.6%
Billing and Collecting					
5335	Bad Debt Expense	$ 490,144	$ 206,195	-$ 283,949	-57.9%
Administrative and General Expenses					
5605	Executive Salaries and Expenses	$ 935,378	$ 1,213,294	$ 277,916	29.7%
5615	General Administrative Salaries and Expenses	$ 992,791	$ 1,352,575	$ 359,784	36.2%
5645	OMERS Pensions and Benefits	$ 1,557,222	$ 1,707,958	$ 150,736	9.7%

<u>5040 Underground Distribution Lines and Feeders – Operation Labour</u>

- $155,000 – An increase in 2011 was experienced in this account related to a decline in the reallocation of billable labour in 2011 to Account 4330 ‘Costs and Expenses of Merchandising’. The reallocation of billable labour in 2010 was higher due to the significant billable work experienced to connect eight 10 MW solar farms to our distribution system under the Green Energy Act.
- ($49,000) – This represents the 27th pay posted to this account in 2010, while 2011 only reflects 26 pays. See Account 5615 below for further explanation.
- $59,000 - Cost of living annual increases and progressions in 2011.

- ($64,000) - Labour Hiring Tax Credit received in 2011 that was not received in 2010.
- $56,000 - An increase in 2011 was experienced in this account caused by a decline in the reallocation of direct labour from this account to capital and billable projects.
- $6,000 – Other

5335 Bad Debt Expense

- ($373,607) - This variance reflects the unusual expense in 2010 for the large customer that went into receivership in early 2011.
- $51,655 - This variance relates to the 2011 receivable amount for the same large customer that went into receivership and reflects the amount recorded to bad debts expense in 2011.
- $20,000 - This relates to an increase in Account 1130 'Accumulated Provision for Uncollectible Accounts – Credit' as the normalized levels of receivable accounts written off have increased.
- $18,003 - General increase in accounts written off over 2010.

5605 Executive Salaries and Expenses

- $47,000 - Cost of living annual increases and progressions in 2011.
- $34,000 – Net increase in the incentive program.
- $197,000 – reflects one new FTE in executive with the addition of the new VP; an increase related to a decline in the reallocation of direct labour to capital and billable projects for 2011 versus 2010; a variance representing the 27th pay posted to this Account in 2010 while 2011 only reflects 26 pays; and other.

5615 General Administrative Salaries and Expenses

- \$63,000 - An increase in costs for this account was experienced related to a decline in the reallocation of direct labour to capital and billable projects in 2011 versus 2010.
- \$218,000 – As noted in variance explanations for other accounts, 2010 was the year where Bluewater Power experienced 27 bi-weekly pay periods that ended in 2010 instead of 26 bi-weekly pay periods. This happens every 11-12 years. Bluewater Power records its payroll costs to the various payroll accounts at the end of each bi-weekly pay period. Each fiscal year should only reflect the costs of 26 bi-weekly pay periods. There is almost always a payroll accrual at the end of each fiscal year to account for the number of days from the end of the last pay period in the fiscal year to December 31st of the fiscal year. Similarly, this end of year accrual is reversed at the beginning of the following fiscal year. Therefore, the combination of these payroll accruals and reversals for each fiscal year will ensure only 26 pays (or 365 days) of payroll costs are reflected in OM&A. These payroll accruals and reversals, summed up for all cost centers of Bluewater Power, are recorded in Account 5615. However, the recording of each pay period throughout the year is allocated to all applicable payroll accounts. The variance in this account represents the bi-weekly pay period ending January 1, 2010. More specifically, the majority of this pay period would have been accrued at the end of 2009 to Account 5615, and reversed at the beginning of 2010. However, the actual payroll costs once known on January 1, 2010 were recorded to the various payroll accounts. The \$218,000 variance is the reversal recorded to this account at the beginning of 2010, whereas there is no accrual made at the end of 2010 since the last pay period in 2010 ended on December 31st (which is rare.)
- \$96,000 - During 2011, the hours of the part-time financial analyst were increased due to work load issues and a new full time Energy Services Coordinator was added for the full year to assist the new VP of Strategic Planning to do administer dealings with generators under the *Green Energy Act*.
- (\$46,000) – For those employees posted to this account, this represents the 27th pay posted to this account in 2010 while 2011 only reflects 26 pays.

- $35,000 - Cost of living annual increases and progressions in 2011.
- ($6,000) – Other

<u>5645 OMERS Pensions and Benefits</u>

- $140,000 – OMERS contribution rate increase experienced in 2011. The increase in rates charged by OMERS is outside the control of Bluewater Power management.
- $11,000 – Other

2.4 2011 Actuals to 2012 Bridge (MIFRS)

For the purposes of the analysis of 2011 to 2012, we have presented the variances as two variances: first, the variance of 2011 to 2012 CGAAP and, second, the variance from 2012 CGAAP to 2012 MIFRS. The only expected variance going from 2012 CGAAP to 2012 MIFRS is the variance attributable to the fact that overhead is not capitalized under MIFRS, so any account that is not materially affected by the loss of capitalized overhead is not addressed below.

Account	Description	2011 Actual[2]	Bridge Year 2012[3]	Bridge Year 2012[3]	2012 MIFRS versus 2011 Actuals		2012 CGAAP versus 2011 Actuals	
	Reporting Basis	CGAAP	CGAAP	MIFRS	Variance ($)	Percentage Change (%)	Variance ($)	Percentage Change (%)
Operations								
5040	Underground Distribution Lines and Feeders - Operation Labour	$ 995,046	$ 866,141	$ 961,197	-$ 33,849	-3.4%	-$ 128,905	-13.0%
Billing and Collecting								
5310	Meter Reading Expense	$ 55,952	$ 161,099	$ 161,099	$ 105,147	187.9%	$ 105,147	187.9%
5335	Bad Debt Expense	$ 206,195	$ 102,000	$ 102,000	-$ 104,195	-50.5%	-$ 104,195	-50.5%
Administrative and General Expenses								
5605	Executive Salaries and Expenses	$ 1,213,294	$ 1,044,857	$ 1,324,165	$ 110,871	9.1%	-$ 168,437	-13.9%
5615	General Administrative Salaries and Expenses	$ 1,352,575	$ 1,147,418	$ 1,470,414	$ 117,839	8.7%	-$ 205,157	-15.2%
5645	OMERS Pensions and Benefits	$ 1,707,958	$ 1,718,110	$ 1,818,515	$ 110,557	6.5%	$ 10,152	0.6%

<u>5040 Underground Distribution Lines and Feeders – Operation Labour (2012 CGAAP vs 2011 CGAAP)</u>

- ($208,000) – This negative variance is driven by the increase in capitalized labour and reallocation of other internal costs for 2012.
- ($130,000) – A further negative variance based on a projected decline in overtime for 2012 resulting from new hires.

- $88,000 - Cost of living annual increases and progressions in 2012.
- $64,000 - Hiring credit received in 2011, but not forecast for 2012.
- $57,000 – Replacement of a lineman who left in 2011.

<u>5040 Underground Distribution Lines and Feeders – Operation Labour (2012 MIFRS vs 2012 CGAAP)</u>

- $95,000 – This amount represents overhead in 2012 under CGAAP that is not allowed to be capitalized under MIFRS in 2012 and therefore will remain in this account under MIFRS.

<u>5310 Meter Reading Expense</u>

- $96,000 – New Smart Meter remote reading fees for eight months in 2012.
- $9,000 – Other

5335 Bad Debt Expense

- ($51,655) - This relates to the amount expensed in 2011 for the large customer that went into receivership in 2011; the negative variance reflects the fact this one-time costs was not forecast in 2012.
- ($20,000) – The 2012 Bridge Year does not reflect the additional $20,000 increase in Account 1130 'Accumulated Provision for Uncollectible Accounts – Credit' that was recorded during the 2011 year end process (after the 2012 budget was set in November 2011).
- ($32,540) – The residual difference of the variance in this account relates to the 2012 budget being set too low as compared to the normalized actual bad debt expense experienced in 2011.

5605 Executive Salaries and Expenses (2012 CGAAP vs 2011 CGAAP)

- ($146,000) – this negative variance represents a forecast increase in direct capitalized labour and reallocation of other internal costs for 2012.
- $78,000 - Cost of living annual increases and progressions in 2011.
- ($47,000) - Unused vacation payout or accrual from 2011, not budgeted in 2012, thereby creating a negative variance.
- ($53,000) – Other

5605 Executive Salaries and Expenses (2012 MIFRS vs 2012 CGAAP)

- $279,000 – This amount represents overhead in 2012 under CGAAP that is not allowed to be capitalized under MIFRS in 2012 and therefore will remain in this account under MIFRS.

5615 General Administrative Salaries and Expenses (2012 CGAAP vs 2011 CGAAP)

- ($169,000) – The negative variance represents a forecast increase in capitalized overhead discussed in Exhibit 2, Tab 2, Schedule 1.
- ($79,000) – This net decrease in 2012 is driven by an increase in the reallocation of direct labour to billable projects, smart meters and capital projects.

- $69,000 - Cost of living annual increases and progressions in 2011.
- ($26,000) – Other

<u>5615 General Administrative Salaries and Expenses (2012 MIFRS vs 2012 CGAAP)</u>

- $323,000 – This amount represents overhead in 2012 under CGAAP that is not allowed to be capitalized under MIFRS in 2012 and therefore will remain in this account under MIFRS.

<u>5645 OMERS Pensions and Benefits (2012 CGAAP vs 2011 CGAAP)</u>

- ($64,000) - A decrease in 2012 was experienced in this account which relates to an increase in the reallocation of direct benefits to capital and billable projects.
- $74,000 - OMERS contribution rate increase experienced in 2012. The increase in rates charged by OMERS is outside the control of Bluewater Power management.

<u>5645 OMERS Pensions and Benefits (2012 MIFRS vs 2012 CGAAP)</u>

- $100,000 - This amount represents overhead in 2012 under CGAAP that is not allowed to be capitalized under MIFRS in 2012 and therefore will remain in this account under MIFRS.

2.5 2012 Bridge (MIFRS) to 2013 Test (MIFRS)

Account	Description	Bridge Year 2012[3]	Bridge Year 2012[3]	Test Year 2013	2013 TEST versus 2012 CGAAP		2013 TEST versus 2012 MIFRS	
	Reporting Basis	CGAAP	MIFRS	MIFRS	Variance ($)	Percentage Change (%)	Variance ($)	Percentage Change (%)
Operations								
5040	Underground Distribution Lines and Feeders - Operation Labour	$ 866,141	$ 961,197	$ 1,089,225	$ 223,084	25.8%	$ 128,028	13.3%
Billing and Collecting								
5315	Customer Billing	$ 790,720	$ 797,284	$ 1,179,268	$ 388,548	49.1%	$ 381,984	47.9%
Administrative and General Expenses								
5605	Executive Salaries and Expenses	$ 1,044,857	$ 1,324,165	$ 1,338,330	$ 293,473	28.1%	$ 14,165	1.1%
5615	General Administrative Salaries and Expenses	$ 1,147,418	$ 1,470,414	$ 1,591,130	$ 443,712	38.7%	$ 120,716	8.2%
5630	Outside Services Employed	$ 243,132	$ 306,658	$ 389,845	$ 146,713	60.3%	$ 83,187	27.1%
5645	OMERS Pensions and Benefits	$ 1,718,110	$ 1,818,515	$ 2,075,079	$ 356,969	20.8%	$ 256,564	14.1%
5665	Miscellaneous General Expenses	$ 657,773	$ 817,641	$ 947,730	$ 289,957	44.1%	$ 130,089	15.9%

<u>5040 Underground Distribution Lines and Feeders – Operation Labour (2013 MIFRS vs 2012 MIFRS)</u>

- $77,000 – this variance represents a new lineman position added for the full year in 2013 to assist in meeting the increased capital budget set under Bluewater Power's updated Asset Management Plan.
- $63,000 - Cost of living annual increases and progressions in 2013.
- ($12,000) – Other

<u>5315 Customer Billing (2013 MIFRS vs 2012 MIFRS)</u>

- $99,000 - In 2013, two new positions are added for 2013 related to the implementation of monthly billing. These include a new full time billing representative and a new full time mailroom/clerk.
- $117,000 – Additional postage relating to the implementation of monthly billing.
- $58,000 - An increase in 2013 will occur in this account which relates to the cessation in the reallocation of direct labour to Smart Meter deferral accounts. The variance represents the amount reallocated from this account in 2012.
- $61,000 - Cost of living annual increases and progressions in 2013.
- $47,000 – Other

<u>5615 General Administrative Salaries and Expenses (2013 MIFRS vs 2012 MIFRS)</u>

- $169,000 - An increase in 2013 will occur in this account which relates to the cessation in the reallocation of direct labour to smart meter capital software. The variance represents the amount reallocated in 2012.
- $56,000 - Cost of living annual increases and progressions in 2013.
- ($60,000) – net change in FTEs, including the retirement of a full time accountant proposed to be replaced on a full-time contract basis.
- ($44,000) – Other

5645 OMERS Pensions and Benefits (2013 MIFRS vs 2012 MIFRS)

- $85,000 - OMERS contribution rate increase that will occur in 2013. The increase in rates charged by OMERS is outside the control of Bluewater Power management.
- $33,000 – This amount corresponds to the increase in benefits for the new positions budgeted for the change to monthly billing.
- $53,000 – Other benefit rate increases in 2013.
- $91,000 – Benefit cost increases based on increased payroll in 2013.
- ($5,000) – Other

5665 Miscellaneous General Expenses (2013 MIFRS vs 2012 MIFRS)

- $22,000 – New costs relating to additional supplies due to the implementation of monthly billing.
- $47,000 – New Smart Meter related costs for software maintenance which pertain to SAP AMI extensions software license maintenance, XI/PI software license maintenance, and Cleo AS2 software license maintenance.
- $17,000 – New costs relating to SCADA connectivity to Hydro One
- $44,000 – Other

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Exhibit:	4
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Date:	22-Oct-2012

Appendix 2-H
OM&A Detailed Variance Analysis
(excluding Depreciation and Amortization)

Account	Description	Last Board-approved Rebasing Year (2009 Year)	Most Current Actuals Year 2011	Test Year 2013	Test Year Versus Last Rebasing		Test Year Versus Most Current Actuals	
					Variance ($)	Percentage	Variance ($)	Percentage
Reporting Basis		CGAAP	CGAAP	MIFRS				
Operations								
5005	Operation Supervision and Engineering	$ 835,073	$ 814,674	$ 792,514	-$ 42,559	-5.10%	-$ 22,160	-2.72%
5010	Load Dispatching	$ 184,799	$ 212,873	$ 221,350	$ 36,551	19.78%	$ 8,477	3.98%
5012	Station Buildings and Fixtures Expense	$ 88	$ 1,917	$ 500	$ 412	465.45%	-$ 1,417	-73.92%
5014	Transformer Station Equipment - Operation Labour	$ 22,991			-$ 22,991	-100.00%	$ -	
5015	Transformer Station Equipment - Operation Supplies and Expenses	$ -			$ -		$ -	
5016	Distribution Station Equipment - Operation Labour	$ -			$ -		$ -	
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ 371	$ 25,130	$ 26,600	$ 26,229	7062.36%	$ 1,470	5.85%
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ -			$ -		$ -	
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ 204,588	$ 267,780	$ 289,300	$ 84,712	41.41%	$ 21,520	8.04%
5030	Overhead Sub-transmission Feeders - Operation	$ -			$ -		$ -	
5035	Overhead Distribution Transformers - Operation	$ 1,738	$ 1,878		-$ 1,738	-100.00%	-$ 1,878	-100.00%
5040	Underground Distribution Lines and Feeders - Operation Labour	$ 795,488	$ 995,046	$ 1,089,225	$ 293,737	36.93%	$ 94,179	9.46%
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	$ 270,909	$ 120,553	$ 124,669	-$ 146,240	-53.98%	$ 4,116	3.41%
5050	Underground Sub-transmission Feeders - Operation	$ -			$ -		$ -	
5055	Underground Distribution Transformers - Operation	$ -	$ 1,122	$ -	$ -		-$ 1,122	-100.00%
5060	Street Lighting and Signal System Expense	$ -	$ -	$ -	$ -		$ -	
5065	Meter Expense	$ 386,874	$ 359,545	$ 435,738	$ 48,864	12.63%	$ 76,193	21.19%
5070	Customer Premises - Operation Labour	$ -	$ -	$ -	$ -		$ -	
5075	Customer Premises - Operation Materials and Expenses	$ 38,217	$ -	$ -	-$ 38,217	-100.00%	$ -	
5085	Miscellaneous Distribution Expenses	$ 357,866	$ 344,988	$ 451,608	$ 93,742	26.19%	$ 106,620	30.91%
5090	Underground Distribution Lines and Feeders - Rental Paid	$ -			$ -		$ -	
5095	Overhead Distribution Lines and Feeders - Rental Paid	$ 27,138	$ 31,891	$ 35,500	$ 8,362	30.81%	$ 3,609	11.32%
5096	Other Rent	$ -			$ -		$ -	
Total - Operations		$ 3,126,141	$ 3,177,397	$ 3,467,004	$ 340,863	10.90%	$ 289,607	9.11%
Account	**Description**							
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	$ 30,357	$ 18,000	$ 11,567	179.81%	-$ 12,357	-40.71%
5120	Maintenance of Poles, Towers and Fixtures	$ 12,645	$ 4,986	$ 9,000	-$ 3,645	-28.82%	$ 4,014	80.51%
5125	Maintenance of Overhead Conductors and Devices	$ 73,853	$ 64,602	$ 68,000	-$ 5,853	-7.92%	$ 3,398	5.26%
5130	Maintenance of Overhead Services	$ -			$ -		$ -	
5135	Overhead Distribution Lines and Feeders - Right of Way	$ -			$ -		$ -	
5145	Maintenance of Underground Conduit	$ -	$ 14	$ -	$ -		-$ 14	-100.00%
5150	Maintenance of Underground Conductors and Devices	$ 14,944	$ 25,926	$ 19,200	$ 4,256	28.48%	-$ 6,726	-25.94%
5155	Maintenance of Underground Services	$ 4,549	$ 775	$ 400	-$ 4,149	-91.21%	-$ 375	-48.39%
5160	Maintenance of Line Transformers	$ 22,991	$ 30,102	$ 27,500	$ 4,509	19.61%	-$ 2,602	-8.64%
5165	Maintenance of Street Lighting and Signal Systems	$ -			$ -		$ -	
5170	Sentinel Lights - Labour	$ -			$ -		$ -	
5172	Sentinel Lights - Materials and Expenses	$ -			$ -		$ -	
5175	Maintenance of Meters	$ 3,979	$ 455	$ 500	-$ 3,479	-87.43%	$ 45	9.89%
5178	Customer Installations Expenses - Leased Property	$ -			$ -		$ -	
5195	Maintenance of Other Installations on Customer Premises	$ -			$ -		$ -	
Total - Maintenance		$ 139,393	$ 157,217	$ 142,600	$ 3,207	2.30%	-$ 14,617	-9.30%
Account	**Description**							
Billing and Collecting								
5305	Supervision	$ 110,356	$ 208,714	$ 230,451	$ 120,095	108.82%	$ 21,737	10.41%
5310	Meter Reading Expense	$ 130,998	$ 55,952	$ 241,109	$ 110,111	84.05%	$ 185,157	330.92%
5315	Customer Billing	$ 784,936	$ 818,456	$ 1,179,268	$ 394,332	50.24%	$ 360,812	44.08%
5320	Collecting	$ 206,153	$ 191,529	$ 242,549	$ 36,396	17.66%	$ 51,020	26.64%
5325	Collecting - Cash Over and Short	$ -	$ 120	$ 100	$ 100		-$ 20	-16.67%
5330	Collection Charges	$ 697	$ 309	$ 400	-$ 297	-42.59%	$ 91	29.45%
5335	Bad Debt Expense	$ 90,976	$ 206,195	$ 189,234	$ 98,258	108.00%	-$ 16,961	-8.23%
5340	Miscellaneous Customer Accounts Expenses	$ -			$ -		$ -	
Total - Billing and Collecting		$ 1,324,117	$ 1,481,275	$ 2,083,111	$ 758,994	57.32%	$ 601,836	40.63%
Account	**Description**							
Community Relations								
5405	Supervision	$ -			$ -		$ -	
5410	Community Relations - Sundry	$ 45,981	$ 106,039	$ 95,900	$ 49,919	108.56%	-$ 10,139	-9.56%
5415	Energy Conservation	$ 40,269	$ 27,391	$ 39,342	-$ 927	-2.30%	$ 11,951	43.63%
5420	Community Safety Program	$ 105,519	$ 122,273	$ 123,241	$ 17,722	16.80%	$ 968	0.79%
5425	Miscellaneous Customer Service and Informational Expenses	$ -	$ 596	$ -	$ -		-$ 596	-100.00%
5505	Supervision	$ -			$ -		$ -	
5510	Demonstrating and Selling Expense	$ -			$ -		$ -	
5515	Advertising Expenses	$ -			$ -		$ -	
5520	Miscellaneous Sales Expense	$ -			$ -		$ -	
Total - Community Relations		$ 191,769	$ 256,299	$ 258,483	$ 66,714	34.79%	$ 2,184	0.85%
Account	**Description**							
Administrative and General Expenses								
5605	Executive Salaries and Expenses	$ 851,116	$ 1,213,294	$ 1,338,330	$ 487,214	57.24%	$ 125,036	10.31%
5610	Management Salaries and Expenses	$ 184,825	$ 74,042	$ 85,356	-$ 99,469	-53.82%	$ 11,314	15.28%
5615	General Administrative Salaries and Expenses	$ 1,515,325	$ 1,352,575	$ 1,591,130	$ 75,805	5.00%	$ 238,555	17.64%
5620	Office Supplies and Expenses	$ 2,529	$ 5,269	$ 4,569	$ 2,040	80.67%	-$ 700	-13.29%
5625	Administrative Expense Transferred - Credit	-$ 543,487			$ 543,487	-100.00%	$ -	
5630	Outside Services Employed	$ 157,994	$ 281,162	$ 389,845	$ 231,851	146.75%	$ 108,683	38.65%
5635	Property Insurance	$ 146,853	$ 127,829	$ 148,023	$ 1,170	0.80%	$ 20,194	15.80%

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Appendix 2-H
OM&A Detailed Variance Analysis
(excluding Depreciation and Amortization)

Account	Description	Last Board-approved Rebasing Year (2009 Year)	Most Current Actuals Year 2011	Test Year 2013	Test Year Versus Last Rebasing		Test Year Versus Most Current Actuals	
					Variance ($)	Percentage	Variance ($)	Percentage
5640	Injuries and Damages	$ -			$ -		$ -	
5645	OMERS Pensions and Benefits	$ 1,756,541	$ 1,707,958	$ 2,075,079	$ 318,538	18.13%	$ 367,121	21.49%
5646	Employee Pensions and OPEB	$ -			$ -		$ -	
5647	Employee Sick Leave	$ -			$ -		$ -	
5650	Franchise Requirements	$ -			$ -		$ -	
5655	Regulatory Expenses	$ 387,047	$ 322,518	$ 374,545	-$ 12,502	-3.23%	$ 52,027	16.13%
5660	General Advertising Expenses	$ 18,569	$ 39,301	$ 7,000	-$ 11,569	-62.30%	-$ 32,301	-82.19%
5665	Miscellaneous General Expenses	$ 640,900	$ 719,664	$ 947,730	$ 306,830	47.87%	$ 228,066	31.69%
5670	Rent	$ -			$ -		$ -	
5672	Lease Payment Charge	$ -			$ -		$ -	
5675	Maintenance of General Plant	$ 91,788	$ 146,944	$ 166,023	$ 74,235	80.88%	$ 19,079	12.98%
5680	Electrical Safety Authority Fees	$ -	$ 714		$ -		-$ 714	-100.00%
5681	Special Purpose Charge Expense	$ -			$ -		$ -	
5685	Independent Electricity System Operator Fees and Penalties	$ -			$ -		$ -	
5695	OM&A Contra Account	$ -			$ -		$ -	
6205	Donations	$ -	$ 30,629		$ -		-$ 30,629	-100.00%
6205	Donations, Sub-account LEAP Funding	$ -			$ -		$ -	
Total - Administrative and General Expenses		$ 5,209,999	$ 6,021,899	$ 7,127,630	$ 1,917,631	36.81%	$ 1,105,731	18.36%
Total OM&A		$ 9,991,419	$ 11,094,087	$ 13,078,828	$ 3,087,409	30.90%	$ 1,984,741	17.89%
Adjustments for non-recoverable items								
5681	Special Purpose Charge Expense				$ -		$ -	
6205	Donations[1]		$ 30,629		$ -		-$ 30,629	-100.00%
					$ -		$ -	
					$ -		$ -	
					$ -		$ -	
Total Recoverable OM&A		$ 9,991,419	$ 11,063,458	$ 13,078,828	$ 3,087,409	30.90%	$ 2,015,370	18.22%

[1] Account 6205 - Donations is generally non-recoverable. However, the sub-account LEAP funding of account 6205 is generally recoverable.

Note:

1. If the applicant is adopting IFRS or an alternate accounting standard as of January 1, 2013 for financial reporting purposes, Column D "Most Current Actual Year" must be provided on CGAAP.
2. If the applicant is adopting IFRS or an alternate accounting standard as of January 1, 2012 for financial reporting purposes, Column D "Most Current Actual Year" must be provided on that standard.

Exhibit 4: Operating Costs

Tab 4 (of 8): Employee Compensation

STAFFING AND COMPENSATION LEVELS

As a provider of a public service, the majority of OM&A incurred by Bluewater Power relates to the people it employs to deliver service to its customers. In fact, of the $13.302M in OM&A claimed for recovery for the 2013 Test year, employee compensation (payroll plus all benefits) represents approximately 75% of the total OM&A claimed for recovery through rates.

This schedule has been provided to explain the trends in employees experienced over the five-year period from 2009 to 2013. Included with this schedule are two attachments. First, Appendix 2-K entitled “Employee Costs” (Exhibit 4, Tab 4, Schedule 1, Attachment 1) contains a summary of Bluewater Power’s employee compliment, as well as compensation and benefit levels. The underlying assumptions and the results of the analysis are presented below. The second attachment is provided for further background to ensure the Board understands the cost pressures faced by the utility in managing its employee compliment and costs; that document, entitled “Human Resources Strategy”, is attached as Exhibit 4, Tab 4, Schedule 1, Attachment 2.

Assumptions Used in Preparing Appendix 2-K - “Employee Costs”

The amounts shown as 2009 Rebasing Approved represent a settlement reached with Intervenors and approved by the Board. This presented two challenges in presenting the Employee Costs under the column for 2009 Approved as follows:

- The settlement reached required a reduction to capital spending in the Test Year, as well as a further 12% reduction to Revenue Requirement. The capital items removed from the Capital Budget in 2013 were specifically identified through the settlement process and the impact on amortization and PILs were flowed through to the Revenue Requirement. However, the further reduction to Revenue Requirement required by the settlement was not specifically addressed through settlement process but was left to the discretion of the utility as a blanket reduction. For the purposes of this analysis, we have assumed that the entire reduction was allocated to OM&A, which represented a 12% reduction; therefore approximately $1M of that reduction was allocated on a pro-rata basis to employee costs.

- Similarly, the FTEs proposed with the 2009 Rebasing Application was 99 (plus students and directors), that employee count of 99 was reduced by 12% to approximately 88 for the purposes of the analysis.
- Finally, with respect to FTEs for students and directors, we note that in the 2009 Rebasing Application (Exhibit 4, Tab 2, Schedule 9, Attachment 1) entitled "Bluewater Power Employee Description" (EB-2008-0221) the schedule did not include a row for Students or Directors. In completing Appendix 2-K, we have included the correct number of directors and students that were included in the costs submitted with the 2009 Rebasing Application, although these amounts were not required to be included in the "Bluewater Power Employee Description" table at that time.

Appendix 2-K presents dollar amounts and FTEs presented on a gross basis to lead to the Total Compensation amount for all years at the conclusion of the table. Shown separately below the Total Compensation line are adjustments to reflect employee costs that are reallocated to capital assets through capitalized labour, or reallocated to non-core distribution accounts, or reallocated to affiliates, or charged directly to billable jobs. Netting off these amounts leads to the Total Compensation Charged to OM&A; this amount matches the employee costs included in the 2013 Rebasing Application for recovery through rates.

The key assumptions made in presenting the information contained in Appendix 2-K are as follows:

- Employee numbers are presented as FTEs in Appendix 2-K, rather than headcounts. This presents a more accurate picture if an employee moves from one department to another, or if staff is added or lost part-way through a given year. For example, if an employee retires and the replacement is hired with a 3 month overlap, that position shows as totaling 1.25 FTEs; if we were to use headcount, that would show as 2 FTEs for that year.

- The annual Cost of Living Allowance (COLA) has been included as a 3% increase as per the Collective Agreement and the COLA of 3% has been assumed for non-union positions in 2012 and 2013.
- Base Pay includes wages and salaries only.
- Benefits include statutory and extended benefits, as well as car allowances and unused vacation payouts or accruals.
- Overtime includes overtime paid to employees.
- Incentive Pay has been included in Appendix 2-K as 90% of the gross amount paid to employees under Bluewater Power's Incentive Pay Program to reflect the fact that 90% of the benefit is claimed to be recovered through rates. This treatment is consistent with the 2009 Rebasing Application where the results measured for determining Incentive Pay were determined to be 90% to the benefit of ratepayers and 10% to the benefit of shareholder benefits. The Incentive Pay Program is discussed in greater detail in the Human Resources Strategy included as Exhibit 4, Tab 4, Schedule 1, Attachment 2.
- We have assumed for 2013 that each employee eligible for progression successfully reaches their next progression as per the Collective Agreement or non-union pay scales.
- Certain benefits are discretionary as they require the employee to agree to pay a percentage of the total cost of the benefit; we have assumed that each employee takes advantage of the maximum available benefit.

Status of Pension Funding

Bluewater Power does not have its own pension plan. Bluewater Power employees are members of the OMERS pension plan whereby employee pension contributions are matched by the corporation each pay period.

Employee Benefit Programs

As required by the Filing Requirements, we have presented a summary of Bluewater Power's employee benefits program in Exhibit 4, Tab 4, Schedule 1, Attachment 3. The summary provided is the same summary presented to new staff. The benefits reflected have remained in place at this level since July 1, 2009 and will continue to the 2013 Test Year and the costs are recorded in Account 5645 "OMERS Pensions and Benefits". For the three years prior to July 1, 2009 the vision benefit was $200 every 24 months rather than $250 every 24 months indicated in the attached summary; otherwise, the benefits have been the same for all Historic Years, the Bridge Year and the 2013 Test Year.

Bluewater Power has benefits for retirees and the level of benefits depend upon the year of hire for an employee. Included with this Schedule are the following attachments:

- Exh. 4, Tab 4, Sch. 1, Att. 4 - Retiree Benefits Summary - Hire Date post January 1, 1990
- Exh. 4, Tab 4, Sch. 1, Att. 5 - Retiree Benefits Summary - Hire Date post January 1, 2006
- Exh. 4, Tab 4, Sch. 1, Att. 6 - Retiree Benefits Summary - Hire Date post January 1, 2012

Two notable changes in benefits for retirees were both introduced to control costs. First, any employee hired after January 1, 2006 will be entitled to early retiree benefits up to age 65 only; whereas employees hired before January 1, 2006 will have the early retirement benefits for life. Second, any employee hired after January 1, 2012 is not eligible for Retirement Life Insurance coverage.

Post-Retirement Benefit Cost Accrual

Bluewater Power uses Dion Durrell to prepare its actuarial valuation report for post-retirement non-pension benefits. An updated report prepared on an IFRS basis was completed in March 2012 using an updated discount rate of 4.5%. This actuarial report update is presented in this Schedule as Exhibit 4, Tab 4, Schedule 1, Attachment 8. This report included IFRS forecasted amounts pertaining to the 2013 test year. The employee future benefit liability forecasted at December 31, 2012 is $9,223,374 and at December 31, 2013 is $9,702,041. The growth in this liability of $478,667 is included with OM&A expenses; more specifically it is included in Account 5645 "OMERS Pensions and Benefits" for the 2013 Test Year.

The amounts from this actuarial report are also used in the 2013 PILs model calculation as described in Exhibit 4, Tab 8, Schedule 3.

The employee benefit obligation expense accruals from 2009 to 2013 are presented in Table 1 below. These amounts are from actuarial reports prepared by Dion Durrell, with the exception to 2012 CGAAP which was based on an estimate by management. Bluewater Power has not included these amounts in Appendix 2-K because they are not broken down by employee category.

Table 1 – Employee Benefit Obligation Expense

CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	IFRS
2009 COS	2009	2010	2011	2012	2013
611,085	340,599	468,843	428,095	407,708	478,667

The 2009 COS amount is after settlement and includes a one-time actuarial correction of $326,806 as described in EB-2008-0221 in Exhibit 4, Tab 2, Schedule 3, page 9 of 21.

Year Over Year Variances in ‘Total Salary and Wages’

The following discussion provides a qualitative analysis of the annual variances above the materiality threshold for each category of employee, as presented in Appendix 2-K. The analysis is presented by employee group (Executive, Management, Non-Union, Union, Contract and Student). Only those variances that are material for a given year are explained. The explanation of the variance will generally relate to one or more of the following factors: Change in FTEs, Cost of Living Increase, and Progression in Pay.

Executive

2010 Actuals versus 2009 Actuals: $107,509 variance

- No change in FTEs
- Cost of living of $29,856
- Progressions of $17,853
- 27th Pay Adjustment of $33,713
- Other – $26,087

2011 Actuals versus 2010 Actuals: $139,694 variance

- Vacancy from 2010 for VP Strategic Planning filled in 2011, with remainder explained by Cost of Living, Progressions and all increases partially offset by 27th Pay Adjustment

Management

2010 Actuals versus 2009 Actuals: $285,294

- 3 New positions created as discussed in Human Resource Strategy, being 2 Line Planning Supervisors & Client Services Supervisor for a total increase of $230,550
- Cost of Living of $16,389
- Progressions of $11,843
- 27th pay adjustment of $27,293
- Other being ($781)

Non-Union

2010 Actuals versus 2009 Actuals: $273,671

- 3 New positions (HR Administrator; Programmer Analyst, Design Technologist) offset by the loss of Operations Administrator for a variance of $157,748
- Cost of living of $45,545
- Progressions of $41,943
- 27th pay adjustment of $31,534
- Other being ($3,099)

2011 Actuals versus 2010 Actuals: $120,852

- Changes in FTEs related to one new position (Energy Services Co-ordinator) and Retirement/Replacement overlaps of $90,613
- Cost of living at $48,854
- Progressions for a variance of $23,541
- 27th pay adjustment of ($36,776)
- Other being ($5,380)

Union

2009 COS versus 2009 Actuals: $103,261

- Cost of living = N/A because built into rate application
- Progressions = N/A because built into rate application
- As noted the 2009 COS is a derived amount based on a 12% reduction from the amount claimed in the application; 2009 Actuals exceed the derived amount by $51,618.
- New FTEs added part year (Junior Clerk, HR Admin, Lineman) contributing $71,559 to the variance
- Other being ($19,916)

2010 Actuals versus 2009 Actuals: $110,606

- FTE reduction of -1.63 (combination of retirements, sick leave & staff moves)
- Cost of living - $86,981
- Progressions - $34,533
- 27th Pay - $89,659
- Staff moves or reductions – ($131,571)
- Other - $31,004

2012 Bridge versus 2011 Actuals: $130,303

- There was a reduction in FTEs of 2.13 (retirements and part-year transfer of water billing representative and one meter reader to affiliate) for a negative variance of ($101,076)
- Cost of living of $88,326
- Progressions of $121,059
- Hiring Credit of $64,000 received from government in 2011 as incentive for new hires
- Other being ($42,006)

2013 Test versus 2012 Bridge: $377,363

- 4 new positions included for 2013 (1 lineman and 3 positions to accommodate monthly billing) for an increase of $212,862.
- Cost of living of $96,912
- Progressions of $92,444
- Other being ($24,855)

Contract

2009 COS versus 2009 Actuals: $123,073

- In an effort to control costs and ensure flexibility in the workforce, new positions originally included in the 2009 COS Application were hired under contract. This created an increase of 2.41 FTEs in contract positions (being part years for Power Specialist, Financial Administrator, Junior/Mailroom Clerks, Meter Reader) for a variance of $121,653
- Other being $1420

2010 Actuals versus 2009 Actuals: $122,106

- A further increase of 2.92 FTEs reflecting the full year of contracts added in 2009 representing an increase in cost of $92,948
- Cost of living of $3,883
- Progressions of $13,756
- Other being $11,519

Year Over Year Variances in 'Current Benefits' from Appendix 2-K

Benefits are a function of the level of salary and wages, so the primary explanation for the variance in the benefits lies with the variance in salary and wages discussed above. The other factor affecting benefit costs lies in the benefit rates and there is further guidance on this issue in the Human Resources Strategy found at Exhibit 4, Tab 4, Schedule 1, Attachment 2. The material variances in 'current benefits' identified in Appendix 2-K are found in the Union categories and the explanations are provided below.

Union

2013 Test versus 2012 Bridge: $138,685

- 3 new FTEs related to the move from Bi-monthly to Monthly Billing, as well as Lineman position added to benefits in 2013 for an increase of $66,224
- OMERS increased over 2012 levels by $37,889
- Extended Benefit increased over 2012 by $28,618
- Other being $5,954

Year Over Year Variances in 'Overtime' from Appendix 2-K

The majority of overtime in Bluewater Power is from the Operations group of employees. Overtime can be due to planned capital work during off hours, planned or unplanned billable work for such things as movement of a pole line or plant damage from a car accident, or repairs to plant due to an outage. The most significant variances from year to year are found in the Union category and explanations are provided below.

Union

2010 Actuals versus 2009 Actuals: $127,101

- SAP upgrade in 2010 increased OT in Billing & Call Centre to $127,686 compared to $8,064 in 2009 for an increase of $119,621
- Control Room OT increased by $14,500 over 2009 levels due to workload

2012 Bridge versus 2011 Actuals: ($181,314)

- Line Department OT budgeted in 2012 represents a decrease over 2011 Actuals by ($129,643)
- Billing & Call Centre OT budgeted in 2012 represents a decrease over 2011 Actuals by ($25,668)
- Metering, Control Room & Other departments OT budgeted in 2012 represents a decrease over 2011 Actuals by ($30,233)

Year Over Year Variances in 'Incentive Pay' from Appendix 2-K

There are no significant year over year variances for Incentive Pay identified in Appendix 2-K. For further discussion on Bluewater Power's incentive program see the Human Resources Strategy found as Exhibit 4, Tab 4, Schedule 1, Attachment 2.

File Number:	EB-2012-0107
Exhibit:	4
Tab:	4
Schedule:	1
Attachment	1
Date:	22-Oct-2012

Appendix 2-K
Employee Costs

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	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	50.16	52.97	51.34	53.13	51.00	56.17
Contract	0.88	3.29	6.21	6.58	3.92	2.00
Students = FTE	3.67	5.67	5.44	6.33	5.67	5.33
Total	97.67	105.26	111.32	116.54	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	$ 2,955,758	$ 3,059,019	$ 3,169,625	$ 3,128,275	$ 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	$ 6,134,264	$ 6,360,379	$ 7,288,565	$ 7,507,451	$ 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	$ 705,309	$ 797,603	$ 755,036	$ 832,345	$ 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	$ 1,599,772	$ 1,815,601	$ 1,948,688	$ 2,236,753	$ 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	$ 705,309	$ 797,603	$ 755,036	$ 832,345	$ 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	$ 1,599,772	$ 1,815,601	$ 1,948,688	$ 2,236,753	$ 2,268,919	$ 2,563,763

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	$	3,661,068	$	3,856,622	$	3,924,660	$	3,960,620	$	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	$	7,734,037	$	8,175,979	$	9,237,253	$	9,744,204	$	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	**$**	**58,927**	**$**	**57,750**	**$**	**61,744**	**$**	**58,885**	**$**	**63,894**	**$**	**64,735**
Contract	**$**	**26,580**	**$**	**44,495**	**$**	**43,260**	**$**	**39,663**	**$**	**47,078**	**$**	**68,296**
Students	**$**	**36,018**	**$**	**19,541**	**$**	**24,857**	**$**	**19,863**	**$**	**30,827**	**$**	**40,917**
Total	**$**	**404,656**	**$**	**404,993**	**$**	**438,206**	**$**	**431,326**	**$**	**469,898**	**$**	**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	$	427,119	$	554,220	$	476,814	$	295,500	$	280,000
Contract	$	-	$	1,079	$	2,118	$	2,060	$	1,500	$	-
Students	$	-	$	367	$	1,677	$	17	$	-	$	-
Total	$	443,448	$	461,208	$	617,775	$	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	$	50,597	$	33,118	$	39,730	$	38,379	$	37,147	$	45,899
Total	$	246,865	$	225,403	$	226,017	$	293,614	$	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	$	14,061	$	15,058	$	14,708	$	15,668	$	17,564	$	18,417
Contract	$	11,364	$	3,921	$	3,684	$	3,746	$	1,415	$	4,660
Students	$	2,727	$	1,873	$	2,352	$	1,889	$	2,013	$	4,278
Retirees	$	-	$	-	$	-	$	-	$	-	$	-
Total	$	89,432	$	92,823	$	94,859	$	104,208	$	101,290	$	118,587
Total Compensation	$	7,358,580	$	8,175,979	$	9,237,253	$	9,744,204	$	10,070,074	$	10,862,089
Total Compensation Charged to OM&A	$	-	$	6,621,747	$	7,200,337	$	7,703,615	$	7,758,975	$	8,866,752
Total Compensation Affiliates	$	-	$	472,529	$	544,926	$	502,145.00	$	448,106.00	$	482,499.00
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.

Bluewater Power's Human Resources Strategy

One of Bluewater Power's most valuable assets is our employees. It is critical that we have the right people, in the right jobs, with the right skills and abilities, with a true sense of personal value and a commitment to providing high quality service to our customers.

Our Workforce and Succession Planning encompass a substantial part of both our corporate planning and our annual budgeting processes. This HR Strategy has been developed to help increase the effectiveness, efficiency, preparedness, and overall success of our organization.

The first part of this document entitled "Maintaining our Workforce" discusses the challenges that we face as an electrical utility in Ontario working to maintain a skilled and trained workforce. This strategy discusses the efforts we have undertaken to-date in response to those challenges and the issues we will continue to address going forward.

The second part of this document entitled "Maintaining our Costs" discusses the challenges that we face to manage the costs of our workforce. The discussion focuses on both compensation paid to employees and the management of our benefits program.

1.0 Maintaining our Workforce

Bluewater Power faces two significant challenges to maintaining an adequate workforce with the right skills and abilities. The first challenge relates to the age of our workforce; the average age of our workforce is 44 years and retention of these workers will become an important strategy in order to avoid a loss of skills, experience, and corporate knowledge. It will also be key to avoiding labour shortages. The second challenge relates to the ever-changing demands in the Ontario Electricity Sector which creates the need for departments to re-tool their staff to meet the challenges of new requirements. The challenges facing departments like Regulatory, Customer Service, Engineering, and Information Technology are discussed separately below.

1.1 Aging Workforce

The current average age of our workforce is 44 years. The graph below indicates that 72% of our staff is over the age of 40. Our trades represent 30% of our current workforce and, within the trades group; the percentage of staff over the age of 40 is 63%.

Figure 1: All Employees by Age Group

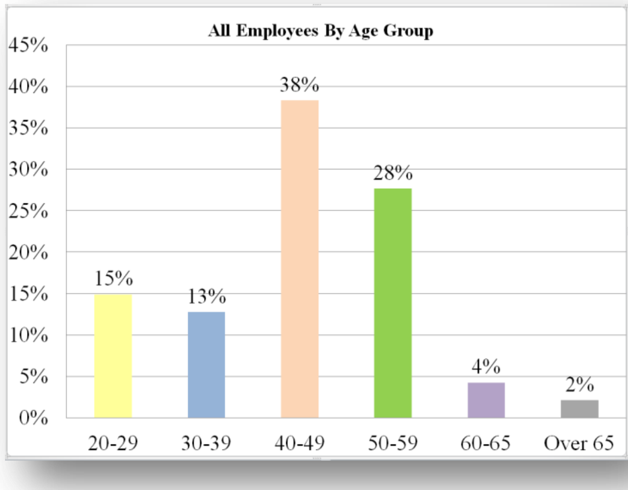
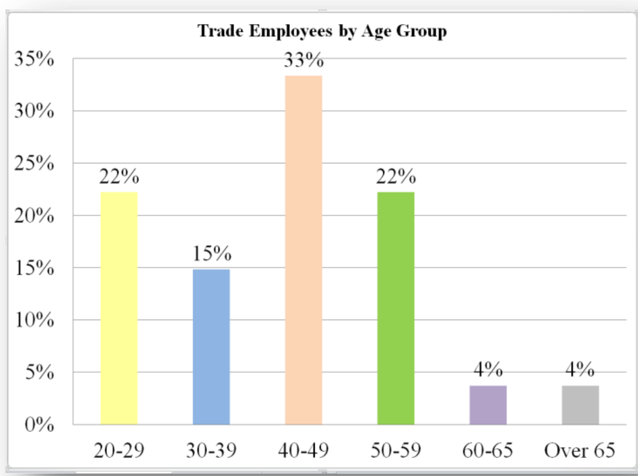


Figure 2: Trades Employees by Age Group



Bluewater Power continues to experience an increase in the number of employees electing to retire from the corporation, either at the age of 55 with a reduced pension or at their earliest unreduced eligibility date.

Since the year 2003 we have had 17 retirements or almost 20% of our workforce. The average age of retirees over the last 10 years has been 58 years of age, but in the interest of being conservative the analysis below reflects likely retirements assuming a retirement age of 55.

In 2011 we experienced 6 retirements, representing 6.2% of our workforce. We expect to see this number increase significantly in the near future as we have a number of “baby boomers” approaching retirement eligibility levels. Table 1 below illustrates the number of eligible retirements for all employees for the next ten years. The table demonstrates that approximately 50% of all employees are eligible to retire in the next ten years.

Table 1: Eligible Retirements for All Employees

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total
18	2	4	3	5	3	2	5	3	4	49

Bluewater Power needs to continue to recruit and retain a skilled, knowledgeable workforce. As the number of retirements continues to grow over the next decade, Bluewater Power’s ability to deliver on its core business must be addressed through workforce planning to ensure sufficient skilled and trained resources are in place to meet those demands.

Additional attrition factors including resignations and internal promotions of existing employees to supervisory and management levels to backfill retirements will also contribute to a potential labour and knowledge shortage.

Trades Staff

The Trades Staff consists of the following positions: Linepersons, Meter Technicians, and Operators. Table 2 below illustrates the number of eligible retirements for the Trades Staff for the next ten years.

Table 2: Eligible Retirements for Trades Staff

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total
3	0	1	1	2	0	0	4	1	0	12

Of the 49 employees eligible to retire over the next ten year period, 12 are trades employees. This represents 24% of the employees eligible to retire. Bluewater Power has recognized that the trades and the technical workforce require a four-year time period in which to become proficient and certified journeymen. Accordingly, we have invested in the apprenticeship program to deal with pending trades staff retirements.

Bluewater Power has partnered with the Powerline Technician programs at Cambrian College, Conestoga College and St. Clair College. Over the last 5 years, we have recruited from, and participated in, 12 cooperative work terms involving 10 different students (each for a 4 month term). To date, we have permanently hired 6 apprentices from these programs.

Bluewater Power will continue to recruit and hire apprentices as appropriate. Apprentices will be considered a preferred replacement option for vacancies created through attrition due to resignations and retirements, or new hires required to handle increased work load as dictated by the demands of the Asset Management Plan for the distribution system.

Management

The Management group consists of executives, directors, managers and supervisors.

Table 3 below illustrates the number of eligible retirements for the management group of employees for the next ten years.

Table 3: Eligible Retirements for Management Employees

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total
1	0	0	0	3	1	1	1	1	2	**10**

Of the 49 employees that are eligible to retire over the next ten year period, 10 of these are Management employees. This represents 20% of the staff eligible to retire over the next decade, which reflects the relatively lower age of the management group. Proper succession planning in this area has created a stable and smooth work force in the Management area.

Non-Union Positions

The Non-Union group consists of Engineering, Finance, Human Resources, Information Technology, Regulatory and Administration staff.

Table 4 below illustrates the number of eligible retirements for the Non-Union group of employees for the next ten years.

Table 4: Eligible Retirements for Non-Union Employees

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total
6	2	2	0	0	1	1	0	1	2	15

Of the 49 employees eligible to retire over the next ten year period, 15 of these are Non-Union positions. This represents 31% of staff eligible to retire. The Non-Union group may be affected by the transition of certain employees into Management positions, so the priority will be to ensure proper training and skill sets to take on potential new responsibilities.

Union Positions

The unionized workforce is represented by the International Brotherhood of Electrical Workers ("IBEW") Local 1802. They represent both the tradespersons and customer service staff, sometimes referred to as the "outside" and "inside" staff.

Table 5 below illustrates the number of eligible retirements for the union group of employees for the next ten years.

Table 5: Eligible Retirements for Union Employees

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total
11	0	1	3	2	1	0	4	1	0	23

Of the 49 employees eligible to retire over the next ten year period, 23 of these are Union positions. This represents 47% of the Staff eligible to retire over the next decade. This group of employees represents the most significant challenge from a succession planning perspective. To assist with this, we encourage our staff to take on-line courses or night courses to enhance their knowledge and education. We offer a benefit of 1% of their annual salary toward courses since we do strive to promote from within the company. This has been a successful practice in the past and we will continue to promote from within, in the future.

1.2 Demands on Our Workforce

Not only do we have to be cognizant of current demands on our staff, but we need to ensure that we are on top of upcoming and future demands on our workforce. The following sections focus on five key areas and the demands that they face:

a) Demands on Management

Utilities in Ontario are managing with major changes driven by regulatory change, the Green Energy Act and demands on Infrastructure. These new demands require leadership. Bluewater Power required additional staff in order to strengthen the capacity in key support areas to meet the corporation's business objectives and priorities, support the operations of the business and customer service, and ensure compliance and sustainability as it relates to the requirements of the corporation. Table 6 lists the resulting new positions in 2010 and 2011. No further positions are required for the years 2012 or 2013.

Table 6: Strengthening Key Support Functions

2010 Positions	2011 Positions
2 Line Supervisors	*VP, Strategic Planning (Moved back to BWP)
1 Client Service Supervisor	**Executive Assistant to VP
1 IT Programmer (replacement)	
1 Design Technician	

*Budgeted for a replacement but was not filled until 2011

**Moved back from our Affiliate Company Bluewater Power Generation Corporation.

b) Demands of Aging Infrastructure

Bluewater Power's electrical infrastructure has an estimated age between 30 and 40 years. Our 5 year capital plan assists us to ensure that our longer term plans are adequately captured.

For the system to be maintained and replaced as necessary we have to ensure that we have the availability of a skilled and capable workforce. Line crew size and succession planning are key factors to addressing the demands of our aging distribution system. Our plan is to anticipate turnover and hire apprentices to meet needs not only at the time of retirement, but rather, 1 to 2 years prior to ensure there is a beneficial knowledge transfer.

c) Demands of Customer Service

The nature of Bluewater Power's relationship with our customers is evolving. Customers demand and deserve timely and accurate responses to their inquiries, despite the increasing complexity of our sector. We have to ensure our staff is well versed in our industry and trained to manage our customers to ensure they are receiving the correct and most current, up-to-date information. The customer service department functions in a pressure filled environment as customers demand accurate responses in a limited amount of time. Electric utilities are mandated by the Ontario Energy Board to monitor and report performance indicators such as the percentage of calls answered within 30 seconds of presentation. Customer service representatives must be able to respond to customer inquiries with excellent customer service while keeping in mind that the call must be expedited as quickly as possible.

Customer demand for alternative methods of inquiry such as email access or online access has increased significantly in the last 5 years. Bluewater Power has initiated an online presence where customers can access limited information about their utility account. This change itself resulted in increased call volumes as customers new to the website require assistance in navigating through the website. As well, as the electricity industry has become very complex, customer service representatives must stay apprised of all of the various charges used in the calculation of bills.

Additionally, there has been a significant increase in the number of calls that are at an elevated level as customers deal with rising costs and the complicated nature of our industry.

d) Demands of Technological Advancements

Technological advances and adoption in the electricity industry in Ontario is growing at an exponential rate. Yet these changes, primarily driven by regulation, innovation and customer petition, are relatively recent in the utility industry and now extend to all levels of the organization. As a result, Bluewater Power requires a workforce that is both knowledgeable and skilled as it pertains to the on-going changes in the use of technology.

This presents a challenge for Bluewater Power. We must foster an environment of continuous learning for existing employees and have in place mechanisms to attract new employees who are technically savvy and have the propensity and aspiration to continue to advance.

The demands of technology on business functions no longer remain isolated to traditional skilled positions. Rather, transformation flows throughout the organization. Whether it's with the Lines and Field crews who are new 'mobile' workers maintaining a smarter grid, smart meters and the underpinning wireless networks, Billing staff who handle complex meter reading and time-of-use billing via integrated systems, or Customer Service Representatives who interact with customers facing complex regulatory change through various technical and social media avenues, technology is now pervasive within all roles throughout the organization.

The traditional method of rolling out new systems and processes and then training employees to adapt no longer works given the fast pace of technological change. Rather, it's critical that Bluewater Power ensure it has in place the specialized workforce to support and drive these technological advancements. IT staff that implement and support these technologies must have both deep technical expertise in specific systems and broad technical knowledge in the vast number of requisite solutions.

e) Demands of Policy and Regulatory Changes

The electricity sector in Ontario faces new challenges from changes in government policy and the regulatory framework in which we operate. The last decade in Ontario's Electricity Sector has seen consistent change each year. Beginning in 2002 with market opening, followed by the introduction to Ontario LDCs of full Cost of Service applications and three different generations of IRM, as well as increasing reporting requirements to the OEB. In the last 5 years, the most significant demands on resources from a policy and regulatory perspective have been:

- C&DM targets imposed on LDCs as a condition of their licences.

- The deployment of Smart Meters was the single biggest capital project that Bluewater Power has seen in its history and in the 90 year history of its predecessor companies. It placed, and continues to place, significant demands on resources.
- The *Green Energy and Green Economy Act* challenged resources from a regulatory and an engineering perspective as we responded to new rules, new obligations and technical/operational challenges that were new to LDCs in Ontario. The burden was significant for Bluewater Power as our utility was the leading edge of change as we worked to host what is now the world's largest operating solar farm.
- The Renewed Regulatory Framework for Electricity represents an opportunity to improve upon the regulatory process, but the dialogue itself represents a challenge as we work through redesign and implementation.

Regulatory change is common in many industries, but the magnitude of the change and the sheer number of new initiatives has placed Ontario's LDCs in a genuinely unique position. Bluewater Power has responded to this change without adding new staff in the Regulatory Department, although staff have been reassigned to initiatives from time-to-time as we respond through a teamwork approach. This has meant that regulatory change has impacted not only the regulatory department, but also engineering, customer service and IT.

2.0 Maintaining our Costs

There are ever increasing pressures on costs in Ontario's distribution sector. As a service provider, approximately 75% of our costs relate to the employees who deliver that service. Accordingly, the task of managing compensation and benefits presents a significant challenge. That challenge is heightened by the current skilled labour shortage, in the areas of our fully qualified Linepersons and our ability to both attract and retain appropriate staff. Bluewater has experienced the loss of an Engineer and Lineman to the private sector, our recent effort to require a Vice President of Operations took almost a year, and we have been attempting unsuccessfully to recruit a fully qualified lineperson since 2011.

This section of the Human Resources strategy will discuss the efforts by Bluewater Power to balance those demands with the need to manage both Wages and Employee Benefits.

2.1 Wages and Salaries

Compensation increases arise from annual increases in base pay for existing staff that are not at the top of their respective ranges, as well as cost of living increases negotiated with IBEW Local 1802 and non-union staff. Any increase in pay contributes to an increase in the cost for benefit programs that must be monitored and managed. New FTEs are driven by succession planning, as discussed above, but also driven by the need to manage overtime. Overtime relates to both the capital needs for the distribution system (poles, wires and substations) and customer service infrastructure (IT and Smart Meters, for example), as well as demands due to power outages, weather and customer service issues.

The sections that follows speaks to two programs that Bluewater Power utilizes to achieve fair compensation of its employees sufficient to retain skilled personnel. First, the section on Annual increases to base pay discusses the Collective Agreement with unionized employees and the Hay evaluation process designed to measure non-union compensation. The second discussion introduces Bluewater Power's Incentive Compensation program intended to ensure that the corporation and the individual achieve their performance targets.

Annual Increases to Base Pay

As of April 1, 2009, a new five-year collective agreement was reached with the IBEW Local 1802. The Collective Agreement resulted in a 3% annual increase in unionized wages for 2009 through to 2013. Our Collective Agreement will expire on March 31, 2014. These percentages are consistent with increases negotiated within the industry at the time.

Increases for Non-Union employees are comparable to the increase for unionized staff. In managing compensation for Executive employees, every year we participate in The Hay Group Salary Survey. Our participation entitles us to the Hay Group Canada's compensation database, which holds information for more than 250,000 incumbents from over 500 organizations. 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. In 2011 it was determined by Management not to utilize this information every year, but every other year instead. For 2012 we assumed a cost of living increase only and will complete another Compensation Report for our Board of Directors at the end of 2012 for the 2013 wages.

Bluewater Power salaries for executive and management in 2010 are consistent with the average (see definition below) for comparable industries. The 2013 Budget has been prepared assuming a 3% increase over 2012 levels for all employees, including executive and management, as well as an allocation for progression increases across the executive and management of approximately $50,000 in total. Therefore, salaries for executive and management in 2013 are expected to remain in-line with industry averages.

Bluewater Power's compensation for executive and management is determined by the Compensation Committee of the Board of Directors. The committee relies upon data presented from the Hay Group. The Hay Group is a consulting firm well recognized as a leader in the area of compensation.

The Compensation Committee looks at each position's actual salary compared to Base Salary for comparable positions within two relevant categories within the Hay Group's data base – "Industrial Organizations with Revenue <$125M" and "Utilities with Revenue <$1B". In making that comparison, actual salaries in 2010 were compared to base salaries using the Hay point system. It is important to note that we are not comparing titles with these organizations but rather Hay points. As such, the CEO of Bluewater Power is not compared to the CEO of these organizations, but rather compared to a role within these organizations with the same range of points. Base Salary under the Hay Group system is the mid-range of that salary grid for a given position. Therefore, the conclusions reached by this method of comparison are conservative because Bluewater Power's actual compensation is compared to the mid-range for the comparable positions.

The analysis is shown in Attachment 1 entitled "Compensation Report", which is an excerpt from the report of the Vice President of Human Resources to the Compensation Committee in December of 2010. The report demonstrates the following:

- When compared to Industrial Organizations, two of the ten positions considered by the Compensation Committee do not meet the average compensation when compared to the Utilities, four of the ten positions do not meet the average compensation.
- Incentives for the Industrial Organizations, all positions are below the average and approximately half of the positions are below Utilities average.
- Total Compensation (salary plus incentive) four of the ten positions do not meet the average for Industrial Organizations.
- Total Compensation (salary plus incentive) three of the ten positions do not meet the average for Utilities, with the remainder of positions exceeding average by less than 7%.

Also provided in the Attachment are the Hay Group analyses based on comparing the Base Salary for each position at Bluewater Power with the 50th percentile of Base Salaries for comparable positions.

