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

March 8, 2013

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

Re: Reply to Supplementary Interrogatories EB-2012-0107

Dear Ms. Walli:

Bluewater Power hereby files its responses to the supplemental interrogatories filed by the following parties: Board Staff, VECC, School Energy Coalition, Energy Probe and AMPCO.

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

Yours Truly,

L. Dugas

Leslie Dugas
Manager of Regulatory Affairs
Bluewater Power Distribution Corporation
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Bluewater Power Distribution Corporation

2013 COS Application

Response to Interrogatories

EB-2012-0107

Rates Effective: May 1, 2013

Date Filed: March 8, 2013

Bluewater Power Distribution Corporation

855 Confederation Street

P.O. Box 2140

Sarnia, ON

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BLUEWATER POWER
DISTRIBUTION CORPORATION

File Number:	EB-2012-0107
Date Filed:	March 8, 2013

Tab 1 of 9

Exhibit 1 - Administrative Document

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Reference
T9\S1

1.0 - Staff 58 - Letter of Comment

Ref: 2.1-1-Staff-1

Bluewater Power has not responded directly to the author of the letter of comment filed in this proceeding. It is Bluewater Power's interpretation that the author's concerns with commodity price increases and the debt of the former Ontario Hydro are beyond the control of management of Bluewater Power.

Please confirm that Bluewater Power is of the view that it has no responsibility as an LDC to assist its customers in clarifying or explaining electricity related matters that are beyond the control of Bluewater Power. If confirmed, please provide Bluewater Power's view as to how this approach is consistent with the LDC's customer service objectives.

The assertion made by Board Staff is not confirmed. Bluewater Power routinely plays the role of public educator for an electricity sector that has grown increasingly complicated. In fact, small and mid-sized LDCs like Bluewater Power are the "face" of Ontario's electricity sector to customers and we have developed a relationship of trust.

The author of the letter of comment is a customer with whom Bluewater Power's management is familiar. We accepted her letter of comment at face value as the letter was addressed to the Ontario Energy Board and the letter did not ask for a reply from the utility.

1.0 - Staff 59 - IFRS Date

Ref: 3.2-1-EP-2

In its response to Energy Probe's IR, Bluewater Power indicated that it will be adopting IFRS as of January 1, 2014.

In February 2013, the Accounting Standards Board ("AcSB") decided to extend the existing deferral of the mandatory IFRS changeover date for entities with qualifying rate-regulated activities by an additional year to January 1, 2015.

Please confirm that Bluewater Power will still be adopting IFRS as of January 1, 2014, notwithstanding the recent decision of the AcSB.

Not confirmed for external reporting purposes. In February 2013, Bluewater Power's audit committee decided to remain on CGAAP for external reporting purposes until a mandatory IFRS conversion date is established.

For regulatory accounting purposes, the application was filed on a MIFRS basis in accordance with our understanding of the Filing Guidelines. MIFRS related issues have been addressed throughout this second round of IRs, that have caused Bluewater Power to carefully examine its position with respect to certain MIFRS related items. We can advise as follows:

- Bluewater Power is committed to adopting revised useful lives and ceasing the practice of capitalizing overhead as discussed in 1-Staff-61 and as required by the letter from the Board Secretary dated July 17, 2012.
- As discussed in 1-SEC-40, we have adjusted the Employee Future Benefit to reflect the CGAAP amount in the first round of IRs. It was determined that is the relevant cost to Bluewater Power.

- Upon consideration of the request in 2-EP-35, Bluewater Power would consider foregoing its claim in respect of Account 1575 and place the ending balance for 2012 net book value under CGAAP into Rate Base for rate making purposes. We are not in a position to provide the revised 2013 CGAAP Continuity schedule at this time, but we will provide the information requested as early as possible.

1.0 - Staff 60 - IFRS and Employee Benefit Obligation

Ref: 3.2-1-EP-2

In its response to Energy Probe's IR, Bluewater Power stated that, "The 2013 Test Year will remain on an MIFRS basis, even though the 2013 reporting year will be based on CGAAP."

Bluewater Power also indicated that it has adjusted the employee future benefit expense from $478,667 on an IFRS basis to $577,399 on a CGAAP basis. Board staff noted that the revenue requirement was increased by $98,732, which reflects the increase in employee future benefits.

a) Given that the 2013 test year will "remain on an MIFRS basis" as stated by Bluewater Power, please explain why the employee future benefit expense was adjusted from an IFRS basis to a CGAAP basis.

The statement that Bluewater Power will "remain on an MIFRS basis" refers to all other significant items related to capital assets. This includes overhead capitalization, useful lives for depreciation purposes, contributed capital, etc. Bluewater Power had made a concerted effort to align its CGAAP accounting practices surrounding all items related to capital assets with the MIFRS practices that we will follow for regulatory purposes.

The only significant item that deviates from the intention to "remain on an MIFRS basis" related to the treatment of the employee future benefit expense. The reason is that, while CGAAP is flexible enough for Bluewater Power to adjust depreciation rates and overhead capitalization, it would not permit the utility to follow MIFRS rules for Employee Future Benefits. Accordingly, there is no way to bring regulatory and accounting practices in alignment on this issue.

Accordingly, Bluewater Power seeks to recover through rates the actual Employee Future Benefit expense that it will incur in 2013. Bluewater Power has acknowledged that this treatment deviates from the mandated MIFRS rate making treatment. However, the resulting amount in rates will result in fair rates to both ratepayers and shareholders. Bluewater Power does not intend to “win” by this treatment when (or if) it converts to MIFRS; as discussed in the response to 1-EP-2 (last paragraph), when Bluewater Power converts to IFRS in the future:

“… Bluewater Power will request a deferral account in a later proceeding that will hold customers and the utility whole. The deferral account will not only address the one-time transitional adjustment, but will also address the variance between the annual CGAAP expense amounts embedded in rates and the resulting actual IFRS expense amounts recorded after adoption of IFRS.”

b) Please specify any other areas in the application that are based on CGAAP rather than IFRS. If any, please provide the quantification and the impacts to revenue requirement of the changes.

There are currently no other areas in the application that are based on CGAAP.

1.0 - Staff 61 - Accounting Policy

Ref: 3.2-1-EP-2

In its response to Energy Probe's IR, Bluewater Power stated that although it will be under CGAAP for 2012, Bluewater Power has made the decision to make the following changes under CGAAP effective January 1, 2013:

- Indirect overhead will no longer be capitalized (same as MIFRS)
- The useful lives of capital assets for depreciation purpose will be changed to the same basis as filed in the 2013 Test Year (same as MIFRS)
- The useful lives for the amortization of contributed capital will be changed as the same basis as filed in the 2013 Test year (same as MIFRS)

With respect to each area of PP&E listed below, please identify the accounting policy choices (still under CGAAP, or aligned with IFRS) for 2013 Test Year under MIFRS:

#	Area of PP&E policy in 2013 Test Year in the Rate Application	Still Under CGAAP or Aligned with IFRS	External Auditor agreement with the policy? (Y/N)[1]	Impact of the change, if any, to the revenue requirement of 2013
1.	Asset Useful Lives			
2.	Componentization of Assets			
3.	Capitalization of Overheads			
4.	De-recognition of PP&E (including asset retirement)			
5.	Asset impairment			
6.	Asset contribution			
7.	Others – please specify			

Note 1: Please provide the reasons if the answer is “No” in the table. Please provide the plan for consultation with its auditor if Bluewater Power has not obtained the agreement with its external auditor.

Please see the chart below and explanatory notes afterwards with respect to the the accounting policy choices (still under CGAAP, or aligned with IFRS) for the 2013 Test Year under MIFRS.

#	Area of PP&E policy in 2013 Test Year in the Rate Application	Still Under CGAAP or Aligned with IFRS	External Auditor agreement with the policy? (Y/N)[1]	Impact of the change, if any, to the revenue requirement of 2013
1	Asset Useful Lives	Aligned with IFRS	Y	none
2	Componentization of Assets	Aligned with IFRS	Y	none
3	Capitalization of Overheads	Aligned with IFRS	Y	none
4	De-recognition of PP&E (including asset retirement)	Aligned with IFRS	Y	none
5	Asset impairment	Aligned with IFRS	Y	none
6	Asset contribution	Aligned with IFRS	Y	none
7	Others - please specify: Employee Future Benefit Expense	Still Under CGAAP	Y	increase of $98,732 if remain under CGAAP

<u>Useful Lives, Componentization, Overhead, Contributions</u>

These four areas impacting capital assets are already included in the 2013 test year on a MIFRS basis. Effective January 1, 2013, it can be said that these four areas will have the identical accounting policy treatment under CGAAP for external reporting as they are required to have under regulatory accounting for the 2013 test year.

For a potential update to this chart, please refer to the response to 1-Staff-59.

De-recognition and Impairment

For de-recognition under MIFRS, there is $10,000 budgeted for ‘gain on retirement’ which is treated as a reduction to depreciation expense in the 2013 test year revenue requirement. Under CGAAP, this would have been recorded with ‘Other Revenue’.

There are no amounts budgeted for impairment in the 2013 test year.

Employee Future Benefit Expense

In addition to the response to 1-EP-2, please also refer to the response to 1-Staff-60. This is the only requested departure from the mandated MIFRS regulatory accounting treatment for the 2013 test year for rate making purposes.

External Auditor Agreement With The Policy

Bluewater Power is unsure why its external auditor would be asked if it is in agreement with OEB mandated accounting policies such as the requirement for a utility to file its 2013 test year on a MIFRS basis. In addition, the one departure that Bluewater Power is requesting of the OEB related to the Employee Future Benefit Expense does not fall under the mandate of an external auditor.

Bluewater Power can confirm that its auditor is in agreement with the 2013 changes under CGAAP for external reporting purposes for the change in useful lives, componentization, overhead capitalization and contributed capital. De-recognition and asset impairment were not discussed due to their immateriality.

1.0 - EP 32 - Distribution Revenue

Ref: 1.0-Staff-2, Attachment 1

Please explain the decrease in distribution revenue from $18,420,658 to $18,275,857 as shown in the At Proposed Rates column of the Interrogatory Responses on the Revenue Deficiency/Sufficiency Sheet of the RRWF.

It appears that the OEB's RRWF model calculates the above noted distribution revenue of $18,275,857 by taking the proposed base revenue requirement of $22,081,809 less the calculated deficiency of $3,805,952.

The amount of $18,420,658 is the distribution revenue 'at current rates'. The reader must sum Line 1- Revenue Deficiency, and Line 2 – Distribution revenue under the 'At Proposed Rates Column' of the Revenue Deficiency/Sheet of the RRWF in order to arrive at the proposed base revenue requirement.

1.0 - EP 33 - Weighted Average rate increase

Ref: 1.0-SEC-12 &
1.0-Staff-2

Based on the revised revenue requirement and rate impacts provided in the response to 1.0-Staff-2, please calculate the weighted average increase from 2012 to 2013 in distribution rates only, excluding the impacts associated with rate riders or adders and transmission related costs.

Table 1 below provides the increase by rate class for the fixed and variable rates only based on the difference between proposed rates and existing rates using the 2013 load forecast.

Table 1 – Distribution Revenue Increase

Customer Class Name	2013 Distribution Revenue at Existing Rates	2013 Distribution Revenue at Proposed Rates	Variance	
Residential	10,126,325	12,138,958	2,012,633	19.9%
General Service < 50 kW	2,625,746	3,147,620	521,874	19.9%
General Service > 50 to 999 kW	2,905,671	3,483,180	577,509	19.9%
General Service 1000 to 4999 kW	693,814	888,662	194,849	28.1%
Large Use	1,213,404	1,446,544	233,140	19.2%
Unmetered Scattered Load	144,300	124,056	(20,245)	-14.0%
Sentinel Lighting	51,175	61,346	10,171	19.9%
Street Lighting	660,223	791,443	131,221	19.9%
Base DISTRIBUTION REVENUE	18,420,657	22,081,809	3,661,152	19.9%

1.0 - EP 34 - PP&E Deferral Account

Ref: 1.0-Energy Probe-2

Based on the response provided, please confirm that there is no PP&E deferral account (1575) to be disposed of as part of this application.

Not confirmed. The response to 1-EP-2, point #2, indicates that "… *no changes are made to Account 1575 and therefore no changes are made to the related ratebase and depreciation adjustments in the 2013 Test Year.*"

Bluewater Power has proposed the disposition of Account 1575 in conjunction with the 2013 Test Year rate application in accordance with the Filing Guidelines which Bluewater Power assumes must be on a MIFRS basis. This includes the proposed disposition by adjusting depreciation expense and ratebase.

However, as discussed in 1-Staff-59, we are prepared to consider forgoing the disposition of Account 1575.

1.0 - SEC 40 - Deferral Account - employee benefit

[1.0 EP-2] Please describe in more detail the proposed deferral or variance account, including what would be charged or credited to the account, and how it would be cleared.

At a future time when Bluewater Power converts to MIFRS, we intend to propose a deferral account for the one-time transitional adjustment as well as a variance account for the ongoing year to year changes in the employee benefit obligation expense attributable to the change from CGAAP to MIFRS. Both are explained more fully below.

<u>One-Time Transitional Adjustment – Deferral Account</u>

Please refer to the response to 4-Staff-35 regarding the detail supporting the amount to be recorded in this proposed deferral account. Once IFRS is adopted, the applicable one-time transitional adjustment would be recorded to the deferral account, at which time Bluewater Power will request disposition during a subsequent IRM or COS rate application. We expect that the OEB will develop standards for such a deferral account by that point in time. If no standards are developed for this transitional adjustment, it would be Bluewater Power's recommendation that the disposition be based on a fixed charge rate rider (similar to late payment and smart meter disposition) over the same number of years as the disposition of the EDDVAR accounts. This would maintain consistency with all EDDVAR accounts while keeping rate mitigation in mind.

<u>Ongoing Year-to-Year Changes in Expense – Variance Account</u>

After conversion to IFRS, the annual IFRS employee benefit obligation expense will be reduced compared to the amount embedded in rates. To the extent that the variance created by the conversion to IFRS exceeds Bluewater Power's materiality threshold, a variance account will be requested. This variance account will track the cumulative variance between the annual expense amount under IFRS compared to what the annual expense amount would have been under CGAAP.

Once IFRS is adopted, and Bluewater Power can demonstrate a material variance, a variance account will be requested. If approved, the applicable amount will be recorded to this variance account for each year end thereafter. Bluewater Power will request disposition of this account at its subsequent IRM or COS rate application in accordance with OEB standards if developed by then. If no standards are developed for this variance account, it would be Bluewater Power's recommendation that the disposition be based on a variable rate rider over the same number of years as the disposition of the EDDVAR accounts. This would maintain consistency with all EDDVAR accounts while keeping rate mitigation in mind.

1.0 - SEC 41 - Financial Statements

[1.0 SEC-4] Please provide the requested financial statements, which are needed to assess the reasonableness of the allocations of costs between the regulated entity and its various affiliates.

Although Bluewater Power has already filed a report prepared by a third-party intended to evaluate the reasonableness of the allocations of costs between the regulated entity and its various affiliates (see Exhibit 4-5-1, Attachment 2), it is prepared to provide the requested financial statements. However, because the affiliates' financial statements contain commercially sensitive information (unrelated to the distribution business) that could prejudice their competitive positions, we must provide the financial statements on a confidential basis. Bluewater Power would be prepared to provide the requested financial statements to the SEC (and any other party) immediately upon receiving a Declaration and Undertaking as contemplated by the Board's *Practice Direction on Confidential Filings*.

We note that in agreeing to provide these statements on a confidential basis, we are not conceding to the relevance of the financial statements to this proceeding. In the event that the Board decides that some or all of the financial statements should not be treated confidentially, then we reserve the right to argue that their disclosure should not be compelled on the basis of relevance.

1.0 - SEC 42 - Strategic Plan

[1.0 SEC-5(b)] With respect to this response:

a. Please confirm that neither the Applicant nor its parent company has a written strategic plan. If confirmed, please describe the long-term framework within which business decisions are made, and provide any documents that establish, approve, or describe that framework.

As outlined in SEC-5 the business plan of the Corporation in a given year is contained in the annual budget passed in November of the preceding year. The annual business plan forms a central part of the corporate performance criteria found in the employee incentive plan. The annual incentive plan criteria objectives include annual elements of cost control, profitability and service objectives of Bluewater Power.

Through the process of managing the annual budget, long-term business planning issues are raised and acted upon routinely. Those efforts are not necessarily compiled into a document intended for the company to hold out as its “Strategic Plan” for the future, but threats and opportunities are acted upon immediately. The approach to long-term planning is possible because the relatively small size of Bluewater Power permits it to function effectively and efficiently on a less formal basis. As a mid-sized utility, the Senior Management Team (SMT) meets weekly to discuss issues facing the organization. The SMT consists of the CEO and her seven direct reports plus two other managers from within the operations group. In fact, there are only two positions with the title “manager” who do not sit on the SMT. That structure means that when a matter is discussed at SMT, it is discussed with nearly the entire management group present. That structure relieves the organization of the need to document and communicate its plan for the organization, because the plan is developed by the people charged with its implementation.

Bluewater Power believes its approach gives the organization the "nimbleness" required to function in the ever-changing environment faced by electricity distributors in Ontario. With the rapid pace of change in the electricity industry over the past decade, it is critical for utilities to react quickly. A documented strategic plan can become outdated with one change in regulation, so resources are best dedicated to reacting rather than documenting.

Having said that, there are certain business aspects of the organization that are less susceptible to regulatory change and for which the organization does document its long-term strategy. At the risk of repeating the answer stated to SEC 5(b), those two areas are the focus of long-term strategic planning for a public utility and comprise planning for its physical assets and its people assets. Long-term business decisions regarding the maintenance and improvement of distribution assets are made within the context of the Asset Management Plan (filed at Exh.2-4-3, Attachment 3), and succession and employee resource planning are discussed in the Human Resources Strategy (filed at Exh. 4-4-1, Attachment 2).

b. Please provide the monthly reviews referred to with respect to November 2012, April 2012, June 2011 and August 2010.