Attachments 2 and 3 have been produced using data collected and presented by the Hay Group. The attachment labelled ‘Base Salary Policy’ displays Base Salaries for the executive members of Bluewater Power’s team compared to two relevant categories within the Hay Group’s data base – “Industrial Organizations with Revenue <$125M” and “Utilities with Revenue <$1B”. The data has been presented in a modified format; the actual salary information for each position has been removed to protect private information. What remains is as follows:

- **Job Title:** Ten positions ranging from Manager to President are considered by the Compensation Committee
- **Total Points:** In the Hay Group system, positions are ranked utilizing a comprehensive process that results in points designed to represent level of knowledge required (technical/practical knowledge; managerial skills required; human relation skills required), problem solving, accountability and working conditions
- **Base Salary:** this information has been removed, but would ordinarily show current salary
- **Percentile Benchmarks:** The data would ordinarily show the benchmark base salary for each of the listed percentiles for the given industrial category; this information has also been removed as it is proprietary in nature
- **Variance from P50:** this column shows the percentage variance of the base salary from the 50th percentile of the industrial category
- **Market Position:** this column shows the position that base salary scores for the industrial category expressed as a percentile

The analysis shows that comparing Base Salaries to the 50th percentile of Base Salaries, the compensation for our executive and management falls well below the 50th percentile. In fact, the market position for our Base Salaries actually falls between the 15th and 48th percentiles.

The attachment labelled ‘Supplementary Table, Market Actual and Target Incentive Pay’, is the Hay Group evaluation of Bluewater Power’s Incentive Pay. Bluewater Power’s compensation structure also includes an incentive program designed to incent superior performance in the four key areas of spending, reliability/service, financial results and safety. The Hay Group analysis attached shows that “target” and “actual” bonuses for Bluewater Power are 11% to 158% less than the average for “Industrial Organizations with Revenue<$125M” category. The Hay Group analysis attached also shows that the incentives are less than the target and actual averages for “Utilities with Revenue <$1B” category, with the exception of four positions.

Incentive Pay

The incentive program applies to union and non-union employees alike and will continue in 2013. The incentive plan is based on the following corporate performance indicators:

1. Spending Performance
2. Reliability & Service Performance
3. Financial Performance
4. Safety Performance

Bluewater Power Distribution Corporation must meet all four levels of corporate performance on an annual basis in order for employees to qualify for 100% incentive compensation payments for that period. If Bluewater Power does not meet one or more of the above Corporate performance indicators, payment will be based on the number of indicators met. For example, if only two of the four indicators are met, payment will be at 50%. Each of the Performance indicators are weighed at 25%. Once the criteria are met corporate-wide, then individual payouts depend upon the level of achievement of each employee in their annual performance appraisal. Since inception of the Incentive Compensation Program in 2005, Bluewater Power has been successful in meeting these 4 performance indicators.

2.2 Benefit Costs

Benefit coverage for all employees includes coverage for prescription drugs, hospital, vision, dental care, paramedical services, hearing aids, employee assistance counselling and services, long term disability insurance (LTD), life insurance and accidental death and dismemberment insurance.

Bluewater Power has successfully managed benefit costs with its carriers, and increases have been lower than the industry trend. Our Benefit Consultants, The Williamson Group, have assisted in the management of our portfolio for over 11 years and were selected to continue as our consultants following a Request for Quotation in 2008.

Bluewater Power has successfully managed certain aspects of its benefits program through our efforts with Wellness Programs and our Early and Safe Return to Work Programs. These concerted and diligent efforts have assisted to control cost increases in Prescription Drugs, Hospital coverage, and Paramedical Services. Table 7 indicates our efforts in managing these benefits.

Table 7: Extended Health Care Coverage

Benefits	2010	2011	2012	2013 Projection
Extended Health Care Only	10.1%	-1.0%	-9.5%	-8.0%

Bluewater Power also provides retirees life, health and dental benefits. Two notable changes in benefits for retirees were both introduced to control costs. First, any employee hired after January 1, 2006 will be entitled to early retiree benefits up to age 65 only; whereas employees hired before January 1, 2006 will have the early retirement benefits for life. Second, any employee hired after January 1, 2012 is not eligible for Retirement Life Insurance coverage.

Pension Costs

Bluewater Power’s participation in OMERS is mandatory based on provincial legislation. Pension contributions have increased since the global economic downturn in 2008. We have been experiencing increases since 2010 which continue until 2013.

Table 8: Pension Contribution Rates for Members with a Normal Retirement age of 65

	2008	2009	2010	2011	2012	2013
Up to CPP earnings limit	6.5%	6.3%	6.4%	7.4%	8.3%	9.0%
Above CPP earnings limit	9.7%	9.5%	9.7%	10.7%	12.8%	14.6%

Actuarial Estimates of Employee Future Benefit Obligations

Bluewater Power uses an actuary to determine the cost of these benefits and as well measures the plans obligation. The last full Actuarial Valuation was completed in 2011. These are normally completed every 3 years and will not be completed again until 2014. In recent years we have completed extrapolations annually, to ensure we are capturing all our changes with our workforce.

Summary

Our Human Resource Strategy

Bluewater Power has planned and continues to plan for our future needs of ensuring we have a supply of skilled, prepared and knowledgeable workers. We will continue to take a proactive approach to succession planning and management. We will continue to encourage our staff to take on-line course and night courses so we can continue to promote within to ensure we have the right staff at the right time with the right skill set.

In response to the ever changing environment and to ensure that Bluewater Power has a sustainable, skilled, well prepared, and knowledgeable workforce, Bluewater Power has developed a human resource strategy to sustain current corporation effectiveness and address emerging requirements.

Bluewater Power’s Human Resources Strategy documents the management of those efforts to respond to change and ensure that the appropriate resources are in place to meet the long-term needs of the business and its customers.

COMPENSATION REPORT

of the

VICE PRESIDENT
of
HUMAN RESOURCES

HAY SURVEY

Hay Data

Hay information includes Industrial Organizations. This information is broken down into six percentiles:

- 90th Percentile
- **75th Percentile**
- **Average**
- 50th Percentile
- **25th Percentile**
- 10th Percentile

For comparison purposes, only variances from the **75th Percentile, Average** and **25th Percentile** are used.

Analysis:

Once again for 2010, there are only two positions below the average for Industrial Organizations (CEO and VP, Human Resources). All other positions are above the average.

When analyzing Total Compensation for the Industrial Sector, four positions fall below the average (CEO; VP, Corp Service; VP, HR and Manager, Design Services). All other positions are above.

Comparison to Industrial Organizations

Base Salary

Bluewater Power Benchmark Job Title	Current Salary	Industrial Organizations Base Salaries						Variance from P75	Variance from AVG	Variance from P25
		P90	P75	AVG	P50	P25	P10			
President & Chief Executive Officer								-27.3%	-10.0%	7.0%
VP, Corporate Services & General Counsel								-8.5%	0.7%	14.2%
VP, Operations & COO								-5.1%	6.1%	17.7%
VP, Strategic Planning								-10.2%	1.5%	13.7%
VP, Human Resources								-16.2%	-3.3%	9.2%
Chief Financial Officer								2.3%	12.0%	23.4%
Director, Information Technology								-3.0%	7.5%	19.6%
Director, Client Services								-1.8%	7.6%	19.1%
Manager, Design Services								-6.8%	3.0%	15.1%
Manager, Meter Services								4.6%	13.7%	23.8%

Data Information as of: **May 1, 2010**

Comparison to Utilities

Base Salary

Bluewater Power Benchmark Job Title	Base Salary Policy	Utilities Base Salaries						Variance from P75	Variance from AVG	Variance from P25
		P90	P75	AVG	P50	P25	P10			
President & Chief Executive Officer		*					*	-21.1%	-8.8%	0.8%
VP, Corporate Services & General Counsel		*					*	-7.7%	-0.4%	8.4%
VP, Operations & COO		*					*	2.4%	5.7%	14.7%
VP, Strategic Planning		*					*	-2.4%	1.1%	10.6%
VP, Human Resources		*					*	-6.9%	-3.8%	6.4%
Chief Financial Officer		*					*	1.3%	7.3%	18.4%
Director, Information Technology		*					*	-4.6%	2.5%	14.5%
Director, Client Services		*					*	-0.6%	3.0%	13.5%
Manager, Design Services		*					*	-5.6%	-1.7%	9.2%
Manager, Meter Services		*					*	0.9%	5.3%	14.6%

** Denotes insufficient data*

Data Information as of: **May 1, 2010**

Comparison to Industrial & Utilities Organizations
Incentives

		Average of Industrial Organizations				Average of Utilities Organizations			
Bluewater Power Benchmark Job Title	Target	Actual Incentive	% Difference	Target Incentive	% Difference	Actual Incentive	% Difference	Target Incentive	% Difference
President & Chief Executive Officer			-51.5%		-69.5%		-78.0%		-36.0%
VP, Corporate Services & General Counsel			-20.0%		-30.9%		4.6%		14.3%
VP, Operations & COO			-11.3%		-26.0%		0.7%		9.3%
VP, Strategic Planning			-11.3%		-26.0%		0.7%		9.3%
VP, Human Resources			-57.0%		-81.0%		-43.0%		-32.0%
Chief Financial Officer			-77.3%		-112.0%		-20.0%		-20.0%
Director, Information Technology			-84.0%		-118.7%		-30.7%		-26.7%
Director, Client Services			-61.3%		-96.0%		2.7%		-4.0%
Manager, Design Services			-142.0%		-194.0%		-46.0%		-56.0%
Manager, Meter Services			-86.0%		-158.0%		-12.0%		-20.0%

Data Information as of: **May 1, 2010**

Comparison to Industrial Organizations
Total Compensation

		Industrial Organizations Total Compensation								
Bluewater Power Benchmark Job Title	**Total Compensation**	**P90**	**P75**	**AVG**	**P50**	**P25**	**P10**	**Variance from P75**	**Variance from AVG**	**Variance from P25**
President & Chief Executive Officer								-38.2%	-19.4%	-1.0%
VP, Corporate Services & General Counsel								-11.7%	-2.3%	11.6%
VP, Operations & COO								-6.7%	4.7%	16.5%
VP, Strategic Planning								-11.9%	0.1%	12.4%
VP, Human Resources								-22.2%	-8.7%	4.5%
Chief Financial Officer								-5.9%	5.0%	17.4%
Director,Information Technology								-6.1%	4.5%	16.9%
Director, Client Services								-6.2%	3.6%	15.7%
Manager, Design Services								-11.4%	-1.1%	11.5%
Manager, Meter Services								3.0%	12.3%	22.5%

Data Information as of: **May 1, 2010**

Comparison to Utilities
Total Compensation

Bluewater Power Benchmark Job Title	Total Compensation	Utilities Total Compensation						Variance from P75	Variance from AVG	Variance from P25
		P90	P75	AVG	P50	P25	P10			
President & Chief Executive Officer		*					*	-36.9%	-22.9%	-12.1%
VP,Corporate Services & General Counsel		*					*	-7.0%	0.3%	9.0%
VP, Operations & COO		*					*	2.5%	5.8%	14.8%
VP, Strategic Planning		*					*	-2.3%	1.2%	10.7%
VP, Human Resources		*					*	-11.1%	-7.9%	2.7%
Chief Financial Officer		*					*	-3.8%	3.3%	15.2%
Director, Information Technology		*					*	-3.1%	3.2%	14.8%
Director, Client Services		*					*	-0.4%	3.2%	13.6%
Manager, Design Services		*					*	-5.4%	-1.5%	9.4%
Manager, Meter Services		*					*	2.7%	7.0%	16.1%

** Denotes insufficient data*

Data Information as of: **May 1, 2010**

Comparison to Market Using Bluewater Power Base Salary Policy
Base Salary Policy

May 1, 2010

			Industrial Organizations with Revenue < $125MM							
Bluewater Power Benchmark Job Title	Total Points	Base Salary Policy	P90	P75	AVG	P50	P25	P10	Variance from P50	Market Position
President & Chief Executive Officer	1566								-24.1%	P17
Vice-President Corporate Services & Gen	954								-14.2%	P21
Chief Operating Officer	830								-12.3%	P20
VP Operations & COO	830								-8.0%	P28
Vice-President Human Resources	800								-16.1%	P15
Director - Information Technology	677								-6.6%	P33
Controller	657								-2.0%	P45
Manager - Design Services	611								-11.5%	P23
Director - Client Services	611								-7.1%	P32
Manager - Meter Services	432								-0.7%	P48

*Note: * indicates data insufficient to report*

Comparison to Market Using Bluewater Power Base Salary Policy
Base Salary Policy

May 1, 2010

			Utilities Organizations with Revenue < $1B							
Bluewater Power Benchmark Job Title	Total Points	Base Salary Policy	P90	P75	AVG	P50	P25	P10	Variance from P50	Market Position
President & Chief Executive Officer	1566		*					*	-24.9%	<P25
Vice-President Corporate Services & Gen	954		*					*	-11.9%	<P25
Chief Operating Officer	830		*					*	-14.0%	<P25
VP Operations & COO	830		*					*	-9.8%	<P25
Vice-President Human Resources	800		*					*	-18.7%	<P25
Director - Information Technology	677		*					*	-11.5%	<P25
Controller	657		*					*	-7.0%	P30
Manager - Design Services	611		*					*	-15.6%	<P25
Director - Client Services	611		*					*	-11.5%	<P25
Manager - Meter Services	432		*					*	-7.2%	<P25

HayGroup®

May 1, 2010

Supplementary Table

Market Actual and Target Bonus as % of Salary

(Includes bonus eligible only)

Bluewater Power Benchmark Job Title	Total Points	Average of Industrial Organizations with Revenue less than $125 Million			
		Actual Bonus	Target Bonus	Variance From Actual	Variance From Target
President & Chief Executive Officer	1566			-51.5%	-69.5%
Vice-President Corporate Services & Gen	954			-20.0%	-30.9%
Chief Operating Officer	830			-11.3%	-26.0%
VP Operations & COO	830			-11.3%	-26.0%
Vice-President Human Resources	800			-57.0%	-81.0%
Director - Information Technology	677			-84.0%	-118.7%
Controller	657			-77.3%	-112.0%
Manager - Design Services	611			-142.0%	-194.0%
Director - Client Services	611			-61.3%	-96.0%
Manager - Meter Services	432			-86.0%	-158.0%

Bluewater Power Benchmark Job Title	Total Points	Average of Utilities Organizations with Revenue less than $1 Billion			
		Actual Bonus	Target Bonus	Variance From Actual	Variance From Target
President & Chief Executive Officer	1566			-78.0%	-36.0%
Vice-President Corporate Services & Gen	954			4.6%	14.3%
Chief Operating Officer	830			0.7%	9.3%
VP Operations & COO	830			0.7%	9.3%
Vice-President Human Resources	800			-43.0%	-32.0%
Director - Information Technology	677			-30.7%	-26.7%
Controller	657			-20.0%	-20.0%
Manager - Design Services	611			-46.0%	-56.0%
Director - Client Services	611			2.7%	-4.0%
Manager - Meter Services	432			-12.0%	-20.0%

Attachment 2

Bluewater Power Distribution Corporation
Incentive Compensation Program

Introduction

The Incentive Compensation Program is designed to recognize and reward both corporate and individual achievement as measured over a fiscal year. Participation in the Program is open to all permanent employees of Bluewater Power Distribution Corporation.

For the purposes of determining individual achievement, performance is measured against objectives, goals and performance standards in each employee's Performance Review and Job Description.

Please note that this Program is discretionary. The President & CEO and/or the Board of Directors, can modify, change or terminate this program at any time.

Purpose

The Incentive Compensation Program is an integral part of enhancing organizational effectiveness.

The Incentive Compensation Program:

- Emphasizes organizational goals throughout all levels of the organization
- Clarifies work goals and objectives; the employee, the manager/supervisor and the organization know what is expected
- Encourages individuals to reach their highest performance potential and be accountable and recognized for superior results
- Strengthens communication
- Promotes an awareness and accountability of corporate performance at all levels of the organization

The Incentive Compensation Program is an integral part of the organization's commitment to high standards of performance. The program is designed to set and recognize performance standards for all staff.

Participation

Employees will receive an annual performance review, which will summarize the level of individual performance. If corporate performance is achieved, then the level of individual performance determines the monetary compensation for each individual.

Employees in any year who are entitled to an incentive for that year will receive his or her final calculated incentive once the Board of Directors has approved the Plan, provided the employee is actively on the payroll at time of payout.

Actual incentives will be pro-rated based on periods of eligible employment, which is generally active employment in an eligible class of employees. Periods of leave of absence, including maternity or parental leave, extended sick leave of 4 weeks or more and periods of disability (WSIB) are not considered to be periods of eligible employment.

An employee who is transferred from one position to another during the year will have his or her actual incentive calculated for the entire period of eligibility based on the performance area in which he or she spent the longer period. If the employee spent equal amounts of time in two different areas, the area in which the employee last spent time will be used.

Other Factors

The Board of Directors may decide from year to year to vary the terms of the program and may change or terminate the program at any time.

Payments from the Program will not be used for purposes of any company benefits. For example, the calculation of life insurance coverage, optional insurance and LTD benefits will be based on actual annual salary only.

A. Corporate Performance

Bluewater Power Distribution Corporation must meet all four levels of corporate performance on an annual basis in order for employees to qualify for 100% incentive compensation payments for that period.

If Bluewater Power does not meet one or more of the below overall Corporate Performance indicators, payment will be based on the number of indicators met. For example, if only two of the four indicators are met, payment will be at 50%. Each of the Performance Indicators will be weighed at 25%.

Furthermore, since the Reliability and Service Indicators have 10 different indicators within the overall Reliability and Service Performance – it is appropriate to break this indicator down and award incentives based on performance towards each indicator. These Indicators will be weighted as follows:

1. Total # appointments scheduled within 5 days & 4 hour window – 10%
2. Total # of times arrived on time – 10%
3. Number of appointments rescheduled within 1 day (if needed) – 10%
4. # Phone calls answered in less than 30 seconds – 10%
5. # of Qualified calls abandoned after 30 second wait – 10%
6. # Written responses to enquiries responded to in less than 10 days – 10%
7. # Low Voltage connections request completed in less than 5 days – 10%
8. # High Voltage connection requests completed in less than 10 days – 10%
9. Rural emergencies responded to within 120 minutes – 10%
10. # Urban emergencies responded to within 60 minutes – 10%

The four overall Corporate Performance indicators are as follows:

1. **Spending Performance** – Gross Operating & Maintenance spending (net of unbudgeted billable expenses which generate revenue and other similar unbudgeted expenses) must be within the company's annual budget, as approved by the Board of Directors.

2. **Reliability and Service** - Bluewater Power Distribution Corporation must meet all Ontario Energy Board's requirements for performance service quality indicators, absent any extraordinary circumstances. This includes acceptable levels of reliability, outages, customer service. This ensures employees are not encouraged to sacrifice service levels.

3. **Financial Performance** - Bluewater Power Distribution Corporation must exceed the budgeted net income before taxes (with IFRS being adjusted) for the fiscal year, absent any extraordinary factors beyond the control of the Corporation. This may include significant weather impacts or Ontario Energy Board decisions or rulings.

4. **Safety Performance** – Bluewater Power Distribution Corporation must maintain a safe environment for their employees and the public. As a general rule, if a lost-time accident has occurred, during the calendar year, the Senior Management team, in consultation with the Board of Directors, will determine, (a) if the incident was significant and (b) if the incident could have been avoided through improved training or attention to safety, prior to any compensation payout.

The Board of Directors will have the final approval to proceed with the Incentive Compensation Program once the corporate performance criteria are met.

B. **Individual Performance**

If acceptable corporate performance is attained, individuals will be compensated based upon their individual performance rating and their individual target incentive. Role classifications are at the sole discretion of the President & C.E.O., and the Vice President of Human Resources. Targets and performance ratings are determined by the President & CEO from time-to-time, in consultation with the Compensation Committee.

Responsibilities

Supervisor:

- To communicate to the employee requirements for the coming year in terms of performance standards, objectives, goals, and job responsibilities
- Regularly communicate throughout the year to let the employee know how he or she is progressing in terms of requirements and to review and revise objectives in response to changing conditions
- Conduct an annual performance review with the employee

Employee:

- To take an active role in developing his/her annual performance plan
- Discuss with his/her supervisor, understand and agree to expected goals, performance standards and job responsibilities
- Identify areas for job and performance enhancement and contribute toward establishing performance goals and objectives

Performance Incentive

Individuals will have an annual performance review completed. Once the review has been completed, with the appropriate authorizations and the overall performance rating has been approved by the President & CEO, the performance review will be forwarded to Human Resources for processing.

Human Resources will take the results of the overall performance rating, determine the Target Incentive and apply this to the Incentive Compensation Calculator to determine the total incentive.

Human Resources will be responsible for processing all the incentives as soon as possible once the prior year's financial are finalized and once approved by the Board of Directors, upon the recommendation from the Compensation Committee.

BLUEWATER POWER
EMPLOYEE BENEFIT SUMMARY

Provider	Benefit	Coverage
Great-West Life: (Group #328690)	*Extended Health Care* (Employer paid) Deductible: $10/yr single; $20/yr family	▪ prescription drugs ▪ private hospital coverage ▪ hearing aids - $500/60 months ▪ orthotics - $400/6 months ▪ vision $250/24 months ▪ out of the country travel ▪ paramedical services - $500/12
	Dental (25% employee, 75% by BPDC) Single $8.18; Family $18.92 24 pays/year	▪ 100 % coverage of basic services ▪ 50 % coverage of major services ▪ Orthodontics (50 % up to a lifetime maximum of $1500)
	Group Life Insurance (1/3 employee; 2/3 BPDC) 24 pays/year *Life* $5.17 / pay	▪ two times annual salary (up to a maximum of $100,000/coverage)
	Dependant Life 0.32¢ / pay 24 pays/year	▪ dependent life insurance coverage; Spouse - $5,000 & Child - $2,500
RBC Insurance	*Long Term Disability* (Employer Paid)	▪ 75 % of basic monthly earnings to a max. $6,000/month
ACE/INA: (Group #102888)	*Accidental Death & Dismemberment* (Employer Paid)	▪ two times annual salary up to a max. $200,000
MEARIE: **Great West Life**	*Group Life Insurance* (Employer Paid)	▪ 1 ½ times annual salary (optional and spousal insurance available for Employee purchase)
Family Counselling Centre	*Employee Assistance Program* (Employer Paid)	▪ 336-0120

Benefits are subject to change due to rate changes and/or management discretion.

Updated: June 2012

BLUEWATER POWER
RETIREE BENEFIT SUMMARY

Great-West Life: (Group #328690)	Extended Health Care (Paid by Employer)	• prescription drugs • private hospital coverage • hearing aids - $500/60 months • orthotics - $400/6 months • paramedical services - $500/12 ($10/yr single; $20/yr family)
MEARIE: **Great West Life** (Group # 331030)	Group Life Insurance (Paid by Employer)	• Hired after March 1, 1980, and retire with 10 or more years of service 50% of your final earnings, reducing by 2 ½ % of final earnings on the anniversary date of your retirement date each year following for 10 years to a minimum of 25% of final earnings • less than 10 years of service $2,000.00 *Refer to the MEARIE Handbook for further details*

Early Retirees Benefits:

In addition to the benefits listed above, employees retiring after January 1, 1998 are entitled to the benefits listed below, on a cost share basis for *<u>five years or until age 65</u>* (whichever occurs first):

Premiums will be paid on a cost shared basis for the extended benefits as follows:

1st Year	100% paid by BPDC	0% paid by Retiree
2nd Year	80% paid by BPDC	20% paid by Retiree
3rd Year	60% paid by BPDC	40% paid by Retiree
4th Year	40% paid by BPDC	60% paid by Retiree
5th Year	20% paid by BPDC	80% paid by Retiree

Great-West Life:	Vision Care	• $250 / 24 months
	Dental Coverage	• Basic Services Only

<u>Benefits are subject to change due to rate changes and / or management's discretion</u>

BLUEWATER POWER
RETIREE BENEFIT SUMMARY

Great-West Life: (Group #328690)	Extended Health Care (Paid by Employer) ***Minimum 10 years service up to age 65***	• prescription drugs • private hospital coverage • hearing aids - $500/60 months • orthotics - $400/6 months • paramedical services - $500/12 • ($10/yr single; $20/yr family)
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4th Year	40% paid by BPDC	60% paid by Retiree
5th Year	20% paid by BPDC	80% paid by Retiree

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	Dental Coverage	• Basic Services Only

Benefits are subject to change due to rate changes and / or management's discretion

BLUEWATER POWER
RETIREE BENEFIT SUMMARY

Great-West Life: (Group #328690)	Extended Health Care (Paid by Employer) ***Minimum 10 years service up to age 65***	• prescription drugs • private hospital coverage • hearing aids - $500/60 months • orthotics - $400/6 months • paramedical services - $500/12 • ($10/yr single; $20/yr family)

Early Retirees Benefits:

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1st Year	100% paid by BPDC	0% paid by Retiree
2nd Year	80% paid by BPDC	20% paid by Retiree
3rd Year	60% paid by BPDC	40% paid by Retiree
4th Year	40% paid by BPDC	60% paid by Retiree
5th Year	20% paid by BPDC	80% paid by Retiree

Great-West Life:	Vision Care	• $250 / 24 months
	Dental Coverage	• Basic Services Only

<u>***Benefits are subject to change due to rate changes and / or management's discretion***</u>

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November 16, 2011

BY COURIER

Ms. Karen Otton
Human Resources Administrator
Bluewater Power Distribution Corporation
855 Confederation Street
P.O. Box 2140
Sarnia, ON N7T 7L6

Dear Ms. Otton:

Re: Bluewater Power Corporation Actuarial Valuation Report as at January 1, 2011: Post-Retirement Non-Pension Benefit Plan

Attached is our actuarial valuation report as at January 1, 2011 for the above-captioned plan.

In addition, this letter provides you with our calculation of the FY 2011 benefit expense and December 31, 2011 Accrued Benefit Obligation ("ABO") for the above noted benefit plan.

The intended users of this letter and attachments include Bluewater Power Corporation and its auditors for financial reporting in compliance with CICA guidelines in respect of its post-retirement non-pension benefit plan.

For the post-retirement non-pension plan, the FY 2011 benefit expense is approximately $763,000 and the December 31, 2010 ABO is approximately $9,175,000 with their supporting calculations summarized in the accounting worksheets hereby attached.

We have performed our calculations of the FY 2011 benefit expense and the December 31, 2011 ABO based on the following:

- **Plan provisions**: The plan provisions as summarized in our January 1, 2011 actuarial valuation report ("Report").
- **Data**: We have used the data as at January 1, 2011 which is summarized in the Report.
- **Assumptions**: Your confirmation that all assumptions as summarized in the Report remain as management's best estimates as at December 31, 2011.
- **Method**: We have done our calculations as at January 1, 2011 using the above information and the method described in the Report. The December 31, 2011 ABO is based on a roll forward of the January 1, 2011 ABO calculations using membership data as at January 1, 2011 and management's best estimate assumptions as at December 31, 2011.

- **Accounting policy**: We have applied the same accounting policies as described in the Report.

We are not aware of any subsequent events that would have a significant impact on our calculations.

The calculations were performed in accordance with The Canadian Institute of Chartered Accountants (CICA) guidelines outlined in Employee Benefits, Section 3461 of the CICA Handbook – Accounting.

Results under International Financial Reporting Standards ("IFRS")

Also, included in separate accounting worksheets attached hereto, are the following items on the basis of International Financial Reporting Standards IAS 19 (Employee Benefits):

- Calculations of the present value of the defined benefit obligations at January 1, 2011.
- Extrapolation of the January 1, 2011 IAS 19 results for fiscal years ending December 31, 2011, December 31, 2012, and December 31, 2013.

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 IFRSs, i.e. January 1, 2011. We note that this does not impact the Corporation's choice of approach to recognizing future actuarial gains or losses under IFRS after the transition date when they occur.

The following is noted in regards to the attached IAS19 figures:

- The employee data used is as detailed in the Report on the Actuarial Valuation of Post-Retirement Non-Pension Benefits as at January 1, 2011 ("Valuation Report") for Bluewater Power Corporation.
- The methodology used in the calculation of the present value of the defined benefit obligation and current service cost is the same as outlined in the Valuation Report, with the exception of the changes described below in respect of the application of the provisions in Sections 67-71 of IAS 19 regarding attributing benefits to periods of service. More specifically, the following changes were made to the attribution period for post-retirement non-pension benefits to reflect underlying post-retirement benefit service eligibility requirements under these plans and the application of IAS 19 to same:
    - For employees hired post January 1, 2006, due to the minimum 10 year service requirement to be eligible for post-retirement health and dental benefits, the attribution period under IFRS for these benefits commences at the later of the date of hire and age 45 and ceases at the later of age 55 or the date at which 10 years of service is reached.

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- The assumptions used are the same as those detailed in the Valuation Report.
- Our calculations conform to the standards as set out in International Accounting Standard 19 (Employee Benefits).

If you have any questions regarding the above, the attached valuation report and accounting schedules, or the impact of IFRS on the accounting results of your post-retirement non-pension benefit plan, please do not hesitate to give us a call.

Yours truly,

Stanley Caravaggio, FSA FCIA
Consulting Actuary
[E-mail: stanleyc@dion-durrell.com]
[Telephone: 416.408.5306]

Patrick G. Kavanagh
Actuarial Analyst
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[Telephone: 416.408.5327]

SC/PK:ecs

Encls.

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BLUEWATER POWER CORPORATION

REPORT ON THE ACTUARIAL VALUATION OF POST-RETIREMENT NON-PENSION BENEFITS

As At January 1, 2011

FINAL—November 16, 2011

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TABLE OF CONTENTS

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EXECUTIVE SUMMARY

PURPOSE

MEARIE Actuarial Services and Dion, Durrell + Associates Inc. were engaged by Bluewater Power Corporation (the "Corporation") to perform an actuarial valuation of the post-retirement non-pension benefits sponsored by the Corporation and to determine the accounting results for those benefits for the fiscal period ending December 31, 2011. The nature of these benefits is defined benefit.

The Corporation includes Bluewater Power Distribution Corporation, Electek Power Services Inc., and Bluewater Power Services Corporation.

This report is prepared in accordance with The Canadian Institute of Chartered Accountants (the "CICA") guidelines outlined in Employee Future Benefits, Section 3461 of the CICA Handbook-Accounting ("CICA Section 3461"). CICA Section 3461 was first applied to the Corporation with effect from January 1, 2002.

The most recent full valuation was prepared as at January 1, 2008 based on the then appropriate assumptions.

The purpose of this valuation is threefold:

i) to determine the Corporation's liabilities in respect of post-retirement non-pension benefits at January 1, 2011;

ii) to determine the benefit expense for fiscal year 2011; and

iii) to provide all other pertinent information necessary for compliance with CICA Section 3461.

The intended users of this report include the Corporation and their auditors. This report is not intended for use by the plan beneficiaries or for use in determining any funding of the benefit obligations.

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SUMMARY OF KEY RESULTS

The key results of this actuarial valuation as at January 1, 2011 with comparative results from the previous valuation as at January 1, 2008 are shown below:

	January 1, 2008 ($000s)	January 1, 2011 ($000s)
Accrued Benefit Obligation (ABO)		
a) People in receipt of benefits	3,689	4,424
b) Fully eligible actives	1,159	1,010
c) Not fully eligible actives	2,836	3,296
Total ABO	**7,684**	**8,730**
Current Service Cost: *for following 12 months*	245	276
Benefit Expense: *for following 12 months*	744	763
Prepaid Benefit Liability: *at January 1*		7,294

The January 1, 2011 Prepaid Benefit Liability is based on the Corporation's financial statements as at December 31, 2010.

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ACTUARIAL CERTIFICATION

An actuarial valuation has been performed on the post-retirement non-pension benefit plans sponsored by the Corporation as at January 1, 2011, for the purposes described in this report.

In accordance with the Canadian Institute of Actuaries Consolidated Standards of Practice General Standards, we hereby certify that, in our opinion, for the purposes stated in the Executive Summary:

1. The data on which the valuation is based is sufficient and reliable;
2. The assumptions employed, as outlined in this report, have been selected by the Corporation as management's best estimate assumptions (no provision for adverse deviations) and we have reviewed the assumptions and consider them to be appropriate for the purposes of the valuation outlined herein;
3. The actuarial methods employed, as outlined in Section C, are appropriate for the purpose and consistent with sound actuarial principles;
4. All known substantive commitments with respect to the post-retirement non-pension benefits sponsored by and identified by the Corporation are included in the calculations; and
5. The valuation conforms to the standards set out in the Canadian Institute of Chartered Accountants Accounting Handbook Section 3461.

We are not aware of any subsequent events from January 1, 2011 up to the date of this report that would have a significant effect on our valuation.

The latest date on which the next actuarial valuation should be performed is January 1, 2014. If any supplemental advice or explanation is required, please advise the undersigned.

Respectfully submitted,

DION, DURRELL + ASSOCIATES INC.

Stanley Caravaggio

Stanley Caravaggio FSA, FCIA

Patrick G. Kavanagh

Patrick G. Kavanagh
Actuarial Analyst

Toronto, Ontario
November 16, 2011

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SECTION A—
VALUATION RESULTS

Table A - 1 shows the key valuation results for the prior valuation and the current valuation.

Table A - 2 shows the sensitivity of the valuation results to certain changes in assumptions. We have shown a change to the assumed retirement age from age 60 to 58, and an increase/decrease in the health and dental claims cost trend rates by 1% per annum.

Table A - 3 presents the determination of the actuarial gain/(loss) from the previous valuation at January 1, 2008.

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VALUATION RESULTS

**Table A.1—Valuation Results
(in thousands of dollars)**

			January 1, 2008	January 1, 2011
1.	Accrued Benefit Obligation			
	a)	People in receipt of benefits	3,689	4,424
	b)	Fully eligible actives	1,159	1,010
	c)	Not fully eligible actives	2,836	3,296
Total ABO			**7,684**	**8,730**
2.	Benefit Expense			
	a)	Current Service Cost	245	276
	b)	Interest Cost	391	444
	c)	Expected Return on Assets	-	-
	d)	Amortization of Transition Amount	-	-
	e)	Amortization of Past Service Cost	-	-
	f)	Amortization of (Gain)/Losses	108	43
Total Benefit Expense *for following 12 months*			**744**	**763**
3.	Expected Benefit Payments *for following 12 months*		223	275

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SENSITIVITY ANALYSIS

Table A.2—Sensitivity Analysis (in thousands of dollars)

	January 1, 2011			
	Valuation Results	**Retirement Age 58**	**1% Higher Trend**	**1% Lower Trend**
1. Accrued Benefit Obligation				
a) People in receipt of benefits	4,424	4,424	4,796	4,111
b) Fully eligible actives	1,010	1,051	1,161	888
c) Not fully eligible actives	3,296	3,528	4,196	2,627
Total ABO	**8,730**	**9,003**	**10,153**	**7,626**
2. Current Service Cost *for following 12 months*	276	301	351	221
3. Interest Cost *for following 12 months*	444	458	518	385
4. Expected Average Remaining Service Lifetime of the Current Active Employees (years)	13	12	13	13

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DEVELOPMENT OF NET GAINS OR LOSSES

Table A.3—Development of Net Gains or Losses (in thousands of dollars)

Expected ABO at December 31, 2010 per financial statements	9,169
Actual ABO at January 1, 2011	8,730
Actuarial Loss/(Gain)	(439)
Amortization of Unamortized Actuarial Loss	
Unamortized Net Actuarial Loss (Gain) at December 31, 2010	1,875
Actuarial Loss (Gain) for Current Year at January 1, 2011	(439)
Total Loss (Gain) at January 1, 2011	1,436
Less: Actual Amortization for 2011	43
Expected Unamortized Actuarial Loss (Gain) at December 31, 2011	1,393

Please note that the actual ABO at January 1, 2011 is approximately $439,000 lower than the expected ABO at December 31, 2010. This is due to a combination of the following factors:

- A change in the health claims cost trend rate assumption (an increase of approximately $212,000)
- A change in the retirement age assumption (an increase of approximately $94,000)
- A change in the salary scale assumption (an increase of approximately $9,000)
- Differences between the actual and expected benefit cost rates (a decrease of approximately $745,000)
- Deviations from the expected demographic changes of the valued group and other miscellaneous factors (a decrease of approximately $9,000 in the total ABO)

CICA Section 3461 states that any gain or loss in excess of 10% of the ABO must, at minimum, be amortized over the expected average remaining service lifetime ("EARSL"). The EARSL of the current active group is 13 years. Under these guidelines, the minimum required amortization for the year 2011 is approximately $43,000. CICA Section 3461 also allows for a method of amortization which recognizes gains and losses sooner than the minimum. However, the method chosen must be applied consistently from year to year. The Corporation has previously chosen to recognize the minimum required amortization and therefore the amortization required in year 2011 is approximately $43,000.

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SECTION B—
PLAN PARTICIPANTS

Table B – 1 sets out the summary information with respect to the plan participants valued in the report, along with comparisons to the participants in the previous valuation at January 1, 2008.

Table B – 2 reconciles the number of participants in the last valuation to the number of participants in the current valuation.

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PARTICIPANT DATA

Table B.1—Participant Data

Membership data as at January 1, 2011 was received from the Corporation via e-mail and included information such as sex, age, date of hire, current salary, benefit amounts and other applicable details for all active employees and people in receipt of benefits.

We have reviewed the data and compared it to the data used in the prior valuation for consistency and reliability for use in this valuation. The main tests of sufficiency and reliability that were conducted on the membership data are as follows:

- Date of birth prior to date of hire;
- Salaries less than $20,000 per year, or greater than $250,000 per year;
- Ages under 18 or over 100;
- Abnormal levels of benefits and/or premiums; and
- Duplicate records.

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In addition, the following tests were performed:

- A reconciliation of statuses from the prior valuation to the current valuation;
- A review of the consistency of individual data items and statistical summaries between the current and prior valuations; and
- A review of the reasonableness of changes in such information since the prior valuation.

Active Employees

As of January 1	2008			2011		
	Male	**Female**	**Total**	**Male**	**Female**	**Total**
Number of Employees	58	33	91	73	36	109
Average Length of Service	13.8	12.6	13.4	11.3	10.4	11.0

As of January 1, 2011	Current Age					
	Active Lives—Not fully eligible			**Active Lives—Fully eligible**		
	Count			**Count**		
	Male	**Female**	**Total**	**Male**	**Female**	**Total**
Age Band						
Less than 30	13	1	14	-	-	-
30-35	7	2	9	-	-	-
36-40	7	5	12	-	-	-
41-45	23	8	31	-	-	-
46-50	12	9	21	-	-	-
51-55	4	7	11	1	-	1
56-60	-	-	-	2	4	6
61-65	-	-	-	4	-	4
66-70	-	-	-	-	-	-
71-75	-	-	-	-	-	-
Greater than 75	-	-	-	-	-	-
Total	**66**	**32**	**98**	**7**	**4**	**11**

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As of January 1, 2011	Average Service					
	Active Lives—Not fully eligible			Active Lives—Fully eligible		
	Service			Service		
	Male	Female	Total	Male	Female	Total
Age Band						
Less than 30	2.08	-	1.93	-	-	-
30-35	4.57	3.50	4.33	-	-	-
36-40	7.25	7.05	7.17	-	-	-
41-45	12.54	6.33	10.94	-	-	-
46-50	14.31	15.86	14.98	-	-	-
51-55	24.40	12.61	16.89	32.92	-	32.92
56-60	-	-	-	20.88	12.79	15.49
61-65	-	-	-	20.02	-	20.02
66-70	-	-	-	-	-	-
71-75	-	-	-	-	-	-
Greater than 75	-	-	-	-	-	-
Total	**10.11**	**10.12**	**10.12**	**22.11**	**12.79**	**18.72**

People in Receipt of Benefits (including LTD)

As of January 1	2008			2011		
	Male	Female	Total	Male	Female	Total
Number of Members	39	26	65	40	32	72

As of January 1, 2011	Expected Annual Benefit Payments		
Age Band	Male	Female	Total
Less than 30	$ -	$ -	$ -
30-35	-	-	-
36-40	-	-	-
41-45	-	-	-
46-50	-	-	-
51-55	5,998	6,759	12,757
56-60	5,782	13,033	18,815
61-65	33,151	12,564	45,715
66-70	38,788	13,971	52,759
71-75	20,047	7,393	27,440
Greater than 75	77,930	38,794	116,724
Total	**$ 181,696**	**$ 92,514**	**$ 274,210**

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PARTICIPATION DATA

Table B.2—Participation Data

	Actives	LTD	Dependents	Retirees
As at January 1, 2008	**91**	**5**	**14**	**46**
New Entrants	30	-	-	-
New Dependents	-	-	3	-
Active	-	2[1/]	-	9[2/]
LTD	(2)[1/]	-	-	1
Terminated	(1)	-	-	-
Deceased	-	(1)	(1)	(5)[3/]
Retired	(9)[2/]	(1)	-	-
As at January 1, 2011	**109**	**5**	**16**	**51**

1/ 1 individual who was became disabled during 2011 is included as disabled.
2/ 6 individuals who retired during 2011 are included as retired.
3/ 2 individuals who were deceased during 2011 are included as deceased.

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SECTION C— SUMMARY OF ACTUARIAL METHOD AND ASSUMPTIONS

ACTUARIAL METHOD

The aim of an actuarial valuation of post-retirement non-pension benefits is to provide a reasonable and systematic allocation of the cost of these future benefits to the years in which the related employees' services are rendered. To accomplish this, it is necessary to:

- make assumptions as to the discount rates, salary rate increases, mortality and other decrements;
- use these assumptions to calculate the present value of the expected future benefits; and
- adopt an actuarial cost method to allocate the present value of expected future benefits to the specific years of employment.

The ABO and Current Service Cost were determined using the projected benefit method, pro-rated on service. This is the method stipulated by CICA Section 3461 when future salary levels or cost escalation affect the amount of the employee's future benefits. Under this method, the projected post-retirement benefits are deemed to be earned on a pro-rata basis over the years of service in the attribution period. CICA Section 3461 stipulates that the attribution period commences at the employee's hire date and ends at the earliest age at which the employee could retire and qualify for the post-retirement non-pension benefits valued herein.

For each employee not yet fully eligible for benefits, the ABO is equal to the present value of expected future benefits multiplied by the ratio of the years of service to the valuation date to the total years of service in the attribution period. The Current Service Cost is equal to the present value of expected future benefits multiplied by the ratio of the year (or part) of service in the fiscal year to total years of service in the attribution period.

For health and dental benefits, we have used the premium rates charged to retirees as an estimate of the benefit costs to be incurred. The total monthly premium rates, inclusive of premium taxes, used are as follows:

	Health Care		***Vision Care***		***Dental Care***	
	Single Coverage	Family Coverage	Single Coverage	Family Coverage	Single Coverage	Family Coverage
All retirees	$143.70	$325.76	$5.07	$14.85	$60.60	$140.17

The above premium rates were provided by the Corporation and represent the rates effective June 1, 2011 to May 31, 2012.

The ABO at January 1, 2011 is based on membership data and management's best estimate assumptions at January 1, 2011.

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	Current Valuation		Previous Valuation	
End of Year	***Health***	***Dental***	***Health***	***Dental***
2018	5.38%	5.00%	5.00%	5.00%
2019 and Thereafter	5.00%	5.00%	5.00%	5.00%

** The actual benefit cost information for the period from January 1, 2011 to May 31, 2012, and expected benefit cost information for the period from June 1, 2012 to May 31, 2013 was provided by the Corporation and reflected in the valuation.*

DEMOGRAPHIC ASSUMPTIONS

Mortality table

Mortality is assumed to be in accordance with the 1994 Uninsured Pensioner Mortality (UP-94) table, with a projection of mortality improvements to the year 2020 based upon Projection Scale AA. The use of these rates seems reasonable given this is the mortality table to be used in accordance with the Canadian Institute of Actuaries' Standard of Practice for Determining Pension Commuted Values, effective April, 2009 to February, 2011.

Mortality rates are applied on a sex-distinct basis.

The prior valuation used the 1994 Uninsured Pensioner Mortality (UP-94) table, with a projection of mortality improvements to the year 2015 based upon Projection Scale AA.

Rates of Withdrawal

Termination of employment prior to age 55 was assumed to be equal to 2.00% per annum. This is the same assumption used in the prior valuation.

Retirement Age

All active employees are assumed to retire at age 60, or immediately if currently over age 60.

In the prior valuation, all active employees before January 1, 2006 were assumed to retire at age 61, or immediately if currently over age 61. For employees hired on or after January 1, 2006, the assumed retirement age was increased, if necessary, to the minimum of the age at which 10 years of service is reached and age 65.

Disability

No provision was made for future disability. It is assumed that individuals currently receiving long-term disability benefits will remain disabled until retirement at age 65. This assumption remains unchanged from the previous valuation.

Family/Single Coverage

It is assumed that the coverage type as at January 1, 2011 will remain the same into retirement. This assumption remains unchanged from the previous valuation.

Expenses and Taxes

We have assumed 10% of benefits is required for the cost of sponsoring the program for life insurance. We have assumed taxes and expenses are included in the premium rates for extended health and dental benefits. These are the same assumptions that were used in the prior valuation.

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SECTION D— SUMMARY OF POST-RETIREMENT BENEFITS

The following is a summary of the plan provisions that are pertinent to this valuation.

GOVERNING DOCUMENTS

The program is governed by the following documents and agreements:

- Collective Agreement between Bluewater Power Distribution Corporation and Local Union No. 1802 of the International Brotherhood of Electrical Workers A.F.L./C.I.O./C.L.C. in full force and effect from April 1, 2009 until March 31, 2014.
- Bluewater Power Distribution HR Policy No. HR-HR-002 (Pensioners/Early Retirement Benefits) issued on November 1, 2000 and most recently revised on June 28, 2011.
- Bluewater Power Distribution HR Policy No. HR-HR-009 (Survivor's Benefits) issued on November 1, 2000 and most recently revised on June 28, 2011.

What follows is only a summary of the post retirement non-pension benefits program. For a complete description, please refer to the above-noted documents.

ELIGIBILITY

All employees who retire from the Corporation are eligible for MEARIE post-retirement life insurance coverage. In addition, employees hired prior to December 31, 1989 who retire from the Corporation are eligible for an additional life insurance benefit from Great West Life.

All employees hired prior to January 1, 2006 are eligible for post-retirement health, dental, and vision insurance benefits. Employees hired on or after January 1, 2006 must retire with a minimum of 10 years of service to be eligible for post-retirement health, dental, and vision insurance benefits.

PARTICIPANT CONTRIBUTIONS

The Corporation shall pay shall pay 100% of the cost of the MEARIE life insurance benefits and 2/3 of the cost of the Great West Life insurance benefits for all eligible retirees.

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The Corporation shall pay 100% of the cost of the extended health insurance benefits and shall pay for post-retirement vision and dental benefits according to the following reducing schedule of premiums:

Year	Corporation Share	Retiree Share
1	100%	0%
2	80%	20%
3	60%	40%
4	40%	60%
5	20%	80%

PAST SERVICE

Past service is defined as continuous service prior to joining the plan if the participant was employed by another electrical distribution company/hydro prior to joining the Corporation.

LENGTH OF SERVICE

Length of service is defined as continuous service from the date of hire to the valuation date, measured in years and months.

SUMMARY OF BENEFITS

Post-Retirement Life Insurance

All current employees who retire from Bluewater Power Corporation are eligible for post-retirement life insurance, as per the MEARIE plan, administered by Great West Life, based upon the following table:

Classification		Amount of Retirement Life Insurance
A.	If you retire with less than 10 Years of Service in this Plan	$2,000
B.	If you were not insured under the Superseded Plan* and retire with 10 or more Years of Service in this Plan OR if you were insured under the Superseded Plan* but at any time prior to retirement elected coverage under Options 2, 3 or 4	50% of your final annual earnings, reducing by 2-1/2% of final annual earnings on the anniversary of your retirement date each year following for ten years, to a minimum of 25% of your final annual earnings

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Classification		Amount of Retirement Life Insurance
C.	If you were insured under the Superseded Plan*: 1.If at any time you elected coverage under Options 2, 3 or 4; 2.If you were hired on or after May 1, 1967 and never elected coverage under Options 2, 3 or 4 at any time prior to retirement; or 3.If you were hired prior to May 1, 1967 and never elected coverage under Options 2, 3 or 4 at any time prior to retirement	Amount will be determined in accordance with provision B above 50% of your final annual earnings 70% of the amount of coverage you were insured for immediately prior to your retirement date
Notes:	*All amounts of retirement life insurance are rounded upward to the nearest $1.00.* **Superseded Plan means the prior life insurance plan which this Plan replaced effective March 1, 1980.* *Years of Service means your service in this Plan or the Superseded Plan with your current employer you retire from, together with service credited to you in this Plan or the Superseded Plan by reason of your prior service with any other employer participating in this Plan, where the transfer occurs without intervening employment.*	

In addition to life insurance coverage under the MEARIE plan, employees hired on or before December 31, 1989 who retired from Bluewater Power Corporation are eligible for an additional life insurance benefit from Great West Life for life in the amount of 25% of a retiree's amount of basic coverage immediately prior to retirement to a maximum of $12,500.

Post-Retirement Health, Vision and Dental Benefits

For employees hired prior to January 1, 2006

All eligible employees who retire from the Corporation are entitled to the following benefits:

- Lifetime extended health coverage, with health coverage continuing to the eligible dependents of a deceased employee or retiree for life or until they cease to qualify as dependent(s).
- Vision care for up to 5 years or until the retiree turns age 65, whichever occurs first.
- Dental coverage for up to 5 years or until the retiree turns age 65, whichever occurs first. Dental coverage continues to the eligible dependent(s) of a deceased employee or retiree until age 65.

For employees hired on or after January 1, 2006

All eligible employees who retire from the Corporation are entitled to the same health, vision and dental benefits as retirees who were hired prior to January 1, 2006 with the exception of health

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benefits ceasing at age 65. Health, vision and dental benefits to eligible dependents of a deceased employee or retiree for a period of 2 years or until the dependent would have turned age 65.

For employees on LTD

Employees who retire from long-term disability are eligible for the same benefits as outlined above.

A detailed description of the post-retirement non-pension benefits program can be found in the above-noted governing documents.

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SECTION E
EMPLOYER CERTIFICATION

Post-Retirement Non-Pension Benefit Plan
of Bluewater Power Corporation
Actuarial Valuation as at January 1, 2011

I hereby confirm as an authorized signing officer of the administrator of the Post-Retirement Non-Pension Benefit Plan of Bluewater Power Corporation that, to the best of my knowledge and belief, for the purposes of the valuation:

i) the membership data summarized in Section B is accurate and complete;

ii) the assumptions upon which this report is based as summarized in Section C are management best estimate assumptions and are adequate and appropriate for the purposes of this valuation; and

iii) the summary of Plan Provisions in Section D is an accurate and complete summary of the terms of the Plan in effect on January 1, 2011.

BLUEWATER POWER CORPORATION

Nov 1, 2011
Date

Mark Hutson
Signature

Mark Hutson
Name

CFO
Title

Bluewater Power Distribution Corporation
ESTIMATED BENEFIT EXPENSE (IAS 19)
FINAL

	Calendar Year 2011	Projected Calendar Year 2012	Projected Calendar Year 2013
Discount Rate at January 1	5.00%	5.00%	5.00%
Discount Rate at December 31	5.00%	5.00%	5.00%
Salary Scale Rate	3.30%	3.30%	3.30%
Annual Increase in Healthcare Costs	-5.00%	7.63%	7.25%
Annual Increase in Dental Costs	5.00%	5.00%	5.00%
Withdrawal Rate	2.00%	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*	expected*

A. Determination of Amounts Recognized in Balance Sheet

	Calendar Year 2011	Projected Calendar Year 2012	Projected Calendar Year 2013
Net Liability as at January 1	8,418,225	8,789,458	9,197,166
Expense Recognized in Income Statement	646,073	703,174	759,291
Benefits Paid by the Employer	(274,841)	(295,466)	(309,331)
Net Liability/(Asset) as at December 31	8,789,458	9,197,166	9,647,126

B. Determination of Expense Recognized in Income Statement

	Calendar Year 2011	Projected Calendar Year 2012	Projected Calendar Year 2013
Current Service Cost	220,984	258,179	292,539
Interest Cost	425,089	444,995	466,752
Expected Return on Plan Assets	-	-	-
Past Service Cost/(Gain) – Non-vested benefits	-	-	-
Past Service Cost/(Gain) – Vested benefits	-	-	-
Net Actuarial Loss/(Gain) Recognized in Year	-	-	-
Expense Recognized in Income Statement	646,073	703,174	759,291

C. Change in the Present Value of Defined Benefit Obligation

	Calendar Year 2011	Projected Calendar Year 2012	Projected Calendar Year 2013
Present Value of Defined Benefit Obligation as at January 1	8,418,225	8,789,458	9,197,166
Current Service Cost	220,984	258,179	292,539
Interest Cost	425,089	444,995	466,752
Past Service Cost - Non-vested benefits	-	-	-
Past Service Cost - Vested benefits	-	-	-
Unrecognized Past Service Cost/(Gain)	-	-	-
Benefits Paid	(274,841)	(295,466)	(309,331)
Actuarial Loss/(Gain)	-	-	-
Present Value of Defined Benefit Obligation as at December 31	8,789,458	9,197,166	9,647,126

D. Reconciliation of Present Value of the Defined Benefit Obligation and Net Liability

	Calendar Year 2011	Projected Calendar Year 2012	Projected Calendar Year 2013
Present Value of Defined Benefit Obligation as at December 31	8,789,458	9,197,166	9,647,126
Unfunded Present Value of Obligation	8,789,458	9,197,166	9,647,126
Unrecognized Actuarial (Loss)/Gain	-	-	-
Unrecognized Past Service (Cost)/Gain	-	-	-
Assets as at December 31	-	-	-
Net Liability/(Asset) as at December 31	8,789,458	9,197,166	9,647,126

* based on estimated employer Benefits Paid for those expected to be eligible for benefits

Projected calendar year 2012-2013 results are provided for informational purposes only. Significant changes in 2012-2013 such as re-negotiated benefits, increased benefit costs, or significant swings in demographics may require a full actuarial review.

Bluewater Power Distribution Corporation
ESTIMATED BENEFIT EXPENSE (IAS 19)
FINAL

	Calendar Year 2011	Projected Calendar Year 2012	Projected Calendar Year 2013
Discount Rate at January 1	5.00%	5.00%	5.00%
Discount Rate at December 31	5.00%	5.00%	5.00%
Salary Scale Rate	3.30%	3.30%	3.30%
Annual Increase in Healthcare Costs	-5.00%	7.63%	7.25%
Annual Increase in Dental Costs	5.00%	5.00%	5.00%
Withdrawal Rate	2.00%	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*	expected*

E. Calculation of Component Items

	Calendar Year 2011	Projected Calendar Year 2012	Projected Calendar Year 2013
Calculation of the Current Service Cost			
- Current Service Cost	220,984	258,179	292,539
Interest Cost			
- Present Value of Defined Benefit Obligation as at January 1	8,418,225	8,789,458	9,197,166
- Current Service Cost	220,984	258,179	292,539
- Benefits Paid	(137,420)	(147,733)	(154,665)
- Accrued Benefits	8,501,789	8,899,904	9,335,040
- Interest Cost	425,089	444,995	466,752
Expected Return on Plan Assets			
- Assets at January 1	-	-	-
- Funding	(137,420)	(147,733)	(154,665)
- Benefits Paid	137,420	147,733	154,665
- Expected Assets	-	-	-
- Interest Cost	-	-	-
Expected Present Value of Defined Benefit Obligation as at December 31			
- Present Value of Defined Benefit Obligation as at January 1	8,418,225	8,789,458	9,197,166
- Current Service Cost	220,984	258,179	292,539
- Interest Cost	425,089	444,995	466,752
- Benefits Paid	(274,841)	(295,466)	(309,331)
- Expected Present Value of Defined Benefit Obligation as at December 31	8,789,458	9,197,166	9,647,126
Expected Assets as at December 31			
- Assets as at January 1	-	-	-
- Funding	(274,841)	(295,466)	(309,331)
- Interest on Assets	-	-	-
- Benefits Paid	274,841	295,466	309,331
- Expected Assets as at December 31	-	-	-

Projected calendar year 2012-2013 results are provided for informational purposes only. Significant changes in 2012-2013 such as re-negotiated benefits, increased benefit costs, or significant swings in demographics may require a full actuarial review.

Bluewater Power Distribution Corporation
ESTIMATED BENEFIT EXPENSE (IAS 19)
FINAL

	Calendar Year 2011	Projected Calendar Year 2012	Projected Calendar Year 2013
Discount Rate at January 1	5.00%	5.00%	5.00%
Discount Rate at December 31	5.00%	5.00%	5.00%
Salary Scale Rate	3.30%	3.30%	3.30%
Annual Increase in Healthcare Costs	-5.00%	7.63%	7.25%
Annual Increase in Dental Costs	5.00%	5.00%	5.00%
Withdrawal Rate	2.00%	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*	expected*

F. Actuarial Loss/(Gain)

	Calendar Year 2011	Projected Calendar Year 2012	Projected Calendar Year 2013
Required Amortization of Unamortized Net Actuarial Gain			
- Actual Present Value of Defined Benefit Obligation as at January 1	8,418,225	8,789,458	9,197,166
- 10% of Present Value of Obligation	841,823	878,946	919,717
- Unamortized Actuarial Loss/(Gain) January 1	-	-	-
- Amount subject to amortization	-	-	-
Expected Average Remaining Service Life (Years)	13	12	11
Minimum Required Amortization for Current Year	-	-	-
Loss/(Gain) on Present Value of Defined Benefit Obligation as at December 31 due to Change in Discount Rate Assumption			
- Expected Present Value of Defined Benefit Obligation	8,789,458	9,197,166	9,647,126
- Actual Present Value of Defined Benefit Obligation	8,789,458	9,197,166	9,647,126
- Actuarial Loss/(Gain) on Present Value of Defined Benefit Obligation	-	-	-
Total Loss/(Gain) as at January 1	-	-	-
Actual Amortization for Current Year	-	-	-
Unamortized Loss/(Gain) as at December 31	-	-	-

Projected calendar year 2012-2013 results are provided for informational purposes only. Significant changes in 2012-2013 such as re-negotiated benefits, increased benefit costs, or significant swings in demographics may require a full actuarial review.

Mark Hutson

From:	Connie Cheung <ConnieC@dion-durrell.com>
Sent:	Friday, March 23, 2012 11:29 AM
To:	Mark Hutson
Cc:	Stanley Caravaggio; Patrick Kavanagh
Subject:	Bluewater Power - Actuarial Extrapolations as at December 31, 2011
Attachments:	2011-12-30_Natcan_CIA_Stats_EN.pdf; Disclosures_111116_CICA 3461 _Bluewater_FINAL_with 4.5% Discount at Dec 31 2011.pdf; Disclosures_111116_IAS 19 _Bluewater_FINAL_with 4.5% Discount at Dec 31 2011.pdf

Hi Mark,

Further to recent correspondence, attached please find updated accounting disclosures for the period ending December 31, 2011 for Bluewater Power Distribution Corporation, Electek Power Services Inc., and Bluewater Power Services Corporation under both CICA 3461 and IAS 19 accounting standards.

The accrued benefit obligation ("ABO") at December 31, 2011 is based on a roll forward of the January 1, 2011 ABO calculations using membership data at January 1, 2011 and management's best estimate assumptions as set out in the previous valuation report, except for the discount rate assumption which was updated to 4.50% per annum as at December 31, 2011. Please refer to the supporting information below for additional details on the determination of this rate.

The Canadian Institute of Actuaries ("CIA") released an Educational Note on the "Accounting Discount Rate Assumption for Pension and Post-employment Benefit Plans" (Educational Note) in September 2011. The Educational Note was prepared by the Task Force on Pension and Post-Retirement Benefit Accounting Discount Rates and intended to provide guidance to actuaries and plan sponsors in developing a reasonable assumption for the discount rate to be chosen in accounting valuations for pension and post-employment benefit plans. Along with the Educational Note, the CIA has also acquired the services of Natcan Investment
Management (a portfolio investment management firm in Canada) to produce a monthly spot rate curve that is derived using the methodology described in the Educational Note.

We have analyzed Bluewater Power's projected benefit cash flows for post-retirement non-pension benefits using the discount rate curve as at December 30, 2011 published by Natcan Investment Management (please see attached). For additional information, please refer to http://www.natcan.com/en-ca/natcans-cia-method-accounting-discount-rate-curve.html.

In accordance with the CIA's Educational Note, we have developed a discount rate assumption of 4.50% per annum as at December 31, 2011. This rate is based on a determination of the unique discount rate (rounded to the nearest 25 basis points) that, when applied to Bluewater Power's expected benefit payments for post-retirement non-pension benefits, provides for an equivalent present value to the present value that would be calculated using these same expected benefit payments and Natcan's spot rate curve as at December 30, 2011. For clarification, with respect to projected benefit payments beyond 30 years, which is past the end of the Natcan spot rate curve, we have used the 30th year Natcan spot rate value to discount these cash flows in our calculations.

If you have any questions regarding the above or the attached accounting schedules, please do not hesitate to call.

Kind regards,
Connie

Dion Durrell
Connie Cheung
Dion, Durrell + Associates Inc.

Bluewater Power Distribution Corporation
ESTIMATED BENEFIT EXPENSE (IAS 19)
FINAL

	Calendar Year 2011	Projected** Calendar Year 2012	Projected** Calendar Year 2013
Discount Rate at January 1	5.00%	4.50%	4.50%
Discount Rate at December 31	4.50%	4.50%	4.50%
Salary Scale Rate	3.30%	3.30%	3.30%
Annual Increase in Healthcare Costs	-5.00%	7.63%	7.25%
Annual Increase in Dental Costs	5.00%	5.00%	5.00%
Withdrawal Rate	2.00%	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*	expected*

A. Determination of Amounts Recognized in Balance Sheet

	Calendar Year 2011	Projected** Calendar Year 2012	Projected** Calendar Year 2013
Net Liability as at January 1	8,418,225	8,789,458	9,223,374
Expense Recognized in Income Statement	646,073	729,381	787,998
Benefits Paid by the Employer	(274,841)	(295,466)	(309,331)
Net Liability/(Asset) as at December 31	8,789,458	9,223,374	9,702,041

B. Determination of Expense Recognized in Income Statement

	Calendar Year 2011	Projected** Calendar Year 2012	Projected** Calendar Year 2013
Current Service Cost	220,984	293,142	330,848
Interest Cost	425,089	436,239	457,150
Expected Return on Plan Assets	-	-	-
Past Service Cost/(Gain) – Non-vested benefits	-	-	-
Past Service Cost/(Gain) – Vested benefits	-	-	-
Net Actuarial Loss/(Gain) Recognized in Year	-	-	-
Expense Recognized in Income Statement	646,073	729,381	787,998

C. Change in the Present Value of Defined Benefit Obligation

	Calendar Year 2011	Projected** Calendar Year 2012	Projected** Calendar Year 2013
Present Value of Defined Benefit Obligation as at January 1	8,418,225	9,548,794	9,982,709
Current Service Cost	220,984	293,142	330,848
Interest Cost	425,089	436,239	457,150
Past Service Cost - Non-vested benefits	-	-	-
Past Service Cost - Vested benefits	-	-	-
Unrecognized Past Service Cost/(Gain)	-	-	-
Benefits Paid	(274,841)	(295,466)	(309,331)
Actuarial Loss/(Gain)	759,336	-	-
Present Value of Defined Benefit Obligation as at December 31	9,548,794	9,982,709	10,461,376

D. Reconciliation of Present Value of the Defined Benefit Obligation and Net Liability

	Calendar Year 2011	Projected** Calendar Year 2012	Projected** Calendar Year 2013
Present Value of Defined Benefit Obligation as at December 31	9,548,794	9,982,709	10,461,376
Unfunded Present Value of Obligation	9,548,794	9,982,709	10,461,376
Unrecognized Actuarial (Loss)/Gain	(759,336)	(759,336)	(759,336)
Unrecognized Past Service (Cost)/Gain	-	-	-
Assets as at December 31	-	-	-
Net Liability/(Asset) as at December 31	8,789,458	9,223,374	9,702,041

* based on estimated employer Benefits Paid for those expected to be eligible for benefits

Projected calendar year 2012-2013 results are provided for informational purposes only. Significant changes in 2012-2013 such as re-negotiated benefits, increased benefit costs, or significant swings in demographics may require a full actuarial review.

Bluewater Power Distribution Corporation
ESTIMATED BENEFIT EXPENSE (IAS 19)
FINAL

	Calendar Year 2011	Projected** Calendar Year 2012	Projected** Calendar Year 2013
Discount Rate at January 1	5.00%	4.50%	4.50%
Discount Rate at December 31	4.50%	4.50%	4.50%
Salary Scale Rate	3.30%	3.30%	3.30%
Annual Increase in Healthcare Costs	-5.00%	7.63%	7.25%
Annual Increase in Dental Costs	5.00%	5.00%	5.00%
Withdrawal Rate	2.00%	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*	expected*

E. Calculation of Component Items

	Calendar Year 2011	Projected** Calendar Year 2012	Projected** Calendar Year 2013
Calculation of the Current Service Cost			
- Current Service Cost	220,984	293,142	330,848
Interest Cost			
- Present Value of Defined Benefit Obligation as at January 1	8,418,225	9,548,794	9,982,709
- Current Service Cost	220,984	293,142	330,848
- Benefits Paid	(137,420)	(147,733)	(154,665)
- Accrued Benefits	8,501,789	9,694,203	10,158,892
- Interest Cost	425,089	436,239	457,150
Expected Return on Plan Assets			
- Assets at January 1	-	-	-
- Funding	(137,420)	(147,733)	(154,665)
- Benefits Paid	137,420	147,733	154,665
- Expected Assets	-	-	-
- Interest Cost	-	-	-
Expected Present Value of Defined Benefit Obligation as at December 31			
- Present Value of Defined Benefit Obligation as at January 1	8,418,225	9,548,794	9,982,709
- Current Service Cost	220,984	293,142	330,848
- Interest Cost	425,089	436,239	457,150
- Benefits Paid	(274,841)	(295,466)	(309,331)
- Expected Present Value of Defined Benefit Obligation as at December 31	8,789,458	9,982,709	10,461,376
Expected Assets as at December 31			
- Assets as at January 1	-	-	-
- Funding	(274,841)	(295,466)	(309,331)
- Interest on Assets	-	-	-
- Benefits Paid	274,841	295,466	309,331
- Expected Assets as at December 31	-	-	-

Projected calendar year 2012-2013 results are provided for informational purposes only. Significant changes in 2012-2013 such as re-negotiated benefits, increased benefit costs, or significant swings in demographics may require a full actuarial review.

Bluewater Power Distribution Corporation
ESTIMATED BENEFIT EXPENSE (IAS 19)
FINAL

	Calendar Year 2011	Projected** Calendar Year 2012	Projected** Calendar Year 2013
Discount Rate at January 1	5.00%	4.50%	4.50%
Discount Rate at December 31	4.50%	4.50%	4.50%
Salary Scale Rate	3.30%	3.30%	3.30%
Annual Increase in Healthcare Costs	-5.00%	7.63%	7.25%
Annual Increase in Dental Costs	5.00%	5.00%	5.00%
Withdrawal Rate	2.00%	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*	expected*

F. Actuarial Loss/(Gain)

	Calendar Year 2011	Projected** Calendar Year 2012	Projected** Calendar Year 2013
Required Amortization of Unamortized Net Actuarial Gain			
- Actual Present Value of Defined Benefit Obligation as at January 1	8,418,225	9,548,794	9,982,709
- 10% of Present Value of Obligation	841,823	954,879	998,271
- Unamortized Actuarial Loss/(Gain) January 1	-	759,336	759,336
- Amount subject to amortization	-	-	-
Expected Average Remaining Service Life (Years)	13	12	11
Minimum Required Amortization for Current Year	-	-	-
Loss/(Gain) on Present Value of Defined Benefit Obligation as at December 31 due to Change in Discount Rate Assumption			
- Expected Present Value of Defined Benefit Obligation	8,789,458	9,982,709	10,461,376
- Actual Present Value of Defined Benefit Obligation	9,548,794	9,982,709	10,461,376
- Actuarial Loss/(Gain) on Present Value of Defined Benefit Obligation	759,336	-	-
Total Loss/(Gain) as at January 1	759,336	759,336	759,336
Actual Amortization for Current Year	-	-	-
Unamortized Loss/(Gain) as at December 31	759,336	759,336	759,336

** assumes that Bluewater Power Distribution Corporation continues with their current method of recognizing actuarial gains and losses.

Projected calendar year 2012-2013 results are provided for informational purposes only. Significant changes in 2012-2013 such as re-negotiated benefits, increased benefit costs, or significant swings in demographics may require a full actuarial review.

Exhibit 4: Operating Costs

Tab 5 (of 8): Corporate Cost Allocation

SHARED SERVICES & CORPORATE COST ALLOCATION

Bluewater Power is a mid-sized distributor and shares employees with, and provides services to, affiliates in an effort to benefit from economies of scope by sharing costs that would otherwise be passed on to ratepayers. Further background is provided elsewhere in this pre-filed evidence, but provided below is a description of the Transfer Pricing Study undertaken by Bluewater Power in contemplation of this 2013 COS filing, which led to fine tuning of the allocation methodologies used for the 2013 Test Year.

This schedule provides the context for Appendix 2-N, which is entitled “Shared Services and Corporate Cost Allocation”. The Appendix is included as Exhibit 4, Tab 5, Schedule 1, Attachment 1. Included in the text below is the quantitative and qualitative variance analysis required by the Filing Guidelines for the years 2009 Board Approved to 2013 Test Year and for 2011 Actuals to 2013 Test Year. In completing Appendix 2-N and the variance analysis, certain assumptions were required and those are also addressed below under the heading “Assumptions Required”.

In summary, Bluewater Power’s effort to allocate costs that would otherwise form part of OM&A claimed from ratepayers during the 2013 Test Year amount to a reduction of $435,368. In addition, the affiliates provide revenue to Bluewater Power that serve as Revenue Offsets amounting to $122,778 during the 2013 Test Year. This reduction and revenue offset does not include capital work performed by affiliates, which is less predictable and, in any event, does not affect the OM&A claimed from customers through distribution rates.

Background:

The relationship between Bluewater Power and its affiliates is explored in Exhibit 1, Tab 1, Schedule 10 entitled “Corporate Organization”. That schedule describes each of the affiliates, which are defined in that schedule as BPSC, Genco, BPREI and Electek. The “Corporate Organization” schedule contains a high level description of each company, its employees and the nature of activities undertaken in the affiliate company.

Further background is provided in Exhibit 1, Tab 2, Schedule 8 entitled “Affiliate Transactions”. That schedule speaks to the nature of shared services and speaks to two efforts undertaken to review Bluewater Power’s affiliate transactions. First, the voluntary Transfer Pricing Study undertaken by Bluewater Power discussed further in this Exhibit. Second, an OEB initiated Regulatory Compliance Audit was undertaken by the Board’s Regulatory Audit and Accounting division this past summer, which resulted in a Report dated August 30, 2012 that is enclosed as Exhibit 1, Tab 2, Schedule 8, Attachment 1.

In general, Bluewater Power provides administrative services to its affiliates through the following departments: Finance, Human Resources, Information Technology, Purchasing, Client Services, Legal and Management. Management Services Agreements and Cost Sharing Agreements have been in place for each affiliate as each affiliate became active in their respective business. Those agreements and the allocation practices and methodologies have been reviewed and refined over the years.

In 2012, Bluewater Power contracted the services of BDR North America Inc. to further review our Transfer Pricing practices and methodologies. The review took place over several months and resulted in further changes to the practices employed by Bluewater Power to allocate costs to affiliates. The Transfer Pricing Study was undertaken voluntarily by Bluewater Power in contemplation of the 2013 COS Application. The changes in practice, therefore, have been reflected in revised Management Services Agreements and Cost Sharing Agreements approved by our Board of Directors on September 27, 2012 to be effective January 1, 2013 for the 2013 Test Year and beyond. The revised Agreements are filed as Exhibit 1, Tab 2, Schedule 8, Attachments 2 through 7.

The Transfer Pricing Study can be found at Exhibit 4, Tab 5, Schedule 1, Attachment 2 entitled *“Study of Affiliate Service Costs and Cost Allocation”.* The study is presented as expert evidence and the attachment includes the Curriculum Vitae of the author, Paula Zarnett of BDR North America Inc.

A summary of methodologies utilized in sharing services from Bluewater Power to affiliates can be found in the Study as Table ES:1 entitled “Services Provided by BPDC to Affiliates". The results of the Study, as summarized in the table, indicate that Bluewater Power's methodologies are "considered appropriate".

Furthermore, a summary of methodologies utilized in procuring services from affiliates can be found in the Study as Table ES:2 entitled "Services Procured by BPDC from Affiliates". The results of the Study with respect to those activities, as summarized in the table, indicate that the methodologies are "considered appropriate" (or "acceptable" in the case of meter-reading services for which market-based pricing cannot be determined due to the unique nature of the on-demand services required).

Assumptions:

The Filing Guidelines require the completion of Appendix 2-N, as well as a variance analysis for 2009 Approved to the 2013 Test Year and for 2011 Actuals to the 2013 Test Year. Appendix 2-N is attached as Exhibit 4, Tab 5, Schedule 1, Attachment 1 and the variance analyses are included below as Table 1 and Table 2. The completion of each analysis required certain assumptions as follows:

- As discussed elsewhere in this Application, any comparison with 2009 Board Approved presents a challenge because the approved amount was the result of a settlement reached with Intervenors and approved by the Board. For the purposes of the analysis of Shared Costs and Corporate Allocations we have assumed that the amounts applied for in the 2009 COS Application were not affected by the settlement.

- There is a further challenge for the 2009 Board Approved in respect of capital work undertaken by affiliates on behalf of Bluewater Power. Capital projects are budgeted without consideration of who will undertake the work; whether the work is undertaken by an affiliate or a third party has no impact on OM&A. However, for the purposes of this analysis we have assumed a reasonable level of capital work by affiliates for Bluewater Power as follows:
    - 2009 Board Approved: For all charges from affiliates to Bluewater Power shown in Table 1 and Appendix 2-N, the amounts for 2009 Board

Approved have been set at 2009 Actuals for consistency and comparison purposes.

- 2013 Test Year: For 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.

- Appendix 2-N has been completed to include each service from Bluewater Power to each affiliate separately, with a sub-total provided. The sub-total for each service is the amount reflected in the Variance Analysis provided in Table 1. To the extent there is a difference between price and cost, Table 1 has been presented with the cost only as that amount is more meaningful for the variance analysis. Table 1 is provide in the interest of simplifying the information presented since full back-up information is provided in the appendix.

Variance Analysis for Shared Services

Table 1 – Cost for Shared Services

Name of Company		Service Offered	Pricing Methodology	2009 Board Approved	2011	2013
From	To			$	$	$
Distco	*Affiliates*	management services	fully allocated cost	94,310	109,204	186,937
Distco	*Affiliates*	building rent	market value	19,200	21,900	17,200
Distco	*Affiliates*	vehicle rental	fully allocated cost	20,800	46,642	50,176
Distco	*Affiliates*	Interest on Advances	market value	-	12,369	-
Distco	*BPSC*	Water ROIC	market value	-	43,092	55,402
Distco	*BPSC*	Water Billing costs	fully allocated cost		222,565	123,885
Distco	*Municipal Affiliates*	Water Billing costs	Market value	459,979	121,998	
Distco	*Affiliates*	3rd Party Billable	fully allocated cost	-	23,358	-
Distco	*BPSC*	Asset sales-vehicle & stock	market value	-	47,405	-
Distco	*Affiliates*	Shared Staff	fully allocated cost	-	186,601	116,490
BPSC	*Distco*	Capital	market value	264,396	439,021	200,000
BPSC	*Distco*	Repair & Maintenance Work	market value	150,457	116,596	90,000
BPSC	*Distco*	Pass Through -Streetlight Install	market value	75,169	101,120	80,000
BPSC	*Distco – OPA*	OPA programs	market value	-	61,841	50,000
BPSC	*Distco*	3rd Party Billable	market value	60,862	157,456	95,000
Electek	*Distco*	building rent	market value	-	2,375	-
Electek	*Distco*	Capital	market value	40,529	127,421	30,000
Electek	*Distco*	Repair & Maintenance Work	market value	37,908	85,364	25,000
Electek	*Distco*	3rd Party Billable	market value	-	4631	-

Management Services

The 2009 Board Approved included revenue from affiliates for management services and was fully detailed in the 2009 COS Application at Exhibit 3, Tab 3, Schedule 4 (EB 2008-0221). They were identified to be $94,310 in 2009. The 2011 Actual included allocation for management services paid under the Management Services Agreements in place at the time and are identified as $109,204 of revenue. The 2013 Test Year includes forecast management services in the amount of $186,937 as identified in the Management Services Agreements, which are now treated as OM&A offsets rather than revenue, although the impact on rates is identical.

The upward trend in charges to affiliates for management services represents both the growth of the affiliates and the effort by Bluewater Power to review management agreements from time-to-time. More specifically, the efforts undertaken as a result of the most recent review undertaken through the Transfer Pricing Study identified new costs that had not previously been allocated, including Board of Director costs and staff below the senior management level providing services to affiliates.

Building Rent

BPSC rents office space and storage space from Bluewater Power. The 2009 Board Approved amount includes an allocation that was an estimate of the market value of the space ($19,200). The amount charged is a slight increase in 2011 Actuals to $21,900. There is a modest reduction in the 2013 Test Year to $17,200 to reflect the results of the Transfer Pricing Study. As discussed in the Transfer Pricing Study, the rental rates for office and warehouse space were revised to reflect market value as established through a survey of comparable spaces within the service territory. Those market rates were then applied to actual square footage of the space to be rented and utilized during the 2013 Test Year and incorporated into the revised Cost Sharing Agreements, as appropriate.

Vehicle Rent

BPSC rents vehicles owned by Bluewater Power from time to time as required. The actual hours are tracked to a work order system and a standard hourly charge is applied which includes fuel, license, insurance, maintenance, depreciation and cost of capital. This hourly charge represents the fully allocated cost of the vehicles over their estimated usage. The increase from $20,800 in the 2009 Board Approved to $46,642 in the 2011 Actuals reflects the increase in the level of work undertaken by BPSC. We have forecast a further modest increase to $50,176 for the 2013 Test Year.

Interest on Advances

Bluewater Power has, on occasions, provided cash advances to affiliates. Such advances are subject to a market based prime interest lending rate. Table 1 demonstrates that interest payments were received by Bluewater Power in 2011. By the end of year 2012, all cash advances are forecast to be repaid with no future advances anticipated.

Water – Return on Invested Capital (ROIC)

The Return on Invested Capital (ROIC) for Water represents the return to ratepayers at the WACC for that portion of the capital investment in the Bluewater Power billing system determined to be related to the water billing function. For the year 2009-March 31, 2011, there is a recovery of ROIC but it is included in the Water Billing Costs discussed next. The ROIC and the Water Billing Costs both went to Account 4380 – “Expenses of Non Rate-regulated Utility Operations” up until March 31, 2011.

As discussed in Exhibit 1, Tab 1, Schedule 10, the water billing function began to be performed by BPSC starting April 1, 2011. Accordingly, the ROIC for water billing in 2011 only reflects nine months of ROIC. The amount included as ROIC in the 2013 Test Year is the revised amount reviewed by BDR North America Inc. as part of its Transfer Pricing Study.

Water Billing Costs

Bluewater Power provided water billing services for the City of Sarnia and the Town of Petrolia since the year 2005. For the years 2009, 2010 and 2011, the costs and price are shown in Appendix 2-N and Table 1 as between “Distco” and the “Municipal Affiliates” which would include Sarnia and Petrolia. The price is considered a market value since it represents a negotiated price based on benchmarking and that price exceeds the fully-allocated costs, all as required by the *Affiliate Relationships Code*.

On March 31, 2011, Bluewater Power's contract to provide water billing services to Sarnia and Petrolia expired. On April 1, 2011, the service began to be provided by BPSC; however, Bluewater Power continued to provide billing services that were charged to BPSC on a fully-allocated cost basis and Bluewater Power earned a ROIC on its water billing asset shared with the affiliate. The service provided by Bluewater Power represents only part of the billing service. Accordingly, there is no market for the suite of services that Bluewater Power provides and the Affiliate Relationships Code requires the charges to be based on the fully-allocated cost.

Accordingly, the variance in the cost from 2009 to 2011 to 2013 is driven by the change in the nature of the services being provided by Bluewater Power.

The costs for 2009, 2010 and for 3 months of 2011 are costs incurred by Bluewater Power to provide billing services which included all fully allocated costs for billing, meter reading, customer service, and all associated support and management functions. The costs reflected in the 2009 Board Approved amount are taken from Exhibit 4, Tab 2, Schedule 7 (EB-2008-0221). For 2010, and the first three months of 2011, these costs are adjusted by 3% each year for the costs shown in Appendix 2-N and in Table 1 above.

The costs for 2011, 2012 and 2013 are shown as between "Distco" and BPSC under the headings of both ROIC and Water Billing Costs. (Note: the year 2011 is therefore a split year where costs are shown as between DistCo and Municipal affiliates for the first 3 months and as between Distco and BPSC for the last 9 months).

The costs for the year 2011, 2012 and 2013 are costs incurred by Bluewater Power to provide access to its billing system, meter reading (until 2012), and customer service. As of April 1, 2011, one full-time billing representative was transferred from Bluewater Power to BPSC, thereby eliminating the need to share staff with Bluewater Power for a billing representative; although this change is only reflected in the last nine months of 2011, this drives the variance between the 2009 and 2011 when one looks at the sum of the charges to BPSC and the Municipal Affiliates. A further change in the nature of the service occurred in 2012 when Bluewater Power transitioned to smart meters and thereby alleviated its need for manual reads at the utility. Given that Bluewater Power still requires manual reads for non-smart metered customers, in 2013 BPDC will share a ½ FTE from the two meter readers transferred to BPSC in 2012. The transfer of meter reading staff drives the variance in comparison of 2013 Test Year and 2011 Actual.

Third-Party Billable

In 2011, BPSC completed work for a billable customer that included materials and labour purchased from Bluewater Power. This was an extraordinary situation in 2011 and is not expected to be repeated. There were no other billable projects of this nature in 2011 and none are projected for 2013 Test Year.

Asset Sales - Vehicle & Inventory

In 2011, a vehicle was sold by Bluewater Power to BPSC. The cost of the vehicle was set by the fleet manager for Bluewater Power at the fair market value. Additionally, in 2011 BPSC also purchased various stock inventory for future billable jobs. The costs for materials are based on fully allocated costs plus an inventory stocking charge as described in the Transfer Pricing Study. There were no asset sales, nor inventory sales, to affiliates in 2009 and none are anticipated for the 2013 Test Year.

Shared Staff

In order to optimize efficiencies, Bluewater Power shares staff with affiliates as required. Shared staff is allocated based on actual time docketed on time sheets. The 2011 Actual of $186,601 represents, for the most part, the level of demand work provided to the private sector through BPSC utilizing shared Bluewater Power staff. As such, the variance between 2013 Test Year and 2011 Actual represents an anticipated dampened demand for services, primarily linework in chemical valley, due to the downturn in the economy and as seen locally in 2012.

Variances Analysis for Purchased Services from BPSC

The Transfer Pricing Study included as Exhibit 4, Tab 5, Schedule 1, Attachment 2 describes the pricing methodology for services purchased by Bluewater Power from affiliates, including BPSC. The methodology is based on market price and the prices charged by BPSC to Bluewater Power have remained stable; the variance from 2009 hourly rates are forecast to increase by a total of less than 5% over the four year period ending in 2013. Therefore, the driver of the annual variances reflects changes in the level of demand for work.

Capital

Bluewater Power contracts BPSC to conduct capital work on an as needed basis. The nature of the capital work can consist of civil excavation for the installation of underground vaults, hydro vacuum excavation for the installation of new pole lines, and the installation of wire for new customer connections. For comparison purposes in Table 1, Bluewater Power has provided 2009 Actuals (as discussed earlier) when comparing 2009 Board Approved to 2011 Actuals. Similarly, the values reported for the 2013 Test Year are based on reasonable forecasts since no amount is built into Bluewater Power's capital budget. The variances from year to year are driven by the extent of capital work conducted by Bluewater Power in any given year, which dictates the demand for services of the nature that BPSC provides. Whether the work will be undertaken by Bluewater Power, an affiliate or a third-party depends upon the particular circumstances.

The variances in Table 1 demonstrate that 2011 was a high demand year ($439,021), which was dictated by both capital work and billable work undertaken by Bluewater Power. The level of demand in 2009 led to goods and services valued at $264,396. For the purposes of this analysis, only, we have forecast $200,000 in the 2013 Test Year.

Repair & Maintenance

Bluewater Power contracts BPSC to conduct repair and maintenance work on Bluewater Power equipment and facilities on an as needed basis. As a general-rule, BPSC provides Bluewater Power with its on-demand civil excavation work, with the exception of directional drilling which is performed by a third party. In addition to civil excavation, BPSC provides on an as-needed basis general repair and maintenance for Bluewater Power's facilities such as sub-stations.

The variances in Table 1 demonstrate that 2009 was the high year for demand in relation to Repair and Maintenance, with an amount of $150,457. The decrease to $116,596 in 2011 Actuals reflects that demand was low for Repair & Maintenance work because demand for capital and billable work was high in that year. The forecast for 2013 included with this analysis reflects a further decline to $90,000.

Pass-through Streetlight Install

BPSC is contracted by developers through Bluewater Power to install new street lighting facilities in new sub-divisions and developments. These costs are described as pass-through because 100% of the cost paid to BPSC is paid by developers through Bluewater Power. The role of the utility is limited to providing BPSC's cost estimates to developers and, if the developer does not choose an alternate bid, the work is performed by BPSC and its charges are passed-through Bluewater Power to the developer with no mark-up.

The level of work is entirely driven by demand from developers. Variances are attributed to the level of demand from developers, which is a reflection of the economic conditions in Bluewater Power's territory. The costs are relatively stable from year-to-year, with $75,169 in 2009, $101,120 in 2011 and $80,000 forecast for the 2013 Test Year.

OPA Programs

Bluewater Power provides Ontario Power Authority C&DM programs to its electricity consumers. In 2010, as a result of an RFP, BPSC was selected as the sub-contractor to provide administration and installation services for the PeakSaver program on behalf of Bluewater Power. In 2011, through the use of benchmarking using RFP results for other LDCs, BPSC began to provide administration of the Direct Install Small Business Lighting Program on behalf of Bluewater Power. A third program, the OPA Low Income Home Assistance Program has been awarded to BPSC in 2012.

Accordingly, the variance between the 2011 Actual and the 2013 Test Year is a result of costs associated with BPSC providing services related to one additional program (OPA Low Income Home Assistance Program), assuming the continuation of the Direct Install Program (NOTE: at this point, we have not reached agreement on the continuation of the PeakSaver program in 2013 due to difficulties with the program). In any event, we note that all of these costs are passed through to the OPA and have no impact on Bluewater Power ratepayers.

Third Party Billable

Bluewater Power receives requests to relocate its overhead or underground plant by customers for various reasons such as upgrades, new connections, or street widening requested by the road authority. As required depending upon the nature of the work, Bluewater Power may contract BPSC for civil excavation, hydro vacuum excavation and street light relocation. The costs for these services are passed on to the third party requesting the services. This work is entirely dependent upon demand from parties beyond the control of Bluewater Power and the variances are attributed to the demand for work from these third parties.

The amounts shown in Table 1 clearly demonstrates the level of demand experienced in the 2011 Actuals, rising from $60,862 in 2009 to $157,456 in 2011. The forecast included for the purposes of this analysis in the 2013 Test Year is $95,000.

Variances Analysis for Purchased Services from Electek

The Transfer Pricing Study included as Exhibit 4, Tab 5, Schedule 1, Attachment 2 describes the pricing methodology for services purchased by Bluewater Power from affiliates, including Electek. The methodology is based on market price and the prices charged by Electek to Bluewater Power have remained stable; the variance from 2009 hourly rates are forecast to increase by a total of less than 5% over the four year period ending in 2013. Therefore, the driver of the annual variances reflects changes in the level of demand for work.

Building Rent

Due to a lack of available facilities at Bluewater Power's head office, in 2011, a Bluewater Power employee conducted business utilizing office space located at Electek. Rent was paid by Bluewater Power to Electek for use of this office space at market rate. This space was not rented to Bluewater Power in 2009 and is not anticipated to be utilized in 2013.

Capital

Bluewater Power contracts Electek to conduct capital work on an as needed basis. The nature of the capital work typically consists of commissioning of high voltage transformers and sub-stations. Annual variances are driven by the extent of Capital work conducted by Bluewater Power in any given year. The amounts shown in Table 1 clearly demonstrates the level of demand experienced in the 2011 Actuals, rising from $40,529 in 2009 to $127,421 in 2011. The forecast included for the purposes of this analysis in the 2013 Test Year is $30,000.

To demonstrate the benefit of having an affiliate being available to provide services on demand, we provide the 2011 example of Electek assisting with poly-phase Smart Meters. These poly-phase installations were not included in the mass installation contract, but Bluewater Power obtained pricing from multiple service providers; the prices submitted were twice the cost of performing the work "in-house". Although the work was primarily conducted "in-house" with Bluewater Power personnel, the level of workload and the pending deadline meant that Bluewater Power called upon Electek to assist with the installations and the total of internal cost and Electek charges remained half of the bid price received from third parties.

Repair & Maintenance

Bluewater Power contracts Electek to conduct repair and maintenance work on an as needed basis, such as transformer maintenance and sub-station maintenance. This type of work has historically been conducted by Electek, including prior to Electek being purchased by Bluewater Power Corporation in 2007. As such, this highly skilled high voltage work continues to be provided to Bluewater Power from Electek. Variances year over year are attributable to the unique nature of the work performed by Electek and the need for this work based on the types of projects undertaken Bluewater Power.

The amounts shown in Table 1 demonstrate the level of demand experienced in the 2011 Actuals, rising from $37,908 in 2009 to $85,364 in 2011. The forecast included for the purposes of this analysis in the 2013 Test Year is $25,000.

Third Party Billable

In 2009, Bluewater Power completed work that was charged to a Third Party. As part of that work Electek was contracted to complete a small portion of the work. There was no work of this nature in 2011 and Bluewater Power does not anticipate this type of work occurring in 2013.

Corporate Cost Allocation for Board of Director Costs

Table 2 below summarizes the results of Corporate Cost Allocations from Bluewater Power to affiliates. The only corporate cost that is allocated on a percentage basis relates to Board of Director Costs. 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.

<u>Table 2 – Corporate Cost Allocation</u>

Name of Company		Service Offered	Pricing Methodology	2009 Approved Costs	2011 *Costs*	2013 Costs
From	To					
				$	$	$
Distco	*Genco*	Board of Directors		-	-	106
Distco	*BPREI*	Board of Directors		-	-	4,409
Distco	*Servco*	Board of Directors		-	-	2,036
Distco	*Electek*	Board of Directors		-	-	1,505

File Number:	EB-2012-0107
Exhibit:	4
Tab:	5
Schedule:	1
Attachment	1
Date:	22-Oct-2012

Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: **2013**

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	13,915	13,915
Distco	*BPSC*	management services	fully allocated cost	108,624	108,624
Distco	*Genco*	management services	fully allocated cost	2,386	2,386
Distco	*Electek*	management services	fully allocated cost	62,012	62,012
Genco	*Distco*	management services	fully allocated cost		
			Sub-Total	**186,937**	**186,937**
Distco	*Genco*	building rent	market value		
Distco	*BPREI*	building rent	market value		
Distco	*BPSC*	building rent	market value	17,200	17,200
			Sub-Total	**17,200**	**17,200**
Distco	*BPSC*	vehicle rental	market value	50,176	50,176
Distco	*Electek*	vehicle rental	market value		
			Sub-Total	**50,176**	**50,176**
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	55,402	55,402
Distco	*BPSC*	Water Billing costs	fully allocated cost	123,885	123,885
			Sub-Total	**179,287**	**179,287**
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		
Distco	*Electek*	3rd Party Billable	fully allocated cost		
Distco	*Genco*	3rd Party Billable	fully allocated cost		
			Sub-Total	**-**	**-**
Distco	*BPSC*	Asset sales-vehicle & stock	market value	-	-
Distco	*BPSC*	Shared Staff	fully allocated cost	76,816	76,816
Distco	*Electek*	Shared Staff	fully allocated cost	5,106	5,106
Distco	*BPREI*	Shared Staff	fully allocated cost	34,568	34,568
Distco	*Genco*	Shared Staff	fully allocated cost	-	-
			Sub-Total	**116,490**	**116,490**
Total				**550,090**	**550,090**
BPSC	Distco	Capital	market value	200,000	200,000
BPSC	Distco	Repair & Maintenance Work	market value	90,000	90,000
BPSC	Distco	HyrdoVac	market value		
BPSC	Distco	Pass Through -Streetlight Install	market value	80,000	80,000
BPSC	Distco - OPA	OPA programs	market value	50,000	50,000
BPSC	Distco	3rd Party Billable	market value	95,000	95,000
BPSC	Distco	commercial meter reading	fully allocated cost		
BPSC	Distco	Shared Staff	fully allocated cost		
			Sub-Total	**515,000**	**515,000**
Electek	Distco	building rent	market value	-	-
Electek	Distco	Capital	market value	30,000	30,000
Electek	Distco	Repair & Maintenance Work	market value	25,000	25,000
Electek	Distco	3rd Party Billable	market value		
			Sub-Total	**55,000**	**55,000**
				1,120,090	**1,120,090**

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Distco	*Genco*	Board of Directors		0.12%	106
Distco	*BPREI*	Board of Directors		4.98%	4,409
Distco	*BPSC*	Board of Directors		2.30%	2,036
Distco	*Electek*	Board of Directors		1.70%	1,505
				Total	8,056

Note:

1 **This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years.**

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Genco = Bluewater Power Generation Corporation
BPREI = Bluewater Power Renewable Energy Inc.
Distco - OPA = non-utility OPA program costs

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Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2012

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	48,500	48,500
Distco	*Electek*	vehicle rental	market value		
			Sub-Total	**48,500**	**48,500**
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	*BPSC*	Water Billing costs	fully allocated cost	166,192	166,192
			Sub-Total	**222,269**	**222,269**
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		
Distco	*Electek*	3rd Party Billable	fully allocated cost		
Distco	*Genco*	3rd Party Billable	fully allocated cost		
			Sub-Total	**-**	**-**
Distco	*BPSC*	Asset sales-vehicle & stock	market value	-	-
Distco	*BPSC*	Shared Staff	fully allocated cost	104,727	104,727
Distco	*Electek*	Shared Staff	fully allocated cost	3,284	3,284
Distco	*BPREI*	Shared Staff	fully allocated cost	43,443	43,443
Distco	*Genco*	3rd Party Billable	fully allocated cost		
			Sub-Total	**151,454**	**151,454**
Total				**550,863**	**550,863**
BPSC	Distco	Capital	market value	311,500	311,500
BPSC	Distco	Repair & Maintenance Work	market value	95,000	95,000
BPSC	Distco	HyrdoVac	market value	105,000	105,000
BPSC	Distco	Pass Through -Streetlight Install	market value	90,000	90,000
BPSC	Distco - OPA	OPA programs	market value		
BPSC	Distco	3rd Party Billable	market value		
BPSC	Distco	commercial meter reading	fully allocated cost		
BPSC	Distco	Shared Staff	fully allocated cost		
			Sub-Total	**601,500**	**601,500**
Electek	Distco	building rent	market value	-	-
Electek	Distco	Capital	market value		
Electek	Distco	Repair & Maintenance Work	market value		
Electek	Distco	3rd Party Billable	market value		
			Sub-Total	**-**	**-**
				1,152,363	**1,152,363**

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:

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Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2011

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	54,001	54,001
Distco	*Genco*	management services	fully allocated cost	9,888	9,888
Distco	*Electek*	management services	fully allocated cost	41,715	41,715
Distco	*Genco*	building rent	fully allocated cost	-	-
			Sub-Total	**109,204**	**109,204**
Distco	*Genco*	building rent	market value		
Distco	*BPREI*	building rent	market value		
Distco	*BPSC*	building rent	market value	21,900	21,900
			Sub-Total	**21,900**	**21,900**
Distco	*BPSC*	vehicle rental	market value	46,642	46,642
Distco	*Electek*	vehicle rental	market value	-	-
			Sub-Total	**46,642**	**46,642**
Distco	*Genco*	Interest on Advances	market value	2,631	2,631
Distco	*BPREI*	Interest on Advances	market value	2,930	2,930
Distco	*BPSC*	Interest on Advances	market value	6,808	6,808
			Sub-Total	**12,369**	**12,369**
Distco	*BPSC*	Water ROIC	fully allocated cost	43,092	43,092
Distco	*BPSC*	Water Billing costs	fully allocated cost	222,565	222,565
Distco	*Municipal Affiliates*	Water Billing costs	market value	171,218	121,998
			Sub-Total	**436,875**	**387,655**
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	16,582	16,582
Distco	*Electek*	3rd Party Billable	fully allocated cost	4,477	4,477
Distco	*Genco*	3rd Party Billable	fully allocated cost	2,299	2,299
			Sub-Total	**23,358**	**23,358**
Distco	*BPSC*	Asset sales-vehicle & stock	market value	47,405	47,405
Distco	*BPSC*	Shared Staff	fully allocated cost	122,596	122,596
Distco	*Electek*	Shared Staff	fully allocated cost	17,879	17,879
Distco	*BPREI*	Shared Staff	fully allocated cost	46,126	46,126
Distco	*Genco*	Shared Staff	fully allocated cost		
			Sub-Total	**186,601**	**186,601**
Total				**884,354**	**835,134**
BPSC	Distco	Capital	market value	439,021	439,021
BPSC	Distco	Repair & Maintenance Work	market value	116,596	116,596
BPSC	Distco	HyrdoVac	market value		
BPSC	Distco	Pass Through -Streetlight Install	market value	101,120	101,120
BPSC	Distco - OPA	OPA programs	market value	61,841	61,841
BPSC	Distco	3rd Party Billable	market value	157,456	157,456
BPSC	Distco	commercial meter reading	fully allocated cost		
BPSC	Distco	Shared Staff	fully allocated cost		
			Sub-Total	**876,034**	**876,034**
Electek	Distco	building rent	market value	2,375	2,375
Electek	Distco	Capital	market value	127,421	127,421
Electek	Distco	Repair & Maintenance Work	market value	85,364	85,364
Electek	Distco	3rd Party Billable	market value	4,631	4,631
			Sub-Total	**219,791**	**219,791**
				1,980,179	**1,930,959**

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
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Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2010

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	7,200	7,200
Distco	*BPSC*	management services	fully allocated cost	55,872	55,872
Distco	*Genco*	management services	fully allocated cost	9,600	9,600
Distco	*Electek*	management services	fully allocated cost	40,500	40,500
Genco	*Distco*	management services	fully allocated cost	15,000	15,000
			Sub-Total	**128,172**	**128,172**
Distco	*Genco*	building rent	market value	3,600	3,600
Distco	*BPREI*	building rent	market value		
Distco	*BPSC*	building rent	market value	24,000	24,000
			Sub-Total	**27,600**	**27,600**
Distco	*BPSC*	vehicle rental	market value	85,454	85,454
Distco	*Electek*	vehicle rental	market value	2,750	2,750
			Sub-Total	**88,204**	**88,204**
Distco	*Genco*	Interest on Advances	market value	3,968	3,968
Distco	*BPREI*	Interest on Advances	market value	9,932	9,932
Distco	*BPSC*	Interest on Advances	market value	8,654	8,654
			Sub-Total	**22,554**	**22,554**
Distco	*BPSC*	Water ROIC	fully allocated cost		
Distco	*Municipal Affiliates*	Water Billing costs	market value	667,557	473,778
			Sub-Total	**667,557**	**473,778**
Distco	*BPSC*	Capital Work	fully allocated cost	3,660	3,660
Distco	*BPREI*	Capital Work	fully allocated cost	-	-
			Sub-Total	**3,660**	**3,660**
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		
Distco	*Electek*	3rd Party Billable	fully allocated cost	-	-
Distco	*Genco*	3rd Party Billable	fully allocated cost	2,598	2,598
			Sub-Total	**2,598**	**2,598**
Distco	*BPSC*	Asset sales-vehicle & stock	market value	66,934	66,934
Distco	*BPSC*	Shared Staff	fully allocated cost	173,938	173,938
Distco	*Electek*	Shared Staff	fully allocated cost	20,039	20,039
Distco	*BPREI*	Shared Staff	fully allocated cost		
Distco	*Genco*	Shared Staff	fully allocated cost		
			Sub-Total	**193,977**	**193,977**
Total				**1,201,256**	**1,007,477**
BPSC	Distco	Capital	market value	263,710	263,710
BPSC	Distco	Repair & Maintenance Work	market value	147,578	147,578
BPSC	Distco	HyrdoVac	market value		
BPSC	Distco	Pass Through -Streetlight Install	market value	190,571	190,571
BPSC	Distco - OPA	OPA programs	market value	125,073	125,073
BPSC	Distco	3rd Party Billable	market value	254,319	254,319
BPSC	Distco	commercial meter reading	fully allocated cost	7,721	7,721
BPSC	Distco	Shared Staff	fully allocated cost		
			Sub-Total	**988,972**	**988,972**
Electek	Distco	building rent	market value		
Electek	Distco	Capital	market value	51,524	51,524
Electek	Distco	Repair & Maintenance Work	market value	130,790	130,790
Electek	Distco	3rd Party Billable	market value		
			Sub-Total	**182,314**	**182,314**
				2,372,542	**2,178,763**

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:

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Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: **2009**

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	6,000	6,000
Distco	*BPSC*	management services	fully allocated cost	51,560	51,560
Distco	*Genco*	management services	fully allocated cost	8,000	8,000
Distco	*Electek*	management services	fully allocated cost	52,050	52,050
Genco	*Distco*	management services	fully allocated cost		
			Sub-Total	**117,610**	**117,610**
Distco	*Genco*	building rent	market value	5,400	5,400
Distco	*BPREI*	building rent	market value		
Distco	*BPSC*	building rent	market value	21,584	21,584
			Sub-Total	**26,984**	**26,984**
Distco	*BPSC*	vehicle rental	market value	80,916	80,916
Distco	*Electek*	vehicle rental	market value	-	-
			Sub-Total	**80,916**	**80,916**
Distco	*Genco*	Interest on Advances	market value	2,211	2,211
Distco	*BPREI*	Interest on Advances	market value	4,213	4,213
Distco	*BPSC*	Interest on Advances	market value	9,238	9,238
			Sub-Total	**15,662**	**15,662**
Distco	*BPSC*	Water ROIC	fully allocated cost		
Distco	*Municipal Affiliates*	Water Billing costs	market value	668,022	459,979
			Sub-Total	**668,022**	**459,979**
Distco	*BPSC*	Capital Work	fully allocated cost	15,417	15,417
Distco	*BPREI*	Capital Work	fully allocated cost	21,845	21,845
			Sub-Total	**37,262**	**37,262**
Distco	*BPSC*	Repair & Maintenance Work	fully allocated cost	41,187	41,187
Distco	*Electek*	Repair & Maintenance Work	fully allocated cost	30,830	30,830
			Sub-Total	**72,017**	**72,017**
Distco	*BPSC*	3rd Party Billable	fully allocated cost		
Distco	*Electek*	3rd Party Billable	fully allocated cost	6,183	6,183
Distco	*Genco*	3rd Party Billable	fully allocated cost	-	-
			Sub-Total	**6,183**	**6,183**
Distco	*BPSC*	Asset sales-vehicle & stock	market value	-	-
Distco	*BPSC*	Shared Staff	fully allocated cost	148,819	148,819
Distco	*Electek*	Shared Staff	fully allocated cost	23,238	23,238
Distco	*BPREI*	Shared Staff	fully allocated cost		
Distco	*Genco*	Shared Staff	fully allocated cost		
			Sub-Total	**172,057**	**172,057**
Total				**1,196,713**	**988,670**
BPSC	Distco	Capital	market value	264,396	264,396
BPSC	Distco	Repair & Maintenance Work	market value	150,457	150,457
BPSC	Distco	HyrdoVac	market value		
BPSC	Distco	Pass Through -Streetlight Install	market value	75,169	75,169
BPSC	Distco - OPA	OPA programs	market value	-	-
BPSC	Distco	3rd Party Billable	market value	60,862	60,862
BPSC	Distco	commercial meter reading	fully allocated cost		
BPSC	Distco	Shared Staff	fully allocated cost		
			Sub-Total	**550,884**	**550,884**
Electek	Distco	building rent	market value		
Electek	Distco	Capital	market value	40,529	40,529
Electek	Distco	Repair & Maintenance Work	market value	37,908	37,908
Electek	Distco	3rd Party Billable	market value		
			Sub-Total	**78,437**	**78,437**
				1,826,034	**1,617,991**

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:

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Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: **2009 Board Approved**

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	6,000	6,000
Distco	*BPSC*	management services	fully allocated cost	46,560	46,560
Distco	*Genco*	management services	fully allocated cost	8,000	8,000
Distco	*Electek*	management services	fully allocated cost	33,750	33,750
Genco	*Distco*	management services	fully allocated cost		
			Sub-Total	**94,310**	**94,310**
Distco	*Genco*	building rent	market value	7,200	7,200
Distco	*BPREI*	building rent	market value	-	-
Distco	*BPSC*	building rent	market value	12,000	12,000
			Sub-Total	**19,200**	**19,200**
Distco	*BPSC*	vehicle rental	market value	20,800	20,800
Distco	*Electek*	vehicle rental	market value		
			Sub-Total	**20,800**	**20,800**
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		
Distco	*Municipal Affiliates*	Water Billing costs	market value	668,022	459,979
			Sub-Total	**668,022**	**459,979**
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		
Distco	*Electek*	3rd Party Billable	fully allocated cost		
Distco	*Genco*	3rd Party Billable	fully allocated cost		
			Sub-Total	**-**	**-**
Distco	*BPSC*	Asset sales-vehicle & stock	market value	-	-
Distco	*BPSC*	Shared Staff	fully allocated cost		
Distco	*Electek*	Shared Staff	fully allocated cost		
Distco	*BPREI*	Shared Staff	fully allocated cost		
Distco	*Genco*	Shared Staff	fully allocated cost		
			Sub-Total	**-**	**-**
Total				**802,332**	**594,289**
BPSC	Distco	Capital	market value		
BPSC	Distco	Repair & Maintenance Work	market value		
BPSC	Distco	HyrdoVac	market value		
BPSC	Distco	Pass Through -Streetlight Install	market value		
BPSC	Distco - OPA	OPA programs	market value		
BPSC	Distco	3rd Party Billable	market value		
BPSC	Distco	commercial meter reading	fully allocated cost		
BPSC	Distco	Shared Staff	fully allocated cost		
			Sub-Total	**-**	**-**
Electek	Distco	building rent	market value		
Electek	Distco	Capital	market value		
Electek	Distco	Repair & Maintenance Work	market value		
Electek	Distco	3rd Party Billable	market value		
			Sub-Total	**-**	**-**
				802,332	**594,289**

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	-

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Distco - OPA = non-utility OPA program costs

STUDY OF AFFILIATE SERVICE COSTS AND COST ALLOCATION for Bluewater Power Distribution Corporation

October 10, 2012

BDR

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Table of Contents

EXECUTIVE SUMMARY

Introduction and Scope

Bluewater Power Distribution Corporation "BPDC" is a local electricity distributor ("LDC") distributing electricity to approximately 35,000 customers in the municipalities of the City of Sarnia, the Town of Petrolia, the Village of Point Edward, the Village of Oil Springs, the Township of Warwick and the Township of Brooke-Alvinston in south-western Ontario. BPDC is licensed by the Ontario Energy Board ("OEB") and subject to regulation of its rates and charges to consumers.

As is common among Ontario LDCs, BPDC shares goods and services with affiliates in order to benefit from economies of scale and thereby control the level of costs of providing services to customers.

BPDC provides the following services to affiliates:

- typical shared corporate services, including executive management, finance, payroll, human resources, information technology services, purchasing and warehousing; and
- other services including building occupancy; customer service; support services related to billing including data processing, bill printing, mailing, payment processing and collection; use of vehicles; and sharing of certain employees.

BPDC Power receives the following services from affiliates:

- BPSC implements and administers certain OPA C&DM programs on behalf of the LDC, which has overall responsibility for C&DM;
- BPSC provides civil, construction and miscellaneous services to the LDC on a demand basis;
- As of 2012, both remaining meter readers were moved from BPDC to BPSC to read water meters, but provide electricity meter reading for BPDC's non-Smart Metered customers; and
- Electek provides specialized high voltage maintenance and commission work for the LDC on a demand basis.

BDR NorthAmerica Inc. ("BDR") was retained to review the approaches used in the transfer pricing of services provided by BPDC to affiliates, and of the service procured by BPDC from affiliates, and has prepared this report. In making its assessment, BDR relied exclusively on data provided by management. The scope of the study specifically excludes:

  - evaluation of the appropriateness of the services (except as set forth below) or the reasonableness of the levels of the costs, and

- an independent audit of the accounting or analysis which underlies the costs or cost allocation.

The Affiliate Relationships Code for Electricity Transmitters and Distributors ("ARC") provides that services defined as "shared corporate services" and services provided where no reasonably competitive market exists should be priced at fully-allocated costs, and all other services at no more than a market-based price (where the LDC is the purchaser) or no less than a market-based price (where the LDC is the supplier). BDR has taken the provisions of the ARC into account in reviewing the transfer pricing methodology applied to each service.

Conclusions

The following tables summarizes the services provided by BPDC to affiliates, and by affiliates to BPDC, the transfer pricing method presently used, and BDR's comment or recommendation.

Table ES:1 – Services Provided by BPDC to Affiliates (Pricing Policy: Cost-Based)		
Nature of Service	**Allocation Method Used**	**BDR Comment or Recommendation**
Executive	Estimated time spent, to affiliates as a group, operating costs to allocate among affiliates	Reasonable. Implementation of a time system or time sampling should continue to be considered.
Functional management	Estimated time spent	Reasonable. Implementation of a time system or time sampling should continue to be considered.
Finance services other than payroll	Estimated time spent	Reasonable. Continue to consider logging of time on a sample basis.
Insurance premiums	Directly identified	Considered appropriate
Payroll	Estimated time spent for one internal staff; all other payroll services are outsourced separately by each affiliate.	Considered appropriate
Call centre labour	Number and duration of calls	Considered appropriate

Table ES:1 – Services Provided by BPDC to Affiliates (Pricing Policy: Cost-Based)		
Nature of Service	**Allocation Method Used**	**BDR Comment or Recommendation**
Meter reading	Conducted outside of BPDC, no allocation necessary	Considered appropriate
Cashier labour	Meter reads	Considered appropriate
Stationery and consumables for billing	Analysis of paper use	Considered appropriate
Bill mailing, envelopes and postage	Analysis of envelope contents	Considered appropriate
Billing Administration	Included in the time estimates of related staff	Considered appropriate
Building	Occupied square footage	Considered reasonable
Human Resources	Specific identification and costing of initiatives, time estimate for staff	Considered appropriate
IT Labour	Specific identification and costing of initiatives, time estimate for staff	Considered appropriate
SAP Expenses	Number of users	Considered appropriate
SAP Capital	Specific identification of capital programs and allocation proportionate with employee activity	Considered appropriate
Work Stations and Communications Equipment	Number of work stations	Considered appropriate
Procurement	Time estimates of staff	Considered appropriate
Stocking	Value of goods	Considered appropriate
Warehouse services	Square footage of warehouse space	Considered appropriate
Vehicle usage	Standard hourly rates, recorded time used	Considered appropriate
Shared employees	Hourly rate applied to time estimated or scheduled	Considered appropriate

Table ES: 2 – Services Procured by BPDC from Affiliates

Nature of Service	Pricing Method Used	BDR Comment or Recommendation
Administration and implementation of C&DM programs	Market rates determined by comparison with the results of a competitive tendering process.	Considered appropriate
Civil, construction and related miscellaneous service on demand	Consistent rates that are automatically benchmarked against the competitive market by the provision that allows developers to obtain alternative bids.	Considered appropriate
Meter reading for non-smart-metered customers	Fully allocated cost based on estimate of time spent	Allocation method is acceptable, since market pricing cannot be obtained.
High voltage maintenance and commission work on a demand basis.	Same rates as that charged to arms' length clients, therefore market rates	Considered appropriate
Use of vacuum truck	Same or lower rates as those charged to arms' length clients—therefore no more than market rates	Considered appropriate

1 Scope and Methodology

In BPDC's application to the OEB for approval of a 2009 test year cost of service and rates, no unsettled issues arose with respect to affiliate services or transfer pricing. Therefore, there is no requirement stemming from that proceeding requiring an affiliate transfer pricing study of any specific scope. The scope set out in the Executive Summary was therefore defined by BPDC's management in discussions with BDR.

As sources of information for this study, BDR received from BPDC data as to affiliate relationships, the nature of affiliate services provided, pricing, and statistics used in the development of cost allocators. These were accepted by BDR as correct and complete, subject to a review as to reasonableness, but without independent verification.

During the assignment, BDR met in person and by conference call with management of BPDC to confirm our understanding of the data provided, to discuss alternatives and consider possible methodology changes to the proposed transfer pricing.

The focus of the study is entirely on the appropriateness of the transfer pricing arrangements and the costs charged by BPDC to its affiliates, and by the affiliates to BPDC for services rendered, and is not intended as a broader audit of compliance with any other aspect of the ARC.

2 ORGANIZATION STRUCTURE AND AFFILIATE SERVICES

This description of the corporate structure of BPDC is based on information filed with the OEB on September 8, 2008 as part of BPDC's application in EB-2008-0221, and has been confirmed by BPDC's management as correct as of the date of this report. The City of Sarnia, the Town of Petrolia, the Village of Point Edward, the Village of Oil Springs, the Township of Warwick and the Township of Brooke-Alvinston, each through its own holding company, are shareholders in Bluewater Power Corporation, a holding company of which BPDC and three affiliates are wholly-owned subsidiaries. These three affiliates are:

Bluewater Power Services Corporation ("BPSC") —In January, 2009, in response to a Compliance Bulletin with regard to non-core businesses being carried out within an LDC, the functions of street lighting and traffic lighting services to the municipal shareholders, water meter installation and maintenance, contracting for civil construction and miscellaneous on-demand line work outside BPDC's distribution system were moved into BPSC, through the transfer of staff and equipment. In 2011, BPDC's contract to provide water billing service on behalf of the City of Sarnia and Town of Petrolia expired; as part of the continued effort to divest BPDC of non-core distribution activities, new contracts were entered into between BPSC and the municipalities and appropriate staff were transferred from BPDC to BPSC to carry out water-specific functions while BPDC continues to own and operate the shared billing system. BPSC's current staffing includes one (1) administrator, two (2) traffic light maintenance personnel, two (2) meter readers, one (1) water billing representative, four (4) civil project personnel, one (1) C&DM program delivery coordinator, and three (3) water meter maintenance technicians.

Electek Power Services Inc. ("Electek"), which provides a full line-up of highly specialized power distribution system services to its customers. This includes electrical maintenance and commissioning testing, switch gear modifications and retrofits, high/low voltage installations and substation installation turn-key projects. Electek was an established business in the Sarnia area, which provided services to a variety of clients including BPDC, before its acquisition by Bluewater Power Corporation in 2007. Most of Electek's business is still for arms' length clients, but it also continues to provide services to BPDC. Electek provides services through its own staff of one (1) professional engineer, eight (8) engineering technologists, and one (1) administrator.

Bluewater Power Generation Corporation ("Genco") owns two renewable generation projects under the OPA's MicroFit program. It has a wholly-owned subsidiary, **Bluewater Power Renewable Energy Inc. ("BP Renewable"),** which owns and operates a 1.6 MW landfill gas to energy project and has passive (non-operating) ownership interests in a 2.4MW landfill gas to energy project. Genco has no staff, but the 1.6 MW landfill gas to energy project is operated by an employee shared with BPDC.

BPDC maintains its own staffing and assets to conduct its core business as an LDC. BPDC also provides management services, shared employees, and the use of office space and vehicles to its affiliates on a fully-allocated cost basis.

At the commencement of this study, BPDC was supplying services to Electek and to BPSC under separate Management Services Agreements, both dated January 1, 2009,. Early in September, 2012, company management advised BDR that the Agreements would be renewed, to be effective January 1, 2013, in order to respond to issues raised in the course of this review. Likewise, new Management Services Agreements were created for BPDC to supply services to Genco and BP Renewable. The practices reviewed in this report are, therefore, the practices set out in the revised Management Service Agreements which will be in place during the Test Year and beyond.

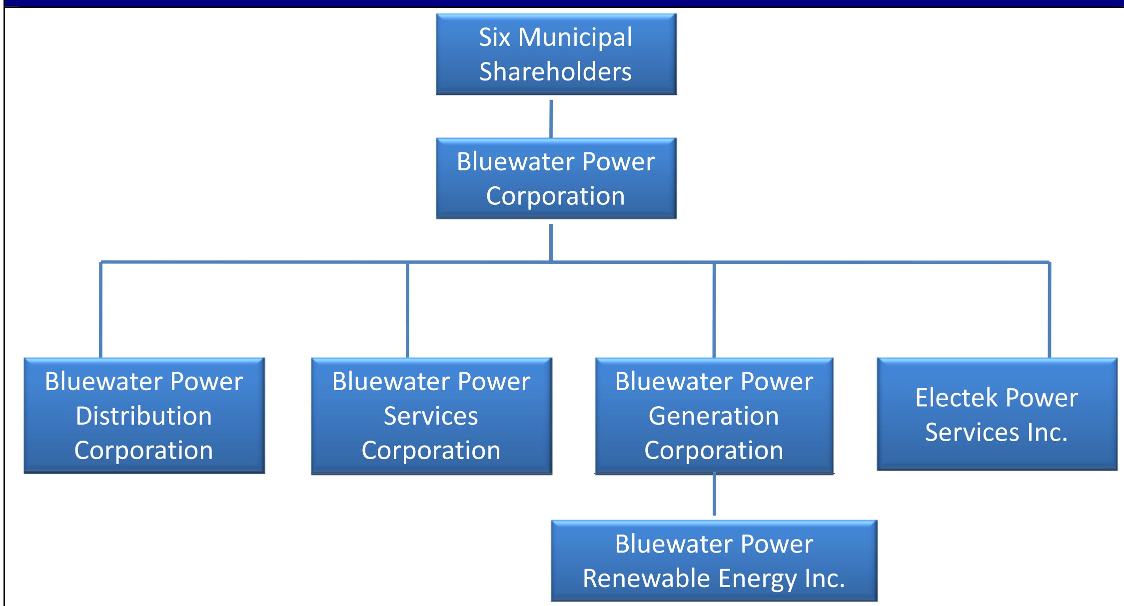
All the affiliates receive the following services to varying degrees:

- Financial management, treasury, audit and taxation services
- Payroll services
- Accounts payable services
- Accounts receivable, billing and collection services
- Human resources services
- Information technology services
- Services related to employee safety; and
- Certain administration services which include document production and records management.

BPSC receives procurement services related to all purchases, and also stocking of purchases not directly stocked by the company. Electek receives procurement services, but that service is utilized to a lesser extent given the company existed prior to its purchase by Bluewater Power Corporation and, therefore, had existing processes in place. BPSC receives services related to strategic management and supervision of their personnel. Electek receives strategic management services, but no supervision as there is a manager of operations and a manager of engineering in place at Electek.

In the past, management and supervisory services were priced at a fixed fee specified in the Management Services Agreements, to be adjusted if necessary based on actual time spent. Due to challenges with implementing time dockets for managers and supervisors, the current practice is for a fixed fee for day-to-day services, determined on the basis of an estimate of average time spent, with time docketed on larger projects. Materials and inventory are provided at cost plus 11% as a handling fee. All other services are provided at “cost”, where cost is defined as the fully-allocated cost.