See Attachment 1 to this interrogatory response for:

- August 2010:
    - Internal financial statements
    - OM&A year-to-date reporting (Actual vs. budget)

- June 2011:
    - Internal financial statements
    - OM&A year-to-date reporting (Actual vs. budget)

- April 2012:
    - Internal financial statements
    - OM&A year-to-date reporting (Actual vs. budget)

- November 2012:
    - Internal financial statements
    - The OM&A year-to-date reporting for November was not completed in 2012 due to workload

Attachment 1 of 1

1.0 - SEC 42 - Financial Reviews

BLUEWATER POWER DISTRIBUTION CORPORATION
Balance Sheet

November 30, 2012, with comparative figures for 2011
(Unaudited)

Assets

	30-Nov 2012	31-Dec 2011
Current assets:		
Cash	$ 7,178,126	$ 3,237,535
Accounts receivable	9,606,758	8,680,373
Due from companies under common control	79,072	5,051
Unbilled revenue	8,514,251	9,559,826
Regulatory balances recoverable	2,668,000	1,662,452
Current portion of note receivable	95,000	95,000
Inventory	630,045	617,875
Prepaid expenses	372,003	650,902
Payment in lieu of income taxes recoverable	-	566,969
	29,143,255	25,075,983
Property, plant and equipment	45,693,601	42,915,253
Regulatory balances recoverable	7,150,242	8,863,319
Promissory note receivable	1,638,750	1,725,833
Future payment in lieu of income taxes	2,451,000	2,451,000
	$ 86,076,848	$ 81,031,388

Liabilities and Shareholder's Equity

	30-Nov 2012	31-Dec 2011
Current liabilities:		
Power purchases payable	$ 8,195,836	$ 8,071,305
Accounts payable and accrued liabilities	3,293,193	3,864,972
Payment in lieu of income taxes payable	125,731	-
Due to shareholders	2,523,306	1,701,503
Accrued interest	291,319	71,416
Dividends payable	-	765,747
Current portion of long-term debt	628,725	608,062
Deposits in aid of construction	932,833	1,342,513
Regulatory balances payable	2,780,000	1,314,262
	18,770,943	17,739,780
Due to shareholders	19,377,604	19,377,604
Long-term debt	8,063,214	7,219,432
Future regulatory taxes payable	2,451,000	2,451,000
Long-term regulatory balances payable	3,100,000	2,197,019
Customer and other deposits	1,308,338	1,543,307
Employee future benefits	7,881,469	7,507,737
Shareholder's equity:		
Share capital	18,022,105	18,022,105
Retained earnings	7,102,175	4,973,404
	25,124,280	22,995,509
	$ 86,076,848	$ 81,031,388

BLUEWATER POWER DISTRIBUTION CORPORATION
Statement of Earnings and Retained Earnings

Year to Date November 30, 2012, with comparative budget figures (Unaudited)

	Actual 2012	Budget 2012	Variance 2012
Revenues:			
Energy	$ 55,031,364	$ 76,883,746	$ (21,852,382)
Distribution	16,887,276	17,019,674	(132,398)
	71,918,640	93,903,420	(21,984,780)
Cost of power	55,031,364	76,883,746	(21,852,382)
Distribution revenue	16,887,276	17,019,674	(132,398)
Other operating revenues:			
Service revenue	414,479	694,441	(279,962)
OPA revenue	353,142	121,440	231,702
LRAM revenue	168,050	303,394	(135,344)
Other revenue	364,863	302,440	62,423
Rental	243,694	252,956	(9,262)
Late payment charges	236,446	220,000	16,446
SSS administrative fees	90,659	85,250	5,409
Interest	128,286	98,859	29,427
	1,999,619	2,078,780	(79,161)
	18,886,895	19,098,454	(211,559)
Operating expenditures:			
Administration:	10,566,984	10,958,856	(391,872)
Amortization:	4,096,974	3,626,051	470,923
Interest:	1,606,720	1,637,444	(30,724)
	16,270,678	16,222,351	48,327
Income before payments in lieu of income taxes	2,616,217	2,876,103	(259,886)
Payments in lieu of income taxes:			
Current	487,446	754,976	(267,530)
Net earnings	2,128,771	2,121,127	7,644

BLUEWATER POWER DISTRIBUTION CORPORATION
Statement of Earnings and Retained Earnings

Year to Date November 30, 2012, with comparative figures for 2011
(Unaudited)

	Actual 2012	Actual 2011	Variance
Revenues:			
Energy	$ 55,031,364	$ 55,898,068	$ (866,704)
Distribution	16,887,276	16,942,572	(55,296)
	71,918,640	72,840,640	(922,000)
Cost of power	55,031,364	55,898,068	(866,704)
Distribution revenue	16,887,276	16,942,572	(55,296)
Other operating revenues:			
Service revenue	414,479	1,649,997	(1,235,518)
Water and sewer billing	-	171,218	(171,218)
OPA revenue	353,142	177,206	175,936
LRAM revenue	168,050	241,193	(73,143)
Other revenue	364,863	353,371	11,492
Rental	243,694	258,659	(14,965)
Late payment charges	236,446	261,844	(25,398)
SSS administrative fees	90,659	85,250	5,409
Interest	128,286	85,531	42,755
	1,999,619	3,284,269	(1,284,650)
	18,886,895	20,226,841	(1,339,946)
Operating expenditures:			
Administration:	10,566,984	11,150,758	(583,774)
Amortization:	4,096,974	3,929,246	167,728
Interest:	1,606,720	1,516,789	89,931
	16,270,678	16,596,793	(326,115)
Income before payments in lieu of income taxes	2,616,217	3,630,048	(1,013,831)
Payments in lieu of income taxes:			
Current	487,446	1,025,489	(538,043)
Net earnings	2,128,771	2,604,559	(475,788)

BLUEWATER POWER DISTRIBUTION CORPORATION
Statement of Cash Flows

Year to Date November 30, 2012, with comparative figures for 2011 (Unaudited)

	YTD 2012	12 months 2011
Cash provided by (used in):		
Operating activities:		
Net earnings	$ 2,128,771	$ 2,297,241
Items not involving cash:		
Amortization of property, plant and equipment	4,096,974	4,259,217
Gain on disposal of property and equipment	-	(23,293)
Employee future benefits	373,732	428,096
Changes in non-cash operating working capital:	441,594	148,960
	7,041,071	7,110,221
Financing activities:		
Dividends on common shares	-	(2,665,747)
Funds received as contributed capital	317,654	682,425
Proceeds from long-term debt	1,472,507	2,175,963
Repayment on long-term debt	(608,062)	-
Regulatory balances	3,076,248	(1,253,025)
Due to shareholders	821,803	(586,614)
Dividends payable	(765,747)	(400,170)
Customer and other deposits	(234,969)	(394,464)
	4,079,434	(2,441,632)
Investing activities:		
Additions to property, plant and equipment	(7,192,976)	(5,379,771)
Due from companies under common control	(74,021)	1,186,119
Promissory note receivable	-	(1,900,000)
Principal repayment on promissory note receivable	87,083	79,167
Proceeds from disposal of property and equipment	-	69,397
	(7,179,914)	(5,945,088)
Increase (decrease) in cash	3,940,591	(1,276,499)
Cash, beginning of year	3,237,535	4,514,034
Cash, end of year	$ 7,178,126	$ 3,237,535

BLUEWATER POWER DISTRIBUTION CORPORATION
Balance Sheet

April 30, 2012, with comparative figures for 2011
(Unaudited)

		30-Apr 2012		31-Dec 2011
Assets				
Current assets:				
Cash	$	1,843,374	$	3,237,535
Accounts receivable		7,637,934		8,680,373
Due from companies under common control		127,337		5,051
Unbilled revenue		7,868,694		9,559,826
Regulatory balances recoverable		1,127,142		1,662,452
Current portion of note receivable		95,000		95,000
Inventory		645,705		617,875
Prepaid expenses		577,362		650,902
Payment in lieu of income taxes recoverable		605,375		566,969
		20,527,923		25,075,983
Property, plant and equipment		43,703,554		42,915,253
Regulatory balances recoverable		10,592,441		8,863,319
Promissory note receivable		1,694,167		1,725,833
Future payment in lieu of income taxes		2,451,000		2,451,000
	$	78,969,085	$	81,031,388
Liabilities and Shareholder's Equity				
Current liabilities:				
Power purchases payable	$	7,226,779	$	8,071,305
Accounts payable and accrued liabilities		2,720,966		3,864,972
Due to shareholders		1,862,807		1,701,503
Accrued interest		151,379		71,416
Dividends payable		-		765,747
Current portion of long-term debt		618,307		608,062
Deposits in aid of construction		1,062,492		1,342,513
Regulatory balances payable		1,313,581		1,314,262
		14,956,311		17,739,780
Due to shareholders		19,377,604		19,377,604
Long-term debt		7,718,095		7,219,432
Future regulatory taxes payable		2,451,000		2,451,000
Long-term regulatory balances payable		1,760,044		2,197,019
Customer and other deposits		1,488,132		1,543,307
Employee future benefits		7,643,640		7,507,737
Shareholder's equity:				
Share capital		18,022,105		18,022,105
Retained earnings		5,552,154		4,973,404
		23,574,259		22,995,509
	$	78,969,085	$	81,031,388

BLUEWATER POWER DISTRIBUTION CORPORATION
Statement of Earnings and Retained Earnings

Year to Date April 30, 2012, with comparative budget figures (Unaudited)

	Actual 2012	Budget 2012	Variance 2012
Revenues:			
Energy	$ 23,936,908	$ 28,227,703	$ (4,290,795)
Distribution	5,997,912	6,220,195	(222,283)
	29,934,820	34,447,898	(4,513,078)
Cost of power	23,936,908	28,227,703	(4,290,795)
Distribution revenue	5,997,912	6,220,195	(222,283)
Other operating revenues:			
Service revenue	200,354	252,524	(52,170)
OPA revenue	96,106	44,160	51,946
Other revenue	125,574	109,410	16,164
Rental	90,054	91,984	(1,930)
Late payment charges	60,733	80,000	(19,267)
SSS administrative fees	32,513	31,000	1,513
Interest	42,490	40,026	2,464
	647,824	649,104	(1,280)
	6,645,736	6,869,299	(223,563)
Operating expenditures:			
Administration:	3,790,498	3,804,275	(13,777)
Amortization:	1,485,911	1,318,564	167,347
Interest:	584,581	585,524	(943)
	5,860,990	5,708,363	152,627
Income before payments in lieu of income taxes	784,746	1,160,936	(376,190)
Payments in lieu of income taxes:			
Current	205,996	304,745	(98,749)
Net earnings	578,750	856,191	(277,441)

BLUEWATER POWER DISTRIBUTION CORPORATION
Statement of Earnings and Retained Earnings

Year to Date April 30, 2012, with comparative figures for 2011 (Unaudited)

	Actual 2012	Actual 2011	Variance
Revenues:			
Energy	$ 23,936,908	$ 19,470,828	$ 4,466,080
Distribution	5,997,912	6,133,836	(135,924)
	29,934,820	25,604,664	4,330,156
Cost of power	23,936,908	19,470,828	4,466,080
Distribution revenue	5,997,912	6,133,836	(135,924)
Other operating revenues:			
Service revenue	200,354	1,013,318	(812,964)
Water and sewer billing	-	171,218	(171,218)
OPA revenue	96,106	47,496	48,610
Other revenue	125,574	112,389	13,185
Rental	90,054	103,619	(13,565)
Late payment charges	60,733	105,774	(45,041)
SSS administrative fees	32,513	30,958	1,555
Interest	42,490	24,612	17,878
	647,824	1,609,384	(961,560)
	6,645,736	7,743,220	(1,097,484)
Operating expenditures:			
Administration:	3,790,498	4,174,673	(384,175)
Amortization:	1,485,911	1,382,409	103,502
Interest:	584,581	532,955	51,626
	5,860,990	6,090,037	(229,047)
Income before payments in lieu of income taxes	784,746	1,653,183	(868,437)
Payments in lieu of income taxes:			
Current	205,996	467,024	(261,028)
Net earnings	578,750	1,186,159	(607,409)

BLUEWATER POWER DISTRIBUTION CORPORATION
Statement of Cash Flows

Year to Date April 30, 2012, with comparative figures for 2011 (Unaudited)

	YTD 2012	12 months 2011
Cash provided by (used in):		
Operating activities:		
Net earnings	$ 578,750	$ 2,297,241
Items not involving cash:		
Amortization of property, plant and equipment	1,485,911	4,259,217
Gain on disposal of property and equipment	-	(23,293)
Employee future benefits	135,903	428,096
Changes in non-cash operating working capital:	552,285	148,960
	2,752,849	7,110,221
Financing activities:		
Dividends on common shares	-	(2,665,747)
Funds received as contributed capital	-	682,425
Proceeds from long-term debt	810,399	2,175,963
Repayment on long-term debt	(301,491)	-
Regulatory balances	(1,631,468)	(1,253,025)
Due to shareholders	161,304	(586,614)
Dividends payable	(765,747)	(400,170)
Customer and other deposits	(55,175)	(394,464)
	(1,782,178)	(2,441,632)
Investing activities:		
Additions to property, plant and equipment	(2,274,212)	(5,379,771)
Due from companies under common control	(122,286)	1,186,119
Promissory note receivable	-	(1,900,000)
Principal repayment on promissory note receivable	31,666	79,167
Proceeds from disposal of property and equipment	-	69,397
	(2,364,832)	(5,945,088)
Increase (decrease) in cash	(1,394,161)	(1,276,499)
Cash, beginning of year	3,237,535	4,514,034
Cash, end of year	$ 1,843,374	$ 3,237,535

YTD O&M ACTUAL, BUDGET AND VARIANCE
As at April 30, 2012

Branch	(All)
Cost Center	(All)
Month	(All)

Dist or Non	Account Name	Actual $	Budget $	Variance
Dist	Salary	1,130,857	1,228,646	(97,789)
	Labour	819,286	873,507	(54,221)
	Bad Debt Expense	(8,531)	34,000	(42,531)
	Utilities	44,864	59,125	(14,261)
	Payroll Accrual	164,896	178,498	(13,602)
	Extended Benefits-NonDist	(43,849)	(31,032)	(12,817)
	Overtime	99,781	112,032	(12,251)
	Tree Trimming	44,613	55,000	(10,387)
	Consulting	5,088	14,462	(9,374)
	Insurance	39,638	49,000	(9,362)
	Contract Employees	30,931	38,997	(8,066)
	Fuel	42,756	48,332	(5,576)
	Telephony	24,919	29,332	(4,413)
	Awards	1,740	6,065	(4,325)
	Print Consumables	722	5,000	(4,278)
	Inventory Adjustment	(3,602)		(3,602)
	Life Ins Mearie Retiree	30,823	33,100	(2,277)
	Rentals	5,041	7,099	(2,058)
	Executive Health	1,200	3,000	(1,800)
	Health Tax	43,063	44,803	(1,740)
	Photocopiers	3,602	5,332	(1,730)
	Tools	6,871	8,547	(1,676)
	SCADA	3,159	4,668	(1,509)
	T1 Internet	11,230	12,520	(1,290)
	Property Tax	63,427	64,708	(1,281)
	Cell Phone/Blackberry	17,840	19,072	(1,232)
	Safety Supplies	1,945	3,132	(1,187)
	Stores - Mtce on Meters	(849)	332	(1,181)
	EBT Hub Services	4,829	6,000	(1,171)
	Car Allowance	16,152	17,256	(1,104)
	Internet	3,240	4,324	(1,084)
	CPP	99,947	100,970	(1,023)
	GWL Emp Life	6,579	7,590	(1,011)
	Locates	3,042	4,000	(958)
	OMERS	205,889	206,844	(955)
	Vacuum Excavation	4,074	5,000	(927)
	Community Relations	23,267	24,135	(868)
	LTD	41,311	42,010	(699)
	Transformer Maintenance	-	668	(668)
	Employee Costs	9,590	10,244	(654)
	Safety Meetings	371	1,000	(629)
	Late Penalty Payment	(605)		(605)
	Fire Safety	977	1,500	(523)
	Office rental	-	500	(500)
	Web Page	750	1,232	(482)
	Vehicle Licence	3,427	3,868	(441)
	Memberships	20,347	20,784	(437)
	Students	342	733	(391)
	Payroll Fees	5,263	5,576	(313)
	Cleaning Supplies	3,690	4,000	(310)
	Vehicle Lease	-	306	(306)
	Communications	726	1,032	(306)
	Janitorial Services	1,373	1,668	(295)
	Bank Service Fees	6,116	6,408	(292)
	Answering Service	1,076	1,368	(292)
	Fitness Expense	3,263	3,518	(255)
	Door Maintenance	1,119	1,336	(217)

Dist or Non	Account Name	Actual $	Budget $	Variance
Dist	OEB Assessment	45,708	45,920	(212)
	Research Studies	-	168	(168)
	Oil Disposal & Testing	1,013	1,168	(155)
	Subscriptions	952	1,100	(148)
	Heating & cooling	3,038	3,164	(126)
	Pest Control	855	968	(113)
	Records Management	558	668	(110)
	Rec Club	343	400	(57)
	Freight	-	33	(33)
	Lawnmower R&M	(25)	-	(25)
	Collection Charge	6,744	6,768	(24)
	GWL ADD	(4)	-	(4)
	Permits	1,667	1,668	(1)
	Audit Fees	17,767	17,768	(1)
	Rate Application Costs	32,768	32,768	(0)
	Building Maintenance	(4,872)	(4,872)	-
	Membership	-		-
	Capital Tax	-		-
	Licences	-		-
	Insulator Washing	-		-
	Tools R&M	-		-
	Inventory Obsolescence	-		-
	Reel Deposits	-	-	-
	Hay Evaluation	-	-	-
	Cash Over & Short	-	-	-
	Manholes & Vaults	-		-
	CNR Lease	4,500	4,500	0
	EAP	2,367	2,357	10
	Software Maintenance	95,172	95,148	24
	Chainsaw R&M	40		40
	GWL Emp Dent	34,381	34,339	42
	Office Supplies	60		60
	Lawn Care	697	571	126
	Travel	18,119	17,950	169
	Stores - Mtce Line Transformers	173		173
	Security System	848	664	184
	Boot/Clothing Allowance	2,936	2,675	261
	Secured Delivery	1,385	1,035	350
	Equipment Testing	6,781	6,332	449
	Plumbing	1,185	732	453
	Prudentials	17,203	16,668	535
	Stationery Supplies	4,061	3,508	553
	Life Ins Mearie Active	8,725	8,114	611
	F.R. & Safety Clothing	6,423	5,700	723
	Locksmith	1,221	332	889
	Advertising	3,686	2,756	930
	Education Assistance	1,897	932	965
	Hardware	4,457	3,468	989
	Non Stock	1,929	832	1,097
	Snow Removal	6,896	5,688	1,208
	Stores-Mtc Ungd Conductors	6,794	5,332	1,462
	Computer Infrastructure	2,002	500	1,502
	Joint Pole Use	6,137	4,500	1,637
	Building Materials	3,002	1,332	1,670
	Waste Disposal	9,018	7,336	1,682
	GWL Ext Active	100,793	99,065	1,728
	Forms	9,712	7,716	1,996
	Stores-Mtc Poles, etc	4,773	2,668	2,105
	Environmental Issues	10,879	8,750	2,129
	Workplace Safety Insurance	23,637	21,428	2,209
	Safety Promotion	2,903	668	2,235
	Training	26,195	23,951	2,244
	Electrical	3,280	832	2,448
	Thermovision	6,184	3,332	2,852
	Miscellaneous Supplies	12,909	9,332	3,577

Dist or Non	Account Name	Actual $	Budget $	Variance
Dist	Legal Costs	8,751	5,000	3,751
	Communications Voice	4,338	268	4,070
	Overhead-NonDistribution	(7,234)	(11,916)	4,682
	Meals	28,651	23,084	5,567
	ESA Assessment	5,780		5,780
	Postage	51,102	44,776	6,326
	EI	53,791	46,996	6,795
	GWL Retired	71,773	63,784	7,989
	Stores-Mtc Ovhd Conductors	18,473	9,332	9,141
	Donations	40,410	30,000	10,410
	Contracted Services - BWPS	44,168	32,864	11,304
	Vehicle Maintenance	53,723	41,832	11,891
	Billable - Other	99,235	83,332	15,903
	Contracted Services	77,434	32,968	44,466
Dist Total		4,157,881	4,312,199	(154,318)
NonDist	Payroll Burden	-		-
	Postage	-		-
	Contract Employees	-		-
	Property Maintenance	-		-
	Fitness Expense	-		-
	Property Tax	-		-
	Labour	-		-
	Salary	-		-
	Overtime	-		-
	Software Maintenance	-		-
	Extended Benefits-NonDist	-		-
	Vehicle Costs	-		-
	Meals	-		-
	Water Billing ROIC	-		-
	Forms	-		-
	Water Billing Interest Charge	-		-
	Computer Infrastructure	-		-
	Rent	-		-
NonDist Total		-		-
Grand Total		4,157,881	4,312,199	(154,318)