Figure 2.1 – Corporate Organization Structure of BPDC and Affiliates



In addition to services under the Management Services Agreement, BPDC provides BPSC with use of its personnel and equipment on an as-needed basis at the fully-allocated cost, and use of space in its substation building and head office building for an annual fee, under a Cost Sharing Agreement dated January 1, 2009. The Cost Sharing Agreement with BPSC has been amended by management to be effective for the Test Year and this report reviews the practices reflected in the revised agreements.

Electek has business space at a separate location, and does not use the building facilities of BPDC. A Cost Sharing Agreement with Electek also exists, but was not amended because services are not actively shared under the Agreement currently. Also a new Cost Sharing Agreement was entered into between BPDC and BP Renewable.

BPDC receives the following services from BPSC:

- Subdivision streetlight and distribution work for land developers contracting with BPDC;
- Trenching and installation/repair of underground electrical distribution plant; and
- Miscellaneous civil work and general labour and ad hoc services as agreed from time to time.

In addition, one employee of BPSC manages delivery of specific CDM programs on behalf of BPDC.

BPDC receives specialized electrical maintenance and commissioning services from Electek. For Electek, which was a well-established competitive business before its acquisition by Bluewater Power Corporation, BPDC represents only a small component of its total business. Services from Electek to BPDC are on request, and priced on the same hourly rate as Electek prices services to its arms' length customers. This pricing can therefore be considered to be market pricing.

BPDC receives no services from Genco.

Through discussions with BPDC management, BDR ascertained that none of these functions duplicate a service which is self-supplied or otherwise procured by BPDC.

Other than the services of the Board of Bluewater Power Corporation, none of the services purchased by BPDC from an affiliate is a "shared corporate service" as defined by the ARC. The ARC requires that if a service is not a "shared corporate service", a determination must be made of whether a competitive market exists for the service. If a competitive market exists, pricing cannot be below market levels if the LDC is the vendor or above market levels if the LDC is the purchaser. If no competitive market exists, pricing must be at fully allocated cost.

3 REQUIREMENTS OF THE ARC

The ARC, in providing direction as to inter-affiliate transfer pricing, provides the following important definition:

> "shared corporate services" means business functions that provide shared strategic management and policy support to the corporate group of which the utility is a member, relating to legal, regulatory, procurement services, building or real estate support services, information management services, information technology services, corporate administration, finance, tax, treasury, pensions, risk management, audit services, corporate planning,

> human resources, health and safety, communications, investor relations, trustee, or public affairs”.[1]

Section 2.3.5 of the ARC provides that fully allocated cost based pricing is the appropriate treatment for these costs.

According to this definition, the management, financial, human resources, and information technology services provided by BPDC to affiliates are “shared corporate services”, but billing, building occupancy, and use of equipment are not “shared corporate services”.

For services that are not “shared corporate services”, the first step in the transfer pricing methodology, whether the transaction is a purchase or a sale by the regulated utility, is necessarily a determination of whether each “service, product, resource or use of asset” has a “reasonably competitive market” or not. If it has a competitive market, the market value must be determined by an acceptable method. If there is no market value, a cost-based price must be determined by an acceptable method. Where a cost-based price is determined, it represents the upper limit for pricing when the regulated company is ***acquiring*** the product or service, and the lower limit for pricing when the regulated utility is ***selling*** the product or service.

4 SERVICES PROVIDED BY BPDC TO AFFILIATES

The following subsections describe each type of service and the existing allocation methodology, and summarize the conclusions of BDR with respect to the allocation of each type of service.

4.1 *Costs of Services Supporting Shared Employees*

BPDC provides services to affiliates including executive and management, finance, customer service and billing, human resources and information technology. The cost of these resources included not only the related salaries or wages and benefits, but also the costs of the facilities and supporting services that enable their functions. Such enablers include building space, furniture, equipment and work stations, information technology and human resource functions. In discussion of the allocation methodology between BDR and BPDC management, it was noted that an approach was necessary to ensure that the affiliates pay the cost of these enablers, not only for their own employees, but also in respect of the services performed for them by employees of BPDC.

BPDC therefore computed the average cost of building space, equipment, IT and HR as a percentage of employee compensation, including benefits, and added this

[1] ARC, Section 1.2.

percentage as a surcharge to labour costs when allocating the cost of shared services. This simple approach does not include any mechanism to address the problem of the exchange of services among functions (for example, that IT receives support from HR and vice versa) but simply assumes that an allowance for all supporting functions is part of the cost of every employee. This might therefore slightly overstate the cost of IT and HR services provided to affiliates, but the inaccuracy is small and favours BPDC's electricity consumers.

The surcharge applies in addition to the building, IT and HR costs that are allocated to affiliates as a result of the cost causation approaches discussed below, and are intended to recover, for example, the costs of building, IT and HR that provide support to staff in the functions of executive, management, finance and customer service.

All references to labour costs in the following sections therefore include salaries and wages, benefits and a surcharge for enabler resources.

4.2 *Executive*

The Executive group within BPDC provides high level management services to all affiliates as well as fulfilling those functions for BPDC itself. The Executive department includes senior management and executive assistants. A timesheet system was considered; however, the staff involved had difficulty docketing their time consistently because much of the time is spent in a series of short intervals of different activities, responding to the needs of customers and employees. They therefore developed an approach which divided their time into two categories: recurring functions and non-recurring special projects.

Overall the Executive group estimated that they spend 200 hours annually in aggregate on recurring functions for the affiliates (not BPDC), and budgeted 50 hours annually on non-recurring special projects with actual time on special projects to be tracked and charged on actuals. Their efforts were costed at a weighted average hourly rate for the group, including salary and all benefits (but not related overheads), and this amount was treated as a reduction in costs attributable to BPDC. The amounts related to recurring functions were then allocated among the affiliates according to the amount of each affiliate's direct O&M costs, before any management fees and material costs. The amounts related to non-recurring projects were re-allocated among the affiliates based on management judgment.

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 judgment

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 judgment 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.

Again in the absence of more specific data, it is BDR's view that operating cost and management judgment are reasonable as a basis of allocation of costs among the affiliates. BDR notes that once the cost attributable to BPDC has been determined, the mechanism for allocation of the remainder of the costs among the other affiliates has no impact on the revenue requirement of BPDC.

BDR recommends that time logs be maintained for large non-recurring projects, and that a time record study be made on a sample basis from time to time to confirm the reasonableness of the estimates.

4.3 *Functional Management*

This group provides management of administrative and operating functions for BPDC, and strategic management to its affiliates. Each of Electek and BPSC employ a full-time administrator and staff for the management of ongoing activities, and therefore require no administrative or operational management resources from BPDC. It was found that one member of the functional management group records time to the work order system, which provides for direct attribution of the costs to the company for whom the work is done. The other members estimated their time spent for each affiliate on an average basis for recurring work and for non-recurring special projects. Management advised BDR that the estimates reflect the experience of each individual as to the level of activity on behalf of affiliates.

The time was costed as the average salary and benefits per hour for the management group.

In the absence of a time log, and bearing in mind that an estimate would be required for forecasting in any case, BDR is of the view that the estimates of the staff involved represent a basis for allocation of costs that is reasonable and consistent with accepted principles of cost allocation.

BDR recommends that, if time logs cannot reasonably be maintained on a permanent basis, a time record study be made on a sample basis from time to time to confirm the reasonableness of the estimates.

4.4 *Finance*

These functions include:

(a) Functions related to financing, banking and treasury
   i. financing and investing
   ii. cash flow management
   iii. banking
   iv. financial guarantees
   v. bonds
   vi. maintaining credit ratings
   vii. reporting
   viii. management of customer deposits
   ix. corporate VISA card

(b) Taxation and remittances including PILS and HST
(c) Financial systems, processes, policies and procedures, financial controls and compliance
(d) Financial reporting, analysis and budgeting, and audit services
(e) Risk management and insurance
(f) Accounts Payable
(g) Accounts Receivable
(h) OEB reporting and regulatory compliance.

For purposes of the services agreements, the following functions are also classified under “finance” within the Service Agreement, but are addressed separately in this report, since their incurrence or treatment for purposes of cost allocation and transfer pricing requires additional discussion:

(i) Fleet
(j) Issuing bills, collecting, and billing system quality control
(k) Facilities
(l) Insurance Premiums
(m) Payroll.

Functions (a) through (h) in the list above are carried out jointly for all of the affiliate companies by the finance staff of BPDC, to the degree required for each company, except that Electek does not receive support of certain banking and treasury functions, accounts payable, or account receivable.

During the timeframe of this study, management considered the option of implementing an on-going time tracking system. They determined that because of the nature of the work, it would be difficult for staff to allocate their time to individual affiliates on an on-going basis. Management has determined that a combination of time estimates by individual staff and periodic sampling of time use would be feasible to implement in the department.

Since each staff member performs a different mix of activities, the time allocation of each individual was estimated by that individual and that allocation was reviewed with the manager responsible. The estimated number of hours for each affiliate was multiplied by the direct (salary and benefit) costs for that individual. The allocation of total finance costs to the affiliates is the sum of these individual allocations.

BDR confirmed through inquiries to management that costs related to OEB licensing and compliance are assigned to Genco in respect of generation licensing, and otherwise regulatory costs are assigned to BPDC. BDR also confirmed that the costs of insurance premiums are specifically identified by the insurer(s) and directly assigned to the affiliates accordingly.

BDR considers that a time basis of allocation best reflects causation of this cost, and therefore considers the proposed time estimation approach to be reasonable in the circumstances and consistent with accepted principles of cost allocation.

BDR recommends that BPDC consider logging of staff time for at least a sample period, at intervals to confirm the reasonableness of estimates.

4.5 *Insurance Premiums*

Three primary insurance policies are maintained in force by BPDC for the benefit of BPDC and affiliates: fleet, property, and general liability. Administration of insurance policies and management of claims is handled by Finance as described in the prior section.

Fleet premiums are reflected by vehicle type and are charged directly to fleet operations and recovered through standard vehicle charge out rates as noted in Section 4.12.

Property insurance premiums are charged directly to Building Maintenance and included in the price for rental of space as described in Section 4.8.

For directors' and officers' liability insurance, BDR recommended that the insurance cost be allocated in proportion to other costs associated with directors and executive, and this recommendation has been adopted. As a related issue, BPDC has not previously allocated Board of Director fees to affiliates, but has adopted our recommendation in the new Management Services Agreements for 2013 and beyond.

For liability insurance, the invoice received from MEARIE (the insurance provider) provides a breakdown of the premium by company, except for the premium with respect to directors' and officers' liability.

On review, BDR has concluded that the information has been provided by the insurer to allow for direct assignment of liability insurance premiums to each affiliate, and considers that this approach is in effect.

4.6 *Payroll*

One employee of BPDC has responsibility for the confidential management and union payroll of all staff of BPDC and affiliates. Payroll is only one of several responsibilities of this employee, who tracks time spent on affiliates for payroll and other functions.

The major payroll functions are outsourced to a third party directly by each affiliate company. As such, the costs are direct costs and no transfer pricing or allocation methodology is required.

On review, BDR considers that the approach used reflects cost causation with respect to this function and is consistent with accepted principles of cost allocation.

4.7 *Billing for Water and Wastewater Services*

4.7.1 Function Overview

The City of Sarnia and Town of Petrolia each provide water and waste water services to consumers within those municipalities. BPSC provides the City and the Town with billing and collection services for these consumers at a negotiated rate. The resources necessary to render the water billing services include the one (1) water billing representative and two (2) meter readers employed by BPSC, as well as shared services from BPDC including labour and information technology, using the same resources that BPDC uses to provide billing and related services to BPDC's electricity customers. Once a customer's call has been answered by BPDC staff, water-related calls of a more complex nature are referred to BPSC's water billing representative. This arrangement reduces the average duration of water-related billing calls within BPDC.

Where the customer receives both electricity service from BPDC and water services from the City of Sarnia or the Town of Petrolia, one bill is provided for the two services. This results in savings in bill production, mailing and postage, stationery, cashier services and payment processing. Some bills are also rendered for electricity service only or for water service only.

Since the sale of billing services by BPSC to the City and Town is not a transaction directly involving BPDC, this section deals entirely with the transfer pricing of services rendered by BPDC to BPSC.

4.7.2 Call Centre Labour

The costs in this category include direct labour and benefits for clerical staff and department supervision. To support this study, management collected statistics as to the number and duration of calls related to electricity and water, including the call itself and follow-on work necessary to correct the problem. From the relative number of calls weighted by duration, they developed an allocation factor of 87% for electricity and 13% for water. These were applied to the costs of the salaries and benefits of all staff shared between the two functions.

On review, BDR considers that this approach effectively reflects relative time spent, and is therefore an appropriate allocator for labour-related call centre costs, which is consistent with accepted principles of cost allocation.

4.7.3 Meter Reading

Meter reading for water is conducted by BPSC employees, and therefore no allocation of BPDC costs is required.

4.7.4 Payment Processing

This expense consists of labour costs of the cashier function. In assessing the treatment of this function, BDR questioned whether there were any additional costs, such as bank charges, that could be attributed directly to this function, and was advised by management that any other such costs were not material and may in fact be insignificant.

The cashier processes all payments on accounts, which are either combined water/electricity accounts, electricity only accounts, or water only accounts. Where a combined bill has been rendered for electricity and water, the customer pays for both services with a single payment. The result is that payment processing relates to some electricity only bills, some water only bills, and some combined bills.

The cost driver for payment processing is number of payments. BPDC management has proposed that the number of meter reads on each of water and electricity be used as a proxy for the number of related payments, and applied as an allocator to approximately $57,000 of cashier costs. This method results in the proportion of cost responsibility of electricity being 57%.

In preparing this report, BDR considered the number of bills as a proxy for the number of related payments. According to data provided by BPDC, making the calculation by counting the combined bills once for water and once for electricity, the method would result in the cost responsibility of electricity rising to 64%.

In BDR's view, either of these approaches is reasonable and consistent with accepted principles of cost allocation. BPDC management has selected the approach that is more favourable to electricity customers.

4.7.5 Stationery and other Consumables for Billing

Costs were first identified by separating the costs of paper for bills from the cost of other paper supplies. The latter were assigned entirely to BPDC, as paper supplies for the affiliate are purchased separately. The entire surface area of the 2-page shared bill was measured and the shared space, utility-only space and water-only space was calculated which determined the proportionate split between electricity and water for each two-page joint bill. Then the number of pages for water-only and electricity-only bills stock was added to the joint water component and the joint electricity component respectively, to compute the proportion of paper utilization. Then the water proportionate share of joint bill stock was added to water-only bill stock and the result multiplied by the cost/sheet of paper to compute the cost assigned to water billing. The result was that 13.8% of stationery cost was allocated to water billing.

For other consumables (toner, etc.), the portion used for billing was first identified. This portion was then allocated on the same proportion as the stationery.

On review, BDR considers that the proposed basis of allocation is reasonable, and reflects accepted principles of cost allocation.

4.7.6 Bill Mailing, Related Equipment, Envelopes and Postage

These costs include envelopes and postage related to bills, annual fees and maintenance of mailroom equipment, and a component of mailroom staff labour (salaries and benefits). One employee spends about half time on mailroom duties related to billing, and the other half on other duties that are entirely related to electricity distribution. Therefore 50% of this employee's labour cost was considered to be related to bill mailing, and allocated with the costs of envelopes and postage for bills.

These costs were allocated on the basis of identification of the paper contents of each billing envelope as either water-related or electricity-related. The allocation of the paper for the bills themselves is discussed in Section 4.6.5. To this was added the full or partial sheets of paper for water and electricity-related billing inserts. On this basis, 12% of the costs are allocated to water billing. This is a smaller share than for billing stationery alone, because of the considerably higher number of bill inserts related to electricity as compared with water.

On review, BDR considers that the proposed basis of allocation is reasonable, and consistent with accepted principles of cost allocation.

4.7.7 Administrative Overheads Related to Billing

The water billing clients, municipalities of Sarnia and Petrolia, have not requested that significant effort be devoted to reporting to them on the billing function. An administrator within BPSC directly handles most of the requirements that do exist, and therefore no allocation related to administration within the billing function is required. Reporting and administration requirements within functional management are included in the time estimate of those staff (see Section 4.2).

4.7.8 Bad Debts

Since electricity and water are billed together and collected together, any partial payment of bills is allocated first to the electricity portion. If any portion of an account has not been collected, the water portion is reimbursed by the municipalities.

In BDR's view, these arrangements reduce the risk of bad debts in the electricity cost of service, and are appropriate.

4.8 *Building*

4.8.1 Head Office

Use of building facilities is not a shared corporate service, and is therefore required by the ARC to be priced at market value.

The head office building at 855 Confederation Street in Sarnia is owned by BPDC. This building houses the employees of BPDC, including those fully dedicated to the distribution business and those performing shared services, and also certain employees of BPSC. Electek has its own building at another location. Genco has no employees.

BPDC incurs the cost of maintenance and repairs, property tax, insurance, grounds maintenance and janitorial services, utilities, and also capital-related costs (depreciation, interest, return on equity and related PILS).

Costs are allocated between BPDC and BPSC on the basis of occupied square footage. BPDC gathered market information to the effect that $10.00 per square foot is the market rent for a comparable building in Sarnia, including all of the landlord's costs and utilities. BPDC also gathered competitive information in support of the business case for acquisition of a building by Electek, which indicated that the comparable rate would be $11.18 per square foot, also including all costs and utilities. The rate of $11.18 was therefore considered to be the relevant market rate, for use in this cost allocation.

BPDC identified each of the BPSC employees with a work area in the head office building, and determined the floor space involved. This floor space was then allocated to BPSC at the rate of $11.18 annually per square foot.

BDR has concluded that an allocation of building costs based on floor space utilization by the affiliate's direct employees reflect cost causation, and are consistent with accepted methods of cost allocation. BDR considers that a market rate has been applied, as required by the ARC.

Costs related to building space utilization by shared employees of BPDC are recovered by adding a factor for their recovery to the costs of the shared employees, as discussed in Section 4.1.

4.8.2 Substation #1

BPSC uses space in BPDC's Substation #1 as office space for the civil staff and garage space for their vehicles. Management was able to identify and measure the floor space used for each purpose. Office space was charged at the rate of $11.18 per square foot, the same rate as for space in the head office building. Garage space was charged at $3.00 per square foot, based on confirmation from a real estate specialist that this is within the range of all-inclusive rental rates for similar space, used for similar purposes.

BDR has concluded that an allocation of building costs based on floor space utilization reflects cost causation, and is consistent with accepted methods of cost allocation. BDR considers that a market rate has been applied, as required by the ARC.

4.9 *Human Resources Services / Safety Services*

Services provided by this department include all, or a portion of, the following services: employee records, labour relations, union contract administration, salary administration, staff training, staff recruitment, human rights management, health and safety training and job evaluation administration. Costs are allocated by estimating the time of each HR staff member spent on the affiliates, and multiplying the hours by a rate comprising salaries and benefits. In order to reflect the costs of supporting services and facilities (such as building, human resources, furniture and work stations, a factor was applied to the labour rate (salaries and benefits) reflecting these costs, as discussed in Section 4.1.

BDR discussed this function with management, and determined that HR programs and initiatives are not shared among the affiliates, and that therefore the HR staff members could clearly distinguish which affiliate is the beneficiary of any specific work effort. On this basis, BDR considers that an allocation based on an estimate of time spent reflects cost causation with respect to this function, and is consistent with accepted principles of cost allocation.

4.10 *Information Technology*

4.10.1 Labour

IT services support finance, customer service, engineering and system operations applications, are housed within BPDC and are provided on a corporate wide basis to BPDC and all affiliates. On discussion of the functions performed by the department for affiliates, it was determined that activities for the benefit of affiliates could be specifically identified but that the brevity, variety and fragmentation of work activities made the maintenance of detailed and accurate time records very difficult. Staff therefore developed an estimate of hours spent for each affiliate. This estimate of hours worked was multiplied by an hourly cost rate, to produce the allocation. In order to reflect the costs of supporting services and facilities (such as building, human resources, furniture and work stations, a factor was applied to the labour rate (salaries and benefits) reflecting these costs, as discussed in Section 4.1.

On review, BDR considers an allocation based estimated time spent to reflect cost causation with respect to this function, and be consistent with accepted principles of cost allocation.

4.10.2 Work Stations and Communications Equipment

The cost driver for this cost is the number of stations. First, BPDC management computed the average cost per station, where annual cost includes any operating costs, depreciation, interest, return on equity at the OEB-approved rate. PILS will also be included for 2013 and beyond. This cost was then multiplied by the number of stations used, to allocate a cost to BPSC. Number of stations was determined to include stations for the water billing clerk, administrator, OPA contract employee and one shared work station, for a total of four. Electek has its own equipment, and therefore did not receive an allocation. Genco has no employees, and therefore did not receive an allocation. Costs associated with work stations for shared employees were addressed as discussed in Section 4.1.

BDR considers that number of work stations reflects cost causation with respect to this cost, and therefore that the approach reflects accepted principles of cost allocation.

4.10.3 Annual Expenses of the SAP System

BPDC incurs an annual license fee for SAP on a per-user basis. Cost causation is therefore on a per-user basis. For allocation of the maintenance cost for BPSC, related to water billing, the number of users was computed as:

- One administrator, employee of BPSC
- One water billing clerk of BPSC
- An allocation for use by six BPDC customer service representatives (CSR), in the same proportion as the time of the CSRs themselves (Section 4.7.2), and
- An allocation for use by the BPDC cashier, in the same proportion as the allocated time of the cashier (Section 4.7.4).

In addition, BPDC is charged by SAP a device charge for each water meter. These costs are allocated 100% to BPSC, as they relate entirely to water meters.

4.10.4 Capital Costs Related to SAP System

The definition of fully allocated cost for transfer pricing purposes in the ARC requires that use of assets be costed to include depreciation and the weighted average cost of capital, as approved by the OEB. Annual costs related to SAP system capital were determined incorporating those cost elements. BDR noted for the attention of BPDC management that the approach should follow the OEB's approach to the determination of rate base (ie. the mid-year value) and revenue requirement. For the project whose implementation is subject to a business case, the off-setting reductions in annual expenses were included in the amount to be allocated.

The SAP system is depreciated on a straight-line basis over a five-year period, so that any capital expenditure 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 2011, the only SAP capital related to smart meters which is entirely electricity related; no allocation was made to water billing for this project. A proposed operations supply chain and work maintenance project for 2013 will service Operations and Engineering staff with BPDC and has nothing to do with billing or customer service; therefore no costs of this project were allocated to water billing. The analysis therefore focused on the remaining projects, for which a component is attributable to water billing, according to the approach described below.

For projects of general applicability to the SAP system, 40% was estimated by management as being the portion relevant to the billing function. Of the 40% a portion was allocated to water billing. The allocations were based on the judgment of the executive responsible, following a review of the costs, as to portion attributable to water. As each project has a different scope, the resulting allocations were somewhat different for each. As an example, the proportion of time of the BPDC Call Centre Labour (see Section 4.7.2) served as proxy for level of activity related to the system, and was a point of reference for the executive in his evaluation.

On review, BDR has concluded that the method reflects the appropriate costs, and that the allocation approach is reasonable and reflects generally accepted principles of cost allocation.

4.11 *Procurement, Stocking, and Warehousing*

All purchasing for BPSC is handled on its behalf by BPDC; Electek receives some procurement services from BPDC, but handles most of its own procurement directly. Costs of procurement are allocated based on the value of goods.

BPDC provides stocking services for some, but not all of the inventory of BPSC. The service includes handling only, as BPSC makes all determinations on the level of stock and pays for rental of storage space separately. Where BPDC stocks on BPSC's behalf, materials and inventory are provided at cost plus a markup of 11% to cover handling. BPDC had not conducted a specific study in support of the adequacy of an 11% markup, but it was the view of management that since both procurement and warehousing are recovered separately, this charge is adequate to recover stocking costs.

BPSC uses space in BPDC's warehouse for storage of street lighting and water meter inventory. This space could be specifically identified and measured. To determine an appropriate rate per square foot, BPDC surveyed the costs of comparable competitive storage facilities and determined that the market rate is $4 per square foot. This rate was applied to the measured square footage to compute the allocated cost.

BDR considers that a percentage markup approach to stocking, which in essence allocates the costs based on the value of the goods stocked, is reasonable and consistent with generally accepted principles of cost allocation. BDR recommends that BPDC management review the markup percentage periodically to ensure that as a minimum, all relevant costs are recovered.

BDR considers the approach taken for use of warehouse space to be reasonable, and consistent with generally accepted principles of cost allocation, as well as market-based pricing as required by the ARC.

4.12 *Use of Vehicles*

BPSC owns a fleet of vehicles for regular operations, but BPDC makes available the use of its vehicles to BPSC for use in its operations as required. Charges to these affiliates for vehicle use are at a standard hourly charge which incorporates recovery of vehicle-related costs, including service and maintenance, fuel, license fees, insurance and depreciation, and the cost of capital. The standard charge is also used to charge vehicle costs to BPDC's capital and operating work orders, and is computed to recover the total costs over the forecast hours of use in the year.

The number of hours charged to BPSC is determined by the use made of vehicles by operators and recorded to work orders in the accounts.

A rate for large vehicles and a rate for small (passenger) vehicles has been determined on a fully allocated cost basis. However, the ARC requires that market-based rates should be used if a "reasonably competitive market" exists for the product or service.

Where service is provided to a utility or other client by a construction contractor, large vehicles specialized to the task are provided along with qualified labour. While the rates charged by arms-length contractors for vehicle use on this basis might be considered a benchmark of market pricing, it does not represent an exact replacement for BPSC's arrangement with BPDC, because, according to an informal survey conducted by BPDC, vehicles are not rented on an hourly basis separately from labour, and no supplier contacted by BPDC was willing to supply rental vehicles on an hourly as-needed basis.

Companies such as Zip Cars provide passenger cars for use at hourly rates that include fuel and insurance. The service in Canada is available in Toronto and Vancouver only, and does not include work trucks, and therefore does not represent a market alternative for BPSC.

On this basis, BDR concludes that there is no "reasonably competitive market" for the rental of the vehicles of the type on the basis required by BPSC.

BDR has therefore concluded that fully allocated cost is an appropriate basis for pricing of as-needed use of BPDC vehicles by BPSC. BDR considers that the basis of allocation (hours of use as recorded to work orders) is reasonable and consistent with accepted principles of cost allocation.

4.13 *Sharing of Employees other than for Shared Corporate Services and Water Billing*

There are three types of employee sharing arrangements in this category.

- When linemen employed by BPDC are available, they can be used to supplement the workforce in BPSC in street lighting services and other contract work. The charges by BPDC to BPSC are based on actual time included in timesheets;
- One employee of BPDC spends 70% of the week on BPDC work as a mechanic, and the remaining 30% on operations of BPREI's landfill gas generation plant. This is based on estimates of time spent on each activity.
- Certain employees are shared on as-needed basis.

In each case, an hourly rate is determined by dividing total annual salary and benefits by the annual productive hours of the employee. The rate also includes allowance for the employee's use of building, IT and HR support resources as noted in Section 4.1.

BDR considers that the use of a time estimate or established assignment of duties for staff labour is reasonable and consistent with accepted cost allocation principles.

BDR recommends that the costs of support services and facilities related to shared staff be included for allocation, either along with the staff time or separately.

5 SERVICES PROCURED BY BPDC FROM AFFILIATES

5.1 *C&DM Program Implementation and Administration Services from BPSC*

BPDC delivers C&DM programs to its customers under an agreement with the OPA. BPSC is responsible for the work of delivering certain of the programs, as a service provider to BPDC. BPSC's resources for C&DM program delivery include one employee of BPSC, who provides administrative and project management to the programs.

The rates charged by BPSC to BPDC are market rates, determined by a competitive tendering process carried out by BPDC or neighbouring LDCs with whom BPDC works from time to time to select a supplier. The costs incurred by BPDC are passed through for reimbursement to the OPA under the agreement between BPDC and the OPA. Acceptance by the OPA, an arms' length third party, validate the costs as being at a competitive level.

On review, BDR accepts that the charges made by BPSC for C&DM services to BPDC are market-based rates, and therefore acceptable as transfer prices in compliance with the ARC.

5.2 *Civil, Construction and Miscellaneous Services from BPSC*

BPDC contracts with BPSC for a variety of civil work on its distribution system.

Some of this work is related to connection of new subdivisions. The terms of the Distribution System Code provide that customers (developers) must pay a contribution to the cost of system expansion, based on an economic evaluation. The distributor must make a cost-based offer to the customer (developer) to construct the facilities; however, the customer (developer) has the option to select an alternative bid for portions of the work, if such a bid results in lower total costs to the customer (developer).

This process provides an automatic competitive market-based benchmark for BPDC's cost offers to customers (developers), including the cost of civil work carried out by BPSC, as these offers compete with the alternative bids that the customer (developer) could obtain.

BPSC prices its work for BPDC for work that is not subject to alternative bids, at the same rates that apply to work subject to alternative bids.

On review, BDR considers that BPSC prices its services to BPDC based on a benchmark provided by the competitive market for similar services. These prices are therefore market-based prices, and acceptable transfer prices in compliance with the ARC.

5.3 *Meter Reading Services from BPSC*

BPSC provides meter reading services for purposes of water billing, using its own complement of two FTEs. In addition, since BPDC has not deployed Smart Meters across all rate categories, BPSC's meter readers continue to read some electricity meters on behalf of BPDC. Charges are on a fully allocated cost basis, with the allocation based on an estimate of time spent.

Meter reads are monthly, and the locations are widely distributed through BPDC's service territory. The requirement for these readings is expected to continue for the foreseeable future as there are no current plans to replace the remaining meters with Smart Meters. Management advised BDR that before the implementation of Smart Meters, cycle meter reading was contracted out, but certain commercial meters and on-demand readings were carried out by BPDC's own staff, because no reasonable arms' length offer for the service was received. As a result, management does not believe that a reasonably competitive market exists for the service.

On review, BDR considers that the approach to cost allocation is reasonable, and that time spent reflects cost causation and is consistent with accepted methods of cost allocation.

If a reasonably competitive market for the service is later determined to exist, a market-based price should be implemented.

5.4 *Vacuum Truck Services*

A **vacuum truck** is a tank truck with a heavy duty vacuum designed to pneumatically load solids, liquids, sludge or slurry through suction lines. Uses include:

- By utilities for excavation and pole holes, particularly in urban areas.
- By towns and municipalities for street cleanup, sewers, individual septic systems and can also be used for cleanup of contaminated soil.
- Commercially, for cleaning of sanitary sewer lift stations and pump out of grease interceptors that are required at many restaurants.
- In the petroleum industry, for cleaning of storage tanks and spills. They are also an important part of drilling oil and natural gas wells, as they are located at the drilling site. Vacuum trucks are used to remove drilling mud, drilling cuttings, cement, spills, and for removal of brine water from production tanks.

BPSC provides vacuum truck services for arms' length parties, but BPDC continues to be its primary customer. When the client is BPDC, the rate charged is the same as, or slightly less than the rate to the arms' length clients, and is therefore a market rate.

On review, BDR accepts that the charges made for use of the vacuum truck to BPDC are market-based rates, and therefore acceptable as transfer prices in compliance with the ARC.

5.5 *High Voltage Maintenance and Commissioning Work, from Electek*

BPDC receives specialized electrical maintenance and commissioning services from Electek. Services from Electek to BPDC are on request, and priced on the same hourly rate as Electek prices services to its arms' length customers.

On review, BDR accepts that the charges made by Electek for high voltage maintenance and commissioning work to BPDC are market-based rates, and therefore acceptable as transfer prices in compliance with the ARC.

APPENDIX A – COMPLIANCE WITH SECTION 13A.03, ONTARIO ENERGY BOARD RULES OF PRACTICE AND PROCEDURE

(a) Name, Business Name and Address, and General Area of Expertise

This evidence was prepared entirely by:

Paula Zarnett, Vice President
BDR NorthAmerica Inc.
34 King Street East, Suite 1000
Toronto, Ontario M5C 2X8

Paula has more than 25 years broadly based experience specializing in regulatory compliance, regulated rates and pricing issues for electricity and gas utilities.

(b) Qualifications, including relevant educational and professional experience in respect of each issue in the proceeding to which the expert's evidence relates.

Paula's evidence in this proceeding relates to the basis of transfer pricing for services provided by Bluewater Power Distribution Corporation to its affiliates, and for services purchased by Bluewater Power Distribution Corporation from affiliates.

Selected projects illustrating her cost allocation experience and expertise include:

- studies for natural gas utilities in Manitoba and Alberta;
- leading an in-house team in a one-year cross functional project to perform Toronto Hydro's first cost allocation study (1985);
- a cost allocation and rate design study for Enwave District Energy;
- two cost allocation studies for Saint John Energy, a municipal utility in New Brunswick;
- advice to the municipal utilities of New Brunswick in their interventions in NB Power Distribution and Customer Service (Disco) rate approval applications in 2005 and 2007, including analysis and critique of Disco's cost allocation methodology;
- a study on behalf of the Toronto Hydro-Electric System Ltd. to allocate the costs of service to customers who are individually metered suites in multi-unit residential buildings (2010-2011).

She participated on behalf of a client in the Ontario Energy Board's stakeholder processes regarding cost allocation for electricity distribution service, and was an instructor in cost allocation and rate design (advanced) at CAMPUT's annual utility regulation course in 2006, 2007 and 2008. She has testified before the regulators in

Ontario, New Brunswick and British Columbia, and has been accepted as an expert in cost allocation by the Ontario Energy Board.[2]

A former Toronto Hydro employee, Paula is knowledgeable in the typical business processes of distribution utilities and their affiliates. As a consultant, she performed a study for Toronto Hydro to identify regulatory issues associated with self-dealing and transfer pricing in considering the formation of a new affiliate. She prepared evidence in support of FortisOntario's shared cost allocation and transfer pricing approach in successive cost of service applications since 2006, and also provided evidence for EnWin Utilities on shared cost allocation and transfer pricing in its 2009 cost of service application, and for Kingston Hydro in an application for its 2011 cost of service. She is presently involved in similar studies for other Ontario LDC clients.

Paula is a Certified Management Accountant, and has an MBA degree (finance) from the University of Calgary.

(c) Instructions provided in Relation to the Proceeding and to the Issue

BDR NorthAmerica Inc. proposed the following scope of work for the assignment, which was accepted by BPDC:

[BDR] suggest that BPDC staff prepare an information package that contains descriptions of the existing shared and affiliate services, amounts of costs for the most recent historic years and test year, and explanation of the methodologies for pricing or allocation now used. The consultants' review will commence with background discussion of this information package.

As the initial step in the assignment, the consultants will review the information provided.

The Affiliate Relationships Code requires that market prices be used for transfer pricing where there is a comparable market or arms' length price that can be established. We will first identify any affiliate transactions for which a market price can or should be established. In these cases, we will look to such market to recommend an approach. Examples, if relevant, might be property or equipment rentals or certain financial services.

Where no market exists, we will be looking to cost causation principles to determine the most appropriate allocation approach. Typical allocation bases include number of transactions, employees' time sheets, floor space or other measures of usage. Our recommendations will reflect consistency with cost causation, precedents, and availability of the necessary data. If these considerations support a methodology

[2] EB-2010-0142, Transcript dated March 29, 2011, page 20.

other than that now used by BPDC, we will work with staff to quantify the impacts of a change in approach.

The Board in its Decision on rates for 2006 for Enbridge Gas listed 5 principles that should be addressed when an independent reviewer assesses corporate cost allocations:

> "10.9.28 The Board further finds that in evaluating each service, the independent review should consider whether:
> - the service is specifically required by the utility;
> - the level of service provided is required by the utility;
> - the costs are allocated based on cost causality and cost drivers;
> - the cost to provide the service internally would be higher than the cost to acquire the service externally on a standalone basis would be higher; and,
> - there are scale economies."

In the rate applications of some other LDCs, OEB staff has questioned whether a study of corporate shared costs and affiliate transfer pricing addressed the above issues, and if not, why not. BDR has therefore included provision for this analysis in its work plan. If desired, we would also discuss with you whether all are in the normal scope of LDC operations (i.e. specifically required by the LDC and at the required level of service) and that there are no duplications in respect of functions being provided by the LDC for itself.

(d) Specific Information and Documents Relied on in Preparing the Evidence

Information from Public Sources:

- EB-2008-0221 Bluewater Power 2009 Rate Application, September 8, 2008
- EB-2008-0221 Decision and Order, March 6, 2009
- Zip Car rental rates http://www.zipcar.com/toronto/business/check-rates
- "Constant, Constant, Multi-tasking Craziness: Managing Multiple Working Spheres", Victor M. González and Gloria Mark, School of Information and Computer Science, University of California, Irvine, Irvine, CA 92697, {vmgyg, gmark}@ics.uci.eduCHI 2004 Paper 24-29 April Vienna, Austria, Volume 6, Number 1
- Affiliate Relationships Code for Electricity Distributors and Transmitters, Ontario Energy Board, Revised March 15, 2010 (Originally issued on April 1, 1999)

Information Provided by Bluewater Power Distribution Corporation:

- Cost Sharing Agreement, dated 1st January, 2009, between Bluewater Power Services Corporation and Bluewater Power Distribution Corporation, and the replacement agreement dated September 27, 2012 to be effective January 1, 2013 for the Test Year and beyond.

- Cost Sharing Agreement dated September 27, 2012 between Bluewater Power Renewable Energy Inc. and Bluewater Power Distribution Corporation.
- Management Services Agreement dated 1st January, 2009, between Electek Power Services Inc. and Bluewater Power Distribution Corporation, and the replacement agreement dated September 27, 2012 to be effective January 1, 2013 for the Test Year and beyond.
- Management Services Agreement Dated 1st January, 2009, between Bluewater Power Services Corporation and Bluewater Power Distribution Corporation, and the replacement agreement dated September 27, 2012 to be effective January 1, 2013 for the Test Year and beyond.
- Management Services Agreement Dated September 27, 2012 between Bluewater Power Generation Corporation and Bluewater Power Distribution Corporation.
- Management Services Agreement Dated dated September 27, 2012 between Buewater Power Renewable Energy Inc. and Bluewater Power Distribution Corporation.
- Schedule of Analysis regarding the allocation of costs for Water Billing
- Excel spreadsheets documenting cost allocation methodology and computations
- Conference calls, meetings and emails exchanged between October 31, 2011 and the date of this report

(e) Points of Agreement and Disagreement with other Expert's Evidence

Not applicable.

Appendix B
Detailed Curriculum Vitae of Paula Zarnett

PAULA ZARNETT

Paula Zarnett has more than 30 years broadly based experience specializing in regulatory compliance, regulated tariffs and pricing issues for electricity and gas utilities. She has been responsible for design and implementation of a wide variety of innovative rates including time of use, both for large industrial and for residential customers, curtailment incentives, and special rates for retention of water heating loads. She has performed cost allocation studies for utilities serving customers with electricity, natural gas and steam, including leading a one-year, cross-functional team project to develop cost allocation methodology and analysis tools for a major electric distribution utility.

Following a series of rate specialist positions in both the electricity and natural gas sectors, she was promoted to the position of Manager of Marketing and Energy Management at Toronto Hydro. There, her responsibilities included all rate and regulatory issues, customer research including load research and forecasting, and customer program design with a focus on conservation and demand management.

In her consulting practice, Paula provides a variety of advisory and analytical services to clients facing the challenges of a changing technological, policy and business environment, with a focus on issues impacted by regulatory policy and process. Her work includes business case and project feasibility analysis, cost allocations and pricing designs, energy sector mergers and acquisitions, and expert testimony before regulators. She is a skilled hands-on analyst and facilitator of cross-functional project teams.

Paula was a member of the Ontario Energy Board's cost allocation working groups in 2003 and 2005-2006. She was an instructor in Cost Allocation and Rate Design at CAMPUT's Energy Regulation Course, 2006, 2007 and 2008, and has been accepted as an expert witness in cost allocation by the regulators in Ontario and New Brunswick.

She has performed assignments for clients in North America, China, Ghana, and Barbados.

SELECTED EXPERIENCE BY SUBJECT AREA

(INCLUDES PROJECTS UNDERTAKEN AS A CONSULTANT, AND IN THE COURSE OF RESPONSIBILITIES WITHIN ORGANIZATIONS)

Preparation of Customer Cost Allocation Studies

Toronto Hydro-Electric System – Study to allocate the cost of service to customers that are individually metered suites in multi-unit residential buildings.

Perth-Andover Electric Light Commission – study to allocate the bundled costs of electricity service to customer classes and assess the impacts on cost allocation of changes to the wholesale rate structure.

Saint John Energy – two studies to allocate the bundled costs of electricity service to customer classes; one of these studies included analysis of metered system load profiles and publicly available typical customer profiles to develop demand allocation factors

Enwave District Energy Limited – study to allocate costs of service for a district steam system as a basis for pricing redesign; study included analysis of detailed time-related customer consumption data as a basis for allocation of costs, as well as operating and financial data.

Toronto Hydro – planning and execution of customer load research projects, including deployment of research metering, load data analysis and related customer research and surveys for use in cost allocation study

Toronto Hydro – coordination of first comprehensive cost of service study, a one-year cross-functional project, including in-depth data collection, selection of allocation methodologies and development of computer-based analytical tools. Led subsequent updates and refinements to the study.

ICG Utilities Ltd. – fully allocated cost of service studies for natural gas distribution systems in Manitoba and Alberta, including data analysis and development of computer-based analytical framework.

Review of Customer Cost Allocation Studies, Methodology Consultations

IGPC Ethanol Inc. – supported the intervention of this industrial consumer in the rate application of its gas supplier, Natural Resource Gas including issues of cost allocation methodology

Summerside Electric/City of Summerside – advisory and analysis service with regard to proposals of Maritime Electric for an Open Access Transmission Tariff, including use of cost allocation methodology to establish transmission revenue requirement

Nova Scotia Department of Energy – advisory and analysis services to support intervention in Nova Scotia Power's request to the regulator for approval of a fuel adjustment mechanism, including customer cost allocation impacts

Rogers Cable and Communications Inc. – represented a consumer stakeholder in a regulator-sponsored stakeholder process to determine a cost allocation methodology and analysis approach for information filings by all electric distribution utilities in Ontario.

Saint John Energy – Review of cost allocation methodology and results in the Cost Allocation and Rate Design application of New Brunswick Power Distribution and Customer Service Corp, including expert testimony recommending certain changes to the methodology, which were adopted

Member – Ontario Energy Board Cost Allocation Working Group (2003 and 2005-6)

Member – Municipal Electric Association Cost of Service Sub-Committee (1986-1988)

Cost Allocation for Affiliate Transfer Pricing

FortisOntario – methodology review of allocation of shared costs to regulated and non-regulated business units and preparation of evidence for application to Ontario Energy Board for approval of 2006 electricity distribution rates

FortisOntario – Three update studies to allocate corporate and shared costs among regulated and non-regulated affiliates

Kingston Hydro – study to review transfer pricing methodologies and allocation of shared costs for services provided by non-regulated affiliates.

EnWin Utilities – study to allocate corporate and shared costs among corporate affiliates

4 studies now in progress, not yet filed.

Rate Designs and Pricing Studies

Rogers Cable and Communications Inc. – representation at Ontario Energy Board staff consultation process with regard to rate designs for Ontario's electric distribution utilities; development of policy and position documents, attendance at stakeholder meetings, analysis in support of positions on rate design for General Service classification and unmetered scattered loads

Oklahoma Gas and Electric – review of results of residential time of use rate pilot including estimation of impact of the rate design on total customer consumption and peak hour consumption (load shifting).

BC Hydro – assisted a staff team in development of a Phase I report on long-term rate strategy; research on rate designs in several North American jurisdictions.

Energy East (RGE and NYSEG) – analysis as to the potential value of load shifting which might take place as result of rate-driven (time of use or critical peak pricing) programs supported by universal interval metering in the State of New York; regulatory precedents as to cost recovery for advanced metering and meter reading technology

East China Grid Company – advice in developing and simulating an unbundled electricity distribution tariff for Shanghai Municipal and four provincial electric power companies

British Columbia Ministry of Energy and Mines – advisory and due diligence services with regard to recommendations by the British Columbia Utilities Commission for implementation of proposed Heritage Contract and stepped rates to wholesale and industrial customers.

Perth-Andover Electric Light Commission – long-term rate strategy and detailed bundled retail rate designs for all electricity consumer classifications.

Volta River Authority (Ghana) – development of tariff structure and preliminary rates for open access use of the national electric transmission system in Ghana.

Enwave District Energy Limited – determination of appropriate customer classification and pricing design alternatives for a district steam system in a context of competitive electricity and gas markets and wider service choices for existing and potential customers.

Toronto Hydro – development and initial implementation of time of use rates for residential and large industrial customers; development of pricing strategies and policies for all customer classes.

Toronto Hydro – development of all customer rate designs, implementation strategy, and preparation of annual submissions for approval of the rates. Managed a team of specialists in the preparation of associated detailed studies, load forecasts and load research.

Testimony before Regulators

ORAL:

Toronto Hydro-Electric System – Testified before the Ontario Energy Board in support of the allocated costs of service to customers that are individually metered suites in multi-unit residential buildings.

Saint John Energy – Testified before the New Brunswick Public Utilities Board in support of intervention in the Cost Allocation and Rate Design application of New Brunswick Power Distribution and Customer Service Corp.

Rogers Cable and Communication Inc. – Testified before Ontario Energy Board in support of consensus for treatment of certain unmetered electricity loads in the development of guidelines for electricity distribution rates.

Toronto Hydro – Testified before Ontario Energy Board on bulk power rate issues

ICG Utilities -- testified in three hearings before British Columbia regulator on the subject of lead-lag studies.

WRITTEN ONLY:

Kingston Hydro – study to review transfer pricing methodologies and allocation of shared costs for services provided by non-regulated affiliates.

FortisOntario – Three studies to allocate corporate and shared costs among regulated and non-regulated affiliates

EnWin Utilities – study to allocate corporate and shared costs among corporate affiliates

Ontario Power Authority – model development and analysis in support of evaluation of a potential generation, transmission and demand response alternatives in York Region; report in support of generation alternative to the Ontario Energy Board.

City of Summerside – expert testimony in support of intervention in the application of Maritime Electric to the Island Regulatory and Appeals Commission for approval of an Open Access Transmission Tariff (public oral hearing to follow).

City of Summerside – preparation of evidence in support of application for leave to construct transmission line, to the Island Regulatory and Appeals Commission (oral hearing scheduled for November, 2012)

Other Assignments Showing Knowledge of the Ontario Electricity Sector

City of Sault Ste. Marie – review of municipally-owned electricity distribution company with regard to ownership options, capital structure and financing.

Brantford Power – facilitation of strategic planning session for Board of Directors.

Orillia Power – facilitation of strategic planning session for Board of Directors and key staff

Oakville Hydro – facilitation of regulatory strategic plan

Burlington Hydro Inc. – advisory services and analysis in connection with bid to acquire a local distribution utility.

Markham Hydro Distribution Inc. and Town of Markham – Due diligence services in support of proposed amalgamation with Hydro Vaughan Distribution Inc.

City of Guelph – independent advisor to the City with regard to fairness of ownership proportion in proposed merger; analysis of ownership options

Oshawa PUC Networks Inc. – policy recommendations for customer connections and capital contributions.

Township of King - advice to municipality staff with regard to potential construction of a peaking generator in response to a contract award from Ontario Power Authority

Hydro Ottawa Holdings Inc. – as part of a larger project to provide strategic advice on four business units, provided financial modeling for valuation of Energy Ottawa Generation.

Town of Markham, City of Vaughan and City of Barrie – analysis, due diligence and advisory services in evaluation of potential investment in the solar business of PowerStream Inc.

PUC Distribution Inc. – advisory services and analysis in connection with certain issues of new assets and affiliate relationships

Regulatory and Industry Policy	**Ontario Energy Board** – cross-jurisdictional review and assessment of regulatory approaches to the issue of farm stray voltage across North-America
	Ontario Energy Board – comparison of heritage contracts and similar arrangements in leading jurisdictions
	Ontario Energy Board – identification of appropriate roles and responsibilities for the OEB under alternative industry and market structure scenarios, including default supply arrangements
	Barbados Public Utilities Board – study to recommend procedures, rules and systems for oversight of the natural gas sector by a new regulatory agency.
	Electricity Distributors Association -- analysis of cash flow patterns of electricity distribution utilities in Ontario reflecting customer payment patterns and market settlement requirements
	Electricity Distributors Association – study to determine the financial benefit to municipalities of ownership of local distribution companies (LDCs).
	National Grid Co. -- Assessment and overview report on regulatory framework and issues in Ontario.
	Bruce Power – Assessment and overview on industry structure, generation and transmission capacity, pricing and issues in New Brunswick
	CMS Energy – report on Ontario electricity industry structure, market, and regulatory environment, in support of decision to respond to RFP for new generation in the province
	New Brunswick Municipal Electric Utilities Association – cross jurisdictional survey with respect to policy as to regulation of municipal utilities and rural cooperatives.
	Ontario Energy Board – assistance to Board Staff on application of a wireless telecommunication service provider for access to distribution poles

CAREER HISTORY

2001 – Present	**BDR** – consultant specializing in rate designs, cost and financial analysis, business planning and energy market restructuring issues.
1998 – 2001	**In association with Acres Management Consulting** – consultant specializing in rate designs, cost and financial analysis, business planning and energy market restructuring issues.
1995 – 1998	**Toronto Hydro** – Manager, Marketing and Energy Management

1993 – 1995	**Toronto Hydro** – Special Assistant to the General Manager (responsible for organizational performance improvement initiatives)
1986 – 1992	**Toronto Hydro** – Supervisor of Rates and Cost Analysis
1984 – 1986	**Toronto Hydro** – Senior Rate Analyst
1981 – 1984	**ICG Utilities Ltd**. – Coordinator, Rate Administration
1979 – 1981	**H. Zinder & Associates Canada Ltd**., Senior Analyst

EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS

Degrees and Designations	Society of Management Accountants of Manitoba, CMA University of Calgary, Masters of Business Administration (Finance) University of Toronto, Bachelor of Arts (Hon), Anthropology
Professional Association	Society of Management Accountants of Manitoba
Continuing Professional Development	Queens University School of Business, Marketing Program Queens University School of Business, Sales Management Program Society of Management Accountants of Canada—Customer Profitability Analysis Society of Management Accountants of Canada—Strategic Cost Management Society of Management Accountants – Auditing I

PROFESSIONAL INVOLVEMENT

Teaching and Training, Industry Committees	Instructor in Cost Allocation and Rate Design for Annual Energy Regulation Course, CAMPUT (Canadian Association of Members of Public Utility Tribunals) 2006, 2007, 2008. Member and Vice-Chair, Electricity Distributors Association Commercial Members Steering Committee (member 2007 to present) Member – Ontario Energy Board Cost Allocation Working Group (2003 and 2005-6) Member – Municipal Electric Association Cost of Service Sub-Committee (1986-1988)

October, 2012

Exhibit 4: Operating Costs

Tab 6 (of 8): Purchase of Non-Affiliate Services

PURCHASES FROM SUPPLIERS

This schedule is provided to speak to Bluewater Power's practices with respect to purchases from non-affiliated suppliers. The first section provides background on Bluewater Power's Purchasing Department. The second section references the list of vendors for the Historical Years at Table 1. Finally, we provide in this schedule an explanation for single-sourced purchases during the Historic Years as required by the Filing Guidelines.

Background:

Bluewater Power's supply of goods and services flow through the utility's Purchasing Department. Purchasing is responsible for two distinct functions – sourcing of goods/services and maintenance of inventory/stock. The Purchasing Department provides limited services for affiliates as described in the prior schedule on Shared Corporate Service (Exhibit 4, Tab 5, Schedule 1). This schedule focuses on the services provided by the purchasing department for the utility.

The first function of the Purchasing Department relates to the acquisition of goods and services where the Purchasing Department is acting as the sourcing agent on behalf of other departments in the utility. Under this scenario, the process is initiated by the department requiring the good or service through the issuance of a Purchase Requisition. Once the requisition is approved in accordance with the company's purchasing policy, the sourcing is undertaken by the Purchasing Department as a Request for Expression of Interest, Request for Quote, or Request for Proposal.

In carrying out the sourcing function, the Purchasing Department is responsible for developing the sourcing documents and selecting the successful bidder. For large purchases (i.e. Smart Meters or a Bucket Truck), the department responsible for requisitioning the purchase is directly involved in both developing the sourcing documents and selecting the successful vendor. Generally speaking, all large purchases are overseen by a team that is established to independently and objectively select the successful vendor.

The second function for the Purchasing Department relates to the maintenance of inventory for stock items. In carrying out this function, the Purchasing Department works closely with the Engineering Department to ensure all acquisitions and existing inventory meet Bluewater Power's Engineering Standards. The Purchasing Department also actively participates in regular planning meetings with the Engineering and Operations groups to ensure that adequate levels of inventory are available to meet all current and future needs.

In carrying out the function of maintaining inventory, the Purchasing Department works closely with qualified vendors. In carrying out the function of sourcing goods and services requested by other department, the Purchasing Department works with qualified vendors as well as new vendors identified through the requisition process. In all cases, the purchasing function is undertaken in accordance with the purchasing policy as represented in Bluewater Power's Procurement Manual. A copy of the Procurement Manual is included as Exhibit 4, Tab 6, Schedule 1, Attachment 1.

List of Vendors:

Provided at Table 1 is a list of third party vendors providing a supply of goods or services in excess of Bluewater Power's materiality threshold. The list of Vendors has been provided for all Historic Years.

Table 1 – List of Vendors

Vendor	2011	2010	2009
AXON SOLUTIONS (CANADA) INC.	2,172,234	2,206,349	
GREAT-WEST LIFE ASSURANCE COMPANY	699,566	660,109	646,978
HD SUPPLY POWER SOLUTIONS	487,915	579,307	694,852
SAP CANADA INC.	307,308	704,964	231,423
MOLONEY ELECTRIC INC	207,092	685,731	349,773
ELSTER METERING	34,467	999,118	2,271
ECHOPOINT SOLUTIONS INC.	31,126	584,607	418,958
DELOITTE INC.	134,244	515,212	368,265
THE MEARIE GROUP	252,345	229,768	188,697
ACRODEX - TORONTO	393,863	86,352	151,336
POSI-PLUS TECHNOLOGIES INC.	272,642	338,364	10,772
AUBI		472,435	142,286
GUARDIAN TREE SYSTEMS INC.	210,168	183,787	164,140
PACHECOS CONTRACTORS LTD.	227,684	151,043	177,842
ERTH HOLDINGS INC.	74,191	68,362	362,833
HONEYWELL LTD.	125,575	359,089	
MID-RANGE Computer Group Inc.			481,265
SOFTCHOICE CORPORATION	271,537	132,147	38,232
RUDDY	160,412	211,701	52,480
WAJAX INDUSTRIES	155	278,696	110,059
KPMG LLP, T 4348	129,422	82,789	156,942
CARTE INTERNATIONAL INC.	254,194	113,442	
GUELPH UTILITY POLE COMPANY LTD	95,418	80,155	138,817
RBC LIFE INSURANCE	122,521	116,663	45,594
BOND PETROLEUM	124,698	92,275	57,608
UTIL-ASSIST INC.	91,584	153,366	
MID-RANGE TECHNICAL SERVICES INC.	28,712	213,899	
ALLAN FYFE EQUIPMENT LTD	61,499	141,140	17,875
FRANCIS DE SENA IN TRUST		198,500	
CANADA POWER PRODUCTS CORPORATION		119,656	28,753
Grand Total	**6,970,571**	**10,759,026**	**5,038,052**

Single-Source Purchasing:

There were no purchases over the materiality threshold that were in non-compliance with Bluewater Power's Procurement Manual. However, there were purchases over the materiality threshold during the Historic Years that were single sourced as permitted by the Procurement Manual in specific circumstances. The following represents the list of third-party vendors who have provided goods or services to Bluewater Power for items where the value exceeds the materiality threshold of $114,785 and the item was single sourced from the supplier. The Vendors, the value of goods and the explanation for the single-sourced purchase is provided below.

- Canada Power Products (2010 purchase of $119,656) is the Canadian distributor of G&W switches. In 2007, Bluewater Power was concerned with its preferred switch regarding functionality and compatibility issues with its SCADA system. Given the limited number of products in the market, Bluewater Power performed an informal review and selected G&W switches as its preferred switch provider based on an assessment of its features, and its price was nearly 40% less than the then current preferred switch. Pricing has remained stable since that time and quality and features remain superior for our purposes.
- Carte International Inc. (2011 purchase of $254,194) is a manufacturer of Substation Transformers. Bluewater Power issued an informal RFQ for Station Transformers in 2002. The supplied transformer became Bluewater Power's accepted standard. Subsequently, and including the purchase in 2011, Bluewater Power has been dealing directly with this Canadian manufacturer to secure optimum pricing as a sole source supplier.
- ERTH Holdings Inc. (2009 purchase of $362,833) has been Bluewater Power's Meter Service Provider since the year 2004. ERTH was selected in 2009 to perform a meter change at the Modeland Transformer Station as they were the low price compared to two other vendors used for benchmarking.
- Pachecos Contractors Ltd. (2009 purchase of $177,842, 2010 purchase of $151,043, and 2011 purchase of $227,684) was selected as Bluewater Power's civil service provider following a public tender in 2002. The work performed by Pachecos today is generally limited to directional boring. This work is specialized

work and there is no other contractor providing services of this magnitude involving directional boring in Bluewater Power's territory. When performing work for Bluewater Power, Pachecos is typically also carrying out directional boring installations on behalf of Cogeco or Bell; Pachecos is a preferred authorized supplier/installer for Cogeco or Bell in Lambton County and a preferred contractor for Cogeco when joint directional drilling installations occur for the simultaneous installation of Cogeco and Bluewater Power plant.

- Bond Petroleum (2011 purchase of $124,698) provides fuel for Bluewater Power's fleet. Bond Petroleum was selected following an informal RFQ for the limited number of vendors capable of providing the service requested (Card-lock service for fuel, with adequate controls and information tracking). The market for fuel is an open market and Bond Petroleum was the only vendor offering a discount on the posted price.
- Softchoice Corporation ($132,147 in 2010 and $271,537 in 2011) has been a preferred vendor for Bluewater Power IT services primarily relating to IT Data Network and Security technical services and Unified Communications implementation and technical support. Softchoice was selected in the year 2007 (Unis Lumin at the time) because Bluewater Power was not pleased with service received from its preferred vendor at the time. After consultation with Cisco Canada, Softchoice was recommended because of their expertise as a Cisco Gold Certified vendor with the highest credentials in Unified Communications and VoIP solutions. Based on our experience with the market for services of this nature, Bluewater Power was satisfied with rates, the expertise and Softchoice's demonstrated ability to provide reliable on-going technical support.
- Acrodex Toronto (2009 purchase of $151,336, 2011 purchase of $393,863) is one of Bluewater Power's primary providers of computer software products, and Bluewater Power selected them as the preferred vendor under its Microsoft Enterprise Software Agreement set to expire in 2013. Acrodex is not the sole source provider for all software; moreover, the market is sufficiently large and open that pricing is readily comparable, thereby making service the paramount factor in choosing the appropriate vendor.

- Mid-Range Computing ($481,265 in 2009, $213,899 in 2010) was selected by Bluewater Power as part of a search for a qualified IBM Authorized Reseller in 2009. That search was held in conjunction with IBM Canada and we engaged in dialogue with a total of three qualified vendors. Bluewater Power has a significant investment in IBM datacenter hardware and relationships are essential to receive fair pricing and optimum service.

BLUEWATER POWER DISTRIBUTION CORPORATION

PROCUREMENT

MANUAL

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1.0 General

1.1 **Procurement Policy -** Exhibit 6.0

It is the policy of Bluewater Power (herein referred to as “BWP”) to purchase or provide equipment, materials, and/or services of all types in a cost effective manner with full consideration given to quality, price, delivery, reliability, engineering specifications and service. Purchases will be made to the Buyer’s best knowledge, with reputable, financially sound suppliers that are capable of meeting the specific needs of BWP.