Plus				
438000111 & 120	OPA Expense - Business Incentive	96,106	44,160	51,946
589999999	Non-Capitalized Cost	5,106	-	5,106
		101,212	44,160	57,052
		4,259,093	4,356,359	(97,265.66)
Less:	Lines & Design Cap'd Labour	(412,047)		
	IT Capitalized Labour	(191,956)		
	Metering Capitalized Labour	(12,807)		
	Other Capitalized Labour	(10,293)		
	Total Capitalized Labour	(627,103)	(694,888)	67,785
564500000	Employee benefit obligation exp	163,137	163,136	0
440500001&603500001	Carrying charges expense	(4,628)	(20,332)	15,704
	OEB O&M Net of Cap'd Labour	3,790,499	3,804,275	(13,776)

BLUEWATER POWER DISTRIBUTION CORPORATION
BALANCE SHEET (unaudited)
AS AT JUNE 30, 2011

ASSETS		June 2011		December 2010
CURRENT ASSETS:				
Bank & Investments	$	-	$	4,514,034
Accounts Receivable		8,112,193		10,488,607
Due From Related Parties		326,234		1,191,170
Regulatory Balances Recoverable		2,442,553		1,599,990
Promissory Note Receivable		95,000		-
Unbilled Revenue		9,234,349		10,411,860
PILS Receivable		850,679		586,380
Inventories		672,156		596,509
Prepaid Expenses		338,055		575,847
TOTAL CURRENT ASSETS	$	22,071,219		29,964,397
PLANT, PROPERTY & EQUIPMENT				
Land & Buildings		6,698,304		6,698,304
Substation Equipment		6,106,086		6,106,086
Distribution - Overhead/Underground		49,953,334		49,953,334
Transformers		14,684,774		14,684,774
Meters & Devices		7,427,858		7,427,858
Rolling Stock & Equipment		4,271,828		4,271,828
Other General Plant		17,951,906		17,951,906
Assets Under Construction		2,271,887		352,445
Spare Parts Inventory		566,276		566,276
	$	109,932,253		108,012,811
Less: Acc Amort - capital assets		(63,049,473)		(60,859,607)
Less: Acc Amort - contributed capital		1,292,029		1,175,372
Less: Contributed Capital		(5,856,604)		(5,805,348)
TOTAL PLANT, PROPERTY & EQUIPMENT	$	42,318,205		42,523,228
Regulatory Balances Recoverable		7,940,520		7,276,579
Promissory Note Receivable		1,773,332		-
Future Payment of Income Taxes		2,450,000		2,450,000
	$	12,163,852		9,726,579
TOTAL ASSETS	**$**	**76,553,276**	**$**	**82,214,204**

LIABILITIES/EQUITY		June 2011		December 2010
CURRENT LIABILITIES:				
Power Purchases Payable	$	7,516,489	$	8,157,376
Accounts Payable & Accruals		2,347,825		4,670,063
Due to Shareholders (Water)		2,355,659		2,288,117
PILS Payable		-		-
Bank Indebtedness		1,763,637		-
Regulatory Balances Payable		1,301,190		1,942,466
Deposits in Aid of Construction		1,279,026		2,957,065
Accrued Interest on LT Debt		-		-
Dividends Payable		-		1,165,917
Other		-		-
TOTAL CURRENT LIABILITIES	$	16,563,826		21,181,004
OTHER LIABILITIES:				
Debt - Payable to Shareholder		19,377,604		19,377,604
Deposits - Energy Customers		1,805,891		1,937,771
Infrastructure Ontario Loan		6,045,349		5,651,531
Regulatory Balances Payable		-		1,172,638
Future Regulatory Taxes Payable		2,450,000		2,450,000
Employee Benefit Liability		7,309,042		7,079,641
TOTAL OTHER LIABILITIES	$	36,987,886		37,669,185
TOTAL LIABILITIES	$	53,551,712		58,850,189
EQUITY:				
Share Capital		18,022,105		18,022,105
Retained Earnings (Jan 1st)		5,341,910		3,010,075
Adjustment for Future Tax Asset		-		-
Current YTD Net Income		1,537,549		3,497,752
Dividends Declared		(1,900,000)		(1,165,917)
TOTAL EQUITY	$	23,001,564		23,364,015
TOTAL LIABILITIES & EQUITY	**$**	**76,553,276**	**$**	**82,214,204**

INCOME STATEMENT FOR YTD JUNE 2011 (unaudited)

	Actual	Budget	Variance
REVENUE			
Residential	16,621,303	15,429,982	1,191,321
Flat Rate	161,437	154,810	6,627
General Service <50	6,029,454	6,047,802	(18,348)
General Service >50	7,396,245	11,033,878	(3,637,633)
General Service >50 TOU	4,226,556	6,932,064	(2,705,508)
Large Users	4,202,773	6,616,323	(2,413,550)
Sentinel	45,344	46,432	(1,088)
Street Lighting	463,416	643,308	(179,892)
Unbilled/Rate Increase	(1,177,511)	-	(1,177,511)
Revenue Offsets (per OEB)	(34,932)	-	(34,932)
TOTAL ENERGY REVENUE	37,934,085	46,904,599	(8,970,514)
COST OF POWER	28,815,535	37,923,555	(9,108,020)
COST OF POWER DEFERRAL	-	-	-
	28,815,535	37,923,555	(9,108,020)
DISTRIBUTION MARGIN	**$ 9,118,550**	**$ 8,981,044**	**$ 137,506**
OTHER REVENUE			
Water Billing Gross Revenue	171,218	-	171,218
OPA Gross Revenue	88,385	184,128	(95,743)
Interest Revenue	40,998	49,213	(8,215)
Rental Revenue	139,751	138,130	1,621
Management Fees from Affliates	56,361	56,376	(15)
Late Payment Charges - electricity	133,647	115,500	18,147
Late Payment Charges - water	11,202	-	11,202
Billable Revenue	1,138,759	175,002	963,757
LRAM Revenue	241,193	241,193	-
Miscellaneous Revenue	157,830	153,781	4,049
Extraordinary Revenue	-	-	-
TOTAL OTHER REVENUE	2,179,344	1,113,323	1,066,021
GROSS MARGIN	**$ 11,297,894**	**$ 10,094,367**	**$ 1,203,527**
O&M - electricity	6,596,861	6,527,670	69,191
O&M - water billing	104,134	-	104,134
O&M - OPA	88,334	167,388	(79,054)
Capitalization	(708,568)	(1,083,606)	375,038
TOTAL O&M	6,080,761	5,611,452	469,309
OTHER EXPENSES			
Other Interest	17,419	15,402	2,017
Carrying Charges	(74,530)	18,498	(93,028)
Employee Benefit Liability	270,252	270,252	-
Amortization of Capital Assets	2,073,209	2,258,550	(185,341)
Infrastructure Ontario Loan Interest	49,570	-	49,570
Shareholder Loan Interest	738,287	738,288	(1)
TOTAL OTHER EXPENSES	3,074,207	3,300,990	(226,783)
TOTAL EXPENSES	9,154,968	8,912,442	242,526
NET INCOME BEFORE TAXES	**$ 2,142,926**	**$ 1,181,925**	**$ 961,001**
INCOME TAXES	605,377	333,893	271,484
NET INCOME AFTER TAXES	**$ 1,537,549**	**$ 848,032**	**$ 689,517**

BLUEWATER POWER DISTRIBUTION CORPORATION
STATEMENT OF CHANGES IN FINANCIAL POSITION (unaudited)
FOR YTD JUNE 2011

	YTD 2011
OPERATING ACTIVITIES:	
Net Earnings	$ 1,537,549
Items not Affecting Cash:	
Amortization of Capital Assets	2,073,209
Net (Gain) Loss on disposition of capital assets	-
Future Income Taxes	-
Employee Benefits Expense	229,401
	2,302,610
Changes in Non-Cash Working Capital Items:	
Accounts Receivable	2,376,414
Due From Related Parties	864,936
Unbilled Revenue	1,177,511
Inventories	(75,647)
Prepaid Expenses	237,792
Current Regulatory Assets - Recoverable	(842,563)
Current Regulatory Assets - Payable	(641,276)
Accounts Payable & Accruals	(2,963,125)
Due to Related Parties	67,542
PILS Receivable/Payable	(264,299)
Accrued Interest on Long-term Debt	-
Dividends Payable	(1,165,917)
Deposits - Billable Work	(1,678,039)
	(2,906,671)
Regulatory Balances - Long Term	(1,836,579)
Deposits - Energy Customers	(131,880)
NET SOURCE (USE) FROM OPERATING ACTIVITIES:	(1,034,971)
FINANCING ACTIVITIES:	
Infrastructure Ontario loan proceeds	393,818
Dividends on common shares	(1,900,000)
Contributed Capital	51,256
NET SOURCE (USE) FROM FINANCING ACTIVITIES:	(1,454,926)
INVESTING ACTIVITIES:	
Plant, Property and Equipment Additions	(1,919,442)
Promissory Note to BPREI	(1,900,000)
Principal repayments on promissory note	31,668
Proceeds on disposition of capital assets	-
Other	-
NET SOURCE (USE) FOR INVESTING ACTIVITIES:	(3,787,774)
NET CASH INFLOW (OUTFLOW)	(6,277,671)
CASH POSITION, BEGINNING OF PERIOD	4,514,034
CASH POSITION, END OF PERIOD	$ (1,763,637)

YTD O&M ACTUAL, BUDGET AND VARIANCE

As at June 30, 2011

Branch	(All)
Month	(All)
Cost Center	(All)

Dist or Non	Account Name2	Actual $	Budget $	Variance
Dist	Billable - Other	254,218	75,000	179,218
	Contracted Services	127,291	89,180	38,111
	Incentive	30,562		30,562
	Donations	94,867	68,267	26,600
	Overtime	186,370	161,202	25,168
	Bad Debt Expense	72,760	49,502	23,258
	OMERS	301,078	288,503	12,575
	Fuel	67,899	56,500	11,399
	Rentals	11,249	1,878	9,371
	Cell Phone/Blackberry	37,155	29,253	7,902
	Miscellaneous Supplies	21,229	13,950	7,279
	Software Maintenance	134,975	128,106	6,869
	Employee Costs	23,178	16,652	6,526
	Vacuum Excavation	8,313	2,000	6,313
	Meals	40,112	34,583	5,529
	Late Penalty Payment	5,123		5,123
	Insulator Washing	36,270	31,500	4,770
	Advertising	12,874	8,150	4,724
	Forms	16,914	12,540	4,374
	Contract Employees	79,824	76,629	3,195
	Memberships	33,943	30,805	3,138
	Insurance	73,477	70,494	2,983
	Stores-Mtc Poles, etc	7,894	5,100	2,794
	OEB Assessment	61,382	58,710	2,672
	Non Stock	3,602	950	2,652
	Workplace Safety Insurance	39,627	37,183	2,444
	T1 Internet	14,780	12,378	2,402
	Health Tax	74,048	71,666	2,382
	Fire Safety	3,958	1,650	2,308
	F.R. & Safety Clothing	13,295	11,089	2,206
	Snow Removal	4,957	2,751	2,206
	Stores-Mtc Ungd Conductors	9,957	7,800	2,157
	Stationery Supplies	7,325	5,542	1,783
	Communications Voice	1,759	350	1,409
	Building Materials	3,145	1,800	1,345
	Telephony	33,818	32,502	1,316
	Tree Trimming	91,298	90,000	1,298
	Secured Delivery	2,643	1,367	1,276
	Utilities	66,041	64,800	1,241
	Waste Disposal	10,994	10,000	994
	Cleaning Supplies	5,725	4,740	985
	ESA Assessment	11,443	10,500	943
	Office rental	750		750
	Postage	71,229	70,500	729
	Life Ins Mearie Active	12,215	11,582	633
	Executive Health	3,600	3,000	600
	Photocopiers	8,217	7,620	597
	Bank Service Fees	9,768	9,276	492
	EAP	2,608	2,200	408
	Safety Meetings	1,892	1,500	392
	Fitness Expense	4,327	4,048	279
	Stores - Mtce on Meters	497	300	197
	Electrical	1,634	1,500	134

Dist or Non	Account Name2	Actual $	Budget $	Variance
Dist	Chainsaw R&M	215	90	125
	Answering Service	1,885	1,800	85
	Plumbing	1,314	1,248	66
	Rec Club	578	517	61
	Communications	1,563	1,540	23
	Cash Over & Short	20	-	20
	Building Maintenance	(7,588)	(7,602)	14
	Prudentials	25,804	25,800	4
	Audit Fees	25,100	25,098	2
	CNR Lease	6,750	6,750	0
	Reel Deposits	-	-	-
	Hay Evaluation	-	-	-
	Capital Tax	-		-
	Transformer Maintenance	-		-
	Rate Application Costs	49,152	49,152	(0)
	Permits	2,500	2,502	(2)
	Joint Pole Use	6,723	6,750	(27)
	Lawnmower R&M	-	34	(34)
	Pest Control	110	150	(40)
	Freight	-	48	(48)
	Vehicle Licence	5,901	6,000	(99)
	Locksmith	578	750	(172)
	Life Ins Mearie Retiree	42,086	42,269	(183)
	Licences	-	198	(198)
	Security System	986	1,250	(264)
	GWL ADD	4,491	4,756	(265)
	Subscriptions	1,632	1,900	(268)
	Vehicle Lease	892	1,200	(308)
	Boot/Clothing Allowance	4,456	4,799	(343)
	Manholes & Vaults	-	420	(420)
	Education Assistance	4,927	5,444	(517)
	Records Management	777	1,320	(543)
	Inventory Adjustment	(654)		(654)
	Research Studies	763	1,426	(663)
	GWL Retired	96,713	97,414	(701)
	SCADA	6,248	6,990	(742)
	Computer Infrastructure	503	1,650	(1,147)
	Heating & cooling	3,288	4,500	(1,212)
	Oil Disposal & Testing	1,278	2,550	(1,272)
	Equipment Testing	9,216	10,500	(1,284)
	Lawn Care	1,211	2,500	(1,289)
	Internet	4,335	5,670	(1,335)
	Web Page	855	2,400	(1,545)
	Property Tax	96,483	98,070	(1,587)
	EBT Hub Services	9,118	10,800	(1,682)
	Car Allowance	24,400	26,100	(1,700)
	EI	78,975	80,795	(1,820)
	GWL Emp Life	10,291	12,158	(1,867)
	Door Maintenance	558	2,450	(1,893)
	Tools	12,108	14,060	(1,952)
	Safety Promotion	(968)	1,002	(1,970)
	Locates	5,485	7,500	(2,016)
	LTD	57,773	60,043	(2,270)
	Safety Supplies	3,212	5,696	(2,484)
	Environmental Issues	-	2,500	(2,500)
	GWL Emp Dent	53,430	56,037	(2,607)
	Print Consumables	4,848	7,470	(2,622)
	Stores-Mtc Ovhd Conductors	16,773	20,000	(3,227)
	Payroll Fees	9,180	12,878	(3,698)
	Legal Costs	3,660	7,502	(3,842)
	Awards	3,773	7,700	(3,927)
	Janitorial Services	1,591	5,550	(3,959)

Dist or Non	Account Name2	Actual $	Budget $	Variance
Dist	Thermovision	2,750	7,500	(4,750)
	Payroll Accrual	262,397	267,574	(5,177)
	GWL Ext Active	154,192	159,599	(5,407)
	Collection Charge	8,012	13,690	(5,678)
	Hardware	2,837	9,148	(6,311)
	Consulting	16,712	23,052	(6,340)
	Travel	23,696	31,121	(7,425)
	Students	48,929	60,878	(11,949)
	CPP	152,798	164,808	(12,010)
	Training	25,438	43,708	(18,270)
	Vehicle Maintenance	52,698	72,500	(19,802)
	Overhead-NonDistribution	(36,047)		(36,047)
	Extended Benefits-NonDist	(43,915)	-	(43,915)
	Salary	1,703,622	1,779,393	(75,771)
	Labour	1,267,114	1,349,507	(82,393)
Dist Total		**6,590,632**	**6,527,670**	**62,962**

NonDist	Labour	39,670		39,670
	Water Billing ROIC	14,364		14,364
	Contract Employees	9,299		9,299
	Extended Benefits-NonDist	7,943		7,943
	Postage	7,085		7,085
	Software Maintenance	5,350		5,350
	Payroll Burden	5,314		5,314
	Property Maintenance	3,748		3,748
	Management fee	3,548		3,548
	Salary	2,406		2,406
	Forms	1,814		1,814
	Rent	900		900
	Water Billing Interest Charge	846		846
	Vehicle Costs	828		828
	Property Tax	794		794
	Computer Infrastructure	622		622
	Fitness Expense	150		150
	Overtime	-		-
	Meals	-		-
NonDist Total		**104,681**		**104,681**

Grand Total		**6,695,312**	**6,527,670**	**167,642**

Plus				
438000120	OPA Expense - Business Incentive Program	88,334	167,388	(79,054)
589999999	Non-Capitalized Cost	10,806	-	10,806
		99,140	167,388	(68,248)
		6,794,452	6,695,058	99,394
Less:	Lines & Design Cap'd Labour	(418,348)	(853,220)	434,872
	IT Capitalized Labour	(243,611)	(199,571)	(44,040)
	Metering Capitalized Labour	(46,473)	(21,030)	(25,443)
	Other Capitalized Labour	(1,271)	(9,785)	8,514
	Total Capitalized Labour	**(709,703)**	**(1,083,606)**	**373,903**
564500000	Employee benefit obligation expense	270,252	270,252	(0)
440500001&603500001	Carrying charges expense	(74,530)	18,498	(93,028)
	OEB O&M Net of Cap'd Labour	**6,280,471**	**5,900,202**	**380,269**

BLUEWATER POWER DISTRIBUTION CORPORATION
BALANCE SHEET (unaudited)
AS AT AUGUST 31, 2010

	August 2010	December 2009
ASSETS		
CURRENT ASSETS:		
Bank & Investments	$ -	$ 7,872,876
Accounts Receivable	9,287,610	8,044,736
Due From Related Parties	1,066,637	381,547
Regulatory Balances Recoverable	-	-
Unbilled Revenue	13,249,971	9,391,221
Inventories	1,520,714	1,204,681
Prepaid Expenses	316,561	248,175
TOTAL CURRENT ASSETS	$ 25,441,493	27,143,236
PLANT, PROPERTY & EQUIPMENT		
Land & Buildings	6,290,281	5,607,642
Substation Equipment	5,768,029	5,768,029
Distribution - Overhead/Underground	48,234,817	48,127,816
Transformers	13,680,946	13,736,285
Meters & Devices	7,254,546	7,253,504
Rolling Stock & Equipment	4,049,944	3,389,989
Other General Plant	16,365,577	14,514,713
Assets Under Construction	3,026,249	981,908
Spare Parts Inventory	-	-
	$ 104,670,389	99,379,886
Less: Acc Amort - capital assets	(59,353,419)	(56,767,920)
Less: Acc Amort - contributed capital	1,102,498	968,203
Less: Contributed Capital	(5,366,195)	(5,352,187)
TOTAL PLANT, PROPERTY & EQUIPMENT	$ 41,053,273	38,227,982
Regulatory Balances Recoverable	7,199,177	5,054,567
Future Payment of Income Taxes	3,133,000	3,133,000
	$ 10,332,177	8,187,567
TOTAL ASSETS	**$ 76,826,943**	**$ 73,558,785**