1.2 Business Ethics

No employee is in any way authorized to take any procurement action on behalf of BWP which would result in an inadequate or inaccurate recording and reporting of assets, liabilities or any other transaction of which would violate any applicable laws. Procurement of goods and/or services for BWP are to be carried out with highest of ethical standards.

If any information comes to the attention of any employee which indicates a departure from conduct consistent with the standards set forth in this clause, the VP of Corporate Services is to be notified of such information for the appropriate action.

1.3 Conflict of Interest

It is the policy of BWP regarding conflict of interest to require all employees to avoid any conflict between their own interests and the interests of BWP when dealing with suppliers, customers and all other organizations or individuals doing or seeking to do business with BWP and or its affiliates. Further to this policy, BWP requires that competitive pricing be used, whenever practical, in the procurement of materials or equipment, and for contracted services.

While it is not practice to enumerate all situations which might be in conflict with this policy, the examples given below indicate some of the relationships which should be avoided. It is considered to be a conflict with BWP’s interest and a violation of trust:

1) For any employee or any dependent member of a family to have an interest in any organization which has, or is seeking to have, business dealings with BWP or an affiliate where there is an opportunity for preferential treatment to be given or received.

2) For any employee or any dependent member of a family to buy, sell or lease any kind of property, facility or equipment to BWP or an affiliate.

3) For any employee to serve as an officer or director, or any other company or in any management capacity for, as a consultant to any individual, firm or any other company doing or seeking to do business with BWP.

4) For any employee, without proper authority, to give or release to anyone not employed by BWP any data or information of a confidential nature concerning BWP, such as that relating to a competitive bid, or to use such information for personal advantage and not in the best interest of BWP.

5) For any employee or any dependent family member to accept commissions, a share in profits, gifts in cash, gift certificates or other payments, loans or advances (from other than established in banking or financial institutions) materials, services, repairs or improvements at no cost or unreasonably low cost, excessive or extravagant entertainment, travel, gifts of merchandise or more than nominal value from any organization seeking to do business with BWP.

1.4 Gifts and Gratuities

BWP employees are not to accept nor solicit, from any supplier or prospective supplier any money, gifts or other favours which might influence or be suspected of influencing any purchasing or contracting decision.

1.5 Entertainment

It is acceptable to meet a business associate for lunch or dinner in order to become better acquainted or to discuss a lengthy business matter. It is *not* acceptable to be entertained solely for the sake of entertainment. Also, repeated entertainment from a particular individual or company is *not* acceptable.

2.0 PURCHASING

2.1 General

Material, equipment, and supplies will be procured with proper consideration given to price, quality, delivery, performance and service. Such considerations will include the following parameters:

- Cost effectiveness based on an estimated target price normally solicited through competitive bidding.
- Timeliness of availability.
- Quality of the product based on standards established by plans and specifications.

The methods employed in affecting purchases will be consistent with established procedures, policies and guidelines. Material purchases should be undertaken in the manner most advantageous to BWP, price/cost, quality and other factors considered. To assure the award of business on an impartial basis, procurement actions shall secure, to the maximum extent possible, full and free competition, through the use of competitive proposals and awards.

Lowest price is not necessarily the determinative factor. The awarded bid is the bidder who can provide the most cost effective total offering to BWP. The factors considered are as follows: most responsive proposal to the terms & conditions, pricing, delivery, service, standards, specifications and drawings, company/individual is financially and technically acceptable, complies with the required safety standards, quality and assurance stipulations. Where the lowest priced bid is not the awarded bid, a full and clear statement of the reasons for the selection must be prepared and made part of the procurement/central file.

Awards may be split on purchase requests where it is clearly an advantage to do so. Where BWP intends to consider split bids the documentation to bidders shall make that intention clear.

Waiver of the competitive bid requirement is provided for in such specific instances as sole source procurements and other clearly defined cases. Selection of the type of purchase orders to be used shall be based on considerations of the nature of supplies and services required, or other circumstances surrounding the procurement.

2.2 Requisitions

The requisition is the basic document required to initiate a procurement action. This section is designed to assist in understanding the preparation and flow of requisitions. **All requisitions shall be prepared by the Requisitioner with all the required information and forwarded to Purchasing for processing.**

2.2.1 <u>Initiation</u>

All procurement actions in excess of $501 (note including tax) will be initiated by means of a properly approved and executed purchase requisition as issued by an authorized employee (See Exhibit 6.1, Purchase Requisition). Such person is hereafter referred to as the "Requisitioner" and the employee within the Purchasing Department responsible for sourcing the goods and/or services shall be referred to as the "Buyer".

Note: It is the responsibility of the Requisitioner to ensure requisition is completed properly ensuring the Buyer will understand what is required; when it is required; where it is to be charged, etc.

For those items $500.00 or less, plus taxes, which does not require drawings or specifications and/or is not for a service or rental, a minor purchase order may be used (See section 2.4.2 Request for Proposal Limits).

2.2.2 <u>Approvals</u>

Approval of all requisitions/purchases shall be authorized as follows;

Level 1	- $0 - $9,999.99	- Manager or Supervisor with budget responsibility
Level 2	- $10,000 – $29,999.99	- Supervisor and VP
Level 3	- $30,000+	- CEO and Board of Directors

* Purchases of coded stock are not subject to authorized dollar limits. Buyers have the authority to sign requisitions and order items as required, to maintain appropriate stock levels.

2.2.3 <u>Requisition – Information required</u>

All requisitions forwarded to Purchasing should define as accurately as possible the needs of the End User.

The following information is required on the requisition;

- a full description of the item
- quantity

- unit of measure
- cost assignments – cost center, order number, GL account
- any pertinent drawings and/or specifications (attach)
- any applicable standards (attach)
- end user or department
- date required
- budgeted amount or expected dollar value
- vendor information
- copy of quote (if applicable)

The requisition shall be issued to Purchasing promptly to allow time for review, bidding, bid evaluation, approvals, and issuance of purchase order.

Requisitions should specify tagging instructions, i.e.: equipment markings identification numbers, work order number.

Requisitions requiring third party rentals should show estimated duration of rental.

If items are specified for brand names, the requisition should clearly state "Equal Acceptable" or "No Substitution Acceptable".

All requisitions will include Account/Work Order/Budget numbers that the Requisitioner wishes applied to the Purchase order. It will also include the appropriate authorization signatures.

2.2.4 Corrective Action

Corrective action may be required following the screening and review. It shall be the responsibility of the Buyer to check with the Requisitioner to ensure that all pertinent data is forwarded for incorporation in the requisition. If, for example the Buyer discovers that delivery dates are unrealistic, it shall be the responsibility of that Buyer to coordinate with the Requisitioner to ensure that:

- Delivery dates are changed to coincide with availability
- Alternate purchase actions are taken to improve delivery
- Project schedules are consulted to determine any negative affects
- Approvals obtained accordingly.

2.3 Request for Information (RFI)

Unlike a Request for Quotation or Request for Proposal, the Request for Information is strictly for information purposes, which could be used in budgetary planning or where estimated cost figures are required. It should be clearly stated to the vendor that this is for information purposes only, and will not be binding.

2.3.1 Request for Quotations (RFQ)

A Request for Quotation is an informal pricing request that is required for any purchases where the anticipated amount will be over $10,000, the scope and specifications are clearly identified, and the pruchase does not meet the sole sourcing criteria.

It is desirable to have a minimum of three quotations, but no less than two.

The vendor quotations will be filed in the Purchasing Department along with the Requisition.

Quotations shall be reviewed by the Buyer and the Requisitioner. The lowest price quote shall be selected unless there are extenuating circumstances upon which this should not occur (e.g. – delivery date, quality factor, warranties, etc.).

The Purchasing Manager shall approve all requisitions for Capital goods/services with a value of $5,000 up to $29,999.

2.4 Request for Proposal (Formal)

Purchasing must call formal proposals when the estimated total amount of the expenditure to acquire the goods and services will be **$30,000** or more.

It is desirable to have a minimum of three proposals, but no less than two.

Proposals will be opened by the Purchasing Manager and the Requisitioner.

The Purchasing Manager shall be the sole authority in (a) awarding contracts and accepting proposals resulting from the opening of sealed proposals and (b) reviewing/accepting/rejecting recommendations will be made by the Purchasing Manager and the Requistioner.

Examples of business that would require solicitation by Proposal, irrespective of value, are as follows:

- Board approved capital projects utilizing the services of contractors or non BWP personnel when such services are estimated to $30,000 or more prior to purchase.

- Purchase of major equipment (e.g. transformers, wire and cable, meters, vehicles, etc.).

- Services, such as janitorial, snow removal, insurance (insurance at least every five years) and other large dollar value purchases.

- BWP would consider participating in CEO approved joint soliciting agreements with government organizations or utilities.

Sealed proposals shall be invited by mail, fax, courier or email.

Proposals not received by BWP or designate at the stated time and place stipulated in the proposal document will be returned to the vendor unopened. Acceptance of the proposal will be awarded by the Purchasing Manager or designate.

The Purchasing Manager shall approve all requisitions for Capital goods/services with a value of $5,000 up to $29,999.

When Proposals are required:

Generally speaking, request for proposals are required in most cases where estimated values exceed $5001, with the exception for specialized equipment or services. In determining the value of a proposal:

- The expenditure must be related to a whole or completed job, item or service.

- The purchase must not be segmented or divided in a manner that would circumvent the request for proposal process.

Exceptions to Request for Proposals

Exceptions to obtaining competitive proposals would be permitted under following conditions:

- As outlined in emergency spending limit authorization

- When there is only one source for the required goods or services

- Where single sourcing can be justified in accordance with Section 2.4.4.

The Purchasing Agent and/or Buyer is responsible for the proper initiation and completion of Request for Proposal forms.

2.4.1 Processing a Formal Request for Proposal (R.F.P.)

The Buyer is to provide, as a minimum, the following information in the R.F.P.

Instruction to Bidders

- Clear instructions as to the method, form and completeness of the proposal
- Proposal and contract securities required
- Other documentation required (i.e.: W.S.I.B./Insurance Certificate(s), proof of EUSA membership)
- Time and place for receiving proposals
- Number of copies of the proposal form to be submitted, which is typically three:
    - One for Commercial (Buyer), Central File
    - One for Technical (engineer/Requisitioner)
    - One spare
- Details of signing, sealing and witnessing
- Instructions concerning unit, itemized, total, alternative and separate pricing, any approvals or standards to be met. i.e.: freight details, packaging, taxes
- Job site visit, i.e.: determine conditions, safety requirements and scope of work
- Required delivery date (should be realistic)
- Freight terms, (i.e.: FOB Delivered)
- Payment terms, (i.e.: Net 30 days)
- Inspection requirements (if applicable)
- Tagging/marking (if applicable)
- Right to access for inspection
- Evaluation process
- Other relevant requirements and instructions

Scope of Work

- Full description and quality of items/services to be included in scope of work (obtain from Requisitioner, Originator/Technical person)

Proposal Documents

- Instruction to bidders
- Proposal forms
- Scope of Work
- Terms & Conditions
- Supplementary Conditions (if applicable)
- Specifications
- Drawings, design detail and schedules
- List of required submissions from bidder, (i.e.: insurance certificates, completed pre-qualification form)
- Addenda (if necessary, issued prior to bid closing)

The R.F.P. will be completed by the Buyer in such a manner that the Bidder will have a clear understanding of all requirements. The proposal due date should be carefully determined, keeping in mind the following:

- Required delivery date
- Time needed by Bidder to prepare a proposal (to ensure accurate and effective price completion)
- Complexity of proposal
- In-house time required to evaluate the proposal, prepare a summary and obtain approvals.
- Lead times

The R.F.P. will be compiled in accordance with Exhibit 6.2.

All items intended to be incorporated into the Purchase Order must be identified in the R.F.P.

It is the responsibility of the Buyer to pursue the R.F.P. with vendors to ensure the timely receipt of proposals.

Proposal Security

Construction proposal, utilizing the services of contractors or non BWP personnel, in excess of $100,000, **if requested**, shall be accompanied by a deposit in the form of a certified cheque, letter of credit or bond acceptable to BWP, payable to the BWP Distribution Corporation, equal to ten percent (10% of the total value of the proposal).

The deposit of the successful bidder will be retained until the contract has been signed and the Performance Bond or Security deposit has been furnished to the satisfaction of BWP.

Performance Security

All successful bidders for construction contracts in excess of $100,000 **may be required** to provide either (a) a Performance Bond from a licensed Canadian Surety Company in an amount equal to fifty percent (50%) of the total proposal, or (b) a Security deposit in the form of cash or irrevocable letter of credit acceptable to BWP, in the amount equal to fifty percent (50%) of the total tender. This Security will be deemed to be necessary and signed off by the Purchasing Agent, VP and/or CEO. The criteria considered will be by past performance, if contracted before, the company or individuals reputation. If required, the above securities shall be maintained in good standing until the fulfilment of the contract, but may be decreased, at the Purchasing Manager’s discretion, at a rate equal to the contract payment schedule.

In determining the value of goods and services to ascertain if the purchase comes within the proposal limit, the following criteria will be used:

- The expenditure must be related to a whole or complete job, item or service,
- The purchase must not be segmented or divided in a manner that would circumvent the request for proposal process.

It is important to define “performance” or “default” in the contract. In defining these terms consideration should be given to:

- Adherence to the specifications
- Measurable quality standards
- Operating parameters
- Timetables
- Notice provisions and timing for remedial work

Furthermore, it should be clearly stated who would judge the performance. It could be the field supervisor, the construction foreman, the engineer, or all of these.

Lastly, the proposal should be accompanied by a letter from the prospective bond holder or financial institution that the bidder is going to be provided with the securities if successful.

Formal and Non-Conforming Proposals

Single Formal Proposal

When one and only one proposal is received, it should be considered acceptable. If BWP is unable or unwilling to award the contract the proposal should be returned unopened to the bidder. If the proposal is opened and it meets all the requirements of the proposal documents and BWP's budget constraints the proposal should be awarded. Once a proposal has been opened re-bidding should be avoided.

Late Proposals

Proposals received after the closing time should be returned unopened, labelled "Late Proposal – Unopened".

Mistaken Proposals

If a bidder informs BWP promptly after the bid closing and before BWP communicates acceptance of the Proposal that a serious and demonstrable mistake has been made and requests to withdraw the Proposal, the Bidder should be allowed to do so without penalty.

Insufficient Proposal Security

If a bidder submits insufficient proposal security as specified in the proposal documents, the bid shall be rejected.

Arithmetic Mistakes

In Unit Price Contracts, if there are arithmetic mistakes in extending or adding unit prices on the proposal form, the *unit prices shall prevail* and the extensions and contract price shall be adjusted accordingly.

2.4.2 <u>Request for Proposal Limits</u>

Note: Purchasing shall solicit for all proposals, except in a true emergency, and only if purchasing is not available, shall the Requisitioner make contact with Vendors with the intention of obtaining a proposal.

The following guidelines will be used in obtaining proposals:

1. From $0 - $500
   - informal telephone call/fax/email or over the counter pick-up. Logged in Minor PO file.

   - *Exception – not to be used for:*
   - rentals
   - services (exception – may be used for services if estimated time one day or less and Insurance, W.S.I.B., Safety requirements, all met prior to coming on site) – must be confirmed through Purchasing.

2.	\$501 - \$5,000	-	one or more informal telephone or telefax proposals with the low bid to be confirmed by fax/email for inclusion in the PO file.
3.	\$5,001 - \$29,000	-	a minimum of two, but preferably three competitive proposals in writing, whether formal or informal procedures are employed.
4.	\$30,000 and over	-	a formal Request for Proposal or Request for Quotation shall be issued for the solicitation of Proposals. These will be in writing.

2.4.3 Formal or Informal Requests for Proposal

Formal or informal solicitations may be used, however, formal written R.F.P.'s shall be used on all capital expenditures; requisitions where drawings and specifications are part of the requisition, (i.e.: truck, wire/cable, transformers, meters, large blanket requirements for inventory items).

2.4.4 Single Source Solicitations

Orders may be placed by solicitation from a single source under the following conditions:

- 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.

- Sole source may be used in the discretion of the Requisitioner for purchases where the anticipated price will be under \$10,000. The quote can be either written or verbal.

- Sole source may only be used for purchases where the anticipated price exceeds \$10,000 when;

    - Quotation from sole source vendor is supplied in writing
    - Written explanation by Requisitioner as to why sole sourcing is to occur. It must be attached to the requisition along with the quote.

- The material is an item of required design or is a proprietary or patented item available only from the patent holder or license.

- A reasonable attempt to identify competition has been unsuccessful.

2.4.5 Manufacturers and Regular Dealers

Proposals are to be solicited only from manufacturers, exclusive representative or distributors. An exclusive representative is that person or firm who has the exclusive rights of distribution of the materials, supplies, articles, or services required. A “distributor” is a person or firm that owns, operates or maintains a store, warehouse, or other establishment in which the materials, supplies, articles, or equipment required are bought, kept in stock, serviced, and sold to the general public in the course of business.

The use of local distributors cannot be overlooked. Their importance in a procurement program contains many intangibles such as support services and information.

2.4.6 Pre-Award Meeting (Bid Review)

It may be necessary to hold a bid review meeting prior to awarding a contract/order. These meetings are to be arranged by the Buyer who will ensure all necessary staff is present as well as bidder’s staff.

The Buyer will chair the meeting and carefully minute the discussions and, as necessary, issue formal addenda to bidders covering clarifications and changes are specified in the meeting.

2.5 Supplier Relationships

It is the responsibility of the Buyer to maintain good and open business relationships with all supplier/contacts.

2.6 Review of Proposals

Proposals are to be directed to the Purchasing Manager and/or Buyer. Although technical questions by the Bidder may be directed to the Requisitioner, contact between Bidders and Requisitioner’s should be kept to a minimum, and the Buyer will be copied on any correspondence. All vendor contacts during the proposal process must be through the Buyer. This is to ensure the Buyer is knowledgeable on all subjects pertaining to any proposal request.

During the proposal process, a vendor meeting may be required to clarify proposal documents and to allow site inspection. In such a case, the Buyer will arrange the meeting with the appropriate departments, taking minutes of the meeting and issue any necessary addenda as a result of this meeting.

On the proposal due date, Informal Proposals may be reviewed by the Buyer. Sealed Proposals requiring the Purchasing Managers approval shall be opened either exclusively by him/her or jointly with the Requisitioner. The original of three proposals submitted shall not be marked up in any way. Later to be filed in Purchasing.

- One copy will be forwarded to the Requisitioner for technical/engineering evaluation

- One copy retained by Buyer for commercial evaluation. The Buyer shall prepare a Bid Summary, obtain signature of Requisitioner and/or resolved to a mutual recommendation.

Award will be based on the following criteria and a decision will be made by Purchasing (with Requisitioner's input) as to which supplier can most effectively/efficiently, at a fair price, provide the goods and/or services to BWP. Lowest unit or total cost may not always be the awarded supplier.

In addition to the actual item or unit prices, the following factors shall be considered in determining the best value:

- Unit prices
- Brief description of FOB point
- Escalation (if any)
- Validity date of proposal
- Delivery date terms of payment
- Freight terms and costs
- Exceptions to R.F.P. specifications, drawings and other documents
- Service
- Reliability
- Quality
- Safety
- History
- Other points that might influence vendor selection

All pricing information should be treated as confidential by all parties before purchase.

2.6.1 <u>Alterations to Proposals</u>

Alterations to proposals by letter or fax are acceptable if received before the scheduled proposal closing date.

2.6.2 Rejection of Proposals

If the initial proposal response does not provide acceptable prices/terms, or material, or delivery schedule, all or partial proposals may be rejected and new proposals requested. It is important to remember that schedule requirements may dictate that proposals not be rejected or that alternate methods or award be made, such as through negotiation.

2.6.3 Change in Scope

Bidders should be advised via formal addendum when the specifications or conditions of bidding are revised. Once the proposals are submitted, should it be found that new conditions are required; the Buyer may either negotiate a price properly reflecting these changed conditions or may reopen the proposal process. If changes occur prior to the receipt of the proposals, all bidders should be expeditiously advised. If bidders require more time to complete the R.F.P. because of the change, it should be granted in writing showing the new closing date, only if the schedule will allow it.

2.6.4 Clerical Errors in Proposal

If a proposal appears to contain clerical errors, the Bidder should be contacted by the Buyer for written clarification.

2.6.5 Mistakes

In the case of a mistake other than a clerical error, where for example it is suspected or alleged that the bidder has mistaken the cost of an item prior to award, the bidder is to be requested to furnish either a verification of the proposal of evidence in support of a mistake, and the proposal shall be considered in the form resubmitted.

In evidence of an error in calculation is submitted, the Buyer shall determine whether the evidence is sufficient to establish that an honest mistake was made, and in so, the bid may be revised only to the extent of correcting the mistake.

2.6.6 Acceptance of Terms and Conditions

Where it is not clearly indicated if the bidder accepts the terms and conditions stated in the Request for Proposal, bidder shall be contacted to determine whether or not he accepts the terms and conditions.

The Terms and Conditions of purchase cannot be taken lightly. Full accord between Buyer and Vendor must be finalized prior to order of issuance. If the Vendor makes a counter-proposal that includes deletions/additions or changes to BWP's Terms and Conditions, consultation with CEO and/or Legal Council should be undertaken, as appropriate.

2.7 Transmittal of Proposal

Upon completion of the commercial evaluation, a copy of the proposal summary, along with a copy of the proposals received, shall be transmitted to the Requisitioner for technical review, recommendation and approval. Approval will be indicated by the appropriate signatures.

The transmittal to the Requisitioner should contain:

- copy of the proposals
- a list of any concerns or consideration factors Purchasing would like the requisitioner to be aware of.

This information shall be treated as confidential at all times.

2.8 Escalation

Firm prices should always be requested, negotiated and agreed upon. This is generally not a problem for a one year or shorter purchase order contract. However, from an efficiency and in-house cost perspective, Purchasing may wish to engage in a long term Blanket Order, (i.e. three to five years). In this instance all increases must be scrutinized and negotiated and be in accordance with the following guideline references: Statistics Canada Industrial Price Indexes Catalogue #62-011 June, 1996 and Man-Hours & Hourly Earnings, complied and published monthly in Catalogue #72-002.

2.9 Pre-Award/Bid Review Meetings

A pre-award meeting with the selected supplier should be held in connection with major complex procurements. The prime objective is to achieve maximum assurance that the work will be performed smoothly and satisfactorily. In no event should a pre-award meeting be used for changing pricing unless warranted by corresponding change in specifications, drawings, quantities, schedules, etc. The pre-award meeting should be conducted by the responsible Buyer or Purchasing Manager directly in charge of awarding the purchase. In order to fully accomplish the objectives stated above, the meeting should be attended by personnel qualified to answer questions relating to matters that are expected to be discussed.

It is important that the persons attending clearly understand that the purpose of the meeting is not to modify the requirements, the contractural agreement or the terms and conditions previously arrived at through the proposal process and/or any subsequent negotiations, but rather to afford an opportunity to explain, to the extent considered necessary, BWP's policies and requirements with respect to the scope and administration of work.

2.10 Approvals, Awards and Preparation of the Purchase Order

Prior to purchase it may be necessary to obtain approval from the CEO and/or Board if total estimated expenditure will exceed the spending limit authorization shown on the requisition.

In order to obtain these approvals a recommendation must be developed. This should incorporate a technical recommendation from the engineering/Requisitioner and a recommendation from the Purchasing Manager or Buyer. This recommendation should be prepared in a Bid Summary.

BWP reserves the right to accept any proposal and not necessarily the lowest proposal and to reject any or all proposals.

BWP reserves the right to award in whole or in part, by item, or class.

No commitment shall be made by BWP in respect of the proposal until such time that the Vendor receives written notification of acceptance and Purchase Order from BWP Purchasing Manager.

Proposals having any erasures or corrections therein may be rejected unless explained or noted over the signature of the Vendor.

Proposal evaluation will include the following criteria:
- the extent to which the proposal is appropriately received and details required are accurately submitted;

- the extent to which the proposal meets all mandatory requirements of this solicitation'
- deemed capabilities, understanding the requirements, integrity, reliability and financial stability of the supplier to meet the requirements of BWP;
- pricing;
- quality of product and samples (where requested) submitted;
- range and scope of services, resources, available to BWP;
- delivery, capabilities to ensure deadlines are met;
- quality of past performance, and references;
- environmental responsibility;
- absence of both conflict of interest and potential or perceived conflict of interest.
- Each criterion above is listed randomly and does not necessarily reflect priority in the actual evaluation process.

2.10.1 <u>Purchase Order</u>

The Buyer may verbally place the order with the successful Bidder, reviewing all criteria such as quantities, description, price, shipping and payment, terms, carrier, tagging, delivery dates, etc. This will ensure a quicker, more accurate response from the Bidder. A confirming order should be issued immediately.

A Purchase Order (see exhibit 6.0) is to be used for purchases over $501.

The purchase order as a minimum must include the following:

- Bidder's legal name and address
- Purchase Order number
- Date
- Terms of payment
- Shipping terms and FOB point
  Complete description of items purchased, quantity, unit and total prices.
- Firm Price Policy (escalation clause if prices not firm)
- Tax status
- Shipping instructions
- Tagging/Marketing instructions
- Customs instructions (if applicable)
- Schedule of engineering/fabrication (if applicable)
- BWP's Terms and Conditions
- If the order was placed verbally it should state: *"Verbal Confirmation between your _ ______ and our ______ on <u>date."</u>*
- Reference any quotation numbers and/or dates

2.10.2 <u>FOB Point and Freight Charges</u>

The FOB (Free on Board) point stated on the purchase order determines the place at which title to the goods passes from the seller to the Buyer. The responsibility for the goods also passes at this point. For example, for a shipment FOB shipping point, it would be the responsibility of the Buyer to file any necessary freight claims whereas if the same shipment had been FOB destination, the seller would be responsible for the claim. The FOB stated on the Purchase Order is usually followed by a statement clarifying who pays freight. Some typical examples are as follows:

FOB Shipping Point, Freight Collect
Buyer – pays freight charges
Buyer – bears freight charges
Buyer – owns goods in transit
Buyer – files claims (if any)

FOB Shipping Point, Freight Prepaid and Allowed
Seller – pays freight charges
Seller – bears own freight
Buyer – owns goods in transit
Buyer – files claims (if any)

FOB Shipping Point, Freight Prepaid and Add
Seller – pays freight charges
Buyer – bears freight charges
Buyer – owns goods in transit
Buyer – files claims (if any)

FOB Destination, Freight Collect
Buyer – pays freight charges
Buyer – bears freight charges
Seller – owns goods in transit
Seller – files claims (if any)

FOB Destination, Freight Prepaid & Allowed
Seller – pays freight charges
Seller – bears freight charges
Seller – owns goods in transit
Seller – files claims (if any)

Note: In most instances FOB Destination, Freight Prepaid and Allowed is the most advantages to BWP.

2.10.3 Harmonized Sales Tax (HST)

The following aspects of the HST should be considered when assessing the bids and preparing the purchase order.

1. *Foreign Currency*
   When the value of the Purchase Order is specified in foreign currency, the HST will be calculated on the Canadian dollar ($) value on the date the payment to the vendor is due.

2. *Payment Discounts/Late Payment Penalty*
   The HST is payable on the full invoice price, not the discounted price.

   In the same fashion, interest on overdue amounts is not considered in the total price for HST purposes. The HST payable is still on the base price *not* the price and accrued interest.

3. *Harmonized Sales Tax*
   Harmonized Sales Tax will be calculated, and shown as a separate line item on quote at 13%.

4. *Imports*
   HST on imported goods will be imposed at the same time as custom duties apply. The HST will be paid by the custom broker on our behalf and shown on the brokers invoice.

5. *Imported Services*
   Services imported into Canada by a Vendor are not subject to HST and should therefore be quoted separately from any equipment/material.

2.11 Purchase Order Number

The purchase order number will be generated in SAP when the document is saved, at which time the number will be provided to the vendor.

2.11.1 Approval of Purchase Orders

All purchase orders shall be signed on behalf of BWP by the Purchasing Manager, Buyer and/or a delegate.

2.12 Distribution of Purchase Order

1. White (original): Vendor copy – mail or fax

2. Copy & Yellow Req.: Requisitioner – tracking/future reference

A copy of the Purchase Order will be filed with the R.F.P. and Bid Summary in the Purchasing Department.

Purchase Orders may not be required for procurement of professional services, common carrier, transportation at tariff rates, postage, telephone metered utilities, subscriptions, credit card purchases, etc. It is usually not customary to cover the aforementioned requirements with a purchase order.

Purchase Orders should be issued before or concurrent with any purchase or commitment, except in emergencies, in which case a confirming order will be written as soon as possible.

2.13 Split Awards

Split Awards should be made when advantageous to do so. Buyers should be sure to check with the bidders prior to order award to ensure that a spit order will be acceptable. All R.F.P.'s should have a provision which states BWP's authority to split awards if deemed desirable.

2.14 Special Consideration Purchase Orders

Suppliers Financial Ability
Prior to issuing an R.F.P. to bidder, the bidder should be pre-qualified financially, technically and to quality assurance level. The bidders pre-qualification forms (Exhibit 6.3 should be used for this purpose).

Insurance Requirements
Anyone providing a service (outside labour) for BWP must have insurance in the following amounts and in form satisfactory to BWP, insuring himself against claim and all liability for property damage and public liability.

General Liability	$2,000,000 per occurrence
Automotive Liability	$2,000,000 third party liability and $2,000,000 third party for non-ownership liability.

Note: Requirement for Live Line Clearing is $5,000,000.

Evidence of Insurance

Certificates of Insurance for Bidder and/or any proposal sub contractor(s) along with a clearance certification from the Workman's Compensation Board are required prior to commencement of work. *Note:* Certificates are filed in Purchasing.

Performance Bond Labour and Material Payment Bond
A Performance and/or Labour and Material Payment Bond *may be required* where risk to BWP is evident. Determination of risk will be made in cooperation with the Purchasing Manager & VP of Corporate Services within BWP.

2.15 General Terms and Conditions

BWP's General Terms and Conditions (Exhibit 6.4) are provided to standardize basic rights and obligations.

2.16 Supplementary Terms and Conditions

Clauses developed to cover a specific requirement or risk.

2.17 Additional Terms and Conditions of Order

Occasionally there will be a need for the insertion of special clauses to further define the rights and obligations of the parties to the Purchase Order.

By definition, these statements are written to cover a special situation, therefore standardization is not possible.

2.18 Types Of Purchase Orders

2.18.1 Fixed-Price Indefinite Quantity Purchase Order

Requirements for supplies which are requisitioned on a repetitive basis may, in some cases, be fulfilled most advantageously with the use of a fixed-price indefinite quantity purchase order. While this type or order clearly offers the advantage of simplifying purchases and reducing transaction costs, it should be used when all of the following conditions are present:

- Required items can be grouped properly into a single R.F.P.
- Estimates of requirements are reasonable
- Subject to the fixed price procurements
- A stable market is anticipated

- Anticipated quantities of individual orders are not sufficient to obtain favourable prices by individual orders

All such orders must state a dollar limitation of the commitment and termination date. The use of these types of contracts is beneficial and should be sought out.

2.18.2 Blanket Orders

Blanket Orders are a version of Purchase order utilizing the SAP option of setting dollar values or date limits.

Blanket orders are useful and offer cost saving benefits for the purchase of consumables, repetitive items, and miscellaneous supplies picked up or ordered on a frequent basis. Can also be used successfully to cover ongoing services. Normally blanket orders are renewed annually; however, longer duration contracts may have price advantages and save on precious in-house resources.

Blanket orders can reduce inventory costs by supplying materials/equipment only as they are required “Just In Time”. BWP needs only to maintain minimum stock.

When possible, Blanket Orders should state the dollar limitation of the commitments and the termination date of the order. The names of the persons who are authorized to obtain such material should be specified and only the Purchasing Department or those authorized persons should be allowed to make releases against the order.

Releases should be confirmed in writing with copies to Purchasing, Receiving and Accounting.

No Blanket Order should be issued without first soliciting proposals from vendors that are capable of furnishing quality products and services. The date of the contract must be noted on the Purchase Order. Continual review of such orders should be made to ensure that pricing schedule remains as quoted.

2.19 Rentals

Bare Rentals – Equipment, Tools, etc.
The following information is required on the Purchase Order:

- Complete description – make, model, serial number
- General description, age, condition

- Rental fees (day, week, month)
- Rental period
- Replacement cost
- Freight, loading terms and charges – incoming and outgoing
- Responsibility for maintenance, repairs, downtime
- Insurance arrangements/costs
- Maximum expenditure authorized for payment

Note: In addition to normal receiving procedures, as bare rental equipment is received, the receiver should perform an inspection. The following should be noted on receiving report:

- Conditions of equipment
- Make, model, serial number
- Mechanical condition
- Condition of tires (if applicable)
- Mileage and/or hour meter reading
- Other relevant observations/comments

If there appear to be excessive wear or the presence of defects, the Lessor should be made aware of the problems in writing. This will preclude claims or back charges when equipment is returned “Off Rent”.

Purchasing is to be made aware of when the equipment is returned.

2.20 Time and Material (Labour/Material/Equipment)

A Time and Material Contract is recommended where the scope of work is not clearly defined or services are required on a per-unit of time basis. Contract costs are then established on progress billings based on previously bid hourly, daily or crew “charge out rates”. All invoices must be substantiated by copies of time/material sheets duly approved by BWP Supervisor.

2.21 Fuelled, Maintained and Operated Equipment

Operators must be covered by Workman’s Compensation and the Lessor must present certification of insurance satisfactory to lessee prior to equipment being placed into operation.

Daily time sheets must be approved by the BWP Site Contact and copies of same must accompany invoices. The labour requirements clause must be part of the order.

2.22 Rental With Option to Purchase

If equipment is required for a substantial period of time it would be good business practice to negotiate a rental with option to purchase prior to rental.

2.23 Leases

Rentals and Leases are often thought of synonymous, but there are differences which have financial and tax ramifications.

Simply stated, leasing is a form of financing whereby the lessee (user) utilizes the money of the lessor to obtain equipment.

True lease agreements should be reviewed by the General Manager and/or Director of Finance.

2.24 Emergency Procurement

If the emergency is so great as to out weigh all considerations of possible price savings through the use of competitive proposals, then a full statement of the reasons justifying it shall be made a part of the purchase order file. Approval shall be sought from the Controller.

2.25 Minor Purchase Orders

These are purchases not to exceed $500, and will be issued by Purchasing or the Stockroom Clerk.

2.26 Changes to Purchase Orders

2.26.1 Processing Change

Change Orders are initiated to supplement purchase orders which require amendment to provide for additions to, or deletions from, original quantities of material and equipment or scope of work, changes in design, revisions to terms and conditions and shipping instructions, and completion of delivery dates.

Processing of Change Orders conforms to the procedure for processing purchase orders. A duly approved Change Order/Requisition is required prior to executing a Change Order.

2.26.2 Initiated by Engineering/Requisitioner

Change Orders to Purchase Orders involving changes in engineering design and specifications, quantity of items to be furnished, scope of work to be performed, price of goods or work, or scheduling of work are initiated by the engineer/Requisitioner who will complete a Change Order and forward a copy to Purchasing for processing.

Note: Changes regarding engineering/design/schedule must be covered on a Change Order Form (see Exhibit 6.5). Changes regarding goods supplied, quantities, price, etc. shall be covered on a Requisition.

2.26.3 Initiated by Buyer

Change Orders concerning the commercial provisions and Terms and Conditions of the original Purchase Order which do not involve a change in work scope or schedule, are initiated by the Buyer. These changes may be covered on a Requisition, but require the same levels of approval as the Purchase Order.

2.26.4 Preparation of Change Orders

Purchasing shall initiate ***all*** changes by way of a Revised Purchase Order which must include the following:

- Description of the change
- Reason for the change
- Any additional or revised plans and specifications referred to in the change
- Other subject matter pertaining to the change
- Total of Change Order and Purchase Order's cumulative value to date

2.27 Purchase Order Termination

Purchase Orders are terminated when it is in the best interest of BWP to do so. Appropriate clauses must be included in all purchases orders to establish a basis of termination and/or refer to General Terms and Conditions number seventeen (17), Termination of Convenience.

Approval for termination must be obtained from the appropriate level of authority.

2.27.1 Restocking Charges

In many cases it is possible to terminate for convenience or cancel an order at no cost when the items involved are standard to the vendor's production line and the vendor has and immediate market elsewhere for them. The first goal will always be to attempt to terminate orders on this basis.

The agreement to no-cost termination will be reflected by a Change Order to the Purchase Order indicating that such and agreement has been reached.

In many cases a termination for convenience can be arranged by agreement of the vendor to accept back into stock the items being cancelled in exchange for a reasonable restocking charge to cover the extra expense to which the vendor has been put by this action. All costs for restocking require approval by the necessary level. Purchasing will then issue a Change Order to cover.

2.28 Cost Savings

In the course of the buying function there are situations which, due to the Buyer's skills and persistence, can realize a cost savings. Such instances should be documented.

Cost savings can be realized through a number of actions such as:

1. Value analysis resulting in specific material substitution for lower cost/better value.
2. Combined requirements.
3. Negotiated price decreases or additional benefits.
4. Vendor sourcing beyond the normal procedures.

Reduction in costs from normal purchasing practices such as proposal solicitation are not recognized as cost savings.

3.0 EXPEDITING

The successful completion of a project depends on the timely scheduled delivery of material and equipment. Expediting efforts are primarily directed toward meeting and/or maintaining the current required on-site delivery dates for these products. Expediting activity involves maintaining close contact with the vendors.

All purchase orders placed are subject to expediting.

The buyer through expediting will analyze vendor plant capabilities, labour conditions, damage to vendor's premises by acts of nature, i.e.; flood, fire.

3.1 Buyer Responsibilities

- The Buyer is also responsible to inform the Requisitioner and concerned departments, i.e. operation, technical, etc., of production lead times.

- Analyze all purchase orders and ensure that all instructions contained therein are compliant by vendors.

- Maintain close adherence to the purchase order delivery dates.

- The Buyer is responsible for ensuring "Approval Drawings" are approved and returned in a timely manner, i.e. transformers.

Contractor Pre-Qualification Form (PQF) (Exhibit 6.3)

- The purpose of this form is to document the qualifications of potential contractors having NO PREVIOUS WORK HISTORY with Bluewater Power Corp., or affiliates, and who are being considered to do projects $50,000 and above.

- All BWP personnel entrusted with the hiring of Contractors will have the potential Contractor complete this form (available from Purchasing). They will either approve or reject the form and provide a copy to Purchasing. The BWP Safety Co-coordinator will be involved in this review of the information provided by the potential Contractor. The completed form will be sent to the Purchasing Manager to become part of the Contractor's file, and added to the Approved Vendor List if approved.

3.2 Procurement Card Purchases

Procurements cards are authorized and controlled by VP of Finance.

The Purchasing Manager holds a procurement card with a limit of $10,000 for purchases. The purpose of the Visa Purchasing Card is to provide an efficient, cost effective method of purchasing and processing small dollar, or “one off” type purchases. These purchases will typically be for online ordering, or from a vendor we do not have a charge account with.

The items purchased still require an appropriately filled out requisition with all pertinent information and approvals. This information will be required when the Purchasing Manager fills out a monthly Visa Expense Report, on which the description of the item, as well as account assignments is listed.

3.3 Fleet Gas Cards

Fleet Gas Cards are issued by the Purchasing Manager as directed by the Lines VP or Lines Supervisor. Any stolen, lost or malfunctioning cards will be reported to the Purchasing Manager and a replacement will be issued.

These cards are for BWP vehicles and company use only.

Monthly reports are sent to Accounts Payable to be paid. At the time the charges are assigned to the appropriate cost center and general ledgers.

3.4 Invoicing Approvals

All invoices are received by BWP’s Accounts Payable; the AP clerk will then forward the invoice to the Requisitioner or Supervisor for approval to pay.

If there is any discrepancy in the dollar amount, a change order will be filled out by the Requisitioner and given to Purchasing to make any necessary changes in SAP.

The AP clerk will then process the payment.

4.0 SHIPPING ORDER

The Originator of a shipping action will see the Stockroom Clerk in regards to shipping. The appropriate shipping forms, (by Freight company) will be filled out by the Stockroom Clerk with information provided by the Originator.

The originator is responsible for providing the accurate information required such as:

- Purpose of Shipment
  - Defective unit
  - Return "Off Rent"
  - Return a loaned sample, literature, piece of equipment
  - Repair of equipment
  - Calibration/Testing of equipment etc.
- Ship To
  - Complete company name and address
- Value of Goods
  - Important for Shipper/Purchaser to determine a carrier with adequate insurance to cover.
- Number of packages and estimated weights
- Quantity and description

Shipping/Purchasing will complete the following:

- Shipped via
- B.L. NO. and Date
- Freight terms – prepaid and charge
- Approved by Purchasing/Warehousing

Note: Copies can be made once the carrier/driver signs forms.

4.1 Bill of Lading

(Shippers Responsibility)
A carrier's Bill of Lading must be completed by the shipper and signed by both the shipper and the carrier. The Bill of lading provides evidence of the Contract of Carriage for the goods included in the shipment, as such, is an important legal document.

5.0 CUSTOMS

BWP has appointed a Canadian Customs Broker to act on their behalf in all matters pertaining to importation of goods into Canada and payment of import duties and taxes. Purchasing is the contact point for all correspondence with Canada Customs and the Customs Broker.

Shipper/Broker – BWP uses UPS.

5.1 US – Canada Free Trade Agreement – Exporters Certificate of Origin

Purchasing shall maintain a file with Certificates of Origin

BWP does not pay duty on goods which have been manufactured (100%) in the USA. To substantiate this, the Exporter shall provide a Certificate of Origin to the Customs Broker with a copy to Purchasing. This document indicates the degree of value added in the USA.

5.2 ESA Compliance

In order to comply with the Electrical Distribution Safety Regulation 22/04 Section 6, requires all electrical equipment that is part of the distribution system to be approved by:

a) meeting any of the standards for approval of equipment set out in Rule 2-024 of the Electrical Safety Code; or
b) compliant with a code or standard under a rule of the distributor that provides an assurance of safety of the equipment that is equivalent of the assurance of safety provided by option (a).

When ordering this equipment, special procedures will be used, please refer to US-EN-014 in the BWP Policies and Procedures.

On these purchase orders, it will be stamped with "**ONLY ITEMS THAT MEET THE STANDARD AS SPECIFIED IN THE BLUEWATER POWER ITEM DESCRIPTION (IF APPLICABLE) WILL BE ACCEPTED BY BLUEWATER POWER**". The Stock/Purchasing lead hand will be maintaining the item information, including manufacturer part number, BWP Stock number and the standards attached to the item and this list of BWP approved list will be faxed to the supplier. It will be noted that the supplier is to advise of any changes to the item, and standards/approvals.

When these items are inspected and received and deemed they are as ordered, the packing slip will be stamped with "**ALL ITEMS ARE RECEIVED AS ORDERED**".

If any items are not as ordered, the vendor will be contacted and arrangements made for replacement/return of the goods.

6.0 EXHIBITS

Exhibit 6.0 – Purchase Order

Exhibit 6.1 – Purchase Requisition

Exhibit 6.2 – RFP

Exhibit 6.3 – Contractor Pre-Qualification Form

Exhibit 6.4 – Terms and Conditions

Exhibit 6.5 – Change Order Form

Exhibit 4: Operating Costs

Tab 7 (of 8): Depreciation and Amortization

DEPRECIATION RATES AND METHODOLOGY

Bluewater Power has completed the following Appendices at Exhibit 4, Tab 7, Schedule 1, Attachments 1, 2, 3, and 4 which provide the details by asset account for 2011 Historical Year, 2012 Bridge Year and 2013 Test Year. The schedules include the asset amount, number of years for depreciation, and the rate of depreciation.

- Appendix 2-CE – Depreciation and Amortization Expense 2011 (CGAAP)
- Appendix 2-CF – Depreciation and Amortization Expense 2012 (CGAAP)
- Appendix 2-CG – Depreciation and Amortization Expense 2012 (MIFRS)
- Appendix 2-CH – Depreciation and Amortization Expense 2013 (MIFRS)

Bluewater Power confirms that the depreciation expense amounts reconcile to the fixed asset amounts presented in Exhibit 2, Tab 3, Schedule 2, Attachment 2.

Bluewater Power does not have any asset retirement obligations and therefore there is no corresponding depreciation amount included for the 2013 test year.

Bluewater Power has provided its Depreciation Policy in Exhibit 2, Tab 2, Schedule 4. That policy confirms that, for rate making purposes, Bluewater Power follows the “half-year” rule where capital additions in the 2013 test year attract six months of depreciation expense when they enter service. Bluewater Power’s historical accounting practice is to commence recording depreciation expense in the month an asset enters service.

Bluewater Power has also provided a schedule of the Asset Components and Depreciation Rates at Exhibit 2, Tab 2, Schedule 4, Attachment 1.

File Number:	EB-2012-0107
Exhibit:	4
Tab:	7
Schedule:	1
Attachment:	1
Date:	22-Oct-12

Appendix 2-CE
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013

Year 2011 **CGAAP**

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2011 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2011 Depreciation Expense (h) = (e) / (f)	2011 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 8,481,130	$ 3,419,090	$ 5,062,040	$ 1,019,754	$ 5,571,917	5.29	18.91%	$ 1,053,505	$ 1,053,505.00	$ -
1612	Land Rights (Formally known as Account 1906)	$ 283,160	$ 253,355	$ 29,805		$ 29,805	25.00	4.00%	$ 1,192.00	$ 1,192.00	$ -
1805	Land	$ 489,817		$ 489,817	$ 7,672	$ 493,653	-		$ -	$ -	$ -
1808	Buildings			$ -		$ -			$ -	$ -	$ -
1810	Leasehold Improvements			$ -		$ -			$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV			$ -		$ -			$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 6,106,086	$ 1,539,400	$ 4,566,686	$ 349,496	$ 4,741,434	30.44	3.29%	$ 155,763.00	$ 155,763.00	$ -
1825	Storage Battery Equipment			$ -		$ -			$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 1,781,988		$ 1,781,988	$ 475,690	$ 2,019,833	25.68	3.89%	$ 78,639.00	$ 78,639.00	$ -
1835	Overhead Conductors & Devices	$ 27,076,679	$ 6,296,523	$ 20,780,156	$ 409,256	$ 20,984,784	25.06	3.99%	$ 837,355.00	$ 837,355.00	$ -
1840	Underground Conduit	$ 958,584		$ 958,584	$ 191,772	$ 1,054,470	25.84	3.87%	$ 40,803.00	$ 40,803.00	$ -
1845	Underground Conductors & Devices	$ 19,704,320	$ 3,909,689	$ 15,794,631	$ 595,739	$ 16,092,500	25.11	3.98%	$ 640,773.00	$ 640,773.00	$ -
1850	Line Transformers	$ 14,684,774	$ 3,542,866	$ 11,141,908	$ 723,360	$ 11,503,588	25.32	3.95%	$ 454,254.00	$ 454,254.00	$ -
1855	Services (Overhead & Underground)	$ 431,764		$ 431,764	$ 123,324	$ 493,426	25.75	3.88%	$ 19,165.00	$ 19,165.00	$ -
1860	Meters	$ 7,427,858	$ 2,647,962	$ 4,779,896	$ 434,954	$ 4,997,373	24.98	4.00%	$ 200,029.00	$ 200,029.00	$ -
1860	Meters (Smart Meters)			$ -		$ -			$ -	$ -	$ -
1905	Land			$ -		$ -			$ -	$ -	$ -
1908	Buildings & Fixtures	$ 5,925,327	$ 768,716	$ 5,156,611	$ 84,567	$ 5,198,895	59.57	1.68%	$ 87,268.00	$ 87,268.00	$ -
1910	Leasehold Improvements			$ -		$ -			$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 849,162	$ 551,049	$ 298,113	$ 27,471	$ 311,849	10.21	9.80%	$ 30,557.00	$ 30,557.00	$ -
1915	Office Furniture & Equipment (5 years)			$ -		$ -			$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 4,736,268	$ 2,531,904	$ 2,204,364	$ 363,112	$ 2,385,920	5.42	18.46%	$ 440,505.00	$ 440,505.00	$ 0.00
1920	Computer Equip.-Hardware(Post Mar. 22/04)			$ -		$ -			$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			$ -		$ -			$ -	$ -	$ -
1930	Transportation Equipment	$ 4,271,828	$ 1,854,527	$ 2,417,301	$ 314,885	$ 2,574,743	8.14	12.29%	$ 316,324.00	$ 316,324.00	-$ 0.00
1935	Stores Equipment	$ 81,138	$ 42,591	$ 38,547		$ 38,547	8.05	12.43%	$ 4,790.00	$ 4,790.00	$ -
1940	Tools, Shop & Garage Equipment	$ 849,235	$ 496,299	$ 352,936	$ 38,586	$ 372,229	10.02	9.98%	$ 37,149.00	$ 37,149.00	$ -
1945	Measurement & Testing Equipment	$ 246,881	$ 194,133	$ 52,748	$ 66,199	$ 85,848	10.12	9.88%	$ 8,479.00	$ 8,479.00	$ -
1950	Power Operated Equipment			$ -		$ -			$ -	$ -	$ -
1955	Communications Equipment	$ 248,340	$ 122,390	$ 125,950	$ 4,635	$ 128,268	9.76	10.25%	$ 13,142.00	$ 13,142.00	$ -
1955	Communication Equipment (Smart Meters)			$ -		$ -			$ -	$ -	$ -
1960	Miscellaneous Equipment	$ 784,532	$ 570,190	$ 214,342		$ 214,342	8.13	12.30%	$ 26,369.00	$ 26,369.00	-$ 0.00
1975	Load Management Controls Utility Premises	$ -	$ -	$ -		$ -			$ -	$ -	$ -
1980	System Supervisor Equipment	$ 1,210,302	$ 49	$ 1,210,253	$ 28,398	$ 1,224,452	24.18	4.14%	$ 50,642.00	$ 50,642.00	$ -
1985	Miscellaneous Fixed Assets			$ -		$ -			$ -	$ -	$ -
1995	Contributions & Grants	-$ 5,805,348		-$ 5,805,348	-$ 682,425	-$ 6,146,561	25.88	3.86%	-$ 237,487.00	-$ 237,487.00	$ -
1970	Load Management Controls - Customer Premises	$ 464,917	$ 464,917	$ -							
1990	Other Tangible Property	$ 566,276		$ 566,276		$ 566,276			$ -	$ -	$ -
				$ -		$ -			$ -		$ -
	Total	$ 101,855,018	$ 29,205,650	$ 72,649,368	$ 4,576,445	$ 74,937,590			$ 4,259,216.00	$ 4,259,216.00	-$ 0.00
								audited FS =	$ 4,259,217.00		

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

File Number:	EB-2012-0107
Exhibit:	4
Tab:	7
Schedule:	1
Attachment:	2
Date:	22-Oct-12

Appendix 2-CF
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013

Year 2012 CGAAP

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2012 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) 1	Years (f)	Depreciation Rate (g) = 1 / (f)	2012 Depreciation Expense (h) = (e) / (f)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 9,500,884	$ 3,981,024	$ 5,519,860	$ 2,290,004	$ 6,664,862	5.13	19.49%	$ 1,298,870	$ 1,298,870	$ -
1612	Land Rights (Formally known as Account 1906)	$ 283,160	$ 253,355	$ 29,805	$ -	$ 29,805	25.00	4.00%	$ 1,192	$ 1,192	$ -
1805	Land	$ 497,489		$ 497,489	$ -	$ 497,489		0.00%	$ -	$ -	$ -
1808	Buildings	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1810	Leasehold Improvements	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 6,455,582	$ 1,539,400	$ 4,916,182	$ 343,530	$ 5,087,947	30.42	3.29%	$ 167,280	$ 167,280	$ -
1825	Storage Battery Equipment	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 2,257,678		$ 2,257,678	$ 1,104,207	$ 2,809,782	25.00	4.00%	$ 112,391	$ 112,391	$ -
1835	Overhead Conductors & Devices	$ 27,485,935	$ 6,734,667	$ 20,751,268	$ 905,870	$ 21,204,203	25.00	4.00%	$ 848,154	$ 848,154	$ -
1840	Underground Conduit	$ 1,150,356		$ 1,150,356	$ 142,899	$ 1,221,806	25.00	4.00%	$ 48,872	$ 48,872	$ -
1845	Underground Conductors & Devices	$ 20,300,059	$ 4,048,327	$ 16,251,732	$ 1,033,864	$ 16,768,664	24.91	4.01%	$ 673,092	$ 673,092	$ -
1850	Line Transformers	$ 15,367,543	$ 3,654,153	$ 11,713,390	$ 809,618	$ 12,118,199	25.19	3.97%	$ 481,046	$ 481,046	-$ 0.00
1855	Services (Overhead & Underground)	$ 555,088		$ 555,088	$ 48,636	$ 579,406	25.00	4.00%	$ 23,176	$ 23,176	$ -
1860	Meters	$ 7,862,812	$ 2,705,965	$ 5,156,847	$ 28,450	$ 5,171,072	25.25	3.96%	$ 204,766	$ 204,766	$ -
1860	Meters (Smart Meters)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1905	Land	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 6,009,894	$ 768,716	$ 5,241,178	$ 2,178,441	$ 6,330,399	59.41	1.68%	$ 106,560	$ 106,560	$ -
1910	Leasehold Improvements	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 876,633	$ 551,049	$ 325,584	$ 117,811	$ 384,490	10.03	9.97%	$ 38,332	$ 38,332	$ -
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 5,099,380	$ 2,903,985	$ 2,195,395	$ 1,122,129	$ 2,756,460	5.28	18.92%	$ 521,653	$ 521,653	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1930	Transportation Equipment	$ 4,341,254	$ 1,826,199	$ 2,515,055	$ 623,434	$ 2,826,772	7.98	12.53%	$ 354,096	$ 354,096	$ -
1935	Stores Equipment	$ 81,138	$ 42,591	$ 38,547	$ -	$ 38,547	8.05	12.43%	$ 4,790	$ 4,790	$ -
1940	Tools, Shop & Garage Equipment	$ 887,821	$ 496,299	$ 391,522	$ 55,534	$ 419,289	10.00	10.00%	$ 41,929	$ 41,929	$ -
1945	Measurement & Testing Equipment	$ 313,080	$ 194,133	$ 118,947	$ 60,084	$ 148,989	10.00	10.00%	$ 14,899	$ 14,899	$ -
1950	Power Operated Equipment	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ 252,975	$ 122,390	$ 130,585	$ -	$ 130,585	9.92	10.08%	$ 13,167	$ 13,167	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ 784,532	$ 675,138	$ 109,394	$ -	$ 109,394	19.23	5.20%	$ 5,689	$ 5,689	$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 1,238,700	$ 266,928	$ 971,772	$ -	$ 971,772	24.12	4.15%	$ 40,294	$ 40,294	$ -
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1995	Contributions & Grants	-$ 6,487,773		-$ 6,487,773	-$ 491,240	-$ 6,733,393	24.89	4.02%	-$ 270,579	-$ 270,579	-
1970	Load Management Controls - Customer Premises	$ 464,917	$ 464,917	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1990	Other Tangible Property	$ 567,497		$ 567,497	$ -	$ 567,497		0.00%	$ -	$ -	$ -
				$ -		$ -		0.00%	$ -		$ -
	Total	$ 106,146,634	$31,229,236	$ 74,917,398	$10,373,271	$ 80,104,033			$ 4,729,669	$ 4,729,669	-$ 0.00

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

File Number:	EB-2012-0107
Exhibit:	4
Tab:	7
Schedule:	1
Attachment:	3
Date:	22-Oct-12

Appendix 2-CG
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013

Year 2012 MIFRS

Account	Description	Opening NBV as at Jan 1, 2012 [5] (a)	Additions (d)	Average Remaining Life of Opening NBV [4] (i)	Years (new additions only) [3] (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (a) / (i)	Depreciation Expense on Additions 1 (h)=((d)*0.5)/(f)	2012 Depreciation Expense (k) = (j) + (h)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (k) - (l)	Depreciation Expense on 2012 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2012 Full Year Depreciation [6] (p) = (j) + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 3,493,756	$ 2,012,306	2.69	5.00	20.00%	1,299,791	201,230	1,501,021	1,501,021	0	402,461	- 377,575	2,079,827
1612	Land Rights (Formally known as Account 1906)	$ 15,817	$ -	13.00		0.00%	1,217	-	1,217	1,217	-	-		1,217
1805	Land	$ 497,489	$ -	-		0.00%	-	-	-	-	-	-		-
1808	Buildings	$ -	$ -			0.00%	-	-	-	-	-	-		-
1810	Leasehold Improvements	$ -	$ -			0.00%	-	-	-	-	-	-		-
1815	Transformer Station Equipment >50 kV	$ -	$ -			0.00%	-	-	-	-	-	-		-
1820	Distribution Station Equipment <50 kV	$ 3,240,155	$ 301,888	17.22	35.40	2.82%	188,171	4,264	192,435	192,435	-	8,528	75,004	121,695
1825	Storage Battery Equipment	$ -	$ -			0.00%	-	-	-	-	-	-		-
1830	Poles, Towers & Fixtures	$ 1,628,387	$ 985,044	42.56	45.00	2.22%	38,264	10,945	49,209	49,209	-	21,890		60,154
1835	Overhead Conductors & Devices	$ 8,791,434	$ 810,478	33.36	47.84	2.09%	263,493	8,470	271,963	271,963	-	16,940		280,433
1840	Underground Conduit	$ 798,052	$ 127,029	49.61	50.01	2.00%	16,088	1,270	17,358	17,358	-	2,540		18,628
1845	Underground Conductors & Devices	$ 6,691,024	$ 915,874	21.39	41.02	2.44%	312,749	11,164	323,913	323,913	0	22,328		335,077
1850	Line Transformers	$ 5,613,069	$ 715,088	30.01	40.00	2.50%	187,010	8,939	195,949	195,949	- 0	17,878		204,888
1855	Services (Overhead & Underground)	$ 370,482	$ 43,116	22.44	25.01	4.00%	16,509	862	17,371	17,371	$ 0	$ 1,724		$ 18,233
1860	Meters	$ 2,902,375	$ 25,000	14.22	25.00	4.00%	204,080	500	204,580	204,580	-	1,000	155,558	49,522
1860	Meters (Smart Meters)	$ -	$ -			0.00%	-	-	-	-	-	-	- 282,779	282,779
1905	Land	$ -	$ -			0.00%	-	-	-	-	-	-		-
1908	Buildings & Fixtures	$ 4,066,489	$ 1,910,100	36.37	54.77	1.83%	111,799	17,438	129,237	129,237	- 0	34,876		146,675
1910	Leasehold Improvements	$ -	$ -			0.00%	-	-	-	-	-	-		-
1915	Office Furniture & Equipment (10 years)	$ 185,497	$ 108,014	4.37	10.00	10.00%	42,468	5,400	47,868	47,868	-	10,800		53,268
1915	Office Furniture & Equipment (5 years)	$ -	$ -			0.00%	-	-	-	-	-	-		-
1920	Computer Equipment - Hardware	$ 1,145,489	$ 994,250	3.01	5.00	20.00%	380,114	99,425	479,539	479,539	-	198,850	- 3,003	581,967
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -			0.00%	-	-	-	-	-	-		-
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -			0.00%	-	-	-	-	-	-		-
1930	Transportation Equipment	$ 1,525,332	$ 554,434	6.41	9.16	10.91%	237,844	30,254	268,098	268,098	-	60,508	1,750	296,602
1935	Stores Equipment	$ 9,854	$ -	2.00		0.00%	4,927	-	4,927	4,927	-	-		4,927
1940	Tools, Shop & Garage Equipment	$ 234,065	$ 48,800	4.51	10.00	10.00%	51,898	2,440	54,338	54,338	-	4,880	- 4,680	61,458
1945	Measurement & Testing Equipment	$ 89,150	$ 52,852	5.27	10.00	10.00%	16,925	2,643	19,568	19,568	-	5,286		22,211
1950	Power Operated Equipment	$ -	$ -			0.00%	-	-	-	-	-	-		-
1955	Communications Equipment	$ 91,082	$ -	5.51		0.00%	16,526	-	16,526	16,526	-	-		16,526
1955	Communication Equipment (Smart Meters)	$ -	$ -			0.00%	-	-	-	-	-	-		-
1960	Miscellaneous Equipment	$ 72,207	$ -	14.00		0.00%	5,158	-	5,158	5,158	-	-		5,158
1975	Load Management Controls Utility Premises	$ -	$ -			0.00%	-	-	-	-	-	-		-
1980	System Supervisor Equipment	$ 444,006	$ -	11.58		0.00%	38,354	-	38,354	38,354	-	-		38,354
1985	Miscellaneous Fixed Assets	$ -	$ -			0.00%	-	-	-	-	-	-		-
1995	Contributions & Grants	$ -	-$ 491,240		41.11	2.43%	-	- 5,974	- 5,974	- 5,974	-	- 11,948		- 11,948
1990	Other Tangible Property (major spare parts)	$ 567,497				0.00%	-	-	-		-	-		-
						0.00%	-	-	-		-	-		-
	Total	$ 42,472,711	$ 9,113,033				3,433,385	399,270	3,832,655	3,832,655	$ 0	$ 798,541	- 435,725	$ 4,667,651
	Depreciation expense adjustment resulting from Account 4357 - Gain on Retirement =								-$ 5,000	-$ 5,000				
									$ 3,827,655	**$ 3,827,655**				

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence

3 The applicant should ensure that the years for new additions of assets are the asset useful lives determined by management in accordance with IFRS.

4 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding 2012 additions) under IFRS. For example, Asset A had a useful life of 20 years under CGAAP. On January 1, 2012, the date of transition, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) under CGAAP as of January 1, 2012. Due to the transition to IFRS, management re-assessed the asset useful lives under IFRS principles and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of opening balance of Asset A is determined to be 27 years (30 years less 3 years) under IFRS as of January 1, 2012.

5 NBV must exclude assets still on the books but which have been fully amortized or depreciated.

6 This column refers to the calculated full year depreciation but excludes the depreciation expense on assets fully depreciated during the year. This column is used for the purpose of calculating depreciation expense in the following year on the next worksheet.

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

File Number:	EB-2012-0107
Exhibit:	4
Tab:	7
Schedule:	1
Attachment	4
Date:	22-Oct-12

Appendix 2-CH
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013

Year 2013 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2013 Depreciation Expense [1] (h)=2012 Full Year Depreciation + ((d)*0.5)/(f)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 1,265,335.00	5.0	20.00%	$ 2,206,360.20	$ 2,179,195.00	$ 27,165.20
1612	Land Rights (Formally known as Account 1906)	$ 257,200.00	-	0.00%	$ 1,217.00	$ 1,217.00	$ -
1805	Land			0.00%	$ -	$ -	$ -
1808	Buildings			0.00%	$ -	$ -	$ -
1810	Leasehold Improvements			0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV			0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 355,000.00	42.6	2.34%	$ 125,857.00	$ 125,857.00	$ -
1825	Storage Battery Equipment			0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 834,250.00	45.0	2.22%	$ 69,424.00	$ 69,424.00	$ -
1835	Overhead Conductors & Devices	$ 617,000.00	49.0	2.04%	$ 286,725.00	$ 286,725.00	$ -
1840	Underground Conduit	$ 130,000.00	50.0	2.00%	$ 19,929.00	$ 19,929.00	$ -
1845	Underground Conductors & Devices	$ 1,185,000.00	40.7	2.46%	$ 349,626.00	$ 349,626.00	$ -
1850	Line Transformers	$ 704,750.00	40.0	2.50%	$ 213,697.00	$ 213,697.00	$ -
1855	Services (Overhead & Underground)	$ 55,000.00	25.0	4.00%	$ 19,333.00	$ 19,333.00	$ -
1860	Meters	$ 50,000.00	25.0	4.00%	$ 50,522.00	$ 50,522.00	$ -
1860	Meters (Smart Meters)			0.00%	$ 282,779.00	$ 282,779.00	$ -
1905	Land			0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 212,500.00	60.0	1.67%	$ 148,447.00	$ 148,447.00	$ -
1910	Leasehold Improvements			0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 10,000.00	10.0	10.00%	$ 53,768.00	$ 53,768.00	$ -
1915	Office Furniture & Equipment (5 years)			0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 641,190.00	5.0	20.00%	$ 646,086.00	$ 673,251.00	-$ 27,165.00
1920	Computer Equip.-Hardware(Post Mar. 22/04)			0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			0.00%	$ -	$ -	$ -
1930	Transportation Equipment	$ 502,500.00	9.5	10.57%	$ 323,161.00	$ 323,161.00	$ -
1935	Stores Equipment	$ -		0.00%	$ 4,927.00	$ 4,927.00	$ -
1940	Tools, Shop & Garage Equipment	$ 42,000.00	10.0	10.00%	$ 63,558.00	$ 63,558.00	$ -
1945	Measurement & Testing Equipment	$ 50,000.00	10.00	10.00%	$ 24,711.00	$ 24,711.00	$ -
1950	Power Operated Equipment			0.00%	$ -	$ -	$ -
1955	Communications Equipment			0.00%	$ 16,526.00	$ 16,526.00	$ -
1955	Communication Equipment (Smart Meters)			0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment			0.00%	$ 5,158.00	$ 5,158.00	$ -
1975	Load Management Controls Utility Premises			0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 20,000.00	25.00	4.00%	$ 38,754.00	$ 38,754.00	$ -
1985	Miscellaneous Fixed Assets			0.00%	$ -	$ -	$ -
1995	Contributions & Grants	-$ 675,457.00	41.12	2.43%	-$ 20,162.00	-$ 20,162.00	$ -
etc.				0.00%	$ -	$ -	$ -
				0.00%	$ -	$ -	$ -
	Total	$ 6,256,268.00			$ 4,930,403.20	$ 4,930,403.00	$ 0.20
	Depreciation expense adjustment resulting from amortization of Account 1575				$ 91,220.00		
	Depreciation expense adjustment resulting from Account 4357 - Gain on Retirement				-$ 10,000.00		
	Total Depreciation expense to be included in the test year revenue requirement				**$ 5,011,623.20**		

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

Exhibit 4: Operating Costs

Tab 8 (of 8): Income & Capital Taxes

OVERVIEW OF PROVISION IN LIEU OF TAXES (PILS)

Bluewater Power's PILs amount of $586,513 included in the 2013 revenue requirement is comprised of the following two components outlined in Table 1 below.

Table 1 – PILs Amount Included in 2013 Revenue Requirement

	2013
Total Grossed-Up Amount per PILs Model	494,144
Adjustment re: Smart Meter Software	92,369
Amount included in Revenue Requirement	586,513

Adjustment of $92,369 related to Smart Meter Software

Bluewater Power has proposed an adjustment to the 2013 PILs calculation to reflect the one-time nature of tax savings incurred during the 2013 Test Year only. The adjustment is akin to One-time Costs which are costs incurred during the Test Year that are spread evenly over the IRM period to smooth impacts on customers (see Exhibit 4, Tab 2, Schedule 4). Bluewater Power submits that it would be asymmetrical to adjust one-time costs to smooth impacts on ratepayers and not smooth one-time tax savings.

The treatment claimed is supported by the unique nature of Smart Meter spending. Utilities in Ontario were mandated to implement Smart Meters for residential and GS<50kW customers in their distribution territory. The nature of the expenditures and the timing of the expenditures were beyond the control of utilities. The OEB's philosophy in developing the Smart Meter Final Disposition process was to hold whole both the utility and its customers. The proposed treatment is an extension of that approach to remove a one-time legacy of Smart Meter spending on software which is a significant one-time tax-savings in 2013 that does not continue for the three years of the IRM period that follow.

The calculation is based on Bluewater Power's final spending on smart meter software of $770,255 in the year 2012. This capital claim was included in Bluewater Power's Smart Meter Final Disposition (EB-2012-0263), along with other capital and O&M spending up to December 31, 2012. For PILs purposes, the capital expenditure of $770,255 was included in the Smart Meter model as a Class 12 asset with a CCA deduction of 100%. Due to the application of the half-year rule, the remaining $385,128 will be deducted in the 2013 PILs model (Note: The PILs return filed with the Ministry of Finance in 2011, and to be filed in 2012 and 2013, will have the same tax treatment for smart meter software). The resulting savings in the grossed-up PILs amount in 2013 is forecast to be $123,158.

The adjustment proposed is required because the $123,158 grossed-up tax savings included in the $494,144 PILs grossed-up amount is a one-time tax savings pertaining to the 2013 test year only. The calculation is set out in Table 2 below.

Table 2 – Corresponding Grossed-Up PILs on $385,128 CCA Deduction

	2013
CCA 100% Deduction	385,128
Combined 2013 Tax Rate per PILs Model	24.23%
Tax Savings	93,317
Divide By Gross Up Factor (1 - 24.23%)	75.77%
Grossed-Up Tax Savings	123,158

By the end of 2013, the full tax deduction for all historical smart meter software will have been realized in Bluewater Power's PILs return filed with the Ministry of Finance. Therefore, the savings of $123,158 embedded in the $494,144 PILs amount will result in an under-recovery of PILs during the subsequent three year IRM period; that is, the tax-savings expire in 2013 so, all other things being equal, the tax liability to the Ministry of Finance will be restored to normal levels. This would result in a total under recovery of $369,474 ($123,158 over 3 years) of grossed-up PILs. Accordingly, Bluewater Power has adjusted the PILs calculation by adding back $92,369 ($369,474 divided by 4) to the PILs recovery estimated in the PILs model submitted with this application. This amount will be recovered evenly over the four year period of Cost of Service.

2013 PILs Model

Bluewater Power has prepared its 2013 PILs Model on a MIFRS basis. It is presented in Attachment 1 in Exhibit 4, Tab 8, Schedule 3. As part of this Application, a working Excel version of the PILs model has been uploaded to the OEB Web Portal. The total grossed-up PILs amount calculated by the PILs model is $494,144.

2013 - MIFRS vs. CGAAP

The grossed-up PILs liability under the 2013 MIFRS PILs model is $494,144, compared to the 2013 CGAAP PILs model result of $880,931. This difference of $386,787 is primarily attributable to the difference in depreciation expense. The addback of depreciation expense is approximately $1.3 million higher under CGAAP which is due, for the most part, to the newly revised useful lives under MIFRS being longer than the useful lives under CGAAP.

HISTORICAL PILS

Previously Approved PILs Model

Bluewater Power's 2009 COS PILs model is presented in Attachment 1 in Exhibit 4, Tab 8, Schedule 2. This model formed part of Bluewater Power's 2009 COS rate application (EB-2008-0221) which was approved by the OEB.

Latest Filed Corporate PILs Return

Bluewater Power's 2011 PILs return that was filed with the Ministry of Finance is presented in Attachment 2 in Exhibit 4, Tab 8, Schedule 2. The corresponding 2011 audited financial statements that were included with this 2011 PILs return are the same as those presented in Attachment 1 in Exhibit 1, Tab 3, Schedule 1.

Tax Assessments and Correspondence

The 2011 notice of assessment has not been received at the time of filing this rate application. The 2009 and 2010 notices of assessments are presented in Attachment 3 of Exhibit 4, Tab 8, Schedule 2.

There has been no other correspondence from the Ministry of Finance for these three years.

Model Overview

Tab	ShortName	Title	Instruction	Link
P		**PILS Calculationa**		P0 Administration
P0	Admin	Administration	Enter administrative information about the Application	P0 Administration
P1	UCC	Undepreciated Capital Costs (UCC)	Enter actual balances and projected asset additions & retirements	P1 Undepreciated Capital Costs (UCC)
P2	CEC	Cumulative Eligible Capital (CEC)	Enter actual balance, projected changes and deduction rates	P2 Cumulative Eligible Capital (CEC)
P3	Interest	Interest Expense	Enter deemed and projected actual interest amounts	P3 Interest Expense
P4	LCF	Loss Carry-Forward (LCF)	Enter details of historical losses available to offset projected taxable income	P4 Loss Carry-Forward (LCF)
P5	Reserves	Reserve Balances	Enter balance amounts and projected changes in tax and accounting reserves	P5 Reserve Balances
P6	TxblIncome	Taxable Income	Enter amounts required to calculate taxable income	P6 Taxable Income
P7	CapitalTax	Capital Taxes	Enter rate base amounts	P7 Capital Taxes
P8	TotalPILs	Total PILs Expense	Enter tax credit amounts	P8 Total PILs Expense
Y		**Reference Information**		Y1 Tax Rates and Exemptions
Y1	TaxRates	Tax Rates and Exemptions	Enter applicable rates and exemption amounts	Y1 Tax Rates and Exemptions
Y2	CCA	Capital Cost Allowances (CCA)	Enter asset classes and applicable rates for CCA deductions	Y2 Capital Cost Allowances (CCA)
Z		**Model Parameters**		Z1 Model Variables
Z1	ModelVariables	Model Variables		Z1 Model Variables
Z0	Disclaimer	Software Terms of Use		Z0 Software Terms of Use

Bluewater Power Distribution Corporation (EB-2002-0517)

PILs Calculations for 2009 EDR Application (EB-2008-0221)

August 22, 2008

P0 Administration

Enter administrative information about the Application

Application Version		
Name of Applicant		Bluewater Power Distribution Corporation
License Number		EB-2002-0517
Test Year		2009
File Number(s)		EB-2008-0221
Date of Application		22-Aug-2008
Contact:		
	Name	Mark Hutson
	email	mhutson@bluewaterpower.com
	phone	519-337-8201 x261
Date of previous Test Year approval		15-Apr-2006

Undepreciated Capital Costs (UCC)

Class	Description	UCC Balance 31 Dec/07 [1]	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC 2008 Opening Balance
1	Distribution System - post 1987	17,774,795			**17,774,795**
2	Distribution System - pre 1988	12,648,854			**12,648,854**
8	General Office/Stores Equip	1,563,219			**1,563,219**
10	Computer Hardware/ Vehicles	1,196,950			**1,196,950**
10.1	Certain Automobiles				
12	Computer Software	238,150			**238,150**
13.1	Leasehold Improvement # 1				
13.2	Leasehold Improvement # 2				
13.3	Leasehold Improvement # 3				
13.4	Leasehold Improvement # 4				
14	Franchise				
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs				
43.1	Certain Energy-Efficient Electrical Generating Equipment				
45	Computers & Systems Software acq'd post Mar 22/04	158,600			**158,600**
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				
47	Distribution System post Feb 22/05	5,145,146			**5,145,146**
50	Computers & Systems Software acq'd post Mar 19/07	256,117			**256,117**
98	Transformers in inventory at YE - no CCA taken until used	1,208,729			**1,208,729**
	TOTAL	**40,190,560**			**40,190,560**

[1] per Schedule 8 of 2007 corporate tax return

Undepreciated Capital Costs (UCC)

Class	Description	2008 Projected Additions	2008 Projected Retirements	UCC Before 1/2 Yr Adjustment	1/2 Year Reduction	Reduced UCC	Rate %	2008 CCA
1	Distribution System - post 1987	398,023		18,172,818	199,012	17,973,807	4.0%	718,952
2	Distribution System - pre 1988			12,648,854		12,648,854	6.0%	758,931
8	General Office/Stores Equip	97,791		1,661,010	48,896	1,612,115	20.0%	322,423
10	Computer Hardware/ Vehicles	504,440	252,339	1,449,051	126,051	1,323,001	30.0%	396,900
10.1	Certain Automobiles						30.0%	
12	Computer Software	938,835		1,176,985	469,418	707,568	100.0%	707,568
13.1	Leasehold Improvement # 1						25 years	
13.2	Leasehold Improvement # 2						4 years	
13.3	Leasehold Improvement # 3							
13.4	Leasehold Improvement # 4							
14	Franchise						6 years	
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs						8.0%	
43.1	Certain Energy-Efficient Electrical Generating Equipment						30.0%	
45	Computers & Systems Software acq'd post Mar 22/04			158,600		158,600	45.0%	71,370
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)						30.0%	
47	Distribution System post Feb 22/05	2,475,438		7,620,584	1,237,719	6,382,865	8.0%	510,629
50	Computers & Systems Software acq'd post Mar 19/07	143,621		399,738	71,811	327,928	55.0%	180,360
98	Transformers in inventory at YE - no CCA taken until used			1,208,729		1,208,729		
	TOTAL	**4,558,148**	**252,339**	**44,496,369**	**2,152,905**	**42,343,465**		**3,667,133**

¹ per Schedule 8 of 2007 corporate tax return

Undepreciated Capital Costs (UCC)

Class	Description	UCC 31 Dec/08
1	Distribution System - post 1987	17,453,866
2	Distribution System - pre 1988	11,889,923
8	General Office/Stores Equip	1,338,587
10	Computer Hardware/ Vehicles	1,052,151
10.1	Certain Automobiles	
12	Computer Software	469,418
13.1	Leasehold Improvement # 1	
13.2	Leasehold Improvement # 2	
13.3	Leasehold Improvement # 3	
13.4	Leasehold Improvement # 4	
14	Franchise	
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	
43.1	Certain Energy-Efficient Electrical Generating Equipment	
45	Computers & Systems Software acq'd post Mar 22/04	87,230
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	
47	Distribution System post Feb 22/05	7,109,955
50	Computers & Systems Software acq'd post Mar 19/07	219,378
98	Transformers in inventory at YE - no CCA taken until used	1,208,729
	TOTAL	**40,829,236**

[1] *per Schedule 8 of 2007 corporate tax return*

Undepreciated Capital Costs (UCC)

Class	Description	2009 Projected Additions	2009 Projected Retirements	UCC Before 1/2 Yr Adjustment	1/2 Year Reduction	Reduced UCC	Rate %	2009 CCA
1	Distribution System - post 1987	204,002		17,657,868	102,001	17,555,867	4.0%	702,235
2	Distribution System - pre 1988			11,889,923		11,889,923	6.0%	713,395
8	General Office/Stores Equip	72,509		1,411,096	36,255	1,374,842	20.0%	274,968
10	Computer Hardware/ Vehicles	565,599	26,500	1,591,250	269,550	1,321,700	30.0%	396,510
10.1	Certain Automobiles						30.0%	
12	Computer Software	722,025		1,191,443	361,013	830,430	100.0%	830,430
13.1	Leasehold Improvement # 1							
13.2	Leasehold Improvement # 2							
13.3	Leasehold Improvement # 3							
13.4	Leasehold Improvement # 4							
14	Franchise							
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs						8.0%	
43.1	Certain Energy-Efficient Electrical Generating Equipment						30.0%	
45	Computers & Systems Software acq'd post Mar 22/04			87,230		87,230	45.0%	39,254
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)						30.0%	
47	Distribution System post Feb 22/05	2,894,134		10,004,089	1,447,067	8,557,022	8.0%	684,562
50	Computers & Systems Software acq'd post Mar 19/07	465,762		685,140	232,881	452,259	55.0%	248,742
98	Transformers in inventory at YE - no CCA taken until used			1,208,729		1,208,729		
	TOTAL	**4,924,031**	**26,500**	**45,726,767**	**2,448,766**	**43,278,001**		**3,890,096**

[1] per Schedule 8 of 2007 corporate tax return

Undepreciated Capital Costs (UCC)

Class	Description	UCC 31 Dec/09
1	Distribution System - post 1987	16,955,633
2	Distribution System - pre 1988	11,176,527
8	General Office/Stores Equip	1,136,128
10	Computer Hardware/ Vehicles	1,194,740
10.1	Certain Automobiles	
12	Computer Software	361,013
13.1	Leasehold Improvement # 1	
13.2	Leasehold Improvement # 2	
13.3	Leasehold Improvement # 3	
13.4	Leasehold Improvement # 4	
14	Franchise	
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	
43.1	Certain Energy-Efficient Electrical Generating Equipment	
45	Computers & Systems Software acq'd post Mar 22/04	47,977
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	
47	Distribution System post Feb 22/05	9,319,527
50	Computers & Systems Software acq'd post Mar 19/07	436,397
98	Transformers in inventory at YE - no CCA taken until used	1,208,729
	TOTAL	**41,836,671**

¹ per Schedule 8 of 2007 corporate tax return

P2 Cumulative Eligible Capital (CEC)

	2008				2009			
CEC Opening Balance [1]				**2,005,239**				**1,725,372**
Eligible Capital Property (ECP) Acquisitions								
Other Adjustments								
Subtotal		**x 3/4 =**				**x 3/4 =**		
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after December 20, 2002		**x 1/2 =**				**x 1/2 =**		
Amount transferred on amalgamation or wind-up of subsidiary								
Subtotal before deductions				**2,005,239**				**1,725,372**
ECP Dispositions (net)	200,000							
Other Adjustments								
Subtotal	200,000	**x 3/4 =**	150,000	**(150,000)**		**x 3/4 =**		
Balance before tax deduction				**1,855,239**				**1,725,372**
Tax Deduction		*Rate:*	***7.0%***	**129,867**		*Rate:*	***7.0%***	**120,776**
CEC Ending Balance				**1,725,372**				**1,604,596**

[1] 2008 amount per ending balance on Schedule 10 of 2007 corporate rax return

P3 Interest Expense

	2008	2009	
Deemed Interest Expense (A)	1,803,527	1,944,998	
3900-Interest Expense	1,461,696	1,461,696	
Add: Capitalized Interest (USA #6040)			*Enter credit to P&L as positive number*
Add: Capitalized Interest (USA #6042)			*Enter credit to P&L as positive number*
Less: non-debt interest expense (USA #6035)	(56,820)	(56,820)	
			Enter other adjustments for tax purposes
Total Interest Projected (B)	**1,404,876**	**1,404,876**	
Excess Interest Expense			*(B) less (A); if negative: zero*

P4 Loss Carry-Forward (LCF)

	Balance 31 Dec/07 [1]	Less: Non-Distribution Portion	Utility Balance 31 Dec/07	2008	2009
Non-Capital LCF:					
Opening Balance					
Application of LCF to reduce taxable income					
Ending Balance					
Net Capital LCF:					
Opening Balance					
Application of LCF to reduce taxable capital gains					
Ending Balance					

[1] per Schedule 7-1 of 2007 corporate tax return

P5 Reserve Balances

	Balance 31 Dec/07 [1]	Less: Non-Distribution Portion	Utility Balance 31 Dec/07	Changes (+ / -) in 2008	Balance 31 Dec/08	Changes (+ / -) in 2009	Balance 31 Dec/09
Capital Gains Reserves ss.40(1)							
Tax Reserves not deducted for book purposes:							
Reserve for doubtful accounts ss. 20(1)(l)							
Reserve for goods and services not delivered ss. 20(1)(m)							
Reserve for unpaid amounts ss. 20(1)(n)							
Debt & Share Issue Expenses ss. 20(1)(e)							
TOTAL							
Accounting Reserves not deducted for tax purposes:							
General Reserve for Inventory Obsolescence (non-specific)							
General reserve for bad debts							
Accrued Employee Future Benefits:							
- Medical and Life Insurance							
- Short & Long-term Disability							
- Accumulated Sick Leave							
- Termination Cost							
- Other Post-Employment Benefits							
Provision for Environmental Costs							
Restructuring Costs							
Accrued Contingent Litigation Costs							
Accrued Self-Insurance Costs							
Other Contingent Liabilities							
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)							
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)							
TOTAL							

[1] per Schedule 13 of 2007 corporate tax return

Taxable Income

	T2 S1 line #	2006 EDR Approved Tax Return	2006 EDR Approved Less: Non-Distribution Portion	2006 EDR Approved Utility Only	2008 Projection	2009 @ existing rates	2009 @ new dist. rates
Income/(Loss) before PILs/Taxes (Accounting) [1]		2,098,932		2,098,932	1,186,162	(868,584)	1,660,212
Additions:							
Interest and penalties on taxes	103	5,540		5,540	2,049	2,049	2,049
Amortization of tangible assets	104	3,130,369		3,130,369	4,045,269	4,332,522	4,120,022
Amortization of intangible assets	106						
Recapture of capital cost allowance from Schedule 8	107						
Gain on sale of eligible capital property from Schedule 10	108						
Income or loss for tax purposes- joint ventures or partnerships	109						
Loss in equity of subsidiaries and affiliates	110						
Loss on disposal of assets	111						
Charitable donations	112	9,852		9,852			
Taxable Capital Gains	113						
Political Donations	114						
Deferred and prepaid expenses	116						
Scientific research expenditures deducted on financial statements	118						
Capitalized interest	119						
Non-deductible club dues and fees	120						
Non-deductible meals and entertainment expense	121	20,862		20,862	29,398	29,398	29,398
Non-deductible automobile expenses	122						
Non-deductible life insurance premiums	123						
Non-deductible company pension plans	124						
Tax reserves beginning of year	125						
Reserves from financial statements- balance at end of year	126						
Soft costs on construction and renovation of buildings	127						
Book loss on joint ventures or partnerships	205						

Taxable Income

	T2 S1 line #	2006 EDR Approved Tax Return	Less: Non-Distribution Portion	Utility Only	2008 Projection	2009 @ existing rates	2009 @ new dist. rates
Income/(Loss) before PILs/Taxes (Accounting) [1]		2,098,932		2,098,932	1,186,162	(868,584)	1,660,212
Capital items expensed	206	5,974		5,974			
Debt issue expense	208						
Development expenses claimed in current year	212						
Financing fees deducted in books	216						
Gain on settlement of debt	220						
Non-deductible advertising	226						
Non-deductible interest	227						
Non-deductible legal and accounting fees	228						
Recapture of SR&ED expenditures	231						
Share issue expense	235						
Write down of capital property	236	2,088,064		2,088,064			
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237						
Net employee future benefits (accrual less amounts paid)	292	354,570		354,570	847,994	694,415	694,415
Interest on a/c 6035 (customer deposits)					56,820	56,820	
Interest on a/c 6005 (long term debt)					1,404,877	1,404,876	
Capital taxes expensed (included in IBT)					135,000	135,000	
Carrying charges accrued (expensed not paid)					223,924	243,636	243,636
Total Additions		**5,615,231**		**5,615,231**	**6,745,331**	**6,898,716**	**5,089,520**

Taxable Income

	T2 S1 line #	2006 EDR Approved Tax Return	2006 EDR Approved Less: Non-Distribution Portion	2006 EDR Approved Utility Only	2008 Projection	2009 @ existing rates	2009 @ new dist. rates
Income/(Loss) before PILs/Taxes (Accounting) [1]		2,098,932		2,098,932	1,186,162	(868,584)	1,660,212
Deductions:							
Gain on disposal of assets per financial statements	401				57,300	26,500	26,500
Dividends not taxable under section 83	402						
Capital cost allowance from Schedule 8	403	2,903,731		2,903,731	3,667,133	3,890,096	3,890,096
Terminal loss from Schedule 8	404						
Cumulative eligible capital deduction from Schedule 10 CEC	405	174,508		174,508	129,867	120,776	120,776
Allowable business investment loss	406						
Deferred and prepaid expenses	409						
Scientific research expenses claimed in year	411						
Tax reserves end of year	413						
Reserves from financial statements - balance at beginning of year	414						
Contributions to deferred income plans	416						
Book income of joint venture or partnership	305						
Equity in income from subsidiary or affiliates	306						
Deemed interest expense (per rate model)					1,803,527	2,101,466	
Carrying charges accrued (revenue not received)	393	2,794,381		2,794,381			
Capital taxes calculated by PILS model					81,212	73,870	
Total Deductions		**5,872,620**		**5,872,620**	**5,739,039**	**6,212,707**	**4,037,372**

Taxable Income

	T2 S1 line #	2006 EDR Approved Tax Return	2006 EDR Approved Less: Non-Distribution Portion	2006 EDR Approved Utility Only	2008 Projection	2009 @ existing rates	2009 @ new dist. rates
Income/(Loss) before PILs/Taxes (Accounting) [1]		2,098,932		2,098,932	1,186,162	(868,584)	1,660,212
NET INCOME (LOSS) FOR TAX PURPOSES		**1,841,543**		**1,841,543**	**2,192,454**	**(182,575)**	**2,712,360**
Charitable donations from Schedule 2		9,852		9,852			
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)							
Non-capital losses of preceding taxation years from Schedule 4							
Net-capital losses of preceding taxation years from Schedule 4							
Limited partnership losses of preceding taxation years from Schedule 4							
TAXABLE INCOME (LOSS)		**1,831,691**		**1,831,691**	**2,192,454**	**(182,575)**	**2,712,360**

[1] 2049 = ''Earnings before Tax' (sheet E1); 2049 = ''Earnings before Tax' (sheet E2); 2049 = ''Deemed Return On Equity' (sheet E3)

Capital Taxes

	2008	2009
OCT (Ontario Capital Tax):		
Rate Base	51,094,378	47,830,944
Less: Exemption	15,000,000	15,000,000
Deemed Taxable Capital	36,094,378	32,830,944
Tax Rate	0.225%	0.225%
OCT payable	**81,212**	**73,870**
Federal LCT (Large Corporations Tax):		
Rate Base	51,094,378	47,830,944
Less: Exemption	50,000,000	50,000,000
Deemed Taxable Capital	1,094,378	
Tax Rate		
LCT payable		

P8 Total PILs Expense

	2008 Projection	2009 Projection [1]	2009 Test [1]
Regulatory Taxable Income/(Loss)	2,192,454	(182,575)	2,712,360
Combined Income Tax Rate	33.50%		33.00%
Total Income Taxes	734,472		895,079
Investment & Miscellaneous Tax Credits			
Income Tax Payable	**734,472**		**895,079**
Large Corporations Tax (LCT)			
Ontario Capital Tax (OCT)	81,212	73,870	73,870
Grossed-up Income Tax			1,335,938
Grossed-up LCT			
Total PILs Expense	**815,684**	**73,870**	**1,409,808**

[1] 'Projection' per existing rates; 'Test' based on proposed revenue requirement

Y1 Tax Rates and Exemptions

2008 INCOME TAXES

Income Range		Income Tax Rates			SBD
From	To	Federal	Ontario	Combined	Clawback
$0	$300,000	19.50%	14.00%	33.50%	
$300,000	$500,000	19.50%	14.00%	33.50%	
$500,000	$1,500,000	19.50%	14.00%	33.50%	4.25%
$1,500,000		19.50%	14.00%	33.50%	

2008 CAPITAL TAXES

	LCT	OCT
Exemption	$50,000,000	$15,000,000
Capital Tax Rate		0.225%
Surtax Rate		

2009 INCOME TAXES

Income Range		Income Tax Rates			SBD
From	To	Federal	Ontario	Combined	Clawback
$0	$300,000	19.00%	14.00%	33.00%	
$300,000	$500,000	19.00%	14.00%	33.00%	
$500,000	$1,500,000	19.00%	14.00%	33.00%	4.25%
$1,500,000		19.00%	14.00%	33.00%	

2009 CAPITAL TAXES

	LCT	OCT
Exemption	$50,000,000	$15,000,000
Capital Tax Rate		0.225%
Surtax Rate		

Y2 Capital Cost Allowances (CCA)

Class	Description	Rate	Years	½ Year Rule
1	Distribution System - post 1987	4.0%		YES
2	Distribution System - pre 1988	6.0%		YES
8	General Office/Stores Equip	20.0%		YES
10	Computer Hardware/ Vehicles	30.0%		YES
10.1	Certain Automobiles	30.0%		YES
12	Computer Software	100.0%		YES
13.1	Leasehold Improvement # 1		25	YES
13.2	Leasehold Improvement # 2		4	YES
13.3	Leasehold Improvement # 3			YES
13.4	Leasehold Improvement # 4			YES
14	Franchise		6	NO
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	8.0%		YES
43.1	Certain Energy-Efficient Electrical Generating Equipment	30.0%		YES
45	Computers & Systems Software acq'd post Mar 22/04	45.0%		YES
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	30.0%		YES
47	Distribution System post Feb 22/05	8.0%		YES
50	Computers & Systems Software acq'd post Mar 19/07	55.0%		YES
98	Transformers in inventory at YE - no CCA taken until used			

Bluewater Power Distribution Corporation (EB-2002-0517)

PILs Calculations for 2009 EDR Application (EB-2008-0221)

August 22, 2008

Z1 Model Variables

CRLF	□
CRLF2	□□
ApprovedYr	2006 EDR Approved
RMpilsVer	v1.02
FakeBlank	
FolderPath	Q:\1.2013 Rebasing\Mark - final\PILs\4.8.2 - Historical PILs\

SOFTWARE TERMS OF USE

Elenchus Research Associates' intent in licensing *RateMaker PILs* (the "Model") is to provide utilities with a generic tool to assist in the development of cost of service applications for electricity distribution rates under the Forward Test Year approach. Certain adaptations of the Model may be required to meet regulatory requirements for any given rate application. It is the responsibility of the utility to ensure all data and documentation included in such an application, including output from the Model, will fulfill regulatory requirements. In particular, utilities should consult their tax adviser(s) to ensure the Model produces a complete and accurate calculation of expected PILs in accordance with applicable tax rules and legislation. Please see Appendix A in the *RateMaker.xls* documentation for complete terms of the software license.

Terms accepted?	**YES**

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

CLIENT COPY

200

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business Number (BN) **001** 86572 7390 RC0001

Corporation's name

002 Bluewater Power Distribution Corporation

Address of head office

Has this address changed since the last time we were notified? .... **010** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 011 to 018.)

011 855 Confederation Street

012 PO Box 2140

City **015** Sarnia — Province, territory, or state **016** ON

Country (other than Canada) **017** — Postal code/Zip code **018** N7T 7L6

Mailing address (if different from head office address)

Has this address changed since the last time we were notified? .... **020** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 021 to 028.)

021 c/o

022

023

City **025** — Province, territory, or state **026**

Country (other than Canada) **027** — Postal code/Zip code **028**

Location of books and records

Has the location of books and records changed since the last time we were notified? .... **030** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 031 to 038.)

031 855 Confederation Street

032 PO Box 2140

City **035** Sarnia — Province, territory, or state **036** ON

Country (other than Canada) **037** — Postal code/Zip code **038** N7T 7L6

040 **Type of corporation at the end of the tax year**

1 [X] Canadian-controlled private corporation (CCPC)

2 [ ] Other private corporation

3 [ ] Public corporation

4 [ ] Corporation controlled by a public corporation

5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. **043** ________ YYYY MM DD

To which tax year does this return apply?

Tax year start **060** 2011-01-01 (YYYY MM DD) — Tax year-end **061** 2011-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? .... **063** 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired .... **065** ________ YYYY MM DD

Is the date on line 061 a deemed tax year-end according to:

subparagraph 88(2)(a)(iv)? .... **064** 1 Yes [ ] 2 No [X]

subsection 249(3.1)? .... **066** 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? .... **067** 1 Yes [ ] 2 No [X]

Is this the first year of filing after:

Incorporation? .... **070** 1 Yes [ ] 2 No [X]

Amalgamation? .... **071** 1 Yes [ ] 2 No [X]

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? .... **072** 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? .... **076** 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? .... **078** 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used **079**

Is the corporation a resident of Canada?

080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.

081

Is the non-resident corporation claiming an exemption under an income tax treaty? .... **082** 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085

1 [ ] Exempt under paragraph 149(1)(e) or (l)

2 [ ] Exempt under paragraph 149(1)(j)

3 [ ] Exempt under paragraph 149(1)(t)

4 [ ] Exempt under other paragraphs of section 149

Do not use this area

095 **096**

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		———
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	X	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	———
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	———
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

		1 Yes	2 No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution US

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Energy infrastructure provider	285	100.000 %
286		287	%
288		289	%

		1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 YYYY MM DD

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 1 Yes 2 No

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300		1,886,887	A
Deduct: Charitable donations from Schedule 2	311	24,110		
Gifts to Canada, a province, or a territory from Schedule 2	312			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal		24,110 ►	24,110	B
Subtotal (amount A minus amount B) (if negative, enter "0")			1,862,777	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		1,862,777	
Income exempt under paragraph 149(1)(t)	370			
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)			1,862,777	Z

* This amount is equal to 3.2 times the Part VI.1 tax payable at line 724 on page 8. Use 3.5 for tax years ending after 2011.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7	**400**	1,886,887	A
Taxable income from line 360 on page 3, **minus** 100/28* 3.37312 of the amount on line 632** on page 7, **minus** 1/(0.38 - X***) 3.77358 times the amount on line 636**** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax	**405**	1,862,777	B
Business limit (see notes 1 and 2 below)	**410**	500,000	C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 x **415** ***** 125,255 D / 11,250 = 5,566,889 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") **425** ______ F

Small business deduction

Amount A, B, C, or F, whichever is the least ______ x 17 % = **430** ______ G

Enter amount G on line 1 on page 7.

* 10/3 for tax years ending before November 1, 2011. The result of the multiplication by line 632 has to be pro-rated based on the number of days in the tax year that are in each period: before November 1, 2011, and after October 31, 2011.

** Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

*** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

**** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3*			1,862,777	A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		B		
Amount QQ from Part 13 of Schedule 27		C		
Personal service business income**	432	D		
Amount used to calculate the credit union deduction from Schedule 17		E		
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least		F		
Aggregate investment income from line 440 on page 6***		G		
Total of amounts B to G		▶		H
Amount A **minus** amount H (if negative, enter "0")			1,862,777	I

Amount I	1,862,777	x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year 365	x	9 %	=		J
Amount I	1,862,777	x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year 365	x	10 %	=		K
Amount I	1,862,777	x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 365 / Number of days in the tax year 365	x	11.5 %	=	214,219	L
Amount I	1,862,777	x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year 365	x	13 %	=		M

General tax reduction for Canadian-controlled private corporations – Total of amounts J to M .... 214,219 N

Enter amount N on line 638 on page 7.

* For tax years ending after October 31, 2011, line 360 or amount Z, whichever applies.

** For tax years beginning after October 31, 2011.

*** Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)				O
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		P		
Amount QQ from Part 13 of Schedule 27		Q		
Personal service business income*	434	R		
Amount used to calculate the credit union deduction from Schedule 17		S		
Total of amounts P to S		▶		T
Amount O **minus** amount T (if negative, enter "0")				U

Amount U		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year 365	x	9 %	=		V
Amount U		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year 365	x	10 %	=		W
Amount U		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 365 / Number of days in the tax year 365	x	11.5 %	=		X
Amount U		x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year 365	x	13 %	=		Y

General tax reduction – Total of amounts V to Y .... Z

Enter amount Z on line 639 on page 7.

* For tax years beginning after October 31, 2011.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7	440	× 26 2 / 3 % =		A
Foreign non-business income tax credit from line 632 on page 7				
Deduct: Foreign investment income from Schedule 7	445	× 9 1 / 3 % =		
		(if negative, enter "0")	▶	B
Amount A **minus** amount B (if negative, enter "0")				C
Taxable income from line 360 on page 3		1,862,777		
Deduct:				
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least				
Foreign non-business income tax credit from line 632 on page 7	× 25 / 9 (25/9*) =			
Foreign business income tax credit from line 636 on page 7	× 3.77358 (1(0.38 - X**)) =			
	▶	1,862,777		
		× 26 2 / 3 % =	496,741	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8)			276,667	E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least	450			F

* 100/35 for tax years beginning after October 31, 2011.

** General rate reduction percentage for the tax year. It has to be pro-rated.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	460	2,740		
Deduct: Dividend refund for the previous tax year	465	2,740		
			▶	G
Add the total of:				
Refundable portion of Part I tax from line 450 above				
Total Part IV tax payable from Schedule 3				
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	480			
			▶	H
Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H	485			

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3	3,065,917 × 1 / 3	1,021,972	I
Refundable dividend tax on hand at the end of the tax year from line 485 above			J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784 on page 8)			

Part I tax

Base amount of Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied by** 38 %			550	707,855	A
Recapture of investment tax credit from Schedule 31			602		B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6			i
Taxable income from line 360 on page 3	1,862,777		
Deduct:			
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			
Net amount	1,862,777 ►	1,862,777	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii	604		C
Subtotal (**add** lines A to C)		707,855	D

Deduct:

Small business deduction from line 430 on page 4			1		
Federal tax abatement	608	186,278			
Manufacturing and processing profits deduction from Schedule 27	616				
Investment corporation deduction	620				
Taxed capital gains 624					
Additional deduction – credit unions from Schedule 17	628				
Federal foreign non-business income tax credit from Schedule 21	632				
Federal foreign business income tax credit from Schedule 21	636				
General tax reduction for CCPCs from amount N on page 5	638	214,219			
General tax reduction from amount Z on page 5	639				
Federal logging tax credit from Schedule 21	640				
Federal qualifying environmental trust tax credit	648				
Investment tax credit from Schedule 31	652	30,691			
Subtotal		431,188	►	431,188	E

Part I tax payable – Line D **minus** line E	276,667	F

Enter amount F on line 700 on page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	276,667
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		276,667

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . 750 ON

(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	119,759	
Provincial tax on large corporations (Nova Scotia Schedule 342)	765		
		119,759 ▶	119,759
Total tax payable	770		396,426 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from page 6	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld 801			
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	989,622	
Total credits	890	989,622 ▶	989,622 B

Refund code 894 1 Overpayment 593,196

Balance (line A **minus** line B) -593,196

If the result is negative, you have an **overpayment.**
If the result is positive, you have a **balance unpaid.**
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . .

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910

Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . 896 1 Yes ☐ 2 No ☒

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Certification

I, 950 McMichael 951 Janice 954 President & CEO

Last name in block letters — First name in block letters — Position, office, or rank

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2012-06-11 — Date (yyyy/mm/dd) — Signature of the authorized signing officer of the corporation — 956 (519) 337-8201 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . . 957 1 Yes ☒ 2 No ☐

958 Name in block letters — 959 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering 1 for English or 2 for French.
Indiquez votre langue de correspondance en inscrivant 1 pour anglais ou 2 pour français. 990 1

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES — SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2011-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				2,297,241 A
Add:				
Provision for income taxes – current		101	525,000	
Amortization of tangible assets		104	4,259,217	
Charitable donations and gifts from Schedule 2		112	24,110	
Scientific research expenditures deducted per financial statements		118	60,072	
Non-deductible meals and entertainment expenses		121	42,018	
Subtotal of additions			4,910,417 ▶	4,910,417
Other additions:				
Miscellaneous other additions:				
600 Employee future benefits - end of year		290	7,507,737	
603				
Inducement - ITA 12(1)x)	3,135			
Total	3,135	293	3,135	
604 Smart meter recovery	654,199			
ITC for apprentice credit	10,000			
Capital taxes expensed	747			
Ontario Specified Tax Credits	41,283			
Carryin Charges Recovered over expensed	1,696,158			
Payment of Lawsuit (2010 deduction)	149,122			
Total	2,551,509	294	2,551,509	
Subtotal of other additions		199	10,062,381 ▶	10,062,381
Total additions		500	14,972,798 ▶	14,972,798
Deduct:				
Gain on disposal of assets per financial statements		401	23,293	
Capital cost allowance from Schedule 8		403	7,288,780	
Cumulative eligible capital deduction from Schedule 10		405	105,640	
SR&ED expenditures claimed in the year from Form T661 (line 460)		411	53,957	
Subtotal of deductions			7,471,670 ▶	7,471,670
Other deductions:				
Miscellaneous other deductions:				
700 Employee future benefits - beginning of year		390	7,079,641	
704 Capitalized for actg expensed for tax	512,630			
Smart meter O&M expense	255,211			
2011 Apprentice Tax Credits	64,000			
Total	831,841	394	831,841	
Subtotal of other deductions		499	7,911,482 ▶	7,911,482
Total deductions		510	15,383,152 ▶	15,383,152
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				1,886,887

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 2

CHARITABLE DONATIONS AND GIFTS

Name of corporation	Business Number	Tax year-end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2011-12-31

- For use by corporations to claim any of the following:
  - charitable donations;
  - gifts to Canada, a province, or a territory;
  - gifts of certified cultural property;
  - gifts of certified ecologically sensitive land; or
  - additional deduction for gifts of medicine.
- The donations and gifts are eligible for a five-year carryforward.
- Use this schedule to show a credit transfer following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1) of the *Income Tax Act*.
- For donations and gifts made after March 22, 2004, subsection 110.1(1.2) of the *Income Tax Act* provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- Under proposed changes, the eligible amount of a charitable gift is the amount by which the fair market value of the gift exceeds the amount of an advantage, if any, for the gift.
- Under proposed changes, a gift of medicine made after March 18, 2007, to qualifying organizations for activities outside of Canada, may be eligible for an additional deduction if the gift is an eligible medical gift. This additional deduction is calculated in Part 6.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation – Income Tax Guide*.

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
Various	23,960
Subtotal	23,960
Add: Total donations of less than $100 each	150
Total donations in current tax year	24,110

	Line		Federal	Québec	Alberta
Charitable donations at the end of the previous tax year					
Deduct: Charitable donations expired after five tax years*	239				
Charitable donations at the beginning of the tax year	240				
Add:					
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250				
Total current-year charitable donations made (enter this amount on line 112 of Schedule 1)	210	24,110			
Subtotal (line 250 **plus** line 210)			24,110	24,110	24,110
Deduct: Adjustment for an acquisition of control (for donations made after March 22, 2004)	255				
Total charitable donations available			24,110 A	24,110	24,110
Deduct: Amount applied against taxable income (cannot be more than amount K in Part 2) (enter this amount on line 311 of the T2 return)	260		24,110	24,110	24,110
Charitable donations closing balance	280				

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1st prior year	2010-12-31			
2nd prior year	2009-12-31			
3rd prior year	2008-12-31			
4th prior year	2007-12-31			
5th prior year	2006-12-31			
6th prior year*	2005-12-31			
7th prior year	2004-12-31			
8th prior year	2003-12-31			
9th prior year	2002-12-31			
10th prior year	2001-12-31			
11th prior year	2001-09-30			
12th prior year	2000-09-30			
13th prior year	1999-09-30			
14th prior year	1998-09-30			
15th prior year	1997-09-30			
16th prior year	1996-09-30			
17th prior year	1995-09-30			
18th prior year	1994-09-30			
19th prior year	1993-09-30			
20th prior year	1992-09-30			
21st prior year*	1991-09-30			
Total (to line A)				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 2 – Calculation of the maximum allowable deduction for charitable donations

Net income for tax purposes* **multiplied** by 75 % .... 1,415,165 B

Taxable capital gains arising in respect of gifts of capital property included in Part 1** .... **225** ______ C

Taxable capital gain in respect of deemed gifts of non-qualifying securities per subsection 40(1.01) .... **227** ______ D

The amount of the recapture of capital cost allowance in respect of charitable gifts .... **230** ______

Proceeds of disposition, less outlays and expenses** .... ______ E

Capital cost** .... ______ F

Amount E or F, whichever is less .... **235** ______

Amount on line 230 or 235, whichever is less .... ______ G

Subtotal (**add** amounts C, D, and G) ______ H

Amount H **multiplied** by 25 % ______ I

Subtotal (amount B **plus** amount I) 1,415,165 J

Maximum allowable deduction for charitable donations (enter amount A from Part 1, amount J, or net income for tax purposes, whichever is less) .... 24,110 K

* For credit unions, this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

Part 3 – Gifts to Canada, a province, or a territory

Gifts to Canada, a province, or a territory at the end of the previous tax year			
Deduct: Gifts to Canada, a province, or a territory expired after five tax years	339		
Gifts to Canada, a province, or a territory at the beginning of the tax year	340		▶
Add: Gifts to Canada, a province, or a territory transferred on an amalgamation or the windup of a subsidiary	350		
Total current-year gifts made to Canada, a province, or a territory*	310		
Subtotal (line 350 **plus** line 310)			
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)		355	
Total gifts to Canada, a province, or a territory available			
Deduct: Amount applied against taxable income (enter this amount on line 312 of the T2 return).		360	
Gifts to Canada, a province, or a territory closing balance		380	

* Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date. If no written agreement exists, enter the amount on line 210 and complete Part 2.

Part 4 – Gifts of certified cultural property

		Federal	Québec	Alberta
Gifts of certified cultural property at the end of the previous tax year				
Deduct: Gifts of certified cultural property expired after five tax years*	439			
Gifts of certified cultural property at the beginning of the tax year	440			
Add: Gifts of certified cultural property transferred on an amalgamation or the windup of a subsidiary	450			
Total current-year gifts of certified cultural property	410			
Subtotal (line 450 **plus** line 410)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	455			
Total gifts of certified cultural property available				
Deduct: Amount applied against taxable income (enter this amount on line 313 of the T2 return)	460			
Gifts of certified cultural property closing balance	480			

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Québec	Alberta
1st prior year	2010-12-31			
2nd prior year	2009-12-31			
3rd prior year	2008-12-31			
4th prior year	2007-12-31			
5th prior year	2006-12-31			
6th prior year*	2005-12-31			
7th prior year	2004-12-31			
8th prior year	2003-12-31			
9th prior year	2002-12-31			
10th prior year	2001-12-31			
11th prior year	2001-09-30			
12th prior year	2000-09-30			
13th prior year	1999-09-30			
14th prior year	1998-09-30			
15th prior year	1997-09-30			
16th prior year	1996-09-30			
17th prior year	1995-09-30			
18th prior year	1994-09-30			
19th prior year	1993-09-30			
20th prior year	1992-09-30			
21st prior year*	1991-09-30			
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 5 – Gifts of certified ecologically sensitive land

		Federal	Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year				
Deduct: Gifts of certified ecologically sensitive land expired after five tax years*	539			
Gifts of certified ecologically sensitive land at the beginning of the tax year	540			
Add: Gifts of certified ecologically sensitive land transferred on an amalgamation or the windup of a subsidiary	550			
Total current-year gifts of certified ecologically sensitive land	510			
Subtotal (line 550 **plus** line 510)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	555			
Total gifts of certified ecologically sensitive land available				
Deduct: Amount applied against taxable income (enter this amount on line 314 of the T2 return)	560			
Gifts of certified ecologically sensitive land closing balance	580			

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Gifts of certified ecologically sensitive land

Year of origin:		Federal	Québec	Alberta
1st prior year	2010-12-31			
2nd prior year	2009-12-31			
3rd prior year	2008-12-31			
4th prior year	2007-12-31			
5th prior year	2006-12-31			
6th prior year*	2005-12-31			
7th prior year	2004-12-31			
8th prior year	2003-12-31			
9th prior year	2002-12-31			
10th prior year	2001-12-31			
11th prior year	2001-09-30			
12th prior year	2000-09-30			
13th prior year	1999-09-30			
14th prior year	1998-09-30			
15th prior year	1997-09-30			
16th prior year	1996-09-30			
17th prior year	1995-09-30			
18th prior year	1994-09-30			
19th prior year	1993-09-30			
20th prior year	1992-09-30			
21st prior year*	1991-09-30			
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 6 – Additional deduction for gifts of medicine

		Federal		Québec		Alberta	
Additional deduction for gifts of medicine at the end of the previous tax year							
Deduct: Additional deduction for gifts of medicine expired after five tax years	639						
Additional deduction for gifts of medicine at the beginning of the tax year	640						
Add: Additional deduction for gifts of medicine transferred on an amalgamation or the wind-up of a subsidiary	650						
Additional deduction for gifts of medicine for the current year:							
Proceeds of disposition	602		1		1		1
Cost of gifts of medicine	601		2		2		2
Subtotal (line 1 **minus** line 2)			3		3		3
Line 3 **multiplied** by 50 %			4		4		4
Eligible amount of gifts	600		5		5		5

Federal

A ______ x (B ______ / C) = Additional deduction for gifts of medicine for the current year **610** ______

Québec

A ______ x (B ______ / C) = Additional deduction for gifts of medicine for the current year ______

Alberta

A ______ x (B ______ / C) = Additional deduction for gifts of medicine for the current year ______

where:

A is the **lesser** of line 2 and line 4

B is the eligible amount of gifts (line 600)

C is the proceeds of disposition (line 602)

		Federal	Québec	Alberta
Subtotal (line 650 **plus** line 610)				
Deduct: Adjustment for an acquisition of control	655			
Total additional deduction for gifts of medicine available				
Deduct: Amount applied against taxable income (enter this amount on line 315 of the T2 return)	660			
Additional deduction for gifts of medicine closing balance	680			

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1st prior year	2010-12-31			
2nd prior year	2009-12-31			
3rd prior year	2008-12-31			
4th prior year	2007-12-31			
5th prior year	2006-12-31			
6th prior year*	2005-12-31			
Total				

* These donations expired in the current year.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
Subtotal (line D **plus** line E)		F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income		I
Gifts of musical instruments closing balance		J

Amounts carried forward – Gifts of musical instruments

Year of origin:		Québec
1st prior year	2010-12-31	
2nd prior year	2009-12-31	
3rd prior year	2008-12-31	
4th prior year	2007-12-31	
5th prior year	2006-12-31	
6th prior year*	2005-12-31	
7th prior year	2004-12-31	
8th prior year	2003-12-31	
9th prior year	2002-12-31	
10th prior year	2001-12-31	
11th prior year	2001-09-30	
12th prior year	2000-09-30	
13th prior year	1999-09-30	
14th prior year	1998-09-30	
15th prior year	1997-09-30	
16th prior year	1996-09-30	
17th prior year	1995-09-30	
18th prior year	1994-09-30	
19th prior year	1993-09-30	
20th prior year	1992-09-30	
21st prior year*	1991-09-30	
Total		

* These gifts expired in the current year.

T2 SCH 2 E (07) Canada

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DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year-end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2011-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act.*
- A recipient corporation is connected with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- "X" under column A if dividend received from a foreign source (connected corporation only).
- Enter in column F1, the amount of dividends received reported in column 240 that are eligible.
- Under column F2, enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

Do not include dividends received from foreign non-affiliates.

	A	B (Complete if payer corporation is connected)	C (Complete if payer corporation is connected)	D (Complete if payer corporation is connected)	E
Name of payer corporation (from which the corporation received the dividend)		Enter 1 if payer corporation is connected	Business Number of connected corporation	Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD	Non-taxable dividend under section 83
200		205	210	220	230
				Total (enter on line 402 of Schedule 1)	

Note: If your corporation's tax year-end is different than that of the connected payer corporation, your corporation could have received dividends from more than one tax year of the payer corporation. If so, use a separate line to provide the information for each tax year of the payer corporation.

F	F1	F2	G (Complete if payer corporation is connected)	H (Complete if payer corporation is connected)	I
Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d)*	Eligible dividends (included in column F)		Total taxable dividends paid by connected payer corporation (for tax year in column D)	Dividend refund of the connected payer corporation (for tax year in column D)**	Part IV tax before deductions F x 1 / 3 ***
240			250	260	270
					J

Total (enter the amount from column F on line 320 of the T2 return and amount J in Part 2)

* If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column 270. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

** If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

*** For dividends received from connected corporations: Part IV tax = $\frac{\text{Column F x Column H}}{\text{Column G}}$

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1)			
Deduct:			
Part IV.I tax payable on dividends subject to Part IV tax		320	
		Subtotal	
Deduct:			
Current-year non-capital loss claimed to reduce Part IV tax	330		
Non-capital losses from previous years claimed to reduce Part IV tax	335		
Current-year farm loss claimed to reduce Part IV tax	340		
Farm losses from previous years claimed to reduce Part IV tax	345		
Total losses applied against Part IV tax		x 1 / 3 =	
Part IV tax payable (enter amount on line 712 of the T2 return)		360	

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

	A	B	C	D	D1
	Name of connected recipient corporation 400	Business Number 410	Tax year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD 420	Taxable dividends paid to connected corporations 430	Eligible dividends (included in column D)
1	Bluewater Power Corporation	89247 0410 RC0001	2011-12-31	3,065,917	

Note

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information for each tax year of the recipient corporation.