	August 2010	December 2009
LIABILITIES/EQUITY		
CURRENT LIABILITIES:		
Power Purchases Payable	$ 8,934,738	$ 7,464,977
Accounts Payable & Accruals	1,619,320	3,140,743
Due to Shareholders (Water)	3,299,025	1,874,957
PILS Payable	126,968	(55,390)
Bank Indebtedness	1,980,939	-
Regulatory Balances Payable	2,965,410	2,355,603
Deposits in Aid of Construction	1,634,275	2,341,151
Accrued Interest on LT Debt	246,096	47,798
Dividends Payable	-	939,807
Other	-	-
TOTAL CURRENT LIABILITIES	$ 20,806,771	18,109,646
OTHER LIABILITIES:		
Debt - Payable to Shareholder	19,377,604	19,377,604
Deposits - Energy Customers	1,933,509	1,785,865
Hydro One Low Voltage Charges	-	-
Regulatory Balances Payable	1,312,869	3,536,668
Future Regulatory Taxes Payable	3,133,000	3,133,000
Employee Benefit Liability	6,889,690	6,583,822
TOTAL OTHER LIABILITIES	$ 32,646,672	34,416,959
TOTAL LIABILITIES	$ 53,453,443	52,526,605
EQUITY:		
Share Capital	18,022,105	18,022,105
Retained Earnings (Jan 1st)	3,010,075	3,945,460
Adjustment for Future Tax Asset	-	(2,815,000)
Current YTD Net Income	2,341,320	2,819,422
Dividends Declared	-	(939,807)
TOTAL EQUITY	$ 23,373,500	21,032,180
TOTAL LIABILITIES & EQUITY	**$ 76,826,943**	**$ 73,558,785**

INCOME STATEMENT FOR YTD AUGUST 2010 (unaudited)

	Actual	Budget	Variance
REVENUE			
Residential	21,838,868	20,145,293	1,693,575
General Service <50	7,427,964	8,237,919	(809,955)
General Service >50	9,431,220	13,665,235	(4,234,015)
General Service >50 TOU	6,728,203	8,556,628	(1,828,425)
Large Users	6,279,218	8,283,024	(2,003,806)
Flat Rate	195,155	195,730	(575)
Sentinel	53,399	58,540	(5,141)
Street Lighting	579,053	743,461	(164,408)
Unbilled/Rate Increase	3,962,123	-	3,962,123
Revenue Offsets (per OEB)	(27,852)	-	(27,852)
TOTAL ENERGY REVENUE	56,467,351	59,885,830	(3,418,479)
COST OF POWER	43,860,261	47,674,680	(3,814,419)
COST OF POWER DEFERRAL	-	-	-
	43,860,261	47,674,680	(3,814,419)
DISTRIBUTION MARGIN	**$ 12,607,090**	**$ 12,211,150**	**$ 395,940**
REGULATORY ASSET BILLING	-	-	-
OTHER REVENUE			
Water Billing Gross Revenue	445,038	456,216	(11,178)
OPA Gross Revenue	252,260	242,672	9,588
Interest Revenue	12,535	10,264	2,271
Rental Revenue	164,614	137,600	27,014
Income From Affiliates	114,701	113,752	949
Late Payment Charges - hydro	154,500	142,000	12,500
Late Payment Charges - water	45,375	40,672	4,703
Billable Revenue	927,306	939,336	(12,030)
Miscellaneous Revenue	220,938	215,992	4,946
Extraordinary Revenue	-	-	-
TOTAL OTHER REVENUE	2,337,267	2,298,504	38,763
GROSS MARGIN	**$ 14,944,357**	**$ 14,509,654**	**$ 434,703**
O&M - electricity	8,339,878	8,469,330	(129,452)
O&M - water billing	279,688	284,269	(4,581)
O&M - OPA	180,701	195,736	(15,035)
Capitalization	(1,166,344)	(1,357,688)	191,344
TOTAL O&M	7,633,923	7,591,647	42,276
OTHER EXPENSES			
Other Interest	4,331	8,536	(4,205)
Carrying Charges	12,069	20,000	(7,931)
Employee Benefit Liability	360,336	307,672	52,664
Amortization of Capital Assets	2,506,198	2,755,888	(249,690)
Amortization of Regulatory Assets	-	-	-
Shareholder Loan Interest	984,382	936,584	47,798
TOTAL OTHER EXPENSES	3,867,316	4,028,680	(161,364)
TOTAL EXPENSES	11,501,239	11,620,327	(119,088)
NET INCOME BEFORE TAXES	**$ 3,443,118**	**$ 2,889,327**	**$ 553,791**
INCOME TAXES	1,101,798	924,585	177,213
NET INCOME AFTER TAXES	**$ 2,341,320**	**$ 1,964,742**	**$ 376,578**

BLUEWATER POWER DISTRIBUTION CORPORATION
STATEMENT OF CHANGES IN FINANCIAL POSITION (unaudited)
FOR YTD AUGUST 2010

	YTD 2010
OPERATING ACTIVITIES:	
Net Earnings	$ 2,341,320
Items not Affecting Cash:	
Amortization of Capital Assets	2,506,198
Net (Gain) Loss on dispositin of capital assets	-
Future Income Taxes	-
Employee Benefits Expense	305,868
	2,812,066
Changes in Non-Cash Working Capital Items:	
Accounts Receivable	(1,242,874)
Due From Related Parties	(685,090)
Unbilled Revenue	(3,858,750)
Inventories	(316,033)
Prepaid Expenses	(68,386)
Current Regulatory Assets - Payable	609,807
Accounts Payable & Accruals	(51,663)
Due to Related Parties	1,424,068
PILS Payable	182,358
Accrued Interest on Long-term Debt	198,298
Dividends Payable	(939,807)
Deposits - Billable Work	(706,876)
	(5,454,948)
Regulatory Balances - Long Term	(4,368,409)
Deposits - Energy Customers	147,644
NET SOURCE (USE) FROM OPERATING ACTIVITIES:	(4,522,327)
FINANCING ACTIVITIES:	
Hydro One Low Voltage Charges Payable - Long Term	-
Dividends on common shares	-
Contributed Capital	14,008
NET SOURCE (USE) FROM FINANCING ACTIVITIES:	14,008
INVESTING ACTIVITIES:	
Plant, Property and Equipment Additions	(5,345,496)
Proceeds on disposition of capital assets	-
Other	-
NET SOURCE (USE) FOR INVESTING ACTIVITIES:	(5,345,496)
NET CASH INFLOW (OUTFLOW)	(9,853,815)
CASH POSITION, BEGINNING OF PERIOD	7,872,876
CASH POSITION, END OF PERIOD	$ (1,980,939)

YTD O&M ACTUAL, BUDGET AND VARIANCE

As at August 31, 2010

Branch	(All)
Cost Center	(All)
Month	(All)

Dist or Non	Account Name	Actual $	Budget $	Variance
Dist	Labour	1,870,237	2,096,189	(225,952)
	Consulting	21,895	67,114	(45,219)
	Bad Debt Expense	54,115	93,592	(39,477)
	Insurance	81,128	113,336	(32,208)
	Extended Benefits-NonDist	(29,942)	-	(29,942)
	OMERS	315,373	344,985	(29,612)
	Training	35,040	61,106	(26,066)
	Salary	2,306,269	2,325,177	(18,908)
	Overhead-NonDistribution	(15,465)	-	(15,465)
	Stores-Mtc Ovhd Conductors	19,412	33,936	(14,524)
	Oil Disposal & Testing	1,410	13,336	(11,926)
	Transformer Maintenance	-	10,824	(10,824)
	Community Relations	23,657	34,000	(10,343)
	Software Maintenance	153,942	163,352	(9,410)
	Payroll Accrual	(165,198)	(156,865)	(8,333)
	ESA Assessment	13,636	20,000	(6,364)
	Travel	35,733	42,033	(6,300)
	T1 Internet	17,111	23,360	(6,249)
	Awards	1,100	7,100	(6,000)
	Fuel	68,846	74,640	(5,794)
	Advertising	8,542	13,350	(4,808)
	Education Assistance	10,369	13,910	(3,541)
	Environmental Issues	-	3,336	(3,336)
	Audit Fees	25,835	29,064	(3,229)
	Lawn Care	791	4,000	(3,209)
	Thermovision	8,682	11,536	(2,854)
	Prudentials	23,562	26,304	(2,742)
	Legal Costs	15,740	18,336	(2,596)
	Vehicle Maintenance	91,176	93,768	(2,592)
	Car Allowance	29,690	32,080	(2,390)
	Collection Charge	16,184	18,464	(2,280)
	Fitness Expense	4,292	6,564	(2,272)
	Safety Promotion	(923)	1,336	(2,259)
	Boot/Clothing Allowance	4,370	6,474	(2,104)
	GWL Retired	113,866	115,915	(2,049)
	Print Consumables	8,969	10,664	(1,695)
	Research Studies	-	1,636	(1,636)
	Cleaning Supplies	5,215	6,736	(1,521)
	Reel Deposits	-	1,336	(1,336)
	Hay Evaluation	-	1,000	(1,000)
	Non Stock	1,233	2,136	(903)
	Internet	5,154	6,040	(886)
	Janitorial Services	7,994	8,864	(870)
	Bank Service Fees	12,264	13,096	(832)
	EBT Hub Services	13,657	14,400	(743)
	OEB Assessment	78,427	79,104	(677)
	Rentals	-	672	(672)
	Building Materials	2,013	2,664	(651)
	Meals	44,390	45,009	(619)

Dist or Non	Account Name	Actual $	Budget $	Variance
Dist	Manholes & Vaults	461	1,000	(539)
	Communications Voice	135	660	(525)
	Vehicle Lease	1,555	2,080	(525)
	Security System	1,170	1,664	(494)
	Executive Health	1,200	1,664	(464)
	Answering Service	2,383	2,832	(449)
	SCADA	8,233	8,680	(448)
	Communications	1,453	1,832	(379)
	Snow Removal	2,465	2,751	(286)
	Web Page	1,144	1,336	(192)
	Licences	75	264	(189)
	Rec Club	740	920	(180)
	Contracted Services - BWPS	25,181	25,336	(155)
	Stores - Mtce on Meters	374	496	(122)
	Cash Over & Short	(84)	-	(84)
	Lawnmower R&M	-	68	(68)
	Freight	-	64	(64)
	Pest Control	54	112	(58)
	Chainsaw R&M	118	153	(35)
	Permits	3,333	3,336	(3)
	Rate Application Costs	65,536	65,536	(0)
	Capital Tax	43,336	43,336	-
	CNR Lease	9,001	9,000	1
	Joint Pole Use	8,961	8,936	25
	Safety Meetings	2,129	2,000	129
	Locates	10,142	10,000	142
	Building Maintenance	(9,872)	(10,024)	152
	EAP	2,138	1,943	195
	Payroll Fees	7,141	6,664	477
	Fire Safety	3,015	2,536	479
	Subscriptions	1,900	1,386	514
	Records Management	2,388	1,760	628
	Vehicle Licence	7,165	6,496	669
	Memberships	41,802	41,128	674
	Locksmith	1,387	664	723
	Secured Delivery	2,014	1,264	750
	Computer Infrastructure	2,190	1,336	854
	GWL ADD	4,333	3,444	889
	Plumbing	1,978	1,064	914
	GWL Emp Life	13,183	12,252	931
	Postage	91,552	90,560	992
	Bonus	1,008	-	1,008
	Employee Costs	22,755	21,636	1,119
	Life Ins Mearie Retiree	47,337	45,960	1,377
	Safety Supplies	10,649	8,600	2,049
	Electrical	3,682	1,464	2,218
	Waste Disposal	14,826	12,320	2,506
	Hardware	14,914	12,319	2,595
	LTD	72,417	69,738	2,679
	Life Ins Mearie Active	14,131	11,397	2,734
	Tools	22,184	19,106	3,078
	GWL Emp Dent	63,111	59,903	3,208
	Property Tax	113,587	110,248	3,339
	CPP	186,422	183,026	3,396
	Workplace Safety Insurance	48,295	44,875	3,420
	Door Maintenance	4,764	1,336	3,428
	Forms	19,757	16,232	3,525
	Stores-Mtc Poles, etc	12,197	8,664	3,533

Dist or Non	Account Name	Actual $	Budget $	Variance
Dist	EI	92,576	88,977	3,599
	Heating & cooling	8,448	4,664	3,784
	F.R. & Safety Clothing	18,845	14,760	4,085
	Telephony	42,529	38,336	4,193
	Vacuum Excavation	9,193	5,000	4,193
	Stores-Mtc Ungd Conductors	15,658	10,400	5,258
	Cell Phone/Blackberry	39,384	33,832	5,552
	Utilities	82,489	76,664	5,825
	Contract Employees	100,789	94,959	5,830
	Equipment Testing	20,187	14,000	6,187
	Stationery Supplies	11,894	5,694	6,200
	Donations	39,552	33,328	6,224
	Photocopiers	12,350	5,336	7,014
	GWL Ext Active	187,863	180,107	7,756
	Health Tax	100,537	89,850	10,687
	Insulator Washing	32,992	22,000	10,992
	Miscellaneous Supplies	26,950	15,600	11,350
	Tree Trimming	119,875	103,336	16,539
	Students	115,025	84,589	30,436
	Billable - Other	381,368	327,736	53,632
	Contracted Services	119,667	61,464	58,203
	Overtime	388,475	220,336	168,139
Dist Total		**8,339,879**	**8,469,330**	**(129,451)**

NonDist	Labour	119,523	133,069	(13,546)
	Extended Benefits-NonDist	19,878	26,585	(6,707)
	Vehicle Costs	2,734	3,096	(362)
	Computer Infrastructure	1,591	1,952	(361)
	Payroll Burden	15,648	15,942	(294)
	Property Maintenance	9,872	10,024	(152)
	Forms	4,263	4,368	(105)
	Software Maintenance	12,981	13,040	(59)
	Property Tax	2,118	2,160	(42)
	Water Billing Interest Charge	2,258	2,264	(6)
	Salary	6,417	6,417	(0)
	Water Billing ROIC	38,304	38,304	-
	Meals	60		60
	Postage	17,694	17,440	254
	Overtime	1,717	-	1,717
	Contract Employees	24,628	9,608	15,020
NonDist Total		**279,688**	**284,269**	**(4,581)**

Grand Total		**8,619,566**	**8,753,599**	**(134,033)**

Less:	Lines & Design Cap'd Labour	(583,958)	(983,803)	399,845
	IT Capitalized Labour	(521,568)	(357,887)	(163,680)
	Metering Capitalized Labour	(14,393)	(7,000)	(7,393)
	Other Capitalized Labour	(46,426)	(9,000)	(37,426)
	Total Capitalized Labour	**(1,166,344)**	**(1,357,690)**	**191,346**
	OEB O&M Net of Cap'd Labour	**7,453,223**	**7,395,909**	**57,314**

1.0 - SEC 43 - Payroll budget

[1.0 SEC-11] Please provide the requested payroll budget with all names of individuals, positions, and other identifying features removed. Restating the document to aggregate the budget numbers by department would also be acceptable.

Bluewater Power is a mid-sized utility and many of its departments employ one to three employees. The Filing Guidelines state at page 30 "*Where there are three or fewer employees in any category, the applicant should aggregate this category with the category to which is most closely related. This higher level of aggregation should be continued, if required, to ensure that no category contains three or fewer employees*." Accordingly, the information requested has been provided by allocating Union, Non-Union, Contract and Students amongst the three operational areas, being Corporate, Operations and Customer Service.

Table 1 – Payroll by Department

Summary by Department	Payroll Budget
Board of Directors	106,515.00
Executive	1,607,940.00
Customer Service	1,170,261.00
Corporate Services	1,881,697.00
Operations	3,531,914.00
Total	**8,298,327.00**

1.0 - SEC 44 - Weighted average rate increase

[1.0 SEC-12] Please explain why the Applicant does not believe the agreed percentages reflect weighted average rate increases.

The term “weighted average rate increase” is not a defined term and it is simply the use of that term to which Bluewater Power objects. We have provided the calculation requested by the Interrogatory, but we find the label to be potentially confusing.

File Number: EB-2012-0107

Date Filed: March 8, 2013

BLUEWATER POWER DISTRIBUTION CORPORATION

Tab 2 of 9

Exhibit 2 - Rate Base

2.0 - Staff 62 - Capital Expenditures

Ref: 4.8-2-Staff-7

Bluewater Power has provided preliminary 2012 actual capital expenditures on a MIFRS basis. The preliminary actual expenditure of $8,211,489 is lower than the expenditure of $9,132,166 forecast in the application filed on October 22, 2012. Bluewater Power states that the actual results are subject to review through the audit process, and that the impact of 2012 actuals has not been reflected in rate base. Please provide the status of the audit process and advise when the 2012 actual capital expenditure will be reflected in rate base.

Bluewater Power's financial statement audit for the year 2012 will commence with its external auditors on March 4, 2013. We anticipate the auditors will complete their on-site work by March 15th, 2013 and any adjustments should be known at that time. The 2012 audited financial statements will be approved by the Board of Directors on April 25th, 2013.

2.0 - Staff 63 - Capital Project UT39

Ref: 4.17-2-Staff -10

Project UT39 is a $223,211 capital expense "on implementing upgrade improvements to SAP and connected Operations software to improve workflow efficiencies in Maintenance, Asset Management, Dispatch and Supply Chain." Part (b) of Staff IR #10 sought the measures that Bluewater Power will use to measure the improvements in workflow efficiencies. The response stated:

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

The scope and expected results of this project are unclear. What specific measures will Bluewater Power use to measure the improvements in workflow efficiencies?

The goal of this process optimization project is to streamline the workflow within and between the Engineering, Supply Chain, Lines, Control Room, and Metering departments. It is expected that the recommendations of the assessment phase will include realignment of workflows and improvements to data management, along with supporting technology modifications. Measurement of key performance indicators will form a critical element of the design effort, however, the goal will be to better manage the capital budget as well as O&M work within the whole of the Operations Department. Accordingly, it is anticipated that the achievement of capital and O&M work within budgets will be the primary metric.

2.0 - Staff 64 - IT Asset Management Strategy

Ref: 4.21-2-Staff-14

Bluewater Power indicated that it has no formal IT Asset Management Strategy, but provided a summary of the practices it follows for management of IT assets. How do these practices manage the 21 IT capital projects, so that common requirements, such as system testing, are co-ordinated where possible?

Certainly, the volume of effort involved in provisioning IT services is significant. However, having in place, practices such as those laid out in response to the initial question, and referred to above, make it possible to address the IT capital projects identified and planned for in 2013.

With respect to the interrelation of the 21 identified projects, further coordination of effort is achieved during the planning processes. Each year, a capital project plan is created that identifies the whole of the project effort and schedules that effort in the most efficient manner possible. Regular capital progress meetings are held to ensure timelines are being met, and further coordination of effort between projects is identified, and where possible, executed accordingly.

2.0 - Staff 65 - CN Lease

Ref: 4.25-2-Staff-16

Bluewater Power states that the annual cost of the CN lease has not been removed from the 2013 forecast as the lump sum payment to CN is not expected to be paid until the end of 2013. What is Bluewater Power's proposal for the CN lease during the IRM period?

There is no proposal to adjust the expense during the IRM period, in the same way that Bluewater Power will have no mechanism to adjust new costs that are incurred during the IRM period. In any event, a $13,500 O&M adjustment would not be material during the IRM period.

2.0 - Staff 66 - Reliability

Ref: 4.28-2-AMPCO-6

Ref: 4.26-2-Staff-17

Staff IR 17 queried Bluewater Power reliability performance and specifically questioned what additional measures were put in place following the incident related to the failed arrestor. Bluewater Power replied that arrestor failure is impossible to predict without performing destructive testing. AMPCO IR 6 queried the reliability programs that Bluewater Power has in place to address reliability issues faced by the Large User class. Bluewater Power replied that in some cases, arrestors have been replaced proactively. Please reconcile these two positions.

In regard to Staff IR-17, arrestor failure is of concern to our distribution system, however it is not of the highest priority which is why they are not proactively replaced across our distribution system. Porcelain cap and pin style insulators have a higher probability and frequency of failure therefore we have an ongoing capital replacement program for insulators. Our asset management program identifies nearly 100 rotten poles a year. However, when arrestors fail on all feeders we replace the failed arrestor. We also inspect those in the immediate vicinity for any possible deficiencies. If we suspect that they are degrading and/or suspected of failing in the near future we will replace them as well.

In regard to AMPCO IR-6, and the large user class, based on Bluewater Power and/or customer identified concerns we have assessed the feeders that specifically feed those large users and in some locations have installed animal protection. While completing those installations we inspected, assessed and replaced arrestors proactively where necessary.

2.0 - EP 35 - Continuity for 2013

Ref: 2.0-Energy Probe-11 &
1.0-Energy Probe-2

Given that Bluewater will not be converting to IFRS in 2013, please provide a continuity schedule for 2013 based on Modified CGAAP (modified for the change in capitalization and depreciation), based on the 2012 CGAAP preliminary actuals continuity schedule provided in 2.0-Energy Probe-11.

As discussed in the response to 1-Staff-59, we are unable to provide the information requested at this time but we will provide a response as early as possible.

2.0 - EP 36 - Depreciation for 2012

Ref: 2.0-Energy Probe-9

Has Bluewater Power now had sufficient time to determine and analyse the monthly data for 2012 to provide an estimate of the Recorded depreciation for 2012?

At the time of writing this response, Bluewater Power has finalized its 2012 capital expenditures and depreciation expense in preparation for its audit scheduled to commence on March 4, 2013. Subject to any findings during the audit, Bluewater Power does not anticipate any changes to its figures. Please see the following updated table with respect to 2-EP-9 for the 2012 updated unaudited depreciation expense.

	2009	2010	2011	2012
Recorded	3,968,013	3,939,847	4,259,216	4,567,186
Half year rule	3,983,192	3,946,142	4,289,958	4,656,610
Difference	(15,179)	(6,295)	(30,742)	(89,424)

2.0 - SEC 45 - e-billing

[2.0 Staff-12] Please provide any reports, analyses, memoranda, presentations, forecasts, or other documents dealing with the anticipated impact of e-billing on postage and other billing costs, collections, or working capital requirements, or on how billing costs should be allocated between the Applicant and its affiliates.

Bluewater Power launched MyAccount in July, 2010. This initially gave customers access to view their account information, look at reproductions of their bills, and make minor changes to customer information. In 2012, with the introduction of Time of Use Billing, this service was expanded to include access to customer electricity consumption in hourly intervals up to the day before. In the next phase of development to MyAccount, Bluewater Power is implementing 'Paperless Billing' in response to customer requests for the service. This feature is scheduled to become available to customers near the end of Q1 in 2013.

With respect to the request for documents dealing with the anticipated impact of e-billing on postage, billing costs, collections, or working capital requirements there are no such documents on those issues.

With respect to the allocation of costs to affiliates, the matter is addressed in the Transfer Pricing Study based on data available in the summer of 2012. The Transfer Pricing Study has set the amount allocated to affiliates for billing related costs for the year 2013, which will continue until the Transfer Pricing Study is updated. Any savings or increases in costs will be included in the allocation related to billing as applicable when the Transfer Pricing Study is updated.

2.0 - SEC 46 - IFRS upgrade

[2.0 Staff-13] Please provide a breakdown of the figure of $543,886.

The correct figure is $542,886 as per Exh 9-2-1. This amount is made up of the following:

$ 41,508	Internal Labour
$ 474,162	Deloitte Consulting
$ 27,216	SAP Canada
$ 542,886	

2.0 - SEC 47 - Building

[2.0 Staff-15] Please provide a space plan including detailed floor plan for the renovated building. If such a plan is not available, please break down the 28,000 square feet of space into categories, including at least

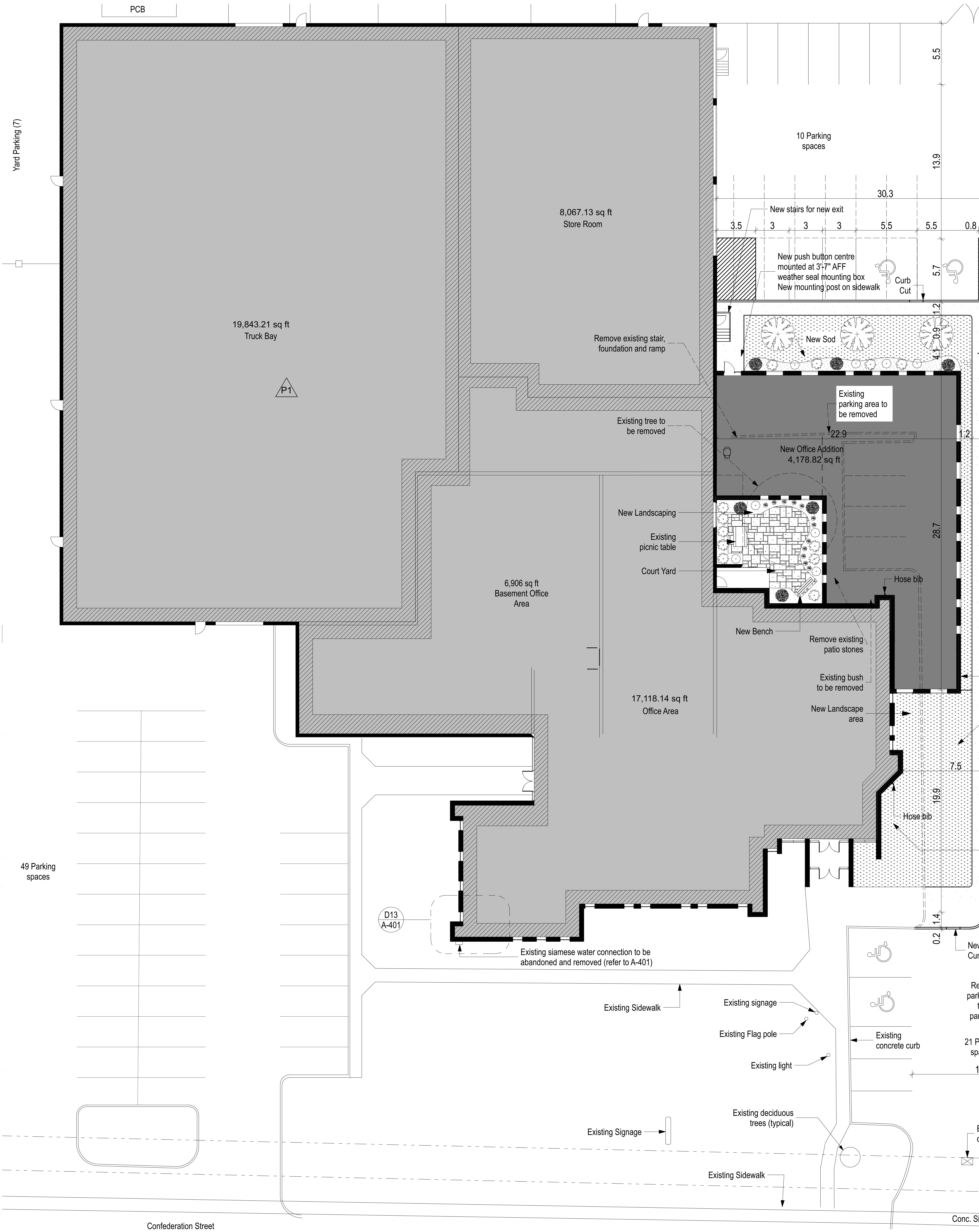
a. Offices
b. Meeting rooms
c. Reception and similar areas
d. Areas for cubicles or other common office areas
e. Training facilities
f. Locker room and similar facilities
g. Workshops and similar operational areas
h. Garages
i. Other

Please find as Attachment 1 a floor plan depicting the entire building, with the addition marked as 'New Office Addition' on the right side of the plan and Attachment 2 which is a detailed plan of the addition only, indicating the use of the space. There are 16 offices, one cubicle, and 1 meeting room in the addition which would incorporate labels "'a-f" as noted above.

The area designated' truck bay' in Attachment 1 includes items "g" and "h" as noted above, but that was not part of the addition.

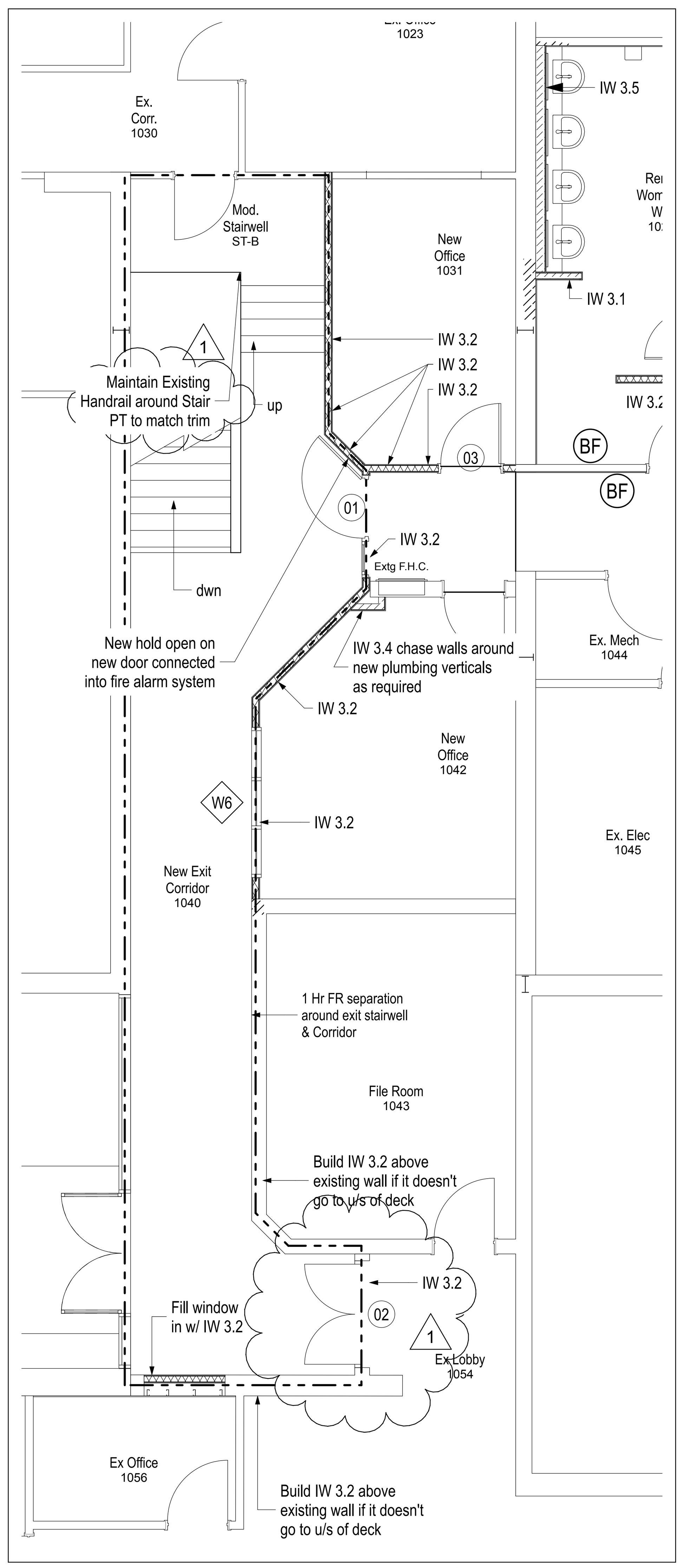
Attachment 1 of 1

2.0 - SEC 47 - New Addition Floor Plan



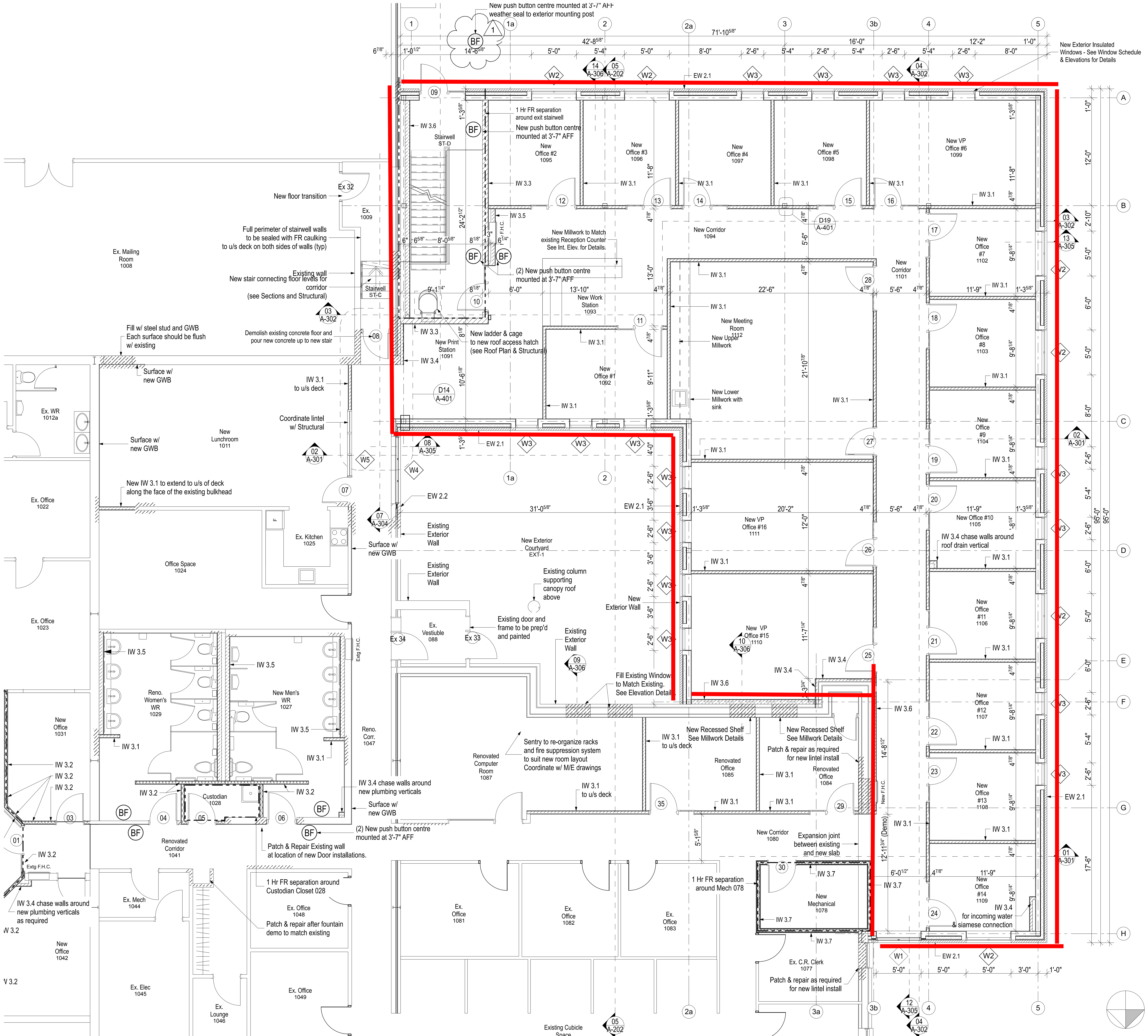
Site Plan Enlarged

SCALE: 1:200



1 Enlarged Floor Plan of Restored Exit

SCALE: 3/16" = 1'-0"



2 Enlarged Floor Plan of Addition

SCALE: 3/16" = 1'-0"

N

D G A

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ONTARIO ASSOCIATION OF ARCHITECTS David Gilchrist LICENCE

Stamp IFC-0 June 13, 2012

DRAWING USE

Bluewater Power Office Addition 2012

DRAWING STATUS:

IFC

PROJECT LOCATION
855 Confederation
Sarnia
Tuesday, June 12, 2012
Drawing set printed on 12-06-12

DRAWING STATUS: Mark
SK-num. = Sketch in Progress: R-num. = Review:
T-num. = Tender Document C-num. Construction Issue:
CO-num. = Change Order

STATUS AS OF: June 13, 2012

R-1	12-03-09	Revised Floor plan
R-3	12-05-07	For Review
P-0	12-05-07	Issued for Permit
T-0	12-05-07	Issued for Tender
A-1-4	May 5-31st	Addenda
P-1	12-06-12	Issued for Permit
IFC-0	12-06-12	IFC
STATUS	DATE	DESCRIPTION

PROJECT NO: 211357
MODEL FILE: BWP Office 1.6 [dgaserver.com]
DRAWN BY: R.Burkhart, A. Tsotos
CHK'D BY: DGA

SHEET TITLE

Enlarged Addition Floor Plan

A-103

2.0 - SEC 48 - Building and 2nd Floor provision

[2.0 Staff-15] Please provide any reports, analyses, memos, presentations, or other documents relating to the expansion of the building, including any presentations to the City connected with the approval of that expansion plan. With respect to the presentation to the Board of directors, please explain the "second floor future provision".

Board documents related to the approval of the building expansion were included in our original response to Board Staff 15. There was no presentation to the City connected with the expansion plan for the building.

The "second floor future provision" referred to the opportunity to add a second floor over the new addition when the need for further expansion is required. This option was selected because the addition required heavier than normal structural steel to be installed to ensure required snow loading specifications were met. Had the structural steel not been increased at time of construction, the second floor option would be an impractical and cost prohibitive possibility for the future. Given this provision, a cost of approximately $12,000 was incurred upfront which has negated the need for very significant future spending to accommodate growth.

2.0 - SEC 49 - Depreciation rates

[2.0 SEC-18] Please confirm that the review of the depreciation rates, and the decisions with respect to the new rates, were made without any documentation whatsoever. If not confirmed, please provide any documentation of that review and those decisions.