Total 3,065,917

Total taxable dividends paid in the tax year to other than connected corporations	450	
Eligible dividends (included in line 450)	450a	
Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column D above **plus** line 450)	460	3,065,917

Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460 above) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above)			3,065,917
Other dividends paid in the tax year (total of 510 to 540)			
Total dividends paid in the tax year		500	3,065,917
Deduct:			
Dividends paid out of capital dividend account	510		
Capital gains dividends	520		
Dividends paid on shares described in subsection 129(1.2)	530		
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540		
Subtotal		►	
Total taxable dividends paid in the tax year that qualify for a dividend refund			3,065,917

Attached Schedule with Total

Taxable dividends paid to connected corporations

Title Taxable dividends paid to connected corporations

Description	Amount	
2010 Dividends Paid in 2011	1,165,917	00
2011 Dividends Paid in 2011	1,900,000	00
Total	3,065,917	00

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SCHEDULE 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2011-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 Enter the Regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes	103		143		
Newfoundland and Labrador offshore	004 1 Yes	104		144		
Prince Edward Island	005 1 Yes	105		145		
Nova Scotia	007 1 Yes	107		147		
Nova Scotia offshore	008 1 Yes	108		148		
New Brunswick	009 1 Yes	109		149		
Quebec	011 1 Yes	111		151		
Ontario	013 1 Yes	113		153		
Manitoba	015 1 Yes	115		155		
Saskatchewan	017 1 Yes	117		157		
Alberta	019 1 Yes	119		159		
British Columbia	021 1 Yes	121		161		
Yukon	023 1 Yes	123		163		
Northwest Territories	025 1 Yes	125		165		
Nunavut	026 1 Yes	126		166		
Outside Canada	027 1 Yes	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** Starting in 2009, if the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act.*

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide.*
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
1,862,777		1,862,777	182,598

	Line	Amount		Total	
Ontario basic income tax (from Schedule 500)	270	218,838			
Deduct: Ontario small business deduction (from schedule 500)	402	36,240			
Subtotal		182,598	►	182,598	A6
Add:					
Surtax re Ontario small business deduction (from Schedule 500)	272				
Ontario additional tax re Crown royalties (from Schedule 504)	274				
Ontario transitional tax debits (from Schedule 506)	276				
Recapture of Ontario research and development tax credit (from Schedule 508)	277				
Subtotal			►		B6
Subtotal (amount A6 **plus** amount B6)				182,598	C6
Deduct:					
Ontario resource tax credit (from Schedule 504)	404				
Ontario tax credit for manufacturing and processing (from Schedule 502)	406				
Ontario foreign tax credit (from Schedule 21)	408				
Ontario credit union tax reduction (from Schedule 500)	410				
Ontario transitional tax credits (from Schedule 506)	414	1,101			
Ontario political contributions tax credit (from Schedule 525)	415				
Subtotal		1,101	►	1,101	D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")				181,497	E6
Deduct: Ontario research and development tax credit (from Schedule 508)	416			4,875	
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")				176,622	F6
Deduct: Ontario corporate minimum tax credit (from schedule 510)	418				
Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0")				176,622	G6
Add:					
Ontario corporate minimum tax (from Schedule 510)	278				
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Ontario capital tax (from Schedule 514 or Schedule 515, whichever applies)	282				
Subtotal			►		H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)				176,622	I6
Deduct:					
Ontario qualifying environmental trust tax credit	450				
Ontario co-operative education tax credit (from Schedule 550)	452	3,663			
Ontario apprenticeship training tax credit (from Schedule 552)	454	50,000			
Ontario computer animation and special effects tax credit (from Schedule 554)	456				
Ontario film and television tax credit (from Schedule 556)	458				
Ontario production services tax credit (from Schedule 558)	460				
Ontario interactive digital media tax credit (from Schedule 560)	462				
Ontario sound recording tax credit (from Schedule 562)	464				
Ontario book publishing tax credit (from Schedule 564)	466				
Ontario innovation tax credit (from Schedule 566)	468				
Ontario business-research institute tax credit (from Schedule 568)	470	3,200			
Other Ontario tax credits					
Subtotal		56,863	►	56,863	J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.	290			119,759	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits 255 119,759

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2011-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes [ ] 2 No [X]

	1 Class number (See Note)	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year)	3 Cost of acquisitions during the year (new property must be available for use)*	4 Net adjustments**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)***	7 Reduced undepreciated capital cost	8 CCA rate % ****	9 Recapture of capital cost allowance (line 107 of Schedule 1)	10 Terminal loss (line 404 of Schedule 1)	11 Capital cost allowance (for declining balance method, column 7 multiplied by column 8, or a lower amount) (line 403 of Schedule 1) *****	12 Undepreciated capital cost at the end of the year (column 6 plus column 7 minus column 11)
	200		201	203	205	207	211		212	213	215	217	220
1.	1		17,284,178	95,023		0	47,512	17,331,689	4	0	0	693,268	16,685,933
2.	2		10,505,936			0		10,505,936	6	0	0	630,356	9,875,580
3.	8		4,933,506	1,029,222		0	514,611	5,448,117	20	0	0	1,089,623	4,873,105
4.	10		1,305,377	366,705		33,500	166,603	1,471,979	30	0	0	441,594	1,196,988
5.	12		1,408,905	3,694,510		0	1,847,255	3,256,160	100	0	0	3,256,160	1,847,255
6.	17	Parking Lot	42,621			0		42,621	8	0	0	3,410	39,211
7.	45		25,967			0		25,967	45	0	0	11,685	14,282
8.	46		356,641	39,650		0	19,825	376,466	30	0	0	112,940	283,351
9.	47		10,045,253	2,028,592		35,896	996,348	11,041,601	8	0	0	883,328	11,154,621
10.	50		87,221	430,707		0	215,354	302,574	55	0	0	166,416	351,512
11.	94	software not available for use	779,688		-779,688	0			0	0	0		
12.	95		1,234,788	1,279,609	-1,234,788	0	639,805	639,804	0	0	0		1,279,609
		Totals	48,010,081	8,964,018	-2,014,476	69,396	4,447,313	50,442,914				7,288,780	47,601,447

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only, if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2011-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	Sarnia Power Corporation		89252 3812 RC0001	3					
2.	Bluewater Power Corporation		89247 0410 RC0001	1					
3.	Bluewater Power Services Corporati		89255 8214 RC0001	3					
4.	Bluewater Power Renewable Energy		85839 3556 RC0001	3					
5.	Electek Power Services Inc.		86220 1712 RC0002	3					
6.	Bluewater Power Generation Corpor		85884 6215 RC0001	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2011-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0") **200** 1,509,140 A

Add: Cost of eligible capital property acquired during the taxation year **222** ______

Other adjustments **226** ______

Subtotal (line 222 plus line 226) ______ x 3 / 4 = ______ B

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 **228** ______ x 1 / 2 = ______ C

amount B minus amount C (if negative, enter "0") ______ ▶ ______ D

Amount transferred on amalgamation or wind-up of subsidiary **224** ______ E

Subtotal (add amounts A, D, and E) **230** 1,509,140 F

Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year **242** ______ G

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) **244** ______ H

Other adjustments **246** ______ I

(add amounts G,H, and I) ______ x 3 / 4 = **248** ______ J

Cumulative eligible capital balance (amount F minus amount J) 1,509,140 K

(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business **249** ______

amount K 1,509,140

less amount from line 249 ______

Current year deduction 1,509,140 x 7.00 % = **250** 105,640 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 105,640 ▶ 105,640 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") **300** 1,403,500 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)				N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988		400	1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)		401	2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402	3		
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408	4		
Line 3 minus line 4 (if negative, enter "0")		►	5	
Total of lines 1, 2 and 5			6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400		7		
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000		8		
Subtotal (line 7 plus line 8)	409	►	9	
Line 6 minus line 9 (if negative, enter "0")			►	O
Line N minus line O (if negative, enter "0")				P
Line 5		× 1 / 2 =		Q
Line P minus line Q (if negative, enter "0")				R
Amount R		× 2 / 3 =		S
Amount N or amount O, whichever is less				T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)			410	

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SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2006	maximum $300,000
2007	$300,001 to $400,000

Calendar year	Acceptable range
2008	maximum $400,000
2009	$400,001 to $500,000

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . **025** Year Month Day

Enter the calendar year to which the agreement applies . . . . **050** Year 2011

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . **075** 1 Yes [ ] 2 No [X]

	1 Names of associated corporations **100**	2 Business Number of associated corporations **200**	3 Association code **300**	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**
1	Bluewater Power Distribution Corporation	86572 7390 RC0001	1	500,000	100.0000	500,000
2	Sarnia Power Corporation	89252 3812 RC0001	1	500,000		
3	Bluewater Power Corporation	89247 0410 RC0001	1	500,000		
4	Bluewater Power Services Corporation	89255 8214 RC0001	1	500,000		
5	Bluewater Power Renewable Energy Inc	85839 3556 RC0001	1	500,000		
6	Electek Power Services Inc.	86220 1712 RC0002	1	500,000		
7	Bluewater Power Generation Corporation	85884 6215 RC0001	1	500,000		
				Total	100.0000	500,000 A

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

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SCHEDULE 31

INVESTMENT TAX CREDIT – CORPORATIONS

General information

1. For use by a corporation that during a tax year:
   - earned an investment tax credit (ITC);
   - is claiming a deduction against its Part I tax payable;
   - is claiming a refund of credit earned during the current tax year;
   - is claiming a carryforward of credit from previous tax years;
   - is transferring a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the federal *Income Tax Act;*
   - is requesting a credit carryback; or
   - is subject to a recapture of ITC.
2. References to parts, sections, and subsections on this schedule are from the federal *Income Tax Act* and the federal *Income Tax Regulations*. References to interpretation bulletins and information circulars are to the latest versions.
3. The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
4. Investments or expenditures, as defined in subsection 127(9) and Part XLVI of the federal *Income Tax Regulations*, that earn the ITC are:
   - qualified property (Parts 4 to 7);
   - expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). Complete and file Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*;
   - pre-production mining expenditures (Parts 18 to 20);
   - apprenticeship job creation expenditures (Parts 21 to 23); and
   - child care spaces expenditures (Parts 24 to 28).
5. Attach a completed copy of this schedule with the *T2 Corporation Income Tax Return.*
6. For more information on ITCs, see the section called "Investment Tax Credit" in the *T2 Corporation – Income Tax Guide*, Information Circular IC 78-4, *Investment Tax Credit Rates,* and its related Special Release. Also, see Interpretation Bulletin IT-151, *Scientific Research and Experimental Development Expenditures.*
7. For information on SR&ED, see Interpretation Bulletin IT-151 (**consolidated**), *Scientific Research and Experimental Development Expenditures*; Information Circular 86-4, *Scientific Research and Experimental Development*; Brochure RC4472, *Overview of the Scientific Research and Experimental Development Program (SR&ED) Tax Incentive Program*; Brochure RC4467, *Support for your R&D in Canada* and T4088, *Guide to Form T661 Scientific Research and Experimental Development (SR&ED) Expenditures Claim.*

Detailed information

1. For the purpose of this schedule, **"investment"** means:
   The capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
2. An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
3. Property acquired has to be "available for use" before a claim for an ITC can be made.
4. Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which the expenditures or capital costs were incurred.
5. Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITC's is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 of the Act is not applicable for the agreement to share any income or loss. Special rules apply to specified and limited partners. For more information, see Guide T4068-1, 2010 Supplement to the 2006 T4068, Guide for the T5013 Partnership Information Return.
6. For SR&ED expenditures, the expression "in Canada" includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone.

Name of corporation	Business Number	Tax year-end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2011-12-31

Part 1 – Investments, expenditures and percentages

	Specified percentage
Investments	
Qualified property acquired primarily for use in Newfoundland and Labrador, Prince Edward Island, Nova Scotia, New Brunswick, the Gaspé Peninsula, or a prescribed offshore region	10 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate.	
If you are a corporation that is not a CCPC that incurred qualified expenditures for SR&ED in any area in Canada	20 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures	10 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? **101** 1 Yes [ ] 2 No [X]

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and the taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC calculating a refundable ITC, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or

c) any combination of persons referred to in a) or b) above.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? **102** 1 Yes [ ] 2 No [X]

Contributions to agricultural organizations for SR&ED **103**

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see the *Guide to the General Index of Financial Information (GIFI) for Corporations.* Enter contributions on line 350 of Part 8.

QUALIFIED PROPERTY

Part 4 – Eligible investments for qualified property from the current tax year

	CCA* class number 105	Description of investment 110	Date available for use 115	Location used (province or territory) 120	Amount of investment 125
1.					

* CCA: capital cost allowance

Total investment – enter in formula on line 240 in Part 5

Part 5 – Calculation of current-year credit and account balances – ITC from investments in qualified property

ITC at the end of the previous tax year

Deduct:

Credit deemed as a remittance of co-op corporations 210

Credit expired 215

Subtotal ►

ITC at the beginning of the tax year 220

Add:

Credit transferred on amalgamation or wind-up of subsidiary 230

ITC from repayment of assistance 235

Total current-year credit: total of column 125 x 10 % = 240

Credit allocated from a partnership 250

Subtotal ►

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line B1 in Part 30) 260

Credit carried back to the previous year(s) (from Part 6) A

Credit transferred to offset Part VII tax liability 280

Subtotal ►

Credit balance before refund B

Deduct:

Refund of credit claimed on investments from qualified property (from Part 7) 310

ITC closing balance of investments from qualified property 320

Part 6 – Request for carryback of credit from investments in qualified property

	Year	Month	Day		
1st previous tax year				Credit to be applied	901
2nd previous tax year				Credit to be applied	902
3rd previous tax year				Credit to be applied	903

Total (enter on line A in Part 5)

Part 7 – Calculation of refund for qualifying corporations on investments from qualified property

Current-year ITCs (total of lines 240 and 250 in Part 5) C

Credit balance before refund (amount B from Part 5) D

Refund (40 % of amount C or D, whichever is less) E

Enter amount E or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

SR&ED

Part 8 – Qualified SR&ED expenditures

Current expenditures

Current expenditures (from line 557 on Form T661)	79,643		
Add:			
Contributions to agricultural organizations for SR&ED*			
Current expenditures (including contributions to agricultural organizations for SR&ED at line 103 in Part 3)* (from line 557 on Form T661)	79,643 ▶	350	79,643
Capital expenditures (from line 558 on Form T661)		360	23,811
Repayments made in the year (from line 560 on Form T661)		370	
Total (this must equal the amount from line 570 on Form T661)*		380	103,454

* Do not file form T661 if you are only claiming contributions made to agricultural organizations for SR&ED.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if the corporation is a CCPC.

Note: A CCPC that calculates SR&ED expenditure limit, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? . . . . 385 1 Yes [X] 2 No [ ]

Complete lines 390 and 398, if you answered **no** to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied). . . . . . . 390 ______

Enter your taxable capital employed in Canada for the previous tax year minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million. . . . . . . 398 ______

* If either of the tax years referred to at line 390 is less than 51 weeks, multiply the taxable income by the following result: 365 divided by the number of days in these tax years.

Part 10 – Calculation of SR&ED expenditure limit for a CCPC

For stand-alone corporations:

Calculation 1A: Tax year ends before January 1, 2010.

[($7,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)] . . . . ____________

Calculation 1: Tax year starts after December 31, 2009.

[($8,000,000 **minus** (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)] . . . . ____________

Calculation 2: Tax year straddles January 1, 2010.

EE + [(FF **minus** EE) x (GG **divided by** HH)] where, ... ____________

EE = [($7,000,000 **minus** (10A)) x (($40,000,000 **minus** B) **divided by** $40,000,000)];

FF = [($8,000,000 **minus** (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)];

GG = number of days in the tax year after December 31, 2009;

HH = number of days in the tax year.

Amount A **408** ____________ Amount B **409** ____________

A = the greater of:

- $400,000; and
- your taxable income for the last tax year* ending in the previous calendar year (tax years ending in 2008) (prior to any loss carry-backs applied).

B = the taxable capital employed in Canada for the last tax year ending in the previous calendar year (tax years ending in 2008) minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million.

* If any of the tax years referred to in **A** above are less than 51 weeks, gross up the taxable incomes for those tax years by the ratio that 365 is of the number of days in those tax years. Use these grossed up amounts when calculating the expenditure limit.

Enter the amount from Calculation 1A, 1 or 2, whichever is applicable ____________ G*

For associated corporations:

If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49 . . . . **400** ____________ H*

Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Line G or H ____________ x Number of days in the tax year / 365 = 365 . . . . ____________ I

Your SR&ED expenditure limit for the year (enter the amount from line G, H, or I, whichever applies) . . . . **410** ____________

* Amount G or H cannot be more than $3,000,000.

Part 11 – Calculation of investment tax credits on SR&ED expenditures

Enter whichever is less: current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10)*	420		x	35 %	=		J
Line 350 minus line 410 (if negative, enter "0")	430	79,643	x	20 %	=	15,929	K
Line 410 minus line 350 (if negative, enter "0")			L				
Enter whichever is less: capital expenditures (line 360 from Part 8) or line L above*	440		x	35 %	=		M
Line 360 minus line L (if negative, enter "0")	450	23,811	x	20 %	=	4,762	N

Repayments (amount from line 370 in Part 8)

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount. Enter the amount of the repayment on the line that corresponds to the appropriate rate.

460		x	35 %	=		
480		x	20 %	=		
			Total		▶	O

Current-year SR&ED ITC (total of lines J, K, M, N, and O; enter on line 540 in Part 12) 20,691

* For corporations that are not CCPCs, enter "0" on lines J and M.

Part 12 – Calculation of current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year				
Deduct:				
Credit deemed as a remittance of co-op corporations	510			
Credit expired	515			
Subtotal			▶	
ITC at the beginning of the tax year			520	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	530			
Total current-year credit	540	20,691		
Credit allocated from a partnership	550			
Subtotal		20,691	▶	20,691
Total credit available				20,691
Deduct:				
Credit deducted from Part I tax (enter on line B2 in Part 30)	560	20,691		
Credit carried back to the previous year(s) (from Part 13)			P	
Credit transferred to offset Part VII tax liability	580			
Subtotal		20,691	▶	20,691
Credit balance before refund				Q
Deduct:				
Refund of credit claimed on expenditures of SR&ED (from Part 14 or 15, whichever applies)			610	
ITC closing balance on SR&ED			620	

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	911	
2nd previous tax year				Credit to be applied	912	
3rd previous tax year				Credit to be applied	913	
				Total (enter on line P in Part 12)		

Part 14 – Calculation of refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101.

Is the corporation an excluded corporation as defined under subsection 127.1(2)?	650	1 Yes [ ]	2 No [X]
Credit balance before refund (amount Q from Part 12)		R	
Current-year ITC (lines 540 plus 550 from Part 12 **minus** line O from Part 11)		S	
Refundable credits (amount R or S, whichever is less)*			T
Amount J from Part 11		U	
Subtract: Amount T or U, whichever is less			V
Net amount (if negative, enter "0")			W
Amount W x 40 %			X
Add: Amount V			Y
Refund of ITC (amounts X **plus** Y – enter this, or a lesser amount, on line 610 in Part 12)			Z

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC on line Z.

Part 15 – Calculation of refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined in Part 2.

Credit balance before refund (amount Q from Part 12)		AA
Amount J from Part 11	BB	
Subtract: Amount AA or BB, whichever is less		CC
Net amount (if negative, enter "0")		DD
Amount M from Part 11		EE
Amount DD or EE, whichever is less x 40 %		FF
Add : Amount CC above		GG
Refund of ITC (amounts FF **plus** GG)		HH

Enter HH, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

RECAPTURE – SR&ED

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997 and did not expire before 2008;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

	Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above **700**	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter this amount on line LL in Part 17) ________ II

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil at line JJ in Part 16.

	A Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720**	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730**	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740**
1.			

Calculation 2 (continued) – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil on line JJ below.

	D Amount determined by the formula (A x B) – C	E ITC earned by the transferee for the qualified expenditures that were transferred **750**	F Amount from column D or E, whichever is less
1.			

Subtotal (enter this amount on line MM in Part 17) ________ JJ

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line KK below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported on line NN in Part 17) **760** ________ KK

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC for calculation 1 from line II in Part 16		LL
Recaptured ITC for calculation 2 from line JJ in Part 16 above		MM
Recaptured ITC for calculation 3 from line KK in Part 16 above		NN
Total recapture of SR&ED investment tax credit – Add lines LL, MM and NN		OO

Enter amount OO at line A1 in Part 29.

PRE-PRODUCTION MINING

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

	List of minerals 800
1.	

For each of the minerals reported in column 800 above, identify each project, mineral title, and mining division where title is registered. If there is no mineral title, identify the project and mining division only.

	Project name 805	Mineral title 806	Mining division 807
1.			

Pre-production mining expenditures *

Pre-production mining expenditures that the corporation incurred in the tax year for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting	810		PP
Geological, geophysical, or geochemical surveys	811		QQ
Drilling by rotary, diamond, percussion, or other methods	812		RR
Trenching, digging test pits, and preliminary sampling	813		SS

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping	820		TT
Sinking a mine shaft, constructing an adit, or other underground entry	821		UU

Other pre-production mining expenditures incurred in the tax year:

	Description 825	Amount 826
1.		

Add amounts at column 826			VV
Total pre-production mining expenditures (add amounts PP to VV)	830		
Deduct: Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above	832		
Excess (line 830 minus line 832) (if negative, enter "0")			WW
Add: Repayments of government and non-government assistance	835		XX
Pre-production mining expenditures (amount WW plus amount XX)			YY

* A pre-production mining expenditure is defined under subsection 127(9).

Part 19 – Calculation of current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year

Deduct:

Credit deemed as a remittance of co-op corporations 841

Credit expired 845

Subtotal ▶

ITC at the beginning of the tax year 850

Add:

Credit transferred on amalgamation or wind-up of subsidiary 860

Expenditures from line YY in Part 18: 870 x 10 % = 880

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line B3 in Part 30) 885

Credit carried back to the previous year(s) (from Part 20) CCC

Subtotal ▶

ITC closing balance from pre-production mining expenditures 890

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day		
1st previous tax year				Credit to be applied	921
2nd previous tax year				Credit to be applied	922
3rd previous tax year				Credit to be applied	923

Total (enter on line CCC in Part 19)

APPRENTICESHIP JOB CREATION

Part 21 – Calculation of total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number or name) appears below? (If not, you cannot claim the tax credit.) 611 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the social insurance number (SIN) or the name of the eligible apprentice. Attach additional schedules if more space is needed.

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
1.	PA6227	Powerline Technician	72,987	7,299	2,000
2.	PA6222	Powerline Technician	72,987	7,299	2,000
3.	PA4110	Powerline Technician	57,845	5,785	2,000
4.	PC7609	Powerline Technician	53,040	5,304	2,000
5.	PC7713	Powerline Technician	53,040	5,304	2,000
				Total current-year credit (enter at line 640)	10,000

* Net of any other government or non-government assistance received or to be received.

Part 22 – Calculation of current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year				
Deduct:				
Credit deemed as a remittance of co-op corporations	612			
Credit expired after 20 tax years	615			
	Subtotal		▶	
ITC at the beginning of the tax year			625	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	630			
ITC from repayment of assistance	635			
Total current-year credit (total of column 605)	640	10,000		
Credit allocated from a partnership	655			
	Subtotal	10,000	▶	10,000
Total credit available				10,000
Deduct:				
Credit deducted from Part I tax (enter on line B4 in Part 30)	660	10,000		
Credit carried back to the previous year(s) (from Part 23)			DDD	
	Subtotal	10,000	▶	10,000
ITC closing balance from apprenticeship job creation expenditures			690	

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	931	
2nd previous tax year				Credit to be applied	932	
3rd previous tax year				Credit to be applied	933	
				Total (enter on line DDD in Part 22)		

CHILD CARE SPACES

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

– Cost of depreciable property from the current tax year

	CCA* class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year	715		EEE
Add: Specified child care start-up expenditures from the current tax year	705		FFF
Total gross eligible expenditures for child care spaces (line 715 **plus** line 705)			GGG
Deduct: Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line GGG)	725		HHH
Excess (amount GGG **minus** amount HHH) (if negative, enter "0")			III
Add: Repayments of government and non-government assistance	735		JJJ
Total eligible expenditures for child care spaces (amount III **plus** amount JJJ)	745		

* CCA: capital cost allowance

Part 25 – Calculation of current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (line 745)			x 25 % =		KKK
Number of child care spaces	755		x $ 10,000 =		LLL
ITC from child care spaces expenditures (amount KKK or LLL, whichever is less)					MMM

Part 26 – Calculation of current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year				
Deduct:				
Credit deemed as a remittance of co-op corporations	765			
Credit expired after 20 tax years	770			
Subtotal			▶	
ITC at the beginning of the tax year			775	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	777			
Total current-year credit (amount MMM above)	780			
Credit allocated from a partnership	782			
Subtotal			▶	
Total credit available				
Deduct:				
Credit deducted from Part I tax (enter on line B5 in Part 30)	785			
Credit carried back to the previous year(s) (from Part 27)			NNN	
Subtotal			▶	
ITC closing balance from child care spaces expenditures			790	

Part 27 – Request for carryback of credit from child care space expenditures

	Year Month Day			
1st previous tax year	2010-12-31	Credit to be applied	941	
2nd previous tax year	2009-12-31	Credit to be applied	942	
3rd previous tax year	2008-12-31	Credit to be applied	943	
		Total (enter on line NNN in Part 26)		

RECAPTURE – CHILD CARE SPACES

Part 28 – Calculating the recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) . . . . . **792** ______ ZZZ

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC . . . . **795** ______

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property . . . . . **797** ______

Amount from line 795 or line 797, whichever is less . . . . . ______ OOO

Corporate partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line PPP below.

Corporate partner's share of the excess of ITC **799** ______ PPP

Total recapture of child care spaces investment tax credit – Add lines ZZZ, OOO, and PPP
Enter amount QQQ on line A2 in Part 29. . . . . . ______ QQQ

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC from line OO in Part 17		A1
Recaptured child care spaces ITC from line QQQ in Part 28 above		A2
Total recapture of investment tax credit – Add lines A1 and A2 Enter amount A3 on line 602 of the T2 return.		A3

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5)		B1
ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12)	20,691	B2
ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19)		B3
ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22)	10,000	B4
ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26)		B5
Total ITC deducted from Part I tax (add lines B1, B2, B3, B4, and B5) Enter amount B6 at line 652 of the T2 return.	30,691	B6

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Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
10,000	10,000			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2010-12-31				
2009-12-31				
2008-12-31				
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				
2002-12-31				
2001-12-31				*
2001-09-30				
2000-09-30				
1999-09-30				
1998-09-30				
1997-09-30				
1996-09-30				
1995-09-30				
1994-09-30				
1993-09-30				
1992-09-30				*
Total				

B+C+D+G **Total ITC utilized** 10,000

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit will only expire at the beginning of the subsequent fiscal period. Consequently, this amount will be posted on line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 of the subsequent fiscal year.

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 99 Cur. or cap. R&D for ITC

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
20,691	20,691			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2010-12-31				
2009-12-31				
2008-12-31				
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				
2002-12-31				
2001-12-31				*
2001-09-30				
2000-09-30				
1999-09-30				
1998-09-30				
1997-09-30				
1996-09-30				
1995-09-30				
1994-09-30				
1993-09-30				
1992-09-30				*
Total				

B+C+D+G **Total ITC utilized** 20,691

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit will only expire at the beginning of the subsequent fiscal period. Consequently, this amount will be posted on line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 of the subsequent fiscal year.

Canada Revenue Agency Agence du revenu du Canada

SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2011-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust)	Provide only one number per shareholder: Business Number (If a corporation is not registered, enter "NR")	Social insurance number	Trust number	Percentage common shares	Percentage preferred shares
	100	200	300	350	400	500
1	Bluewater Power Corporation	89247 0410 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2011-12-31

On: 2011-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 — 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? ☒ Yes ☐ No
   If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

Part 1 – Calculation of general rate income pool (GRIP)

GRIP at the end of the previous tax year				100	13,518,098 A
Taxable income for the year (DICs enter "0") *		110	1,862,777 B		
Income for the credit union deduction * (amount E in Part 3 of Schedule 17)	120				
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less *	130				
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income *	140				
Subtotal (add lines 120, 130, and 140)		►	C		
Income taxable at the general corporate rate (line B minus line C) (if negative enter "0")		150	1,862,777		
After-tax income (line 150 x general rate factor for the tax year ** 0.7)				190	1,303,944 D
Eligible dividends received in the tax year		200			
Dividends deductible under section 113 received in the tax year		210			
Subtotal (add lines 200 and 210)			►		E
GRIP addition:					
Becoming a CCPC (line PP from Part 4)		220			
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)		230			
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)		240			
Subtotal (add lines 220, 230, and 240)			►	290	F
Subtotal (add lines A, D, E, and F)					14,822,042 G
Eligible dividends paid in the previous tax year		300			
Excessive eligible dividend designations made in the previous tax year		310			
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.					
Subtotal (line 300 minus line 310)			►		H
GRIP before adjustment for specified future tax consequences (line G minus line H) (amount can be negative)				490	14,822,042
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2)				560	
GRIP at the end of the tax year (line 490 minus line 560)				590	14,822,042

Enter this amount on line 160 of Schedule 55.

* For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** The **general rate factor** for a tax year is 0.68 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle these dates.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2010-12-31

Taxable income before specified future tax consequences from the current tax year		2,926,749 J1	
Enter the following amounts before specified future tax consequences from the current tax year:			
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	K1		
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	L1		
Aggregate investment income (line 440 of the T2 return)	10,274 M1		
Subtotal (add lines K1, L1, and M1)	10,274 ►	10,274 N1	
Subtotal (line J1 minus line N1) (if negative, enter "0")		2,916,475 ►	2,916,475 O1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences . . . . ______ P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R1

Aggregate investment income (line 440 of the T2 return) . . . . ______ S1

Subtotal (add lines Q1, R1, and S1) ______ ▶ ______ T1

Subtotal (line P1 minus line T1) (if negative, enter "0") ______ ▶ ______ U1

Subtotal (line O1 minus line U1) (if negative, enter "0") ______ V1

GRIP adjustment for specified future tax consequences to the first previous tax year

(line V1 **multiplied by** the general rate factor for the tax year 0.7) . . . . **500** ______

Second previous tax year 2009-12-31

Taxable income before specified future tax consequences from the current tax year 4,108,263 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L2

Aggregate investment income (line 440 of the T2 return) . . . . ______ M2

Subtotal (add lines K2, L2, and M2) ______ ▶ ______ N2

Subtotal (line J2 minus line N2) (if negative, enter "0") 4,108,263 ▶ 4,108,263 O2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R2

Aggregate investment income (line 440 of the T2 return) . . . . ______ S2

Subtotal (add lines Q2, R2, and S2) ______ ▶ ______ T2

Subtotal (line P2 minus line T2) (if negative, enter "0") ______ ▶ ______ U2

Subtotal (line O2 minus line U2) (if negative, enter "0") ______ V2

GRIP adjustment for specified future tax consequences to the second previous tax year

(line V2 **multiplied by** the general rate factor for the tax year 0.7) . . . . **520** ______

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2008-12-31

Taxable income before specified future tax consequences from the current tax year 4,111,537 J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L3

Aggregate investment income (line 440 of the T2 return) . . . . ______ M3

Subtotal (**add** lines K3, L3, and M3) ______ ► ______ N3

Subtotal (line J3 **minus** line N3) (if negative, enter "0") 4,111,537 ► 4,111,537 O3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R3

Aggregate investment income (line 440 of the T2 return) . . . . ______ S3

Subtotal (**add** lines Q3, R3, and S3) ______ ► ______ T3

Subtotal (line P3 **minus** line T3) (if negative, enter "0") ______ ► ______ U3

Subtotal (line O3 **minus** line U3) (if negative, enter "0") ______ V3

GRIP adjustment for specified future tax consequences to the third previous tax year
(line V3 **multiplied** by the general rate factor for the tax year 0.7) . . . . **540** ______

Total GRIP adjustment for specified future tax consequences to previous tax years:
(add lines 500, 520, and 540) (if negative, enter "0") . . . . ______ W

Enter amount W on line 560.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . AA

Eligible dividends paid by the corporation in its last tax year . . . . BB

Excessive eligible dividend designations made by the corporation in its last tax year . . . . . . ______ CC

Subtotal (line BB **minus** line CC) ______ ► ______ DD

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)
(line AA **minus** line DD) . . . . ______ EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC ☐ Post amalgamation ☐ Post wind-up ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year			FF
The corporation's money on hand immediately before the end of its previous/last tax year			GG
Unused and unexpired losses at the end of the corporation's previous/last tax year:			
Non-capital losses			
Net capital losses			
Farm losses			
Restricted farm losses			
Limited partnership losses			
Subtotal		►	HH
Subtotal (**add** lines FF, GG, and HH)			II
All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year	JJ		
Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year	KK		
All the corporation's reserves deducted in its previous/last tax year	LL		
The corporation's capital dividend account immediately before the end of its previous/last tax year	MM		
The corporation's low rate income pool immediately before the end of its previous/last tax year	NN		
Subtotal (**add** lines JJ, KK, LL, MM, and NN)		►	OO
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0")			PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 5 – General rate factor for the tax year

Complete this part to calculate the general rate factor for the tax year.

0.68	x	number of days in the tax year before January 1, 2010 / number of days in the tax year	/ 365	=		QQ
0.69	x	number of days in the tax year in 2010 / number of days in the tax year	/ 365	=		RR
0.7	x	number of days in the tax year in 2011 / number of days in the tax year	365 / 365	=	0.70000	SS
0.72	x	number of days in the tax year after December 31, 2011 / number of days in the tax year	/ 365	=		TT

General rate factor for the tax year (total of lines QQ to TT) . . . . 0.70000 UU

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SCHEDULE 55

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2011-12-31

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- All legislative references on this schedule are to the federal *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Do not use this area

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3				
Taxable dividends paid in the tax year **included** in Schedule 3		3,065,917		
Total taxable dividends paid in the tax year	100	3,065,917		
Total eligible dividends paid in the tax year	150			A
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")	160		14,822,042	B
Excessive eligible dividend designation (line 150 **minus** line 160)				C
Deduct:				
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*	180			D
Subtotal (amount C **minus** amount D)				E
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount E **multiplied** by 20 %)	190			F

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3				
Taxable dividends paid in the tax year **included** in Schedule 3				
Total taxable dividends paid in the tax year	200			
Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54)				G
Deduct:				
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*	280			H
Subtotal (amount G **minus** amount H)				I
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount I **multiplied** by 20 %)	290			J

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends.**

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SCHEDULE 500

ONTARIO CORPORATION TAX CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2011-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only and does not have to be filed with your *T2 Corporation Income Tax Return*.

Part 1 – Calculation of Ontario basic rate of tax for the year

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	/ 365	x	14.00 %	=	%	A1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	181 / 365	x	12.00 %	=	5.95068 %	A2
Number of days in the tax year after June 30, 2011 / Number of days in the tax year	184 / 365	x	11.50 %	=	5.79726 %	A3

Ontario basic rate of tax for the year (total of rates A1 to A3) 11.74794 ► 11.74794 % A4

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . . 1,862,777 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A4 from Part 1) . . . . . 218,838 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit, in addition to Ontario basic income tax, or has Ontario corporate minimum tax, Ontario special additional tax on life insurance corporations or Ontario capital tax payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return)					1,886,887	1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)					1,862,777	2
Federal business limit before the application of subsection 125(5.1) * (amount from line 410 of the T2 return)		x		=	500,000	3
			line 4 on page 4 of the T2 return			
Enter the least of amounts 1, 2, and 3					500,000	D
Ontario domestic factor:	Ontario taxable income ** / taxable income earned in all provinces and territories ***		1,862,777.00 / 1,862,777	=	1.00000	E

Amount D x amount E	500,000	a
Ontario taxable income (amount B from Part 2)	1,862,777	b

Ontario small business income (lesser of amount a and amount b) . . . . . 500,000 F

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	/ 365	x	8.50 %	=	%	G1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	181 / 365	x	7.50 %	=	3.71918 %	G2
Number of days in the tax year after June 30, 2011 / Number of days in the tax year	184 / 365	x	7.00 %	=	3.52877 %	G3

OSBD rate for the year (total of rates G1 to G3) . . . . . 7.24795 % G4

Ontario small business deduction: amount F **multiplied** by OSBD rate for the year (rate G4) . . . . . 36,240 H

Enter amount H on line 402 of Schedule 5.

* For 2011 and later tax years, enter the amount from line 410 of the T2 return on line 3 of this schedule. Otherwise, complete the calculation for this line.

** Enter amount B from Part 2.

*** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 4 – Calculation of surtax re Ontario small business deduction

Complete this part if the corporation is claiming the OSBD and its adjusted taxable income, **plus** the adjusted taxable income of each corporation with which the corporation was associated during its tax year, is greater than $500,000. If the corporation is a member of an associated group, complete Schedule 501, *Ontario Adjusted Taxable Income of Associated Corporations to Determine Surtax re Ontario Small Business Deduction*.

Note: For days in the tax year after June 30, 2010, the small business surtax rate is 0%. You do not have to complete this part if the corporation's tax year begins after June 30, 2010.

Adjusted taxable income * . . . . ______ I

Adjusted taxable income of all associated corporations (amount from line 500 of Schedule 501) . . . . ______ J

Aggregate adjusted taxable income (amount I **plus** amount J) . . . . ______ ▶ ______ K

Deduct:

Ontario business limit 500,000

Subtotal (amount K **minus** Ontario business limit) (if negative, enter "0" on this line and on line P) . . . . ______ L

Small business surtax rate for the year:

$$\frac{\text{Number of days in the tax year before July 1, 2010} \quad \_\_\_}{\text{Number of days in the tax year} \quad 365} \times 4.25\,\% = \_\_\_\,\% \quad M$$

Amount L **multiplied by** % on line M = ... ______ N

$$\text{Amount N} \quad \_\_\_ \times \frac{\text{Ontario small business income (amount F from Part 3)} \quad \_\_\_}{500{,}000 \quad 500{,}000} = \_\_\_ \quad O$$

Surtax re Ontario small business deduction: lesser of amount O and OSBD (amount H from Part 3) . . . . ______ P

Enter amount P on line 272 of Schedule 5.

* Adjusted taxable income is equal to the corporation's taxable income or taxable income earned in Canada for the year **plus** the amount of the corporation's adjusted Crown royalties for the year **minus** the amount of the corporation's notional resource allowance for the year (from Schedule 504, *Ontario Resource Tax Credit and Ontario Additional Tax re Crown Royalties*).

If the tax year of the corporation is less than 51 weeks, **multiply** the adjusted taxable income of the corporation for the year by 365 and **divide** by the number of days in the tax year.

Part 5 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Lesser of amount D and amount b from Part 3 . . . . 500,000 Q

$$\frac{\text{Surtax payable (amount P from Part 4)}}{\text{Ontario domestic factor (amount E from Part 3) x OSBD rate (rate G6 from Part 3)} \quad 7.24795\,\% \quad 0.07248} = \_\_\_ \quad R$$

Note: Enter "0" on line R for tax years beginning after June 30, 2010.

Ontario adjusted small business income (amount Q **minus** amount R) (if negative, enter "0") . . . . 500,000 S

Enter amount S on line U in Part 6 or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 6 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D from Part 3 of Schedule 17			T
Deduct:			
Ontario adjusted small business income (amount S from Part 5)			U
Subtotal (amount T **minus** amount U) (if negative, enter "0")			V
OSBD rate for the year (rate G6 from Part 3)	7.24795 %		
Amount V **multiplied** by the OSBD rate for the year			W
Ontario domestic factor (amount E from Part 3)		1.00000	X
Ontario credit union tax reduction (amount W **multiplied** by amount X)			Y

Enter amount Y on line 410 of Schedule 5.

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SCHEDULE 506

ONTARIO TRANSITIONAL TAX DEBITS AND CREDITS

Name of corporation	Business Number	Tax year-end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2011-12-31

- Complete this schedule if you are a specified corporation that is subject to the Ontario transitional tax debit or are claiming the Ontario transitional tax credit.
- Unless otherwise noted, all legislative references are to the federal *Income Tax Act*.
- File this schedule with the *T2 Corporation Income Tax Return*.
- Unless otherwise noted, terms on this page are defined under subsection 46(1) of the *Taxation Act, 2007* (Ontario).
- **Specified corporation** is defined under subsection 46(5) of the *Taxation Act, 2007* (Ontario) as a corporation:
  - that is not exempt at or immediately before its transition time from tax payable under Part I of the federal Act;
  - that has a tax year that ends before 2009 and a tax year that includes January 1, 2009; or has a tax year that begins after 2008 and a tax year that is deemed to end on December 31, 2008, under subsection 249(3) of the federal Act;
  - that has a permanent establishment (PE) in Ontario at its transition time;
  - that had a PE in Ontario at any time in its last tax year ending before 2009, and was subject to tax under Part II of the *Corporations Tax Act* (Ontario) for that tax year; and
  - whose assets have not been distributed in an eligible pre-2009 windup.
- A specified corporation also includes, under subsection 51(1) of *the Taxation Act, 2007* (Ontario), the parent corporation of an eligible post-2008 windup and the new corporation of an eligible amalgamation.
- A specified corporation may be subject to the Ontario transitional tax debit if:
  - the corporation's total federal balance is more than the total Ontario balance at the end of the tax year; or
  - the corporation has a post-2008 scientific research and experimental development (SR&ED) balance, as defined under subsection 49(2) of the *Taxation Act, 2007* (Ontario), and a federal SR&ED transitional balance, as defined under subsection 49(4) of the *Taxation Act, 2007* (Ontario), at the end of the tax year.
- A specified corporation may be able to claim the Ontario transitional tax credit if:
  - the corporation's total Ontario balance is more than the total federal balance at the end of the tax year; or
  - the corporation has an unused transitional tax credit balance from previous tax years.
- **Transition time** means:
  - the beginning of the corporation's first tax year that starts after 2008 if the previous tax year is deemed under subsection 249(3) of the federal Act to end on December 31, 2008, or
  - the beginning of the corporation's tax year that includes January 1, 2009, in any other case.
- An **eligible amalgamation** means an amalgamation or merger of a particular corporation and one or more other corporations to form a new corporation where:
  - the amalgamation or merger occurs after December 31, 2008, and does not occur at the new corporation's transition time;
  - the new corporation has a PE in Ontario immediately after the amalgamation or merger;
  - the particular corporation has a PE in Ontario immediately before the amalgamation or merger;
  - the particular corporation is a specified corporation at its transition time or at any time before the amalgamation or merger;
  - the amalgamation or merger occurs in the amortization period of the new corporation;
  - the amortization period of the new corporation does not end immediately after the beginning of its reference period; and
  - the amortization period of the particular corporation does not end before the amalgamation or merger.
- An **eligible post-2008 windup** means the windup of a subsidiary corporation into its parent corporation under subsection 88(1) where:
  - the completion time of the windup is after December 31, 2008, and the time immediately after the completion time is within the amortization periods of the subsidiary and parent;
  - the parent's tax year (during which it received the assets of the subsidiary) ends after December 31, 2008;
  - the subsidiary has a PE in Ontario during its tax year ending at the completion time; and
  - the parent has a PE in Ontario during its tax year in which it received the assets from the subsidiary.
- An **eligible pre-2009 windup** means the windup of a subsidiary under subsection 88(1) where:
  - the completion time of the windup is after December 31, 2008, and the parent's tax year (during which it received the assets of the subsidiary) ended before January 1, 2009; or
  - the completion time of the windup is before January 1, 2009, and the parent's tax year (during which it received the assets of the subsidiary) ended after December 31, 2008.
- The **completion time** of a windup means the end of the tax year of the subsidiary during which the subsidiary distributes its assets to the parent for the purposes of paragraph 88(1)(e.2).
- A **specified pre-2009 transfer** under section 52 of the *Taxation Act, 2007* (Ontario) means a transfer of property between corporations not at arm's length that changes the total federal or Ontario balance of either the transferee or the transferor and that occurs:
  - before 2009;
  - at different values under the *Corporations Tax Act* (Ontario) and the federal Act;
  - in a tax year ending after 2008 for either the transferee or the transferor corporation, and that corporation is a specified corporation; and
  - in a tax year of the other corporation ending before 2009, in which the other corporation has a PE in Ontario.

Part 1 – Total federal balance

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

If this is the first year after amalgamation, include the total of all amounts from the predecessor corporations that had a PE in Ontario immediately before the amalgamation.

If the corporation is a life insurer or a non-resident corporation, do not include the amounts under the additional rules in subsection 48(8) of the *Taxation Act, 2007* (Ontario).

For other tax years, go to Part 3.

Federal balances at the end of the previous tax year (tax year ending in 2008)

Total undepreciated capital cost of depreciable properties (total of column 220 from Schedule 8, *Capital Cost Allowance (CCA)*)	110	
Charitable donations not yet deducted from income (from line 280 of Schedule 2, *Charitable Donations and Gifts*) (see Note 1)	112	
Gifts to Canada, a province, or a territory (from line 380 of Schedule 2) (see Note 1)	114	
Gifts of certified cultural property (from line 480 of Schedule 2) (see Note 1)	116	
Gifts of certified ecologically sensitive land (from line 580 of Schedule 2) (see Note 1)	118	
Gifts of medicine (from line 680 of Schedule 2) (see Note 1)	120	
Cumulative eligible capital (from line 300 of Schedule 10, *Cumulative Eligible Capital Deduction*)	122	
Federal SR&ED expenditure pool (from line 470 of Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*) (see Note 2 and Note 3)	124	
Cumulative Canadian exploration expense (from line 249 of Schedule 12, *Resource-Related Deductions*) (see Note 2)	128	
Cumulative Canadian development expense (from line 349 of Schedule 12) (see Note 2)	130	
Cumulative Canadian oil and gas property expense (from line 449 of Schedule 12) (see Note 2)	132	

Federal balances at the beginning of the current tax year

Non-capital losses (line 102 of Schedule 4, *Corporation Loss Continuity and Application*, of the current tax year) (see Note 2 and Note 4)	134	
Net capital losses (from line 200 of Schedule 4 of the current tax year x 50 %) (see Note 2 and Note 4)	136	

Amounts included in the calculation of the Ontario income tax in the previous tax year

Total reserves deducted under paragraph 20(1)(l), (l.1), (m), (m.1), (n), or (o), subsection 32(1), section 61.4 or subparagraph 138(3)(a)(i), (ii), or (iv) of the federal Act, as it applies for the purposes of the *Corporations Tax Act* (Ontario)	150	
One half of the total reserves deducted under subparagraph 40(1)(a)(iii) or 44(1)(e)(iii) of the federal Act, as it applies under the *Corporations Tax Act* (Ontario)	152	
Other discretionary deductions claimed for Ontario income tax, but not claimed federally in the tax years ending after December 12, 2006, and before the transition time	154	

Other amounts

Total adjusted cost base of partnership interests owned by the corporation, under the federal Act, at the beginning of the tax year (see Note 5)	160	
Gain from a negative adjusted cost base of a partnership interest under subsection 40(3) of the federal Act, as it applies under the *Corporations Tax Act* (Ontario), as if all partnership interests were disposed of at the beginning of the tax year	162	
Amount of farming income specified under paragraph 28(1)(b) in the previous tax year	164	
Federal balance before election (total of lines 110 to 164)		A

Deduct:

Lesser of amount D or amount E from Part 4, if an election is made	170	
Total federal balance (amount A **minus** line 170)	180	

Enter amount on line 300 in Part 3.

Note 1: Enter "0" if the corporation was non-resident immediately before its transition time.

Note 2: Enter "0" if control of the corporation was acquired at transition time.

Note 3: Do not include the SR&ED expenditure pool earned before control of the corporation was last acquired.

Note 4: Do not include losses that arose before control of the corporation was last acquired.

Note 5: The adjusted cost base of any particular partnership interest cannot be less than "0".

Part 2 – Total Ontario balance

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

If this is the first year after amalgamation, include the total of all amounts from the predecessor corporations that had a PE in Ontario immediately before the amalgamation.

If the corporation is a life insurer or a non-resident corporation, do not include the amounts under the additional rules in subsection 48(8) of the *Taxation Act, 2007* (Ontario).

For other tax years, go to Part 3.

Ontario balances at the end of the previous tax year (tax year ending in 2008)

Total undepreciated capital cost of depreciable properties (total of column 13 from Ontario Schedule 8, *Ontario Capital Cost Allowance*)	210	
Charitable donations (amount I from Ontario *Schedule 2, Ontario Charitable Donations and Gifts*) (see Note 1)	212	
Gifts to Canada, a province, or a territory (total of closing balance amounts from parts 3 and 5 of Ontario Schedule 2) (see Note 1)	214	
Gifts of certified cultural property (closing balance amount from Part 6 of Ontario Schedule 2) (see Note 1)	216	
Gifts of certified ecologically sensitive land (closing balance amount from Part 7 of Ontario Schedule 2) (see Note 1)	218	
Gifts of medicine (see Note 1)	220	
Cumulative eligible capital (amount Q from Ontario *Schedule 10, Ontario Cumulative Eligible Capital Deduction*)	222	
Ontario SR&ED expenditure pool (line 480 from Ontario *CT23 Schedule 161, Ontario Scientific Research and Experimental Development Expenditures*) (see Note 2 and Note 3)	224	
Adjusted Ontario SR&ED incentive balance (see Note 2 and Note 5)	226	
Cumulative Canadian exploration expense (closing balance of Regular Expenses from Part 2 of Ontario *Schedule 12, Ontario Exploration Expenses*) (see Note 2)	228	
Cumulative Canadian development expense (closing balance of Regular Expenses, Canadian CCDE Expenses, from Part 3 of Ontario Schedule 12) (see Note 2)	230	
Cumulative Canadian oil and gas property expense (closing balance of Regular Expenses from Part 4 of Ontario Schedule 12) (see Note 2)	232	
Non-capital losses (from line 709 of Ontario *Corporations Tax Return CT8* or *CT23 Corporations Tax and Annual Return*) (see Note 2 and Note 4)	234	
Net capital losses (from line 719 of CT8 or CT23 x 50 %) (see Note 2 and Note 4)	236	

Amounts included in the calculation of the federal income tax in the previous tax year

Total reserves deducted under paragraph 20(1)(l), (l.1), (m), (m.1), (n), or (o), subsection 32(1), section 61.4 or subparagraph 138(3)(a)(i), (ii), or (iv)	250	
One half of the total reserves deducted under subparagraph 40(1)(a)(iii) or 44(1)(e)(iii)	252	

Other amounts

Total adjusted cost base of partnership interests owned by the corporation, for the purposes of the *Corporations Tax Act* (Ontario), at the beginning of the tax year (see Note 6)	260	
Gain from a "negative" adjusted cost base of a partnership interest under subsection 40(3) determined as if all partnership interests were disposed of at the beginning of the tax year	262	
Amount of farming income in the previous tax year specified under paragraph 28(1)(b) of the federal Act, as it applies for the purposes of the *Corporations Tax Act* (Ontario)	264	
Total Ontario balance (total of lines 210 to 264)	280	

Enter amount on line 340 in Part 3.

Note 1: Enter "0" if the corporation was non-resident immediately before its transition time.

Note 2: Enter "0" if control of the corporation was acquired at transition time.

Note 3: Do not include the SR&ED expenditure pool earned before control of the corporation was last acquired.

Note 4: Do not include losses that arose before control of the corporation was last acquired.

Note 5: The adjusted Ontario SR&ED incentive balance under subsection 49(7) of the *Taxation Act, 2007* (Ontario) is the total of federal investment tax credits that:

- have been earned and are available without restriction to the corporation;
- are attributable to qualifying Ontario SR&ED expenditures;
- have not been deducted under subsection 127(5) or (6) of the federal Act at the end of the corporation's tax year ending immediately before its transition time; and
- do not expire in the first tax year ending in 2009 under the 10-year carryforward limit,

divided by the relevant Ontario allocation factor as calculated in Part 11.

Note 6: The adjusted cost base of any particular partnership interest cannot be less than "0".

Part 3 – Total federal balance and total Ontario balance at the end of the tax year

Total federal balance:

Total federal balance (amount from line 180 in Part 1, or amount from line 330 in Part 3 of Schedule 506 for the previous tax year)	300	42,931,761		
Add:				
Amount from eligible amalgamation*	310			
Amount from eligible post-2008 windup*	315			
Amount from eligible pre-2009 windup*	320			
Amount from specified pre-2009 transfers*	325			
Total federal balance at the end of the tax year		42,931,761	330	42,931,761

Total Ontario balance:

Total Ontario balance (amount from line 280 in Part 2, or amount from line 370 in Part 3 of Schedule 506 for the previous tax year)	340	42,978,631		
Add:				
Amount from eligible amalgamation*	350			
Amount from eligible post-2008 windup*	355			
Amount from eligible pre-2009 windup*	360			
Amount from specified pre-2009 transfers*	365			
Total Ontario balance at the end of the tax year		42,978,631	370	42,978,631
Transitional balance at the end of the tax year (line 330 **minus** line 370)			390	-46,870

If line 390 is positive, the corporation may be subject to a transitional tax debit. Complete Part 7 of this schedule.
If line 390 is negative, the corporation may be eligible to claim a transitional tax credit. Complete Part 8 of this schedule.

* See page 1 for definitions of eligible amalgamation, eligible post-2008 windup, eligible pre-2009 windup, and specified pre-2009 transfers. To calculate these amounts, you can use *Schedule 507, Ontario Transitional Tax Debits and Credits Calculation.*

Part 4 – Election to reduce federal SR&ED expenditure pool

The corporation may make this election if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

Are you making an election under clause (b) of the definition of "I" in paragraph 1 of subsection 48(4) of the *Taxation Act, 2007* (Ontario)? **400** 1 Yes [ ] 2 No [X]

If you answered **no** to the question at line 400, go to Part 5. If you answered **yes** to the question at line 400, complete the following calculation:

Federal SR&ED expenditure pool closing balance at the end of the previous tax year (amount from line 124 in Part 1)			B
Deduct:			
Adjusted Ontario SR&ED incentive balance at the end of the previous tax year (amount from line 226 in Part 2)	1		
Ontario SR&ED expenditure pool closing balance at the end of the previous tax year (amount from line 224 in Part 2)	2		
Subtotal (amount 1 **plus** amount 2)			C
Subtotal (amount B **minus** amount C) (if negative, enter "0")			D
Federal balance before election (amount A from Part 1)			
Deduct:			
Total Ontario balance (amount from line 280 in Part 2)			
Subtotal (if negative, enter "0")			E

Enter the lesser of amount D and amount E on line 170 in Part 1.

Part 5 – Reference period and amortization period

Reference period

The reference period starts at the beginning of the corporation's first tax year ending after December 31, 2008, and ends on whichever date is earlier:

– five calendar years after the time immediately before the start of the corporation's reference period; or

– December 31, 2013.

Number of days in the corporation's reference period*
(do not include February 29, 2008, and February 29, 2012) . . **410** 1,825

* The number of days in the corporation's reference period is 1825 unless:

– the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3). In this case, count the number of days from the beginning of the 2009 tax year to December 31, 2013; or

– the corporation was incorporated or amalgamated after January 1, 2009. In this case, count the number of days from the date of incorporation or date of amalgamation to December 31, 2013.

Amortization period

The amortization period starts at the beginning of the corporation's reference period and ends on whichever date is earlier:

– the end of the corporation's reference period; or

– the early termination date as indicated under line 430.

Number of days in the amortization period that are in the tax year** (do not include February 29, 2008, or February 29, 2012) **420** 365

** The number of days in the amortization period that are in the tax year is the number of days in the tax year unless:

– the tax year-end is later than the end of the reference period. In this case, count the number of days from the beginning of the tax year to the end of the reference period; or

– the corporation terminates the amortization period before the end of the tax year. In this case, count the number of days from the beginning of the tax year to the day of early termination.

Early termination of the amortization period

The amortization period of the corporation usually coincides with the corporation's reference period. However, if the corporation's amortization period ends in the tax year and before the reference period ends, tick the applicable box below to indicate the reason for the early termination.

430 The corporation:

1 ☐ – ceases to have a PE in Ontario in the tax year for any reason other than an eligible amalgamation or eligible post-2008 windup.

2 ☐ – becomes exempt from tax under Part I of the federal Act immediately after the end of the tax year.

3 ☐ – elects under subsection 47(2) of the *Taxation Act, 2007* (Ontario) to prepay the transitional tax debit.
Note: The Ontario Allocation Factor, calculated in Part 6, has to be at least 90% or the amount on line 390 in Part 3 is not more than $10,000.

4 ☐ – does not object to early termination of the amortization period and accelerated payment of the transitional tax credit, under subsection 46(3) of the *Taxation Act, 2007* (Ontario).
Note: Amount T in Part 8 cannot be more than $1,000.

If you ticked one of the above boxes:

– enter the date of the early termination, if the date is different from the tax year-end and you ticked box 1 at line 430 . . . . **435**

– enter the number of days from the first day of the tax year to the end of the corporation's reference period (do not include February 29, 2008, or February 29, 2012) **440**

Part 6 – Calculation of Ontario allocation factor (OAF)

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation and enter the result on line F:

$$\frac{\text{Ontario taxable income*}}{\text{Taxable income**}} = $$

Ontario allocation factor (OAF) . . . . 1.00000 F

* Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5, *Tax Calculation Supplementary – Corporations.* If taxable income is nil, calculate the amount in column F as if taxable income were $1,000.

** Enter taxable income from line 360 or amount Z of the T2 return, whichever applies. If taxable income is nil, enter "1,000."

Part 7 – Transitional tax debits

Complete this part if the amount on line 390 in Part 3 is positive.

Amount from line 390 in Part 3			G
Amount G x Ontario basic rate of tax*	11.74794 % =		H
Amount H x OAF (from line F in Part 6)	1.00000		I
Number of days from line 440 (if applicable) or line 420 in Part 5 / Number of days in the corporation's reference period from line 410 in Part 5	365 / 1,825 =	0.20000	J

Transitional tax debit before tax on elected reduced SR&ED pool (amount I **multiplied** by amount J)			K
Post-2008 SR&ED balance at the end of the year (amount HH from Part 12)	460		
Federal SR&ED transitional balance at the end of the year (amount QQ from Part 14)	470		
Tax on elected reduced SR&ED pool (the lesser of lines 460 and 470)			L
Total transitional tax debits (amount K **plus** amount L)			M

Enter amount M on line 276 of Schedule 5.

Part 8 – Transitional tax credits

Complete this part if the amount on line 390 in Part 3 is negative.

Amount C6 from Schedule 5		182,598	N	
Deduct:				
Ontario resource tax credit (from line 404 of Schedule 5)				
Ontario tax credit for manufacturing and processing (from line 406 of Schedule 5)				
Ontario foreign tax credit (from line 408 of Schedule 5)				
Ontario credit union tax reduction (from line 410 of Schedule 5)				
Subtotal	►		O	
Subtotal (amount N **minus** amount O)		182,598	P	
Number of days from line 420 in Part 5 / Number of days in the tax year (do not include February 29, 2008, or February 29, 2012)	365 / 365 =	1.00000	Q	
Ontario tax payable for purposes of the current year transitional tax credit (amount P **multiplied** by amount Q)			510	182,598
Amount from line 390 in Part 3 (enter as a positive amount)		46,870	R	
Amount R x Ontario basic rate of tax*	11.74794 % =	5,506	S	
Amount S x OAF (from line F in Part 6)		5,506	T	
Number of days from line 440 (if applicable) or line 420 in Part 5 / Number of days in the corporation's reference period on line 410 in Part 5	365 / 1,825 =	0.20000	U	
Current-year transitional tax credit (amount T **multiplied** by amount U)			520	1,101
Ontario tax payable for purposes of the unused transitional tax credit carryforward (line 510 **minus** line 520) (if negative, enter "0")			530	181,497
Transitional tax credit: Lesser of amounts on line 510 and 520				1,101 V
Lesser of unused transitional tax credit available (amount Y from Part 9) and amount on line 530				W
Transitional tax credits (amount V **plus** amount W)				1,101 X

Enter amount X on line 414 of Schedule 5.

* Enter the rate calculated in Part 1 of Schedule 500, *Ontario Corporation Tax Calculation*.

Part 9 – Unused transitional tax credit

Unused transitional tax credit carryforward from previous year (amount from line 580 of the previous year)*		1		
Add:				
Unused transitional tax credit transferred from a predecessor corporation or a subsidiary on an eligible amalgamation or an eligible post-2008 windup*	560	2		
Unused transitional tax credit available (amount 1 **plus** amount 2)		►		Y
Add:				
Current-year transitional tax credit (amount from line 520 in Part 8)			1,101	Z
Subtotal (amount Y **plus** amount Z)			1,101	3
Deduct:				
Transitional tax credit applied (amount X from Part 8)			1,101	AA
Unused transitional tax credit (available for later years) (amount 3 **minus** amount AA)	580			

* Enter "0" if this is the first tax year ending after 2008.

Complete parts 10 to 14 if the corporation or a predecessor made an election in Part 4 at the transition time.

Part 10 – Federal current SR&ED limit and federal current SR&ED deficit

Current SR&ED expenditures in the year under paragraph 37(1)(a)	610			
Capital SR&ED expenditures in the year under paragraph 37(1)(b)	614			
Repayment of assistance under paragraph 37(1)(c)	618			
Investment tax credit recaptured under subsections 127(27), (29), and (34) in the previous tax year	624			
Subtotal (total of lines 610 to 624)		►		BB
Deduct:				
Assistance under paragraph 37(1)(d)	638			
Investment tax credits deducted under paragraph 37(1)(e)	644			
Subtotal (line 638 **plus** line 644)		►		CC
Federal current SR&ED limit or federal current SR&ED deficit (amount BB **minus** amount CC)	650			

If the amount on line 650 is positive, enter it on line II In Part 13.

If the amount on line 650 is negative, enter it as a positive amount on line DD in Part 12.

Part 11 – Relevant OAF

Enter on line 660 whichever of the following amounts is greatest:

- the corporation's OAF for the tax year that includes its transition time (from line F in Part 6) .... %
- the greatest of the corporation's OAFs for a tax year ending in 2006, 2007, and 2008 as determined under subsection 12(1) of the *Corporations Tax Act* (Ontario) .... %
- the greatest of the weighted OAFs* of the corporation and its designated corporations** for 2006, 2007, and 2008 .... %

Relevant OAF .... 660 ________ %

* The weighted OAF for two or more corporations for their tax years ending in 2006, 2007, or 2008 is the total of the following for each corporation:

  – the corporation's OAF as determined under subsection 12(1) of the *Corporations Tax Act* (Ontario) for the tax year **multiplied** by the corporation's and its share of partnerships' qualified Ontario SR&ED expenditures in the tax year, **divided** by the total of all the corporations' and their shares of partnerships' qualified Ontario SR&ED expenditures in the tax year.

  Qualified Ontario SR&ED expenditure is defined in section 11.2 of the *Corporations Tax Act* (Ontario).

** A designated corporation in respect of a particular corporation is:

1) a corporation that amalgamated with the particular corporation under section 87;
2) a corporation that wound up into the particular corporation under subsection 88(1); or
3) a designated corporation to a corporation identified in 1) or 2).

Part 12 – Post-2008 SR&ED balance

Federal current SR&ED deficit for the year (amount from line 650 in Part 10, if negative) (enter as a positive amount) . . . . DD

SR&ED expenditure amount deducted in the year under subsection 37(1) 670

Deduct:
Cumulative post-2008 SR&ED limit at the end of the year (amount LL from Part 13) 675

Subtotal (line 670 **minus** line 675) (if negative, enter "0") ► EE

Subtotal (amount DD **plus** amount EE) FF

Amount FF x 14 % GG

Post-2008 SR&ED balance at the end of the year (amount GG **multiplied** by line 660 from Part 11) . . . . HH
Enter amount HH on line 460 in Part 7.

Part 13 – Cumulative post-2008 SR&ED limit at the end of the year

Federal current SR&ED limit for the year (amount from line 650 in Part 10, if positive) II
Total of all federal SR&ED limits from previous tax years ending after December 31, 2008 700

Subtotal (line II **plus** line 700) JJ

Total of all amounts deducted under subsection 37(1)
for previous tax years ending after December 31, 2008 705

Total of all transitional tax debits on elected reduced
SR&ED pool calculated under subsection 48(3) of the
Taxation Act, 2007 (Ontario) in the previous years
(total of line L in Part 7 for previous years) 710

Deduct:
Amounts included in line 710 that are
reasonably attributable to the federal
current SR&ED deficit for the year 715

Subtotal (line 710 **minus** line 715) 720

Line 720 / Relevant OAF (from line 660 in Part 11) x 14 % = ... KK

Subtotal (line 705 **minus** amount KK) ► 730

Cumulative post-2008 SR&ED limit at the end of the year (amount JJ **minus** line 730) (if negative, enter "0") LL
Enter amount LL on line 675 in Part 12.