The review of depreciation rates was conducted internally by the CFO in consultation with the Manager of Lines and the Manager of Design Services. As the rates fell within the recommended range found in the Kinetrics' Report, it was determined that no further documentation was required. The issue of depreciation rates was not considered by the Board of Directors, although the issue was addressed with the Audit Committee and with the entire Board at the time of approval for the annual budget.

2.0 - AMPCO 15 - Outage management

Reference: 2.0-AMPCO 6, Tab 4, Schedule 28

a) Please provide a breakdown of the number of momentary outages by cause for the years 2009 to 2012.

Table 1 – Momentary Outages by Cause

Causes	2009	2010	2011	2012
0-Unknown	12	23	19	25
1-Scheduled	0	0	1	0
2-Loss of Supply	14	11	12	19
3-Tree Contacts	1	2	9	1
4-Lightning	21	13	53	15
5-Defective Equipment	20	27	39	21
6-Adverse Weather	12	16	37	49
7- Adverse Environment	0	0	0	0
8- Human Element	0	9	8	3
9- Foreign Interference	12	14	30	15

b) With respect to comparing Bluewater Power with other utilities in its cohort in terms of reliability, Bluewater Power indicates it does not believe that the data that is gathered in the OEB Yearbook in regard to reliability at this point provides an adequate basis in order to compare utilities. Bluewater Power indicates until the reliability definitions and standards have been revised, fully understood and implemented by distributors there is no basis on which to compare one utility with another.

Please discuss what Bluewater Power has done in the past, prior to EB-2010-0249, to compare its reliability data to other utilities in its cohort and include any comparative analysis.

Bluewater Power has not compared its reliability data to other utilities given the concerns with the data noted in response to 2.0 – AMPCO 6 part (g). Our Operation's group focuses on our own history as its primary comparison and takes a continuous improvement approach. The Operations Group provides monthly reports to Senior Management and reports to the Board of Directors five times annually on outage management. At this point in time, managing outages to our own historical performance is more of a priority than undertaking comparative analysis with other utilities based on suspect data.

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Tab 3 of 9

Exhibit 3 - Revenue

3.0 - Staff 67 - CDM Impact

Ref: 5.16-3-Staff-24
Ref: 5.18-3-VECC-21

Bluewater Power provided the derivation of its proposed adjustment to account for the impacts of CDM in response to Staff IR 24. Bluewater Power also provided the final 2006-2010 CDM Impacts and 2011 CDM Impact Reports as reported by the OPA in response to VECC IR 21.

Board staff observes that the adjustment for historical CDM takes the annual cumulative results as reported by the OPA for each year from 2006 to 2011 and then averages these. However, the results reported by the OPA are annualized, i.e. assume that the program is in place for the full year. For example, the 2006 'net' CDM impacts on 2006 are reported as 2,450,277 kWh. This estimate would only be true if the 2006 CDM programs were fully in place at the stroke of midnight on January 1, 2006. Clearly, they are not. In the absence of detailed information of when the programs took place, when results started to show, and seasonal patterns of CDM impacts, a half-year rule might be a better approach for estimating the actual impact in the first year of a CDM program. The persistence into subsequent years should be on the full-year "annualized" basis.

In using the annualized results, the average annual impact of 2006-2011 CDM programs is likely overstated. Why does Bluewater Power believe that average annual impact based on annualized CDM impacts is appropriate for their adjustment to account for historical CDM on the base forecast?

Bluewater Power relies solely on the final reporting's of the OPA CDM project initiatives as reported by year and would suggest that it relies on the OPA internal reporting practices to fairly and accurately report program initiations and terminations. Subject to alternative prescriptive direction being provided, Bluewater Power is not in a position to qualify the OPA reporting practices.

3.0 - Staff 68 - CDM Adjustment

Ref: 5.16-3-Staff-24

Ref: 5.18-3-VECC-21

Bluewater Power has proposed to use a CDM target of 30% as the CDM adjustment for the 2013 load forecast amount to take into account the persistence of 2011 and 2012 CDM programs, and the impact of 2013 CDM programs on 2013 demand (consumption, measured in kWh).

An alternative approach is to take into account the 2011 results and their persistence, as measured and reported by the OPA for Bluewater Power, and then to assume an equal increment for each of 2012, 2013, and 2014 so as to achieve Bluewater Power's CDM target of 53,730,000 kWh. Board staff views that this approach is preferable as there are results on what the utility has achieved to date, and hence what more will be needed to achieve the cumulative four-year target. In using the measured and reported results from the 2011 programs, including the persistence into 2013, Board staff views that an improved estimate of the CDM impact of 2011-2013 programs on the LRAMVA threshold for 2013 (and 2014) would result, along with the corresponding adjustment to the 2013 test year load forecast.

Based on the final 2011 OPA results provided in response to VECC IR 21, Board staff has prepared the following table, which is also provided in working Microsoft Excel format:

Load Forecast CDM Adjustment Work Form (2013)

Bluewater Power Inc. ***EB-2012-0107***

4 Year (2011-2014) kWh Target:					
53,730,000					
	2011	2012	2013	2014	Total
%					

2011 CDM Programs	9.89%	9.67%	9.67%	9.61%	38.85%
2012 CDM Programs		10.19%	10.19%	10.19%	30.58%
2013 CDM Programs			10.19%	10.19%	20.38%
2014 CDM Programs				10.19%	10.19%
Total in Year	**9.89%**	**19.87%**	**30.06%**	**40.19%**	**100.00%**
kWh					
2011 CDM Programs	5,313,187	5,198,072	5,198,072	5,162,989	20,872,319
2012 CDM Programs		5,476,280	5,476,280	5,476,280	16,428,840
2013 CDM Programs			5,476,280	5,476,280	10,952,560
2014 CDM Programs				5,476,280	5,476,280
Total in Year	**5,313,187**	**10,674,352**	**16,150,632**	**21,591,829**	**53,730,000**
				Check	53,730,000

Net-to-Gross Conversion	**"Gross"**	**"Net"**	**Difference**	**"Net-to-Gross" Conversion Factor ('g')**
2006 to 2011 OPA CDM programs: Persistence to 2013	1	1	0	0.00%

	2011	**2012**	**2013**	**2014**	**Total for 2013**
Amount used for CDM threshold for LRAMVA	5,198,072	5,476,280	5,476,280		16,150,632
Manual Adjustment for 2013 Load Forecast	5,198,072	5,476,280	2,738,140		13,412,492
Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g)			*Only 50% of 2013 CDM impact is used based on a half year rule*		

1

The methodology for this is as follows:

For the first table

- The 2011-2014 CDM target is input into cell B4;
- Measured results for 2011 CDM programs for each of the years 2011 and persistence into 2012, 2013 and 2014 are input into cells C13 to F13;

Based on these inputs, the residual kWh to achieve the 4 year CDM target is allocated so that there is an equal incremental increase in each of the years 2012, 2013 and 2014.

The second table is to calculate the conversion from “net” to “gross” results. While the LRAMVA is based on the “net” OPA-reported results, the load forecast is impacted also by CDM savings of “free riders” and “free drivers”. While Board staff has input values of “1” in each of cells D24 and E24, in the absence of information, these should be populated with the measured “gross” and “net” CDM savings for the persistence of all CDM programs from 2006 to 2011 on 2013, as reported in the final OPA reports.

For the last table, two numbers are calculated:

- The “Amount used for CDM threshold for LRAMVA” is the sum of the persistence of 2011 and 2012 CDM programs and the annualized impact of 2013 CDM programs on 2013; and
- “Manual Adjustment for 2013 Load Forecast” represents the amount to be reflected in the 2013 load forecast. This amount uses the “gross” impact, which is calculated by multiplying each year’s CDM program impact or persistence by (1 + g) from the second table. In addition, the impact of the 2013 CDM programs on 2013 “actual” consumption is divided by 2 to reflect a “half year” rule. Since the 2013 CDM programs are not in effect at midnight on January 1, 2013, the “annualized” results reported in the OPA report will overstate the “actual” impact. In the absence of information on the timing and uptake of CDM programs in their initial year, a “half-year” rule may proxy the impact.

a) Please input the “gross” and “net” cumulative kWh CDM savings from all CDM programs from 2006 to 2011 on 2013 as measured in the final OPA reports into, respectively, cells D24 and E24.

Please Reference excel workbook “LFCDMWF_Bluewater_Power_20130222.xlsx“ filed with this response.

		Net-to-Gross Conversion "Gross"	"Net"	Difference	"Net-to-Gross" Conversion Factor ('g')
2006 to 2011 OPA CDM programs: Persistence to 2013		22,004,666	13,518,553	8486113.02	62.77%

	2011	2012	2013	2014	Total for 2013
Amount used for CDM threshold for LRAMVA	5,198,072	5,476,280	5,476,280		16,150,632
Manual Adjustment for 2013 Load Forecast	8,461,100	8,913,951	4,456,975		21,832,026
Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g)			*Only 50% of 2013 CDM impact is used based on a half year rule*		

b) Please verify the inputs and results of the model.

Bluewater Power confirms the inputs and results of the model “LFCDMWF_Bluewater_Power_20130222.xlsx”

c) Please derive the class CDM kWh and kW savings that would correspond with the “net” CDM savings above.

Bluewater Power presents the following subject to clarification by Board Staff.

Table 1 - kWh Calculation

Year	2013 CDM Threshold (kWh of incremental CDM savings needed in 2013)	Application Factor 1.0 Full Year 0.5 Half Year	2013 Net kWh Load Forecast CDM Adjustment before Gross-Up	2013 Net to Gross Adjustment	2013 Load Forecast CDM Adjustment
	A	B	C = A * B	D	E = C * (1 + D)
2011	5,198,072	1.0	5,198,072	62.8%	8,461,100
2012	5,476,280	1.0	5,476,280	62.8%	8,913,951
2013	5,476,280	0.5	2,738,140	62.8%	4,456,975
	16,150,632		13,412,492		21,832,026

Based on the above kWh calculation the possible allocation to rate class would be as follows:

	Weather Normalized 2013F (Elenchus)		LRAMVA Allocation (kWh)	Net to Gross Load Forecast Adjustment (kWh)	Weather Normalized 2013F CDM Adjusted (kWh)	
	A		B	C	D = A - C	
Residential (kWh)	259,773,254	26%	4,162,607	5,626,909	254,146,345	
GS<50 (kWh)	99,956,659	10%	1,601,705	2,165,146	97,791,513	
GS>50 (kW)	225,433,209	22%	3,612,342	4,883,075	220,550,134	
Intermediate	159,155,521	16%	2,550,308	3,447,444	155,708,077	
Large Users	251,579,433	25%	4,031,309	5,449,424	246,130,009	
Street Lights (kW)	9,137,954	1%	146,427	197,936	8,940,018	
Sentinel Lights (kW)	627,674	0%	10,058	13,596	614,078	
USL (kWh)	2,238,935	0%	35,877	48,497	2,190,438	
Total Customer (kWh)	1,007,902,639	100%	16,150,632	21,832,026	986,070,613	-2.2%

kW Calculation using similar calculation as kWh.

Schedule to achieve 4 Year kW CDM Target

4 Year 2011 - 2014 kW CDM Target

10,650

%	2011	2012	2013	2014	Total
2011 Programs	29.7%	10.1%	10.1%	9.9%	59.7%
2012 Programs		6.7%	6.7%	6.7%	20.1%
2013 Programs			6.7%	6.7%	13.4%
2014 Programs				6.7%	6.7%
	29.7%	16.8%	23.5%	30.1%	100.0%

kWh	2011	2012	2013	2014	Total
2011 Programs	3,159	1,073	1,073	1,058	6,363
2012 Programs		715	715	715	2,144
2013 Programs			715	715	1,429
2014 Programs				715	715
	3,159	1,787	2,502	3,202	10,650

	2013 CDM Threshold (kW of incremental CDM savings needed in 2013)	Application Factor 1.0 Full Year 0.5 Half Year	2013 Net kW Load Forecast CDM Adjustment before Gross-Up	2013 Net to Gross Adjustment	2013 Load Forecast CDM Adjustment
	A	B	C = A * B	D	E = C * (1 + D)
Year					
2011	1,073	1.0	1,073	59.1%	1,707
2012	715	1.0	715	59.1%	1,137
2013	715	0.5	357	59.1%	569
	2,502		2,144		3,413

Based on the above kW calculation the possible allocation to rate class would be as follows:

	Weather Normalized 2013F (Elenchus) A		LRAMVA Allocation (kW) B	Net to Gross Load Forecast Adjustment (kW) C	Weather Normalized 2013F CDM Adjusted (kW) D = A - C	
Residential (kWh)		0%	-	-	-	
GS<50 (kWh)		0%	-	-	-	
GS>50 (kW)	622,378	45%	1,126	1,536	620,842	
Intermediate	335,318	24%	607	828	334,490	
Large Users	398,793	29%	722	984	397,809	
Street Lights (kW)	24,551	2%	44	61	24,490	
Sentinel Lights (kW)	1,452	0%	3	4	1,448	
USL (kWh)		0%	-	-	-	
Total Customer (kWh)	1,382,492	100%	2,502	3,413	1,379,079	-0.25%

d) Please provide Bluewater Power's comments on the methodology above to develop the CDM savings that will underlie the 2013 CDM amount for the LRAMVA and the corresponding CDM adjustment for the 2013 test year load forecast. What refinements to this approach should be considered? For example, since the 2011 actual results are impacted by 2011 CDM programs, should some adjustment (e.g. a half-year rule) be used to account for the fact that 2011 CDM programs would have impacted the 2011 actual results and, in a stochastic manner the resulting regression models and base forecast? Also provide Bluewater Power's views on whether this approach integrates with the adjustment to account for historical CDM impacts as discussed in Staff IR 24.

Bluewater Power has prepared the above as requested by Board staff but would be ambivalent to comment further subject to Board direction.

3.0 - EP 37 - Load Forecast

Ref: 3.0-Staff-21

Please provide the mean absolute percentage error based on the monthly data provided in the response to part (d).

This response must have been inadvertently cut off of the original response. The mean absolute percentage error for the data provided in response to part (d) (pertaining to the GS<50 class) is 3.2%.

3.0 - EP 38 - Load Forecast

Ref: 3.0-Energy Probe-14

Are the kWh and kW figures for 2012 provided in the response to part (a) in Tables 2 and 3 actual figures (with some forecasts) or normalized actuals (with some forecasts)? If yes, please provide Tables 2 and 3 replacing the 2012 Update figures with 2012 Update Normalized figures.

Energy Probe's question, as worded, is unclear.

The response provided in Energy Probe 14 states what is provided in the above referenced tables (see page 1 of 7 of response to Energy Probe 14, filed February 4, 2013), and a more detailed explanation of the data is contained in response to Energy Probe 15, page 2. This response was developed after consulting with Energy Probe and VECC in a telephone call arranged by Board Staff on January 24, 2013. Bluewater Power further confirmed its understanding of intervenors' requests in writing on January 28, 2013 and both VECC and Energy Probe confirmed that Bluewater Power had interpreted their requests correctly. Bluewater Power complied with these requests with respect to Tables 2 and 3 above, by providing the response to Energy Probe 14.

3.0 - EP 39 - Load Forecast

Ref: 3.0-Energy Probe-15

Please confirm that based on the response to part (l) of the question that the normalized actual figures for any given year are independent of the actual figures for that year, other than the actual data for that year was used in the estimation of the regression coefficients used to calculate the normalized actual figures.

Weather normalized consumption for Bluewater Power is based on the regression equations estimated using actual consumption data, as is explained in the response to part (l) of Energy Probe 15. Bluewater Power is unsure to what Energy Probe is referring to in referencing the term "normalized actual figures" as Bluewater Power believes normalized consumption is a calculated figure whereas actual consumption figures are what is observed. Bluewater Power is unaware of any requirement for distribution utilities to file "normalized actual figures" based on the Ontario Energy Board Filing Requirements for Electricity Transmission and Distribution Applications, last revised on June 28, 2012, nor can it find any reference to, or definition of, the term "normalized actual figures" in the OEB Filing Requirements.

3.0 - EP 40 - Other Revenue

Ref: 3.0-VECC-23 &
Exhibit 3, Tab 2, Schedule 1

a) Please show the actual revenues associated with retail service revenue (Table 4 in Exhibit 3, Tab 2, Schedule 1) and with SSS administration charge revenue (Table 6 in Exhibit 3, Tab 2, Schedule 1) for 2012.

<u>Table 1 – Retail Service Revenue with 2012 Actual</u>

	Account	2009 Board Approved	2009	2010	2011	2012 CGAAP	2012 MIFRS	2012 Actual	2013 IFRS
Retail Service Revenue (includes monthly charges, variable charges)	4082	68,097	60,838	56,983	48,541	50,000	50,000	39,362	46,297
Service Transaction Request revenue	4084	5,092	1,746	3,756	3,805	2,000	2,000	1,548	2,037
Total		73,189	62,584	60,739	52,346	52,000	52,000	40,910	48,334

<u>Table 2 – SSS Admin Fee revenue with 2012 Actual</u>

	Account	2009 Board Approved	2009	2010	2011	2012 CGAAP	2012 MIFRS	2012 Actual	2013 IFRS
SSS Administration Fee Revenue	4086	84,603	89,114	90,530	93,861	93,000	93,000	97,854	90,395

b) Please provide the 3 year average analysis for account 4086 referred in the response to VECC that resulted in the 2013 forecast of $90,394.

The precise three year average for 2009, 2010 and 2011 actual revenue for account 4086 is $91,168 based on the values presented in Table 1 in response to part (a) above.

3.0 - VECC 64 - Load Forecast GS<50

Reference: Staff #21 a)
Staff #21 b) (iii)

a) Please re-do the regression analysis for the GS<50 class omitting the employment variable and provide the resulting equation, regression statistics and projected consumption for 2013.

The regression analysis requested is shown below:

OLS, using observations 2006:01-2011:12 (T = 72)
Dependent variable: GSlt50kWh

	coefficient	t-ratio	p-value
const	-3839806	-2.11	0.038676
HDD_Wind	4940.678	17.65	6.87E-27
CDD_Wind	19084.47	18.07	1.84E-27
Monthdays	390606.4	6.54	9.91E-09
time	-21199.1	-9.13	2.28E-13

R-squared	0.88	Adjusted R-sq	0.87
F(4, 67)	125	P-value(F)	2.58E-30
Theil's U	0.3	D-W	1.67

Projected consumption for 2013 using the above regression equation would be 99,833,575.

b) Does Bluewater have any evidence that the trends (to box mall type locations outside the LDC's service area) discussed in Staff #21 b) are actually occurring in Sarnia? If yes, please provide.

The trends indicated in response to 3.0 – Staff 21(b)(iii) noted that "*…being replaced by retailers located in box mall type locations, that are likely not GS<50 customers, and depending on location, may be outside of the LDC's service area*." (underline added). In the case of Bluewater Power's territory, that trend is true, and over the last five years we have seen approximately four strip malls develop outside of the downtown area, and the development of a 'box type' mall with approximately sixteen stores, half of them being GS>50 accounts. All of these developments have been within Bluewater Power's service territory.

c) The response to Staff #21 b) suggests that GS<50 customers in (downtown) Sarnia have been closing. However, page 4 of the Elenchus Load Forecast indicates that the customer count has been increasing. Please reconcile.