Part 14 – Federal SR&ED transitional balance at the end of the year

Amount from line 170 in Part 1 (see Note) . . . . 735 MM
Relevant OAF (from line 660) (see Note) **multiplied** by amount MM . . . . NN
Amount NN x 14 % . . . . ► OO

Federal SR&ED transitional balance transferred on an
eligible amalgamation or an eligible post-2008 wind-up 740

Subtotal (amount OO **plus** line 740) PP

Deduct:
Total of all transitional tax debits on elected reduced SR&ED pool calculated under subsection 48(3) of
the *Taxation Act, 2007* (Ontario) in the previous years (total of line L in Part 7 for previous years) 750

Federal SR&ED transitional balance at the end of the year (amount PP **minus** line 750) . . . . QQ
Enter amount QQ on line 470 in Part 7.

Note: For tax years ending after 2009, enter the amount from line 170 and the relevant OAF from the 2009 tax year.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 508

ONTARIO RESEARCH AND DEVELOPMENT TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2011-12-31

- Use this schedule to:
  - calculate an Ontario research and development tax credit (ORDTC);
  - claim an ORDTC earned in the tax year or carried forward from any of the 20 previous tax years that are a tax year ending after December 31, 2008, to reduce Ontario corporate income tax payable in the current tax year;
  - carry back an ORDTC to reduce Ontario corporate income tax payable in any of the three previous tax years, but not to a tax year that ends before January 1, 2009;
  - add an ORDTC that was allocated to the corporation by a partnership of which it was a member;
  - transfer an ORDTC after an amalgamation or windup; or
  - calculate a recapture of the ORDTC.
- The ORDTC is a 4.5% non-refundable tax credit on eligible expenditures incurred by a corporation in a tax year that ends after December 31, 2008.
- An eligible expenditure is an expenditure for a permanent establishment in Ontario of a corporation, that is a qualified expenditure for the purposes of section 127 of the federal *Income Tax Act* for scientific research and experimental development (SR&ED) carried on in Ontario.
- Only corporations that are not exempt from Ontario corporate income tax and none of whose income is exempt income can claim the ORDTC.
- Attach a completed copy of this schedule to the *T2 Corporation Income Tax Return*.

Part 1 – Ontario SR&ED expenditure pool

	Line	Amount		Total	
Total eligible expenditures incurred by the corporation in Ontario in the tax year	100	111,529	A		
Deduct: Government assistance, non-government assistance, or a contract payment for eligible expenditures	105	3,200	B		
Net eligible expenditures for the tax year (amount A **minus** amount B) (if negative, enter "0")		108,329	C		
Add: Eligible expenditures transferred to the corporation by another corporation	110		D		
Subtotal (amount C **plus** amount D)		108,329	▶	108,329	E
Deduct: Eligible expenditures the corporation transferred to another corporation	115				F
Ontario SR&ED expenditure pool (amount E **minus** amount F) (if negative, enter "0")	120			108,329	G

Part 2 – Calculation of the current part of the ORDTC

				Line	Amount	
Ontario SR&ED expenditure pool (amount G in Part 1)	108,329	x	4.50 %	200	4,875	H
ORDTC allocated to a corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year *				205		I
Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure other than for first term or second term shared-use equipment (210)		x	4.50 %	215		J
Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure for first term or second term shared-use equipment (220) x 1 / 4 =		x	4.50 %	225		K
Current part of the ORDTC (total of amounts H to K)				230	4,875	L

* If there is a disposal or change of use of eligible property, see Part 6

T2 SCH 508 E

Canada

Part 3 – Calculation of ORDTC available for deduction and ORDTC balance

ORDTC balance at the end of the previous tax year				M	
Deduct: ORDTC expired after 20 tax years		**300**		N	
ORDTC at the beginning of the tax year (amount M **minus** amount N)		**305**		O	
Add:					
ORDTC transferred on amalgamation or windup		**310**		P	
Current part of ORDTC (amount L in Part 2)	4,875 Q				

Are you waiving all or part of the current part of the ORDTC? . . . . . . **315** Yes 1 [ ] No 2 [X]

If you answered **yes** at line 315, enter the amount of the tax credit waived on line 320.

If you answered **no** at line 315, enter "0" on line 320.

Deduct: Waiver of the current part of the ORDTC	**320**	R				
Subtotal (amount Q **minus** amount R)	4,875	▶	4,875	S		
ORDTC available for deduction (total of amounts O, P and S)			4,875	▶	4,875	T
Deduct:						
ORDTC claimed * (Enter amount U on line 416 of Schedule 5, *Tax Calculation Supplementary – Corporations*)			4,875	U		
ORDTC carried back to a previous tax year (from Part 4)				V		
Subtotal (amount U **plus** amount V)			4,875	▶	4,875	W
ORDTC balance at the end of the tax year (amount T **minus** amount W)				**325**		X

* This amount cannot be more than the lesser of the following amounts:
- ORDTC available for deduction (amount T); or
- Ontario corporate income tax payable before the ORDTC and the Ontario corporate minimum tax credit (amount from line E6 of Schedule 5).

Part 4 – Request for carryback of tax credit

	Year Month Day			
1st previous tax year	2010-12-31	Credit to be applied	**901**	
2nd previous tax year	2009-12-31	Credit to be applied	**902**	
3rd previous tax year	2008-12-31	Credit to be applied	**903**	
		Total (enter amount on line V in Part 3)		

Part 5 – Analysis of tax credit available for carryforward by tax year of origin

You can complete this part to show all the credits from preceding tax years available for carryforward, by year of origin. This will help you determine the amount of credit that could expire in following years.

Tax year of origin (earliest tax year first) Year Month Day	Credit available		Tax year of origin (earliest tax year first) Year Month Day	Credit available
1992-09-30			2001-12-31	
1993-09-30			2002-12-31	
1994-09-30			2003-12-31	
1995-09-30			2004-12-31	
1996-09-30			2005-12-31	
1997-09-30			2006-12-31	
1998-09-30			2007-12-31	
1999-09-30			2008-12-31	
2000-09-30			2009-12-31	
2001-09-30			2010-12-31	
		Current tax year	2011-12-31	

Total (equals line 325 in Part 3) ____________

The amount available from the 20th preceding tax year will expire after this year. When you file your return for the next year, you will enter the expired amount on line 300 of Schedule 508 for that year.

Part 6 – Calculation of a recapture of ORDTC

You will have a recapture of ORDTC in a tax year when you meet **all** of the following conditions:

- you acquired a particular property in the current year or in any of the 20 previous tax years if the ORDTC was earned in a tax year ending after 2008;
- you claimed the cost of the property as an eligible expenditure for the ORDTC;
- the cost of the property was included in computing your ORDTC or was subject to an agreement made under subsection 127(13) of the federal Act to transfer qualified expenditures and section 42 of the *Taxation Act, 2007* (Ontario) applied; and
- you disposed of the property or converted it to commercial use in a tax year ending after December 31, 2008. You also meet this condition if you disposed of or converted to commercial use a property which incorporates the particular property previously referred to.

Note: The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED in Ontario. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical federal investment tax credit (ITC) rate * of the original user in Calculation 1 below.

You have to report the recapture on Schedule 5 for the year in which you disposed of the property or converted it to commercial use. If the corporation is a member of a partnership, report its share of the recapture.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

* Federal ITC in calculations 1 and 2 should be determined without reference to paragraph (e) of the definition **investment tax credit** in subsection 127(9) of the federal Act.

Calculation 1 – If you meet all of the above conditions

	Y	Z	AA
	Amount of federal ITC you originally calculated for the property you acquired, or the original user's federal ITC where you acquired the property from a non-arm's length party, as described in the note above	Amount calculated using the federal ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case)	Amount from column 700 or 710, whichever is less
	700	710	
1.			

Subtotal (enter amount BB, on line KK in Part 7) ____________ BB

Calculation 2 – If the corporation is deemed by subsection 42(1) of the *Taxation Act, 2007* (Ontario) to have transferred all or part of the eligible expenditure to another corporation as a consequence of an agreement described in subsection 127(13) of the federal Act complete Calculation 2. Otherwise, enter nil on line II.

	CC The rate percentage that the transferee used to determine its federal ITC for a qualified expenditure that was transferred under an agreement under subsection 127(13) of the federal Act 720	DD The proceeds of disposition of the property if you dispose of it to a person at arm's length; or, in any other case, the fair market value of the property at conversion or disposition 730	EE The amount, if any, already provided for in Calculation 1 (this allows for the situation where only part of the cost of a property is transferred for an agreement under subsection 127(13) of the federal Act) 740
1.			

	FF Amount determined by the formula (CC x DD) – EE (using the columns above)	GG The federal ITC earned by the transferee for the qualified expenditure that was transferred 750	HH Amount from column FF or GG, whichever is less
1.			

Subtotal (enter amount II on line LL below) ______ II

Calculation 3

As a member of a partnership, you will report your share of the ORDTC of the partnership after the ORDTC has been reduced by the amount of the recapture. If this is a positive amount, you will report it on line 205 in Part 2. However, if the partnership does not have enough ORDTC otherwise available to offset the recapture, then the amount by which reductions to the ORDTC exceeds additions (the excess) will be determined and reported on line JJ.

Corporate partner's share of the excess of ORDTC (enter amount JJ at line NN below) . . . . **760** ______ JJ

Part 7 – Total recapture of ORDTC

Recaptured federal ITC for Calculation 1 (amount from line BB) . . . . ______ KK

Recaptured federal ITC for Calculation 2 (amount from line II above) . . . . ______ LL

Amount KK **plus** amount LL . . . . ______ x 23.56 % = ______ MM

Add: Corporate partner's share of the excess of ORDTC for Calculation 3 (amount from line JJ above) . . . . ______ NN

Recapture of ORDTC (amount MM **plus** amount NN) (enter amount OO on line 277 of Schedule 5) . . . . ______ OO

Schedule A - Worksheet for eligible expenditures incurred by the corporation in Ontario for the current taxation year

This worksheet allows you to report the amount of eligible expenditures entered on Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim* which represents eligible expenditures as defined in section 127 of the *Income Tax Act* (ITA) with regard to scientific research and experimental development (SR&ED) **carried on in Ontario and attributable to a permanent establishment in Ontario of a corporation.**

Data on the worksheet is calculated based on the amounts on Form T661, but will have to be adjusted according to the rules of Ontario, if applicable, in particular when the corporation has had a permanent establishment in more than one jurisdiction. This data will be used when calculating Schedule 508 and Schedule 566.

Enter the breakdown between current and capital expenditures

		Current Expenditures		Capital Expenditures	
Total expenditures for SR&ED		60,072		24,933	
Add					
• payment of prior years' unpaid expenses (other than salary or wages)	+				
• prescribed proxy amount (Enter "0" if you use the traditional method)	+	26,524			
• expenditures on shared-use equipment			+		
• other additions	+		+		
Subtotal	=	86,596	=	24,933	
Less					
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	−				
• amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier	−				
• prescribed expenditures not allowed by regulations	−		−		
• other deductions	−		−		
• non-arm's length transactions					
− expenditures for non-arm's length SR&ED contracts	−				
− purchases (limited to costs) of goods and services from non-arm's length suppliers	−		−		
Subtotal	=	86,596 I	=	24,933	II
Total eligible expenditures incurred by the corporation in Ontario in the tax year (add amount I and II)			=	111,529	III

Enter amount III on line 100 of Schedule 508.

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SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2011-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
Bluewater Power Distribution Corporation

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent: Ontario

110 Date of incorporation or amalgamation, whichever is the most recent — Year Month Day: 2000-10-20

120 Ontario Corporation No.: 1446363

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number: 855
220 Street name/Rural route/Lot and Concession number: Confederation Street
230 Suite number:

240 Additional address information if applicable (line 220 must be completed first): PO Box 2140

250 Municipality (e.g., city, town): Sarnia
260 Province/state: ON
270 Country: CA
280 Postal/zip code: N7T 7L6

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 1 If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 McMichael (Last name) **451** Janice (First name)

454 (Middle name(s))

460 1 Please enter one of the following numbers in this box for the above-named person: 1 for director, 2 for officer, or 3 for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter 1 or 2.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 [ ] Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)		
520 Street number	**530** Street name/Rural route/Lot and Concession number	**540** Suite number
550 Additional address information if applicable (line 530 must be completed first)		

560 Municipality (e.g., city, town)	**570** Province/state	**580** Country	**590** Postal/zip code

Part 6 – Language of preference

600 [ ] Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

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SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2011-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information: Janice McMichael

120 Telephone number including area code: (519) 337-8201

Is the claim filed for a CETC earned through a partnership?* . . . . . **150** 1 Yes [ ] 2 No X

If you answered **yes** to the question at line 150, what is the name of the partnership? **160**

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . **170** %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes X 2 No
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . **210** 1 Yes 2 No X

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * **300** 1,000,000

For eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \quad \text{minus} \quad \$ \quad 400{,}000}{\$ \quad 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \quad \text{minus} \quad \$ \quad 400{,}000}{\$ \quad 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

	A Name of university, college, or other eligible educational institution **400**	B Name of qualifying co-operative education program **405**
1.	Cambrian College	Powerline Technician
2.	Lambton College	Office Administration

	C Name of student **410**	D Start date of WP (see note 1 below) **430**	E End date of WP (see note 2 below) **435**
1.	Ben Arsenault	2011-09-06	2011-12-23
2.	Eriva Wilson	2011-01-11	2011-04-22

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
1.		10.000 %	11,715	25.000 %		15
2.		10.000 %	2,937	25.000 %		14

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
1.	2,929	3,000	2,929		2,929
2.	734	3,000	734		734

Ontario co-operative education tax credit (total of amounts in column K) 500 3,663 L

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ________ x percentage on line 170 in Part 1 ______ % = ... M

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received. Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

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SCHEDULE 552

ONTARIO APPRENTICESHIP TRAINING TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2011-12-31

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. Before March 27, 2009, the maximum credit for each apprentice is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship. After March 26, 2009, the maximum credit for each apprentice is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. The maximum credit amount is prorated for an employment period of an apprentice that straddles March 26, 2009.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if incurred before March 27, 2009; and
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if incurred after March 26, 2009.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario); and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009* or the *Apprenticeship and Certification Act, 1998* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Make sure you keep a copy of the training agreement or contract of apprenticeship to support your claim. Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*.
- File this schedule with your *T2 Corporation Income Tax Return*.

Part 1 – Corporate information (please print)

110 Name of person to contact for more information: Janice McMichael

120 Telephone number including area code: (519) 337-8201

Is the claim filed for an ATTC earned through a partnership? * . . . . . **150** 1 Yes [ ] 2 No [X]

If yes to the question at line 150, what is the name of the partnership? **160**

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . . **170** %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year* **300** 1,000,000

For eligible expenditures incurred before March 27, 2009:
- If line 300 is $400,000 or less, enter 30% on line 310.
- If line 300 is $600,000 or more, enter 25% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Specified percentage} = 30\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \quad \text{minus} \quad 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . . **310** 25.000 %

For eligible expenditures incurred after March 26, 2009:
- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\,\% - \left[10\,\% \times \left(\frac{\text{amount on line 300} \quad \text{minus} \quad 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . . **312** 35.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice that is in a qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

	A Trade code **400**	B Apprenticeship program/ trade name **405**	C Name of apprentice **410**
1.	434a	Powerline Technician	Brad Hull
2.	434a	Powerline Technician	Andrew Miller
3.	434a	Powerline Technician	William Thurston
4.	434a	Powerline Technician	Mike Lepelaars
5.	434a	Powerline Technician	Dan Veenema

	D Original contract or training agreement number **420**	E Original registration date of apprenticeship contract or training agreement (see note 1 below) **425**	F Start date of employment as an apprentice in the tax year (see note 2 below) **430**	G End date of employment as an apprentice in the tax year (see note 3 below) **435**
1.	PA6227	2008-08-05	2011-01-01	2011-12-31
2.	PA6222	2008-08-05	2011-01-01	2011-12-31
3.	PA4110	2009-09-28	2011-01-01	2011-12-31
4.	PC7609	2010-09-04	2011-01-01	2011-12-31
5.	PC7713	2010-12-18	2011-01-01	2011-12-31

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

Part 4 – Calculation of the Ontario apprenticeship training tax credit (continued)

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	H2 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	H3 Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	I Maximum credit amount for the tax year (see note 2 below) 445
1.		365	365	10,000
2.		365	365	10,000
3.		365	365	10,000
4.		365	365	10,000
5.		365	365	10,000

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
1.		72,987	72,987	25,545
2.		72,987	72,987	25,545
3.		57,845	57,845	20,246
4.		53,040	53,040	18,564
5.		53,040	53,040	18,564

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
1.	10,000		10,000
2.	10,000		10,000
3.	10,000		10,000
4.	10,000		10,000
5.	10,000		10,000

Ontario apprenticeship training tax credit (total of amounts in column N) 500 50,000 O or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O ________ x percentage on line 170 in Part 1 ________ % = ... ________ P

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, add the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.

For H1: The days employed as an apprentice must be within 36 months of the registration date provided in column E.

For H2: The days employed as an apprentice must be within 48 months of the registration date provided in column E.

Note 2: Maximum credit = ($5,000 x H1/365*) + ($10,000 x H2/365*)
* 366 days, if the tax year includes February 29

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

For J1: Eligible expenditures before March 27, 2009, must be for services provided by the apprentice during the first 36 months of the apprenticeship program.

For J2: Eligible expenditures after March 26, 2009, must be for services provided by the apprentice during the first 48 months of the apprenticeship program.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 x line 310) + (J2 x line 312)

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year.
Complete a **separate entry** for each repayment of government assistance.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 568

ONTARIO BUSINESS-RESEARCH INSTITUTE TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2011-12-31

- Use this schedule to claim the Ontario business-research institute tax credit (OBRITC) under section 97 of the *Taxation Act, 2007* (Ontario).
- The OBRITC is a 20% refundable tax credit based on qualified expenditures incurred in Ontario under an eligible contract with an eligible research institute (ERI).
- A list of eligible research institutes and the applicable ERI codes for eligible contracts can be found on our website. Go to **www.cra.gc.ca/ctao** and select "business-research institute tax credit".
- The criteria for a corporation to be eligible for the OBRITC include the eligibility requirements in Part 1 of this schedule.
- The annual qualified expenditure limit is $20 million. If a corporation is associated with other corporations at any time in the calendar year, the $20 million limit must be allocated among the associated corporations.
- Qualifying corporations are defined in subsection 97(3) of the *Taxation Act, 2007* (Ontario).
- For each eligible contract, you must complete a separate Schedule 569, *Ontario Business-Research Institute Tax Credit Contract Information.*
- Keep the eligible contract to support your claim. Do not submit the contract with the *T2 Corporation Income Tax Return.*
- To claim the OBRITC, include the following with the *T2 Corporation Income Tax Return*:
  – a completed copy of this schedule; and
  – a completed copy of Schedule 569 for each eligible contract.

Part 1 – Eligibility

1. Did the corporation, for the tax year, carry on business in Ontario through a permanent establishment in Ontario? . . . . **100** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax for the tax year under Part III of the *Taxation Act, 2007* (Ontario)? . . . . **105** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, the corporation is **not eligible** for the OBRITC.

Part 2 – Qualified expenditure limit for the tax year

Was the corporation associated at any time in the tax year with another corporation? . . . . **200** 1 Yes [X] 2 No [ ]

If the corporation answered **no** at line 200, enter $20,000,000 on line 205. If the corporation answered **yes** at line 200, complete Part 3 and enter on line 205 the expenditure limit allocated to the corporation in column 310 in Part 3.

Qualified expenditure limit . . . . **205** 20,000,000 A

If the tax year is 51 weeks or more, enter amount A on line 210.

If the tax year of the filing corporation is less than 51 weeks, complete the following proration calculation:

Amount A 20,000,000 x (days in the tax year 365 / 365) = ... ______ B

Qualified expenditure limit for the tax year (amount A or amount B, whichever applies) . . . . **210** 20,000,000 C

Part 3 – Allocation of the $20 million expenditure limit between associated corporations

Use this part to allocate the $20 million expenditure limit to the filing corporation and all its associated corporations for each of their tax years ending in the calendar year. See subsection 38(4) of Ontario Regulation 37/09 for expenditure limit allocation rules for associated corporations. Attach additional schedules if you need more space.

	Name of all associated corporations, including the filing corporation (include the associated corporations that have a tax year that ends in the calendar year) 300	Business Number (enter "NR" if corporation is not registered) 305	Expenditure limit allocated 310
1.	Bluewater Power Distribution Corporation	86572 7390 RC0001	20,000,000
2.	Sarnia Power Corporation	89252 3812 RC0001	
3.	Bluewater Power Corporation	89247 0410 RC0001	
4.	Bluewater Power Services Corporation	89255 8214 RC0001	
5.	Bluewater Power Renewable Energy Inc	85839 3556 RC0001	
6.	Electek Power Services Inc.	86220 1712 RC0002	
7.	Bluewater Power Generation Corporation	85884 6215 RC0001	
	Total expenditure limit (cannot exceed $20 million) 315		20,000,000 D

Enter the expenditure limit allocated to the corporation on line 205 in Part 2.

Part 4 – Calculation of the Ontario business-research institute tax credit

Total number of eligible contracts used to determine the OBRITC for this tax year . . . 400 1

Total qualified expenditures for all eligible contracts identified on line 400 for this tax year (total of amounts on line 310 in Part 3 of each **Schedule 569**) . . . 405 16,000 E

Qualified expenditure limit for the tax year (amount C in Part 2) . . . 20,000,000 F

Qualified expenditures for the OBRITC for the tax year (amount E or F, whichever is less) . . . 410 16,000

Ontario business-research Institute tax credit (line 410 x 20 %) . . . 3,200 G

Enter amount G on line 470 of Schedule 5, *Tax Calculation Supplementary – Corporations.*

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 569

ONTARIO BUSINESS-RESEARCH INSTITUTE TAX CREDIT CONTRACT INFORMATION

Name of corporation	Business Number	Tax year-end Year Month Day
Bluewater Power Distribution Corporation	86572 7390 RC0001	2011-12-31

- Use this schedule to support your claim for the Ontario business-research institute tax credit (OBRITC), which is made on Schedule 568, *Ontario Business-Research Institute Tax Credit*. Complete a separate Schedule 569 for each eligible contract.
- The OBRITC is a 20% refundable tax credit based on qualified expenditures incurred in Ontario under an eligible contract with an eligible research institute (ERI). An ERI, for purposes of the OBRITC, is defined in subsection 97(27) of the *Taxation Act, 2007* (Ontario).
- A list of eligible research institutes and the applicable ERI codes for eligible contracts can be found on our web site. Go to **www.cra.gc.ca/ctao** and select "business-research institute tax credit".
- The eligibility requirements in Part 2 of this schedule must be met for the qualifying corporation to claim an OBRITC for this contract.
- Eligible contracts entered into before August 10, 2007 were subject to advanced ruling legislation. OBRITC claims relating to one of these contracts must have the corresponding Ontario Ministry of Revenue ruling reference number entered at line 130 in Part 1 of this schedule.
- Corporations can only claim the OBRITC for the number of days in the tax year that the corporation **was not** connected to the ERI. Connected corporations, for the purposes of the OBRITC, are defined in subsection 97(4) of the *Taxation Act*, 2007 (Ontario).
- Eligible contracts and qualified expenditures are defined in subsections 97(6) and 97(8), respectively, of the *Taxation Act, 2007* (Ontario).
- According to subsections 97(16) and (19) of the *Taxation Act, 2007* (Ontario), qualified expenditures must be reduced by contributions the corporation received, is entitled to receive or may reasonably expect to receive. Qualified expenditures include repayment of government assistance made by the corporation during the year. Contribution and government assistance are defined in subsection 97(27) of the *Taxation Act, 2007* (Ontario).

Part 1 – Contract details

100 Name of person to contact for more information: Tim Vanderheide

105 Telephone number including area code: (519) 337-8201

110 Name of the ERI on the contract: University of Western Ontario

115 ERI code: 118

120 Date of contract (Year Month Day): 2009-03-09

If the date on line 120 is before August 10, 2007, was the contract subject to an advanced ruling? . . . **125** 1 Yes [ ] 2 No [ ]

For all contracts entered into before August 10, 2007, enter the Ontario Ministry of Revenue ruling reference number . . . **130** [ ] – [ ]

Is the claim filed for an OBRITC earned through a partnership?* . . . **135** 1 Yes [ ] 2 No [X]

If the answer on line 135 is **yes**, are you a specified member? . . . **140** 1 Yes [ ] 2 No [ ]

If the answer on line 135 is **yes**, what is the name of the partnership? . . . **145**

Enter the corporation's percentage share of the income or loss of the partnership's fiscal period ending in the corporation's tax year . . . **150** 100.000 %

* When a corporate member of a partnership is claiming an amount for qualified expenditures incurred during the tax year under the eligible contract by the partnership, complete Schedule 569 as if the partnership were a corporation. Each corporate member, other than a specified member, should file a Schedule 569 as if it, instead of the partnership, had entered into the contract with the ERI and can claim the corporation's share of the partnership's qualified expenditures. Specified members of a partnership cannot claim an OBRITC. A definition of "specified member" can be found in subsection 248(1) of the federal *Income Tax Act*.

Part 2 – Eligibility

Contract:

1. Did the corporation enter into a contract with an ERI? . . . **200** 1 Yes [X] 2 No [ ]
2. Do the terms of the contract state that the ERI agrees to perform, in Ontario, scientific research and experimental development (SR&ED) related to the business carried on in Canada by the corporation? . . . **205** 1 Yes [X] 2 No [ ]
3. Was the corporation entitled to exploit the results of the SR&ED carried out under the contract? . . . **210** 1 Yes [X] 2 No [ ]

If you answered **no** to question 1, 2, or 3, the contract is **not** an **eligible** contract for the purposes of an OBRITC.

Expenditures:

4. Were the expenditures made by a payment of money by the corporation to the ERI or by a prescribed payment? . . . **215** 1 Yes [X] 2 No [ ]
5. Were the expenditures incurred in respect of SR&ED carried on in Ontario by the ERI? . . . **220** 1 Yes [X] 2 No [ ]
6. Are the expenditures identified in subparagraph 37(1)(a)(i), (i.1) or (ii) of the federal *Income Tax Act* and would they also qualify as qualified expenditures, as defined in subsection 127(9) of the federal Act, other than prescribed types of expenditures and certain salaries or wages? . . . **225** 1 Yes [X] 2 No [ ]
7. Were the expenditures incurred by the corporation for purposes of SR&ED related to the business carried on in Canada by the corporation? . . . **230** 1 Yes [X] 2 No [ ]

If you answered **no** to question 4, 5, 6, or 7, the expenditures are **not eligible** expenditures for the purposes of an OBRITC.

Part 3 – Qualified expenditures for this contract for the tax year

Qualified expenditures incurred in the tax year . . . **300** 16,000

If the corporation answered **yes** at line 135 in Part 1, and **no** at line 140 in Part 1, determine the partnerships' share of qualified expenditures available to claim in the tax year:

Line 300 16,000 × percentage on line 150 in Part 1 100.000 % = ______ A

Number of days in this tax year that the corporation was **not** connected to the ERI identified on line 110 in Part 1 . . . **305** 365

Qualified expenditures for this contract for the tax year:

(Line 300 or amount A, whichever applies) x line 305 / number of days in the tax year = 5,840,000 / 365 = . . . **310** 16,000 B

Enter amount B on line 405 of **Schedule 568**, *Ontario Business-Research Institute Tax Credit*.

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2012-12-31

Business number 86572 7390 RC0001

The following is a list of federal instalments payable for the current taxation year. The last column indicates the instalments payable to Revenue Canada. The instalments are due no later than on the dates indicated, otherwise non-deductible interest will be charged. A cheque or money order should be made payable to the Receiver General. Payment may be made by cheque or money order payable to the Receiver General either to an authorized financial institution or filed with **the appropriate remittance voucher to the following address:**

Canada Revenue Agency
875 Heron Road
Ottawa ON K1A 1B1

Note that you may also be able to pay by telephone or Internet banking. For more information, consult the *Corporation Instalment Guide.*

Monthly instalment workchart

Date	Monthly tax instalments	Instalments paid	Cumulative difference	Instalments payable
2012-01-31	75,448			75,448
2012-02-29	75,448			75,448
2012-03-31	30,240			30,240
2012-04-30	30,240			30,240
2012-05-31	30,240			30,240
2012-06-30	30,240			30,240
2012-07-31	30,240			30,240
2012-08-31	30,240			30,240
2012-09-30	30,240			30,240
2012-10-31	30,240			30,240
2012-11-30	30,240			30,240
2012-12-31	30,233			30,233
2013-01-31				37,775
2013-02-28				37,775
Total	453,289			528,839

Ontario

Ministry of Revenue
Hydro PIL
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Remittance Advice - Payment-in-Lieu (PIL)

Electricity Act, 1998
Corporations Tax Act, R.S.O. 1990

Account No.
1800052

35
PX5003

BLUEWATER POWER DISTRIBUTION CORPORATION
C/O JANICE MCMICHAEL-DENNIS
855 CONFEDERATION ST
P O BOX 2140
SARNIA ON
N7T 7L6

10 HPL

Taxation Year End: (YYYYMMDD) ________

Payment Amount: $ ___,___,___.__

Taxation Year End: (YYYYMMDD) 2 0 0 9 1 2 3 1

Payment Amount: $ ___,___,___.__

Total Payment Enclosed: $ ___,___,___.__

Ontario

Ministry of Revenue
Hydro PIL
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Keep this portion for your records.

Notice of Assessment

Electricity Act, 1998 • Corporations Tax Act, R.S.O. 1990
from 2009/01/01 **to** 2009/12/31

	Account No.	Assessment Date (year, month, day)	Page
BLUEWATER POWER DISTRIBUTION CORPORATION	1800052	2010/09/30	1 of 1

ASSESSMENT NO. 278

Tax: Federal and Provincial PIL		1,404,305.00
Assessment Interest		327.33CR
Total Assessment Liability		1,403,977.67

SUMMARY OF 2009/12/31 TAXATION YEAR TRANSACTIONS

Payments/Transfers	1,458,589.00CR	
Sub-Total		1,458,589.00CR
CREDIT BALANCE AVAILABLE IN THIS TAXATION YEAR		54,611.33CR

direct deposited to our bank a/c in Oct 2010

In accordance with s.s.80(8) of the Corporations Tax Act, as made applicable by s.95 of the Electricity Act, 1998, notice is hereby given of the amount of tax, penalty and interest for which you are assessed.

Adjustment to the computation of Total Tax payable.

Adjustment to the computation of Capital Tax.

Mathematical error in the computation of Net CMT payable.

As filed:

775,561 Fed
550,626 Ont
1,326,187 Income Tax
93,145 Capital Tax
1,419,332

Ontario

Ministry of Revenue
33 King St W
PO Box 622
Oshawa ON L1H 8H6

HPL - tL059

0000147

BLUEWATER POWER DISTRIBUTION CORPORATION
ATTENTION: C/O JANICE MCMICHAEL-DENNIS
855 CONFEDERATION ST
P O BOX 2140
SARNIA ON N7T 7L6

Issue Date	22-Sep-2011
Identification No.	1800052
Reference No.	L1435516288

Notice of Assessment - Hydro Payment in Lieu

Electricity Act, 1998, Corporations Tax Act

Your account has been assessed resulting in a balance as indicated below.

Period Ending: 31-Dec-2010	**Return As Filed**
Total Federal Tax	$520,881.00
Total Ontario Tax	$418,407.00
Total Credits	($44,023.00)
Loss Carry-back	$0.00
Total Tax Payable	$895,265.00
Interest	$0.00
Current Penalty	$0.00
Credits/Payments	($895,265.00)
Total Assessment	**$0.00**

As of 22-Sep-2011, including the amount assessed above, you have an overall credit balance on your account of ($547,286.00).

If you have any questions concerning this Notice of Assessment, please call the number listed below. After discussion with a ministry representative, if you still do not agree with this assessment you have the right to file a Notice of Objection with the Tax Appeals Branch within 180 days of the issue date of this form. Any taxes, interest and penalties that are outstanding as a result of the assessment are due and payable even if you have filed, or intend to file, a Notice of Objection.

If you have any questions or require additional information, please visit our website or call the Ministry of Revenue at the number listed below.

Ministry use only

Ontario
Ministry of Revenue
33 King St W
PO Box 622
Oshawa ON L1H 8H6

Issue Date	18-Jan-2012
Identification No.	1800052
Reference No.	L0164170624

HPL - tL060

0000002

BLUEWATER POWER DISTRIBUTION CORPORATION
ATTENTION: C/O JANICE MCMICHAEL-DENNIS
855 CONFEDERATION ST
PO BOX 2140 MAIN
SARNIA ON N7T 7L6

Notice of Re-Assessment - Hydro Payment in Lieu

Electricity Act, 1998, Corporations Tax Act

We have received and processed your return for the period ending 31-Dec-2010. Based on the information provided, your return has been corrected as follows:

	Previous	Revised
Total Federal Tax	$520,881.00	$494,360.00
Total Ontario Tax	$418,407.00	$411,014.00
Total Credits	($44,023.00)	($45,223.00)
Loss Carry-back	$0.00	$0.00
Total Tax Payable	$895,265.00	$860,151.00
Interest		$0.00
Current Penalty		$0.00
Credits/Payments		($860,151.00)
Total Assessment		**$0.00**

As of 18-Jan-2012, including the amount assessed above, you have an overall credit balance on your account of ($35,114.00). → 2010 SR+ED claim

If you have any questions concerning this Notice of Re-Assessment, please call the number listed below. After discussion with a ministry representative, if you still do not agree with this re-assessment you have the right to file a Notice of Objection with the Tax Appeals Branch within 180 days of the issue date of this form. Any taxes, interest and penalties that are outstanding as a result of the re-assessment are due and payable even if you have filed, or intend to file, a Notice of Objection.

If you have any questions or require additional information, please visit our website or call the Ministry of Revenue at the number listed below.

Ministry use only

ALLOWANCE FOR PILS

Bluewater Power has prepared its 2013 PILs Model on an MIFRS basis. It is presented in Attachment 1 in Exhibit 4, Tab 8, Schedule 3.

Bluewater Power confirms that all the integrity checks outlined in section 2.7.8.2 of Filing Guidelines have been completed. The information below details the reconciling items.

Additions to Capital Cost Allowance (CCA) Classes

The capital additions for 2012 can be reconciled to OEB Appendix 2-B 'Fixed Asset Continuity Schedule – 2012 CGAAP' plus the corresponding 2012 capital addition amounts from Bluewater Power's smart meter rate model filed under EB-2012-0263. See Table 1 for a breakdown.

Table 1 – Capital Additions to CCA Classes in 2012

CCA Class	Appendix 2-B	Smart Meter	Total
1	2,178,441	-	2,178,441
8	233,429	54,731	288,160
10	1,745,563	-	1,745,563
12	2,290,004	770,255	3,060,259
47	3,925,834	-	3,925,834
	10,373,271	824,986	11,198,257

The capital additions for 2013 can be reconciled to OEB Appendix 2-B 'Fixed Asset Continuity Schedule – 2013 MIFRS'. See Table 2 for a breakdown.

Table 2 – Capital Additions to CCA Classes in 2013

CCA Class	Appendix 2-B
1	212,500
8	102,000
10	1,415,340
12	993,685
47	3,275,545
	5,999,070
CEC	257,200
	6,256,270

Disposals from CCA Classes

The disposal amount of $1,926,645 for 2012 can be confirmed on OEB Appendix 2-S ‘Stranded Meter Treatment’. This is the amount Bluewater Power is submitting for recovery from customers and is more fully explained in Exhibit 9, Tab 1, Schedule 3. There are no disposals included in the 2013 year.

Additions to Cumulative Eligible Capital (CEC)

There are no additions in 2012. There is an addition in 2013 for $257,200 which relates to land rights. This has been explained as Capital Project O6 in Attachment 3 in Exhibit 2, Tab 4, Schedule 3.

Taxable Income – 2013 Test Year – Amortization Addback

The amortization ‘addback’ amount of $2,622,049 for tangible assets plus $2,308,354 for intangible assets total $4,930,403. This can be confirmed in OEB Appendix 2-B ‘Fixed Asset Continuity Schedule – 2013 MIFRS’ at Exhibit 2, Tab 3, Schedule 2 and also in OEB Appendix 2-CH ‘Depreciation and Amortization Expense – 2013 MIFRS’ at Exhibit 4, Tab 7, Schedule 1.

The ‘addback’ amount of $91,220 described as ‘Depreciation Expense Adjustment – Account 1575’, and negative $10,000 described as ‘Depreciation Expense Adjustment – Account 4357’ can be confirmed in OEB Appendix 2-CH ‘Depreciation and Amortization Expense – 2013 MIFRS’ at Exhibit 4, Tab 7, Schedule 1.

In summary, the total depreciation expense that is forecasted for the 2013 test year will be the sum of these four items, being $5,011,623, which is the total shown in OEB Appendix 2-CH ‘Depreciation and Amortization Expense – 2013 MIFRS’. This amount, through these four items explained above, has been added back for purposes of the taxable income calculation in the PILs model.

Taxable Income – 2013 Test Year – Non-Deductible Meals and Entertainment

The ‘addback’ of $45,913 represents the three year average from 2009 to 2011 of the amounts included in Schedule 1 of the PILs returns for those years.

Taxable Income – 2013 Test Year – Employee Future Benefits

The ‘addback’ of $9,702,041 represents the IFRS employee future benefit obligation liability amount at the end of 2013. Similarly, the ‘deduction’ of $9,223,374 is the liability amount at the beginning of 2013. The net difference of $478,667 is a 2013 test year OM&A item which must be added back in the calculation of taxable income. These liability amounts can be confirmed in the actuarial report from Dion Durrell found in Attachment 7 and 8 of Exhibit 4, Tab 4, Schedule 1.

Tax Credits

Bluewater Power does not anticipate having any tax credits in 2013 and therefore no amounts are included in the final PILs calculation.

v 2.0

Income Tax/PILs Workform for 2013 Filers

Utility Name	Bluewater Power Distribution Corp.
Assigned EB Number	EB-2012-0107
Name and Title	Mark Hutson, CFO
Phone Number	519-337-8201 x2261
Email Address	mhutson@bluewaterpower.com
Date	18-Oct-12
Last COS Re-based Year	**2009**

Note: Drop-down lists are shaded blue; Input cells are shaded green.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Income Tax/PILs
Workform for 2013 Filers

Income Tax/PILs Workform for 2013 Filers

Rate Base			**$**	**66,800,816**	
Return on Ratebase					
Deemed ShortTerm Debt %	4.00%	T	$	2,672,033	*W = S * T*
Deemed Long Term Debt %	56.00%	U	$	37,408,457	*X = S * U*
Deemed Equity %	40.00%	V	$	26,720,326	*Y = S * V*
Short Term Interest Rate	2.08%	Z	$	55,578	*AC = W * Z*
Long Term Interest	4.18%	AA	$	1,563,674	*AD = X * AA*
Return on Equity (Regulatory Income)	9.12%	AB	**$**	**2,436,894**	*AE = Y * AB*
Return on Rate Base			**$**	**4,056,146**	*AF = AC + AD + AE*

Questions that must be answered

	Historic	**Bridge**	**Test Year**
1. Does the applicant have any Investment Tax Credits (ITC)?	Yes	No	No
2. Does the applicant have any SRED Expenditures?	Yes	No	No
3. Does the applicant have any Capital Gains or Losses for tax purposes?	No	No	No
4. Does the applicant have any Capital Leases?	No	No	No
5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No	No	No
6. Since 1999, has the applicant acquired another regulated applicant's assets?	No	No	No
7. Did the applicant pay dividends? *If Yes, please describe what was the tax treatment in the manager's summary.*	Yes	Yes	Yes
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	No	No	No

Income Tax/PILs Workform for 2013 Filers

Tax Rates Federal & Provincial As of June 20, 2012	Effective ################	Effective ################	Effective ################	Effective ################
Federal income tax				
General corporate rate	38.00%	38.00%	38.00%	38.00%
Federal tax abatement	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted federal rate	28.00%	28.00%	28.00%	28.00%
Rate reduction	-11.50%	-13.00%	-13.00%	-13.00%
	16.50%	15.00%	15.00%	15.00%
Ontario income tax	11.75%	11.50%	11.50%	11.50%
Combined federal and Ontario	28.25%	26.50%	26.50%	26.50%
Federal & Ontario Small Business				
Federal small business threshold	500,000	500,000	500,000	500,000
Ontario Small Business Threshold	500,000	500,000	500,000	500,000
Federal small business rate	11.00%	11.00%	11.00%	11.00%
Ontario small business rate	4.50%	4.50%	4.50%	4.50%

Income Tax/PILs Workform for 2013 Filers

Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historic per tax returns	Less: Non-Distribution Portion	UCC Regulated Historic Year
1	Distribution System - post 1987	16,685,933		16,685,933
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election			0
2	Distribution System - pre 1988	9,875,580		9,875,580
8	General Office/Stores Equip	4,873,105		4,873,105
10	Computer Hardware/ Vehicles	1,196,988		1,196,988
10.1	Certain Automobiles			0
12	Computer Software	1,847,255		1,847,255
13_1	Lease # 1			0
13_2	Lease #2			0
13_3	Lease # 3			0
13_4	Lease # 4			0
14	Franchise			0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	39,211		39,211
42	Fibre Optic Cable			0
43.1	Certain Energy-Efficient Electrical Generating Equipment			0
43.2	Certain Clean Energy Generation Equipment			0
45	Computers & Systems Software acq'd post Mar 22/04	14,282		14,282
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	283,351		283,351
47	Distribution System - post February 2005	11,154,621		11,154,621
50	Data Network Infrastructure Equipment - post Mar 2007	351,512		351,512
52	Computer Hardware and system software			0
95	CWIP	1,279,609		1,279,609
				0
				0
				0
				0
				0
				0
				0
				0
				0
				0
	SUB-TOTAL - UCC	47,601,447	0	47,601,447

Income Tax/PILs Workform for 2013 Filers

Schedule 10 CEC - Historical Year

Cumulative Eligible Capital				**1,509,140**
Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	x 1/2 =	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**1,509,140**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**1,509,140**
Current Year Deduction		**1,509,140**	**x 7% =**	**105,640**
Cumulative Eligible Capital - Closing Balance				**1,403,500**

Income Tax/PILs Workform for 2013 Filers

Schedule 13 Tax Reserves - Historical

Continuity of Reserves

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only
Capital Gains Reserves ss.40(1)	0		0
Tax Reserves Not Deducted for accounting purposes			
Reserve for doubtful accounts ss. 20(1)(l)	0		0
Reserve for goods and services not delivered ss. 20(1)(m)	0		0
Reserve for unpaid amounts ss. 20(1)(n)	0		0
Debt & Share Issue Expenses ss. 20(1)(e)	0		0
Other tax reserves	0		0
			0
			0
			0
			0
			0
Total	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)			
General Reserve for Inventory Obsolescence (non-specific)			0
General reserve for bad debts			0
Accrued Employee Future Benefits:			0
- Medical and Life Insurance			0
-Short & Long-term Disability			0
-Accmulated Sick Leave			0
- Termination Cost			0
- Other Post-Employment Benefits			0
Provision for Environmental Costs			0
Restructuring Costs			0
Accrued Contingent Litigation Costs			0
Accrued Self-Insurance Costs			0
Other Contingent Liabilities			0
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0
Other			0
			0
			0
Total	**0**	**0**	**0**

Income Tax/PILs Workform for 2013 Filers

Schedule 7-1 Loss Carry Forward - Historic

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historic	0		0

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historic	0		0

Income Tax/PILs Workform for 2013 Filers

Adjusted Taxable Income - Historic Year

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	A	2,822,241		2,822,241
Additions:				
Interest and penalties on taxes	103			0
Amortization of tangible assets	104	4,259,217		4,259,217
Amortization of intangible assets	106			0
Recapture of capital cost allowance from Schedule 8	107			0
Gain on sale of eligible capital property from Schedule 10	108			0
Income or loss for tax purposes- joint ventures or partnerships	109			0
Loss in equity of subsidiaries and affiliates	110			0
Loss on disposal of assets	111			0
Charitable donations	112	24,110		24,110
Taxable Capital Gains	113			0
Political Donations	114			0
Deferred and prepaid expenses	116			0
Scientific research expenditures deducted on financial statements	118	60,072		60,072
Capitalized interest	119			0
Non-deductible club dues and fees	120			0
Non-deductible meals and entertainment expense	121	42,018		42,018
Non-deductible automobile expenses	122			0
Non-deductible life insurance premiums	123			0
Non-deductible company pension plans	124			0
Tax reserves deducted in prior year	125			0
Reserves from financial statements- balance at end of year	126			0
Soft costs on construction and renovation of buildings	127			0
Book loss on joint ventures or partnerships	205			0
Capital items expensed	206			0
Debt issue expense	208			0
Development expenses claimed in current year	212			0
Financing fees deducted in books	216			0
Gain on settlement of debt	220			0
Non-deductible advertising	226			0
Non-deductible interest	227			0
Non-deductible legal and accounting fees	228			0
Recapture of SR&ED expenditures	231			0
Share issue expense	235			0
Write down of capital property	236			0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			0
Other Additions				
Interest Expensed on Capital Leases	290			0
Realized Income from Deferred Credit Accounts	291			0
Pensions	292			0
Non-deductible penalties	293			0
SR&ED inducements	294	3,135		3,135
	295			0
ARO Accretion expense				0
Capital Contributions Received (ITA 12(1)(x))				0
Lease Inducements Received (ITA 12(1)(x))				0
Deferred Revenue (ITA 12(1)(a))				0
Prior Year Investment Tax Credits received				0
				0
Employee future benefits - end of year		7,507,737		7,507,737
Smart meter recovery		654,199		654,199
ITC for apprentice credit		10,000		10,000
Capital taxes expensed		747		747
Ontario Specified Tax Credits		41,283		41,283
Carrying Charges Recovered over expensed		1,696,158		1,696,158
Payment of Lawsuit (2010 deduction)		149,122		149,122
				0
				0
Total Additions		**14,447,798**	**0**	**14,447,798**

Deductions:				
Gain on disposal of assets per financial statements	401	23,293		23,293
Dividends not taxable under section 83	402			0
Capital cost allowance from Schedule 8	403	7,288,780		7,288,780
Terminal loss from Schedule 8	404			0
Cumulative eligible capital deduction from Schedule 10	405	105,640		105,640
Allowable business investment loss	406			0
Deferred and prepaid expenses	409			0
Scientific research expenses claimed in year	411	53,957		53,957
Tax reserves claimed in current year	413			0
Reserves from financial statements - balance at beginning of year	414			0
Contributions to deferred income plans	416			0
Book income of joint venture or partnership	305			0
Equity in income from subsidiary or affiliates	306			0
Other deductions: (Please explain in detail the nature of the item)				
Interest capitalized for accounting deducted for tax	390			0
Capital Lease Payments	391			0
Non-taxable imputed interest income on deferral and variance accounts	392			0
	393			0
	394			0
ARO Payments - Deductible for Tax when Paid				0
ITA 13(7.4) Election - Capital Contributions Received				0
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds				0
Deferred Revenue - ITA 20(1)(m) reserve				0
Principal portion of lease payments				0
Lease Inducement Book Amortization credit to income				0
Financing fees for tax ITA 20(1)(e) and (e.1)				0
				0
Employee future benefits - beginning of year		7,079,641		7,079,641
Capitalized for accounting expensed for tax		512,630		512,630
Smart meter O&M expense		255,211		255,211
2011 Apprentice Tax Credits		64,000		64,000
				0
				0
Total Deductions		**15,383,152**	**0**	**15,383,152**
Net Income for Tax Purposes		**1,886,887**	**0**	**1,886,887**
Charitable donations from Schedule 2	311	24,110		24,110
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320			0
Non-capital losses of preceding taxation years from Schedule 4	331			0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332			0
Limited partnership losses of preceding taxation years from Schedule 4	335			0
TAXABLE INCOME		**1,862,777**	**0**	**1,862,777**

PILs Tax Provision - Historic Year

Note: Input the actual information from the tax returns for the historic year.

						Wires Only	
Regulatory Taxable Income						$ 1,862,777	**A**
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	11.75%	**B**	$ 218,838	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ 500,000	**D**				
	Rate reduction (negative)	-7.25%	**E**	-$ 36,240	**F = D * E**		
Ontario Income tax						$ 182,598	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			9.80%	**K = J / A**		
	Federal tax rate			16.50%	**L**		
	Combined tax rate					26.30%	**M = K + L**
Total Income Taxes						**$ 489,956**	**N = A * M**
Investment Tax Credits							**O**
Miscellaneous Tax Credits						$ 93,530	**P**
Total Tax Credits						**$ 93,530**	**Q = O + P**
Corporate PILs/Income Tax Provision for Historic Year						**$ 396,426**	**R = N - Q**

Schedule 8 CCA - Bridge Year

Class	Class Description	UCC Regulated Historic Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Bridge Year CCA	UCC End of Bridge Year
1	Distribution System - post 1987	$ 16,685,933	$ 2,178,441		$ 18,864,374	$ 1,089,221	$ 17,775,154	4%	$ 711,006	$ 18,153,368
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election				$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 9,875,580			$ 9,875,580	$ -	$ 9,875,580	6%	$ 592,535	$ 9,283,045
8	General Office/Stores Equip	$ 4,873,105	$ 288,160		$ 5,161,265	$ 144,080	$ 5,017,185	20%	$ 1,003,437	$ 4,157,828
10	Computer Hardware/ Vehicles	$ 1,196,988	$ 1,745,563		$ 2,942,551	$ 872,782	$ 2,069,770	30%	$ 620,931	$ 2,321,620
10.1	Certain Automobiles				$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 1,847,255	$ 3,060,259		$ 4,907,514	$ 1,530,130	$ 3,377,385	100%	$ 3,377,385	$ 1,530,130
13 1	Lease # 1				$ -	$ -	$ -		$ -	$ -
13 2	Lease #2				$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3				$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4				$ -	$ -	$ -		$ -	$ -
14	Franchise				$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 39,211			$ 39,211	$ -	$ 39,211	8%	$ 3,137	$ 36,074
42	Fibre Optic Cable				$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment				$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment				$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 14,282			$ 14,282	$ -	$ 14,282	45%	$ 6,427	$ 7,855
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 283,351			$ 283,351	$ -	$ 283,351	30%	$ 85,005	$ 198,346
47	Distribution System - post February 2005	$ 11,154,621	$ 3,925,834	-$ 1,926,645	$ 13,153,810	$ 999,595	$ 12,154,216	8%	$ 972,337	$ 12,181,473
50	Data Network Infrastructure Equipment - post Mar 2007	$ 351,512			$ 351,512	$ -	$ 351,512	55%	$ 193,332	$ 158,180
52	Computer Hardware and system software				$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ 1,279,609			$ 1,279,609	$ -	$ 1,279,609		$ -	$ 1,279,609
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
	TOTAL	$ 47,601,447	$ 11,198,257	-$ 1,926,645	$ 56,873,059	$ 4,635,806	$ 52,237,253		$ 7,565,531	$ 49,307,528

Income Tax/PILs Workform for 2013 Filers

Schedule 10 CEC - Bridge Year

Cumulative Eligible Capital				**1,403,500**
Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**1,403,500**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**1,403,500**
Current Year Deduction		**1,403,500**	**x 7% =**	**98,245**
Cumulative Eligible Capital - Closing Balance				**1,305,255**

Income Tax/PILs Workform for 2013 Filers

Schedule 13 Tax Reserves - Bridge Year

Continuity of Reserves

Description	Historic Utility Only	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Bridge Year Adjustments: Additions	Bridge Year Adjustments: Disposals	Balance for Bridge Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	0		0			0	0	
Accrued Employee Future Benefits:	0		0			0	0	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	0		0			0	0	
Provision for Environmental Costs	0		0			0	0	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Income Tax/PILs Workform for 2013 Filers

Corporation Loss Continuity and Application

Schedule 7-1 Loss Carry Forward - Bridge Year

Non-Capital Loss Carry Forward Deduction	**Total**
Actual Historic	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0

Net Capital Loss Carry Forward Deduction	**Total**
Actual Historic	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0

Income Tax/PILs Workform for 2013 Filers

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Total for Regulated Utility
Income before PILs/Taxes	**A**	2,712,360
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets	104	4,729,669
Amortization of intangible assets	106	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	45,913
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves deducted in prior year	125	0
Reserves from financial statements- balance at end of year	126	0
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	

Income Tax/PILs Workform for 2013 Filers

Adjusted Taxable Income - Bridge Year

Other Additions		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
	295	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		
Employee future benefits - end of year		7,935,832
Smart meter recovery (SMFAs)		411,700
Total Additions		**13,123,114**
Deductions:		
Gain on disposal of assets per financial statements	401	
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	7,565,531
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10	405	98,245
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves claimed in current year	413	0
Reserves from financial statements - balance at beginning of year	414	0
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		

Income Tax/PILs Workform for 2013 Filers

Adjusted Taxable Income - Bridge Year

Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	
Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Employee future benefits - beginning of year		7,507,737
Total Deductions		**15,171,513**
Net Income for Tax Purposes		**663,961**
Charitable donations from Schedule 2	311	
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	
Non-capital losses of preceding taxation years from Schedule 4	331	
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
TAXABLE INCOME		**663,961**

PILS Tax Provision - Bridge Year

							Wires Only	
Regulatory Taxable Income							$ 663,961	**A**
Ontario Income Taxes								
Income tax payable	**Ontario Income Tax**	11.50%	**B**	$	76,355	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ 500,000	**D**					
	Rate reduction	-7.00%	**E**	-$	35,000	**F = D * E**		
Ontario Income tax							$ 41,355	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate				6.23%	**K = J / A**		
	Federal tax rate				15.00%	**L**		
	Combined tax rate						21.23%	**M = K + L**
Total Income Taxes							**$ 140,950**	**N = A * M**
Investment Tax Credits								**O**
Miscellaneous Tax Credits								**P**
Total Tax Credits							**$ -**	**Q = O + P**
Corporate PILs/Income Tax Provision for Bridge Year							**$ 140,950**	**R = N - Q**

Note:

1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.

Income Tax/PILs Workform for 2013 Filers

Schedule 8 CCA - Test Year

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 18,153,368	212,500		$ 18,365,868	$ 106,250	$ 18,259,618	4%	$ 730,385	$ 17,635,483
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 9,283,045			$ 9,283,045	$ -	$ 9,283,045	6%	$ 556,983	$ 8,726,062
8	General Office/Stores Equip	$ 4,157,828	102,000		$ 4,259,828	$ 51,000	$ 4,208,828	20%	$ 841,766	$ 3,418,062
10	Computer Hardware/ Vehicles	$ 2,321,620	1,415,340		$ 3,736,960	$ 707,670	$ 3,029,290	30%	$ 908,787	$ 2,828,173
10.1	Certain Automobiles	$ -			$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 1,530,130	993,685		$ 2,523,815	$ 496,843	$ 2,026,972	100%	$ 2,026,972	$ 496,843
13 1	Lease # 1	$ -			$ -	$ -	$ -		$ -	$ -
13 2	Lease #2	$ -			$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -			$ -	$ -	$ -		$ -	$ -
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bl	$ 36,074			$ 36,074	$ -	$ 36,074	8%	$ 2,886	$ 33,188
42	Fibre Optic Cable	$ -			$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -			$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 7,855			$ 7,855	$ -	$ 7,855	45%	$ 3,535	$ 4,320
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 198,346			$ 198,346	$ -	$ 198,346	30%	$ 59,504	$ 138,842
47	Distribution System - post February 2005	$ 12,181,473	3,275,545		$ 15,457,018	$ 1,637,773	$ 13,819,245	8%	$ 1,105,540	$ 14,351,478
50	Data Network Infrastructure Equipment - post Mar 2007	$ 158,180			$ 158,180	$ -	$ 158,180	55%	$ 86,999	$ 71,181
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ 1,279,609			$ 1,279,609	$ -	$ 1,279,609	0%	$ -	$ 1,279,609
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	$ 49,307,528	$ 5,999,070	$ -	$ 55,306,598	$ 2,999,535	$ 52,307,063		$ 6,323,355	$ 48,983,242

Income Tax/PILs Workform for 2013 Filers

Schedule 10 CEC - Test Year

Cumulative Eligible Capital				**1,305,255**
Additions				
Cost of Eligible Capital Property Acquired during Test Year	257,200			
Other Adjustments	0			
Subtotal	257,200	**x 3/4 =**	192,900	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			192,900	**192,900**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**1,498,155**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year	0			
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**1,498,155**
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")		**1,498,155**	**x 7% =**	**104,871**
Cumulative Eligible Capital - Closing Balance				**1,393,284**

Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

Description	Bridge Year	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Test Year Adjustments: Additions	Test Year Adjustments: Disposals	Balance for Test Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	0		0			0	0	
Accrued Employee Future Benefits:	0		0			0	0	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	0		0			0	0	
Provision for Environmental Costs	0		0			0	0	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Schedule 7-1 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	**Total**	**Non-Distribution Portion**	**Utility Balance**
Actual/Estimated Bridge Year			0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

Net Capital Loss Carry Forward Deduction	**Total**	**Non-Distribution Portion**	**Utility Balance**
Actual/Estimated Bridge Year			0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

Income Tax/PILs Workform for 2013 Filers

Taxable Income - Test Year

	T2 S1 line #	Test Year Taxable Income
Net Income Before Taxes		2,436,894
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	2,622,049
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	2,308,354
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	45,913
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves beginning of year	125	0
Reserves from financial statements- balance at end of year	126	0
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	

Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
	295	
	296	
	297	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		
Employee future benefits - end of year		9,702,041
Depreciation Expense Adjustment - a/c 1575		91,220
Depreciation Expense Adjustment - a/c 4357		-10,000
Total Additions		**14,759,577**
Deductions:		
Gain on disposal of assets per financial statements	401	
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	6,323,355
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10 CEC	405	104,871
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves end of year	413	0
Reserves from financial statements - balance at beginning of year	414	0
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	

Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
	395	
	396	
	397	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Employee future benefits - beginning of year		9,223,374
Total Deductions		**15,651,600**
NET INCOME FOR TAX PURPOSES		**1,544,871**
Charitable donations	311	
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	
Net-capital losses of preceding taxation years (Please show calculation)	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
REGULATORY TAXABLE INCOME		**1,544,871**

Income Tax/PILs
Workform for 2013 Filers

PILs Tax Provision - Test Year

							Wires Only	
Regulatory Taxable Income							$ 1,544,871	**A**
Ontario Income Taxes								
Income tax payable	**Ontario Income Tax**	11.50%	**B**	$	177,660	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ 500,000	**D**					
	Rate reduction	-7.00%	**E**	-$	35,000	**F = D * E**		
Ontario Income tax							$ 142,660	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate				9.23%	**K = J / A**		
	Federal tax rate				15.00%	**L**		
	Combined tax rate						24.23%	**M = K + L**
Total Income Taxes							**$ 374,391**	**N = A * M**
Investment Tax Credits								**O**
Miscellaneous Tax Credits								**P**
Total Tax Credits							**$ -**	**Q = O + P**
Corporate PILs/Income Tax Provision for Test Year							**$ 374,391**	**R = N - Q**
Corporate PILs/Income Tax Provision Gross Up [1]					75.77%	**S = 1 - M**	**$ 119,753**	**T = R / S - R**
Income Tax (grossed-up)							**$ 494,144**	**U = R + T**

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

NON-RECOVERABLE AND DISALLOWED EXPENSES

Charitable donations is the only cost item that Bluewater Power has that is deductible for general tax purposes, but for which recovery in 2013 distribution rates is not allowed. Bluewater Power's 2013 PILs calculations do not have any charitable donation cost amounts included.