There are a number of accounts that have been closing in Sarnia's downtown area, including a mall, but at the same time, there has been an increase in the number of new accounts in small strip malls which has outpaced the number of closures. Therefore there is a small increase in the customer count over the last five years (2007 to 2012) of 70 customers based on the 2012 updated customer count provided in response to 3.0 EP 14 (a), Table 2 which represents an overall increase over that time period of 2.1%, or 0.4% per year.

3.0 - VECC 65 - Load Forecast

Reference: Staff #22 c)

a) Please re-do the regression analysis for the Customer B omitting the employment variable and provide the resulting equation, regression statistics and the change in projected consumption for 2013 for Customer B.

The regression results and change in projected consumption are show below.

OLS, using observations 2010:01-2011:12 (T = 24)
Dependent variable: CustomerBkWh

	coefficient	t-ratio	p-value
const	370373	5.594	1.78e-05
time	-1387.62	-3.229	0.0042
CDD_Wind	455.543	11.44	3.17e-010
Peakdays	4364.92	1.673	0.1099

R-squared	0.88	Adjusted R-sq	0.86
F(3, 20)	50.1	P-value(F)	1.75e-09
Theil's U	0.4	Durbin-Watson	1.36

Using the above regression, the projected change in consumption for Customer B in 2013 would be –3,105 kWh, or approximately -0.07%.

b) Please provide revised versions of Tables 11 and 13 from the Elenchus Load Forecast using the results from part (a) for Customer B.

Revised forecasts are displayed below:

Revised Table 11

Year	Weather Normal GS>50 kWh
2013	225,430,103

Revised Table 13

Year	Weather Normal GS>50 kW
2013	622,369

Please note that the above analysis uses 18 peak days in February 2013 for comparison purposes.

3.0 - VECC 66 - Load Forecast

Reference: VECC 15 b)

a) Given the response to Staff #21 a) (i) regarding the significance of results with a t-ratio of 1.1 in empirical studies such as load forecast, please discuss the appropriateness of using the equation estimated in response to VECC 15 b) to forecast Residential load.

Bluewater Power believes that using the equation estimated in response to VECC 15 (b) would be inappropriate as the equation includes the number of customers as an explanatory variable. Bluewater Power has explained previously, in its response to Board Staff # 20 (a), why it believes that using an employment variable is superior. In addition, there is significant evidence that the number of customers does not perform well as a predictor of class consumption. This issue has been raised by Board Staff and intervenors in other LDC COS proceedings, for example in EB-2009-0259, where it was noted that the regression coefficients in that instance produced “counter-intuitive” signs.[1] For example, in response to VECC #15 (f), Bluewater Power provided regression results for the GS<50 class including customer counts as explanatory variables. In these instances, the signs on the coefficients were negative, which is what Board Staff and intervenors were concerned about in EB-2009-0259.

Given the mixed results with customer counts as an explanatory variable, the *a priori* information that customer counts may not be an accurate predictor of consumption, and the possibility that the relationship may not be stable and may change significantly over a short period of time and from class-to-class, Bluewater Power believes that the balance of the evidence is that it is not appropriate to include customer counts as an explanatory variable. Equally important, Bluewater Power’s consultant believes that it is important not to “cherry pick”

1 Burlington Hydro Inc. EB-2009-0259, Decision and Order, March 1, 2010.

variables to include in a regression equation in order to obtain a desired result. Elenchus has consistently used employment as a measure of economic activity for load forecast regression analyses and has refrained from using customer counts as an explanatory variable because of the inconsistent results it yields.

b) Please provide a forecast of 2013 residential load based on the equation estimated in response to VECC 15 b).

The requested results are provided below, with the proviso as described in response to part (a) of this request.

The regression calculated in response to VECC 15 (b) was:

OLS, using observations 2006:01-2011:12 (T = 72)
Dependent variable: ResKWh

	Coefficient	*t-ratio*	*p-value*
const	-4.16588e+07	-1.8434	0.06976
HDD_Wind	14186.3	16.8298	<0.00001
CDD_Wind	71817.4	22.7167	<0.00001
Monthdays	771643	4.2687	0.00006
W_S_FTE	38570.9	2.4909	0.01526
ResCust	754.216	1.1677	0.24714

R-squared	0.898970	Adjusted R-squared	0.891316
F(5, 66)	117.4538	P-value(F)	1.81e-31
Theil's U	0.32	Durbin-Watson	1.15

In order to develop a monthly customer series that averages to the forecast annual average, the December 2011 actual residential customer count was increased by a factor to generate an annual average customer count for 2012 of 31,954 (the forecast for the test year). The December 2012 value generated from this was then increased by a factor to generate an annual average customer count of 32,122, the forecast for 2013. Using these monthly figures along with the other explanatory variables, a forecast of 266,003,104 kWh results.

3.0 - VECC 67 - Large Use

Reference: VECC #14 a)

a) Please confirm that the "net LU kWh" shown in Table 16 of the Elenchus load forecast is based on the three existing LU customers. If not, what do the annual values represent?

Confirmed.

b) If part (a) is confirmed, please explain why annual growth rates are not the same as those shown in the response to VECC #14 a) – which is also based on the three current LU customers.

Table 1 presented in response to VECC 14 (a) contained a typographical error which is corrected in Table 1 below. The growth rates correlate to those presented in Table 16 of the Elenchus load forecast up to 2012 whereby Table 1 below uses 2012 actual data as compared to Table 16 in the Elenchus report which uses forecast data.

Table 1 – Average Annual Use per Customer, Large Use Class

Year	Large User	% change	# customers
2007	92,306,146		3
2008	86,839,759	-5.9%	3
2009	75,534,468	-13.0%	3
2010	85,983,685	13.8%	3
2011	84,576,579	-1.6%	3
2012	85,363,317	0.9%	3
2013 F	83,859,811	-1.8%	3

3.0 - VECC 68 - Other Revenue - Income and Deductions

Reference: Energy Probe #16

a) Please explain the material variance in the 2012 forecast vs. actual Other Income and Deductions.

See Table 1 below. The $111,667 variance between the 2012 CGAAP budgeted amount of $214,394 and the 2012 draft actual amount of $102,727 is primarily explained by net jobbing revenues. The net jobbing revenues (revenues less expenses) included in the 2012 budget was $189,394. The 2012 draft actual amount was considerably lower at $66,436. This results in a variance of $122,958.

Table 1 – Other Income and Deductions

	OEB Account	2012 CGAAP	2012 MIFRS	2012 Actual	2013 MIFRS
Revenues from Jobbing	4325	$ 757,575	$ 757,575	$ 521,097	$ 641,026
Expenses from Jobbing	4330	-$ 568,181	-$ 568,181	-$ 454,661	-$ 480,769
Gain on disposition	4355	$ 5,000	$ -	$ -	$ -
Loss on disposition	4360	$ -	$ -	-$ 5,422	$ -
Misc. non-operating income	4390	$ 20,000	$ 20,000	$ 41,713	$ 20,000
Total		$ 214,394	$ 209,394	$ 102,727	$ 180,257

b) Please explain the material variance in the 2012 forecast vs. actual Investment Income.

See Table 2 below. The $86,310 variance between the 2012 CGAAP budgeted amount of $169,332 and the 2012 draft actual amount of $255,642 is primarily explained by carrying charges income. This variance results in the 2012 draft actuals being higher by $52,630. The remaining variance of $33,680 is due to interest on bank accounts.

Table 2 – Investment Income – Account 4405

	2012 CGAAP	2012 MIFRS	2012 Actual	2013 MIFRS
Interest on advances to affiliates	0	0	0	0
Interest on bank accounts	23,610	23,610	57,290	33,610
Interest on promissory note receivable	84,955	84,955	84,955	
Carrying Charges Income	60,767	60,767	113,397	52,489
Total	169,332	169,332	255,642	86,099

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Exhibit 4 - Operating Costs

4.0 - Staff 69 - Charitable Donations

Ref: Exh 4-2-9

Ref: 6.10-4-VECC-27

At Exh 4-2-9, it states that "Bluewater Power has not included any amounts for charitable donations in its 2013 OM&A, and therefore nothing is included in revenue requirement." In response to VECC IR #27, it states that account 5410 "Sundry" captures amounts Bluewater Power provides to various agencies such as the Inn of the Good Shepherd. Bluewater Power states that the account increased in 2011 by $24,000 related to LEAP funding. Please confirm whether Bluewater Power has included any amounts for charitable donations in its 2013 OM&A.

Bluewater Power has not included any amounts for charitable donations in its 2013 OM&A. Please also refer to the response for 4-EP-43.

4.0 - Staff 70 - Compensation and unemployment rate

Ref: 6.36-4-Staff-33
Ref: 6.38-4-VECC-36
<u>Ref: Exh 3-1-2 Attachment 1</u>

Bluewater Power states that the 75th percentile for compensation for Executive and Management was selected for the purposes of retention and recruitment. In response to VECC IR #36, Bluewater Power notes competition from the Chemical Valley for staff.

a) What is average staff turnover in per cent for the period 2009 to 2012?

Bluewater Power's average staff turnover refers to the proportion of employees who have left the organization on an annual basis over the period from 2009 to 2012 expressed as a percentage of the total workforce over that same period. Our staff turnover encompasses all employees that leave the corporation, both voluntary and involuntary, including those who resign, retire or are made redundant.

For 2009 to 2012, the average annual turnover was 3%.

b) Bluewater Power's load forecast utilized full-time employment for the Windsor-Sarnia area as reported in Statistics Canada's Monthly Labour Force Survey. Please provide the Windsor-Sarnia unemployment rate from that survey and how that rate compares with other regions in Ontario, as reported by Statistics Canada.

Annual Unemployment Rate

	Windsor-Sarnia	Ontario
2011	9.0	7.9
2012	9.0	7.8

source: Statistics Canada Table 282-0054

4.0 - Staff 71 - Retirement Data

Ref: 6.45-4-Staff-34

Board staff provided a blank table for retirement data. Bluewater Power has populated the table, however, one item is missing. Please provide the prior period balance cumulative.

Table 1 – Retirement Data

Year	Eligible in Year	Eligible Cumulative	Actual Retirement in Year	Balance Cumulative
	A	B=A+D[1]	C	D=B-C
Prior Period				3
2009	3	6	1	2
2010	3	8	2	3
2011	6	12	6	3
2012	2	8	2	3
Total	14		11	

Note 1 - From previous period/year

4.0 - Staff 72 - Tax savings

Ref: 6.51-4-Staff-38

Ref: Exh 4-8-3, Attachment 1 – 2013 PILs model

In its response to part (d) of Board staff IR 38 with respect to adjusting the PILs provision to spread out the tax savings related to smart meter software, Bluewater Power stated that this treatment is no different than certain one-time costs that are spread evenly over the IRM period.

Please provide any regulatory precedent specifically for the one-time tax saving over the IRM period.

Bluewater Power is unaware of any specific precedent for the one-time tax savings over the IRM period.

There is likely no precedents of this nature as this requested PILs adjustment relates solely to the recent OEB mandated smart meter project and the resulting capital expenditures that Bluewater Power was required to incur.

4.0 - Staff 73 - smart meter software

Ref: 6.51-4-Staff-38

Ref: Exh 4-8-3, Attachment 1 – 2013 PILs model

In its response to part (b) of Board staff IR 38, Bluewater Power clarified that the capital expenditure of $770,255 for smart meter software was incurred in 2012 and allocated to Class 12 in 2012. In addition, Bluewater Power stated that the first 50% forms part of the total CCA deduction in 2012, and the remaining forms part of the total CCA deduction in 2013.

In the 2013 PILs model schedule 8 CCA for bridge year (2012), a total addition of $3,060,259 is included for Class 12 computer software. In the 2013 PILs model schedule 8 CCA for test year (2013), a total addition of $993,695 is included for Class 12 computer software and the UCC Test year opening balance for class 12 computer software is $1,530,130.

a) Please confirm that the smart meter computer software of $770,255 is included in the total addition of $3,060,259 in 2012 bridge year schedule 8 CCA.

Confirmed.

b) Please confirm that the UCC Test year opening balance for class 12 of $1,530,130 includes the second half of the $770,255 smart meter software expenditure.

Confirmed.

c) Please confirm that the 2013 addition of $993,695 for class 12 computer software on schedule 8 does not include the $770,255 smart meter software.

Confirmed.

d) If the answer to c) is yes, please explain Bluewater Power's justification of the proposed adjustment to spread the one-time tax saving of the smart meter computer software where there is no adjustment to spread the addition of $993,695 class 12 computer software in 2013.

In addition to the discussion in the pre-filed evidence in Exh 4-8-1 and the responses to all IRs regarding this proposed PILs adjustment, Bluewater Power can add the following argument.

The smart meter project that Bluewater Power completed was mandated and the $993,695 of expenditures in 2013 is discretionary. For the $770,255 smart meter software expenditures, Bluewater Power had no choice as it does with all other software related projects. As a result, the smart meter capital expenditures incurred were directly correlated to the existing software system that Bluewater Power uses and could not be avoided. It is known with certainty that the final CCA deduction related to these otherwise mandated smart meter software expenditures will occur in the 2013 test year. It is also known with certainty that there will be no further smart meter mandated expenditures, which are outside of the decision-making abilities of Bluewater Power, resulting in a material impact to PILs such as the $770,255 amount in the 2013 test year.

To reiterate the response from 4-Staff-38, part (d):

"Furthermore, if this treatment was not done, it would result in unfair and unjust rates during the IRM period, since rates during the IRM period would be deficient by assuming savings that do not exist."

4.0 - Staff 74 - Manual meter reads

Ref: 6.69-4-VECC-49

In its response to VECC IR 49, Bluewater Power notes that it still does about 430 meter reads monthly for GS > 50 kW demand metered customer through its affiliate at a cost of about $6.78 per meter read.

Board staff calculates this annual expense to be: $6.78 x 430 reads x 12 months = $34,984.80.

a) Where is this cost documented in Bluewater Power's OM&A?

This cost is included in OM&A account 5310 'Meter Reading Expenses'.

b) What were the costs for these meter reads for each year from 2009 to 2012?

Please refer to the response for 4-VECC-49(c). The approximate costs are:

2009: $9,288 = $1.80 x 430 reads x 12 months
2010: $9,546 = $1.85 x 430 reads x 12 months
2011: $9,804 = $1.90 x 430 reads x 12 months
2012: $26,677 = ($1.95 x 430 reads x 4 months) plus ($6.78 x 430 reads x 8 months)

Note: smart meter reading commenced approximately May 1, 2012.

4.0 - EP 41 - Account 5085

Ref: 4.0-Staff-25

How much of the increase in account 5085 is related to using MIFRS in 2013 as compared to using CGAAP?

None of the increase in Account 5085 is related to using MIFRS in 2013 as compared to using CGAAP.

4.0 - EP 42 - Account 5175

Ref: 4.0-Energy Probe-19 &
4.0-VECC-26

a) Please explain more fully the inclusion of the $648,986 in account 5175 in 2012.

This amount represents the cumulative smart meter OM&A expenditures approved in Bluewater Power's smart meter rate application EB-2012-0263 which covered the period 2006 to 2012.

As per FAQ #8 from 2008, these OM&A expenditures initially recorded in Account 1556 are reclassified to Account 5175 upon receipt of the Rate Order dated November 8, 2012.

b) When were these expenses actually incurred?

See the response to part (a) above.

c) Has Bluewater received a Board order that allows it to recover these smart meter OM&A costs through a rate rider? If yes, please indicate when the rider was approved and the term of the rider.

Yes. The rate order dated November 8, 2012 approved a six month rate rider for Residential customers and a 24 month rate rider for GS<50 customers.

4.0 - EP 43 - LEAP

Ref: 4.0-VECC-27

a) Please explain why payments made to the Inn of the Good Sheppard are not considered donations?

Payments made to the Inn of the Good Sheppard are to provide financial assistance funding for electricity consumers who may or may not be low income. This funding assists these consumers with paying their Bluewater Power electricity bills and are therefore not considered donations. These payments are in addition to the LEAP funding that is also provided to the Inn of the Good Sheppard.

b) Please provide a breakout of the 2013 expense of $95,900 in account 5420, other than the LEAP amount of $24,000.

Bluewater Power does not budget a set amount for each welfare agency. Since a lump sum amount is budgeted for the year, a breakout cannot be provided at this time. As the year progresses, amounts are forwarded to these various agencies and organizations based on their unique circumstances and need. Examples of welfare agencies included in the 2013 expense that assist consumers with paying their Bluewater Power electricity bills are:

- Inn of the Good Sheppard
- Salvation Army
- St. Vincent De Paul
- Neighbourhood Link (cooperative association on various local churches)

4.0 - EP 44 - Monthly Billing

Ref: 1.0-Energy Probe-4

Please explain how the positive impact on the cash flow of the company of approximately $20,000 has been incorporated into the 2013 test year. Is this related to additional interest income on higher bank balances?

The forecasted cash flow impact of $20,000 has been factored into the calculation of interest income (Account 4405) for the Test Year.

4.0 - EP 45 - Working Capital and Monthly billing

Ref: 4.0-VECC-33

a) What is the basis for the statement that the default value for the WCA is not contingent upon a particular business process and does not vary depending upon whether a utility performs monthly or bi-monthly billing?

The Ontario Energy Board's update on Allowance for Working Capital dated April 12, 2012 states that the default value applicable to 2013 rate applications and beyond shall be 13%. The OEB has not set one rate for utilities providing monthly billing and another rate for utilities billing on a bi-monthly basis.

b) Please confirm that the WCA percentage would vary depending on whether a utility performs monthly or bi-monthly billing.

Bluewater Power has not performed the calculation as we are relying on the default WCA. Accordingly, we are unable to provide comment.

4.0 - VECC 69 - LEAP and Donations

Reference: 4-VECC-27 & 29

a) Please provide the proposed LEAP funding Bluewater is proposing to include for recovery in 2013 rates.

$24,000 as indicated in the response to 4-VECC-27.

b) Please provide the list of other agencies that Bluewater intends to support in 2013 and the amount for these agencies it has included under Account 5410 Sundry.

See the response to 4-EP-43(b).

4.0 - VECC 70 - Incentive Pay

Reference: 4-VECC-37

a) Please provide more detail as to how spending performance impacts incentive pay. Specifically explain what is meant by "*Gross Operating & Maintenance spending () must be **within** the company's annual budget...*" (emphasis added). That is, does within the budget mean not to exceed or some other metric?

We were unable to locate the above-noted quote in the response to 4-VECC 37. However, we can confirm that the metric applied is that actual gross operating and maintenance expense must not exceed the budgeted amount approved by the Board of Directors.

4.0 - VECC 71 - FTE's for 2014

Reference: 4-VECC-35

a) What is Bluewater's estimate of FTE's in 2014 and after anticipated retirements in 2013?

At this time the estimated number of FTE's for 2014 will be the same as 2013. We are not expecting to add any staff, but everyone who retires in 2013 will be replaced.

4.0 - VECC 72 - Liability insurance

Reference: 4-VECC-32 & 41

a) Please explain the large increase in Comprehensive Liability as between 2012 ($61,750) and 2013 ($82,584). Is the increase related to the recent fatality at Bluewater?

The increase is explained in the response to 4-VECC-32 wherein it states "the increase from 2012 to 2013 reflects the fact that 2012 was a year in which a Premium Reduction was available for the Comprehensive Liability Policy". For the record, the fatality occurred nine days after the 2013 Rebasing Application was filed, so there are no costs claimed in this application relating to the fatality.

4.0 - VECC 73 - Storage Fees

Reference: 4-VECC-46

a) What is the total annual storage rental fees collected by Bluewater for street lighting and water inventory in 2012 and forecast for 2013?

$2,400 – Streetlighting 2012 actual
$2,400 – Streetlighting 2013 test year

$2,400 – Water Inventory 2012 actual
$ 400 – Water Inventory 2013 test year

b) Please explain how the “knowledge of the local market” was obtained (e.g. did Bluewater use the services of a real-estate professional or the knowledge of an employee, etc.).

As part of the Transfer Pricing Study, an employee was charged with researching storage rental rates. A search was conducted through sources such as newspaper and on-line advertisements, as well as conversations with local real estate brokers.

4.0 - SEC 50 - Management ratios

[4.0 Staff-26] Please provide all documentation associated with the “internal assessment that management ratios were low”.

The response to 4-SEC-24 contains an excerpt from the Board Report summarizing the assessment that management ratios were low with respect to the decision to increase the number of Line Supervisors.

In order to have been included in the O&M Budget for the next year, the Manager responsible for each aspect of the business (VP of Operations in the case of the Line Supervisors and the Manager of Customer Services in terms of the Customer Services Supervisor) would have submitted his or her costs as part of the budget package to the finance department. We use a zero based budget where all spending must be justified, so there is no distinct process where changes to the budget are separately justified. The O&M budget would have been reviewed by the entire Senior Management Team, and adjustments made, prior to submission to the Board of Directors.

4.0 - SEC 51 - Monthly Billing cash flow

[1.0 EP-4(c)] Please provide the full calculations showing the how the change in cash flow for monthly billing was determined, with all assumptions, and how the change was converted into an interest figure.

Approximately 95% of the General Service <50KW, Unmetered Scattered Load and residential classes of customers are currently billed on a bi-monthly cycle. The following chart demonstrates the total bill revenue (includes all line items on the bill) associated with these rate classes:

	2013 Budget
Residential	$38,045,870
General Service<50	$13,025,841
Unmetered Scattered Load	$ 351,844
Total	$51,423,555

Since approximately 5% of these bills are already produced on a monthly basis, Bluewater Power deducted 5% of the total revenue thereby determining that $48,852,377 in revenue was billed to bi-monthly customers annually. Bluewater Power then divided by 12 months to determine monthly revenue of approximately $4,000,000 would be achieved through monthly billing. Therefore there will be a one-time increase to cash in the bank of approximately $4,000,000. For the purposes of this rate application, Bluewater Power utilized an interest rate of 0.5% thereby assuming an annual interest earned of $20,000.

4.0 - SEC 52 - OM&A activities

[4.0 SEC-22] Please quantify (an estimate is OK) each of the OM&A cutbacks described. Please confirm that these reductions in OM&A activity were not treated as offsets to the smart meters spending for the purposes of calculating the amounts to be included in the deferral account. Please provide an analysis of the impact in 2013 of regular employees returning to their positions. Please explain why those employees are cost-effective when the Applicant has found that they could be replaced at lower cost for a two year period.

The items noted in response to 4.0-SEC-22 were items that were not completed by the Information Technology department, rather than "cutbacks" as referred to in the question. It is difficult to quantify the OM&A represented by the items of work not undertaken in 2012, but a high-level estimate of each item would be as follows:

1. System patching: $8,000 - $12,000
2. PC Rollout: $4,000 - $6,000
3. Website: $15,000 - $20,000
4. IT Policy Review: $10,000 - $20,000
5. Business Process reviews and documentation: $10,000 - $20,000

With respect to the second part of the question, the analysis requested has been provided in Exh.4-1-1 at page 4 where the amount of Capitalized Labour for Smart Meters was shown as $364,078 for 2012. That creates the potential for $364,078 in costs to return to OM&A in 2013. However, the end of the Smart Meter project allows time for IT and Billing/Customer Service to return to normal capital projects. Accordingly, the net increase in OM&A in 2013 is approximately half of the potential increase of $364,078.

With respect to the third part of the question, we point out that the question of whether a particular option (not allowing employees to return to their normal duties) is cost effective is not a valid question when the option is not practical. Employment law and collective bargaining would not permit the action we have been asked to evaluate. It might be appropriate to ask whether we has considered early retirement packages for employees as a result of our experience with Smart Meters, but we can advise that is not an option currently being considered under our Human Resources Strategy.

4.0 - SEC 53 - Asset Management Plan

[4.0 SEC-24] Please confirm that no presentation or report was ever made to the Board of Directors with respect to the Asset Management Program Review, Asset Management Strategy, or Asset Management Plan. If not confirmed, please provide those presentations or reports.

As stated already, the Asset Management Program Review and the Asset Management Strategy were carried out to ensure that Bluewater Power staff was following best-practice of utility asset management. Had either report identified shortcomings, those shortcomings would have been addressed with the Board of Directors.

The Asset Management Plan is the 2013 Capital Budget that was approved by the Board of Directors and disclosed in the pre-filed evidence at Exh.2-4-3, Attachment 3.

4.0 - SEC 54 - Allocations

[4.0 VECC-38] Please explain the reductions in allocations for Billing Administration, Building, Vehicle Usage and Shared Employees.

The reduction in Billing Administration from 2009 to 2013 relates to the restructuring of the water billing function. In 2009, the costs being reallocated included one FTE for the Billing Representative fully dedicated to water billing, a portion of costs for the other billing representatives, and a portion of the mailroom position. In 2013, the affiliate employs its own Billing Representative and it was determined that no other billing representatives impact the water billing function, so the only costs remaining to be allocated to the affiliate related to a portion of the mailroom position.

Building Rent decreased from 2009 to 2013 to reflect the assessment of management as to the true market value of the properties being rented to affiliates. That reassessment was undertaken as part of the Transfer Pricing Study performed in contemplation of this rebasing application. The single biggest variance relates to the space occupied by BPSC in Main Substation #1 for which they were charged previously $12,000 and currently pay $7,500. The indoor space is marginal, so the rent primarily represents outdoor storage, and the revised amount is more indicative of market rent. We should also point out that the office space occupied in the two years is not identical office space due to the movement of employees. The office space in 2009 included one executive office and one executive assistant space for GenCo, while the office space in 2013 includes only five small office spaces.

With respect to Vehicle Usage and Shared Employees, the variance is explained by the fact that both costs are demand driven. As noted throughout the pre-filed evidence, the year 2009 saw heavy demand for line personnel so Shared Employee charges are high in 2009. That same demand is reflect in vehicle charges associated with the Shared Employees. The year 2013 has been forecast at more normal levels.

4.0 - SEC 55 - Monthly Invoices

[1.0 SEC-13] Please provide the monthly invoices requested. The Board and parties are entitled to review source documents to test the evidence provided by the Applicant. Twenty-four documents is not excessive for this purpose. If there is a reason why this results in a large production, please describe in detail.

The question assumes that services provided to the Distribution Company are invoiced on a monthly basis, resulting in twenty-four invoices. That is not the case as the practice is for invoices to be issued as the work is completed (or when phases are completed when the work undertaken is more long-term and composed of more than one phase). For example, we can advise that, in order to complete the table provided by Bluewater Power in response to 4-VECC-50, we compiled information from 85 invoices related to approximately 48 distinct jobs. Compiling invoices from ServCo to Bluewater Power would result in a significantly higher number of invoices, which would be onerous for Bluewater Power to produce and would be overwhelming to the rebasing process.

With respect to the request for invoices from, or to, the generation companies (GenCo and RenewCo) the relationship between the two companies is not material. Aside from the shared services, which are discussed in the next paragraph, the only other relationship is the distribution bills provided by Bluewater Power for each of the generation sites. Although it would not be overwhelming to produce that billing information, there would be no probative value.

Finally, we note that generally the distribution company does not invoice for services that it provides to affiliates. Those services are provided in accordance with the Management Agreement or the Shared Services Agreement and the costs are shared/allocated by accounting entries rather than by formal invoices. Accordingly, a complete set of invoices would not exist so the response would require a summary of numerous journal entries.

We submit that it would be overwhelming to the regulatory process for the OEB and Intervenors to review source documents of this nature. That is particularly true where the utility has (i) undertaken a Transfer Pricing Study reviewed and documented by a third party, (ii) provided summary level information in compliance with the Board's filing guidelines, and (iii) updated the summary level information to reflect 2012 Actuals.

4.0 - SEC 56 - Vehicle Rates

[4.0 SEC-34] Please provide the calculations of the hourly charges for 2013, including all components of each and all assumptions underlying the calculations.

The following chart summarizes the components underlying the hourly rate calculations.

Cost Items:	Heavy	Light
operating	$ 174,230	$ 177,503
amortization	262,893	70,139
licenses	9,539	2,477
insurance	8,848	14,525
WACC	39,500	69,000
	$ 495,010	$ 333,644
Estimated hours	12,500	44,500
Cost per hour	$ 39.61	$ 7.50

The operating costs included in this calculation were based on the 2012 year-to-date actuals prorated for the full year at the time of the calculation. The amortization, licenses and insurance costs are based on the 2013 expected results. The weighted average cost of capital was based on the estimated NBV of the fleet at December 31, 2012 multiplied by the current WACC of 6.07% at the time of the calculation. The resulting WACC amount was prorated between heavy and light based on the total number of vehicles in the fleet.

The estimated hours was explained in the response to 4-SEC-34.

4.0 - SEC 57 - Surcharge

[4.0 SEC-36] Please provide the calculations for each “surcharge for enabler resources” assumed or used for 2013.

The enabler resources represent surcharges added on top of labour allocated to affiliates. The total surcharge for enabler resources is 3.7%

The Office, IT and property related surcharge is made-up of the following costs per employee:

Office Space	$1,100
IT Infrastructure	380
Property	300
TOTAL	$1,800

These costs are divided by an average payroll and benefit cost for the employee group of $90,000 for a 2% contribution to the total surcharge of 3.7%.

The remaining 1.7% of the surcharge represents the total Human Resources costs of $137,000 divided by the total payroll of $8.2M. The Human Resources costs represent the labour costs within the HR group after allocating a portion of the cost to the retiree group, which is an inactive group that continues to place demands on the HR department due to certain retiree benefits.

4.0 - SEC 58 - Increased asset management

[4/2/2, p. 7] Please provide all reports, presentations, memos or other documents provided to senior management or the Board of Directors dealing with the change in focus to increased asset management, and the related changes to personnel.

Please see the answer to SEC-50 and SEC-53.

File Number: EB-2012-0107

Date Filed: March 8, 2013

Tab 5 of 9

Exhibit 5 - Capital Structure and Cost of Capital

5.0 - Staff 75 - Unfunded Debt

Ref: 7.5-5-VECC-53

Ref: 7.4-5-VECC-52

In its response to VECC IR 53, Bluewater Power states that the unfunded debt portion should be based on the Board's deemed debt rate. Board staff observes that the "unfunded debt" that Bluewater Power refers to results from its actual equity thickness of 49%, as documented in the response to VECC IR 52, which is higher than the deemed equity thickness of 40%. This is a decision of Bluewater Power and its shareholder on the capital structure adopted for financing purposes.

Board staff notes that the Board's policy and practice for the treatment of notional debt has been well established in Board decisions relating to both the December 20, 2006 *Report of the Board on the Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* and the current *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* (EB-2009-0084), issued December 11, 2009.[1]

Please provide further reasons why Bluewater Power believes that the deemed long-term debt rate should apply to its notional debt rate rather than the average weighted cost of long-term debt based on the company's actual and forecasted debt instruments in the 2013 test year.

The pre-amble to the Interrogatory does not, in our opinion, contain any new information not already addressed in Bluewater Power's pre-filed evidence or our response to VECC-53. The rationale for Bluewater Power's position stands on its own and, otherwise, this matter can be addressed through clarification during the Argument phase of the hearing.

[1] Decision and Order EB-2008-0235 (London Hydro Inc.), August 21, 2009, page 37 and Decision with Reasons EB-2010-0008 (Ontario Power Generation Inc.), March 10, 2011, page 125

5.0 - Staff 76 - Update Cost of Capital, RRWF, bill impacts

Ref: Exh 5-1-1

On February 14, 2013, the Board issued a letter which set out the cost of capital parameters updates for cost of service applications effective May 1, 2013. Please update Appendix 2-OA, the RRWF and bill impacts (Residential 800 kWh and GS<50 kW 2,000 kWh) accordingly.

Please find as Attachment 1 the following documents which reflect the cost of capital updates per the OEB's February 14, 2013 letter:

1 – Updated Appendix 2-OA, Capital Structure and Cost of Capital
2 – Updated Revenue Requirement Work Form
3 – Bill Impacts for Residential and GS<50 customers

Attachment 1 of 1

5.0 - Staff 76 - Updated Attachments

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

Appendix 2-OA
Capital Structure and Cost of Capital

This table must be completed for the required years of all historical years, the bridge year and the test year.

2013 Test Year

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)		Cost Rate (%)		Return ($)
	Debt							
1	Long-term Debt	56.00%		$37,294,270		4.00%	(3)	$1,490,192
2	Short-term Debt	4.00%	(1)	$2,663,876		2.07%		$55,142
3	**Total Debt**	60.0%		$39,958,146		3.87%		$1,545,334
	Equity							
4	Common Equity	40.00%		$26,638,764		8.98%		$2,392,161
5	Preferred Shares	0.00%		$ -		0.00%		$ -
6	**Total Equity**	40.0%		$26,638,764		8.98%		$2,392,161
7	**Total**	100.0%		$66,596,910	(2)	5.91%		$3,937,495

Notes

(1) 4.0% unless an applicant has proposed or been approved for a different amount.

(2) The rate base value of $66,596,910 includes the IFRS adjustment of $364,881

-(3) The LTD rate is a weighted average of funded and unfunded debt.

2012 Bridge Year

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)		Return ($)
	Debt						
1	Long-term Debt	56.00%		$26,785,329	7.62%		$2,041,042
2	Short-term Debt	4.00%	(1)	$1,913,238	1.33%		$25,446
3	**Total Debt**	60.0%		$28,698,566	7.20%		$2,066,488
	Equity						
4	Common Equity	40.00%		$19,132,378	8.01%		$1,532,503
5	Preferred Shares	0.00%		$ -	0.00%		$ -
6	**Total Equity**	40.0%		$19,132,378	8.01%		$1,532,503
7	**Total**	100.0%	(3)	$47,830,944	7.52%		$3,598,992

Note

(3) The rate base of $47,830,944 is the amount approved as part of 2009 rebasing.

Line

No.	Particulars	Capitalization Ratio				Cost Rate	Return
	2011						
		(%)		($)		(%)	($)
	Debt						
1	Long-term Debt	56.00%		$26,785,329		7.62%	$2,041,042
2	Short-term Debt	4.00%	(1)	$1,913,238		1.33%	$25,446
3	**Total Debt**	60.0%		$28,698,566		7.20%	$2,066,488
	Equity						
4	Common Equity	40.00%		$19,132,378		8.01%	$1,532,503
5	Preferred Shares	0.00%		$ -		0.00%	$ -
6	**Total Equity**	40.0%		$19,132,378		8.01%	$1,532,503
7	**Total**	100.0%	(3)	$47,830,944		7.52%	$3,598,992

Note

(3) The rate base of $47,830,944 is the amount approved as part of 2009 rebasing.

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
	2010 IRM					
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%	(4)	$26,785,329	7.62%	$2,041,042
2	Short-term Debt	4.00%		$1,913,238	1.33%	$25,446
3	**Total Debt**	60.0%		$28,698,566	7.20%	$2,066,488
	Equity					
4	Common Equity	40.00%		$19,132,378	8.01%	$1,532,503
5	Preferred Shares	0.00%		$ -	0.00%	$ -
6	**Total Equity**	40.0%		$19,132,378	8.01%	$1,532,503
7	**Total**	100.0%	(3)	$47,830,944	7.52%	$3,598,992

Note

(3) The rate base of $47,830,944 is the amount approved as part of 2009 rebasing.
(4) The 2010 IRM was the last adjustment for debt/equity modifications.

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
	2009 Board Approved				
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	52.67%	$25,190,964	7.62%	$1,919,551
2	Short-term Debt	4.00%	$1,913,238	1.33%	$25,446
3	**Total Debt**	56.7%	$27,104,202	7.18%	$1,944,998
	Equity				
4	Common Equity	43.33%	$20,726,742	8.01%	$1,660,212
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	43.3%	$20,726,742	8.01%	$1,660,212
7	**Total**	100.0%	$47,830,944	7.54%	$3,605,210

Revenue Requirement Workform

Version 3.00

Utility Name	Bluewater Power Distribution Corp.
Service Territory	*Revised March 8, 2013*
Assigned EB Number	EB-2012-0107
Name and Title	Leslie Dugas, Manager of Regulatory Affairs
Phone Number	519-337-8201 Ext 2255
Email Address	ldugas@bluewaterpower.com

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.

Revenue Requirement Workform

Notes:

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

Data Input [1]

		Initial Application	(2)	Adjustments		Interrogatory Responses	(6)	Adjustments	Per Board Decision	
1	**Rate Base**									
	Gross Fixed Assets (average)	$60,605,808	13	$ -		$ 60,605,808			$60,605,808	
	Accumulated Depreciation (average)	($7,153,078)	(5)	($79,454)		($7,232,532)	A		($7,232,532)	
	Allowance for Working Capital:									
	Controllable Expenses	$13,302,742		$147,232		$ 13,449,974	B		$13,449,974	
	Cost of Power	$89,374,845		($1,104,556)		$ 88,270,289	C		$88,270,289	
	Working Capital Rate (%)	13.00%	(9)			13.00%	(9)		13.00%	(9)
2	**Utility Income**									
	Operating Revenues:									
	Distribution Revenue at Current Rates	$18,420,657		$0		$18,420,657				
	Distribution Revenue at Proposed Rates	$21,876,690		$63,985		$21,940,675				
	Other Revenue:									
	Specific Service Charges	$571,199		$0		$571,199				
	Late Payment Charges	$232,694		$0		$232,694				
	Other Distribution Revenue	$180,257		$0		$180,257				
	Other Income and Deductions	$96,099		($10,000)		$86,099	D			
	Total Revenue Offsets	$1,080,249	(7)	($10,000)		$1,070,249				
	Operating Expenses:									
	OM+A Expenses	$13,078,828		$98,732	B	$ 13,177,560			$13,177,560	
	Depreciation/Amortization	$5,011,623	(10)	$140,343	A	$ 5,151,966			$5,151,966	
	Property taxes	$223,914		$48,500	B	$ 272,414			$272,414	
	Other expenses									
3	**Taxes/PILs**									
	Taxable Income:									
	Adjustments required to arrive at taxable income	($892,023)	(3)			($966,781)				
	Utility Income Taxes and Rates:									
	Income taxes (not grossed up)	$444,375	(12)			$358,429				
	Income taxes (grossed up)	$586,513				$471,865				
	Federal tax (%)	15.00%				15.00%				
	Provincial tax (%)	9.23%				9.04%				
	Income Tax Credits	$69,984	(14)			$125,231				
4	**Capitalization/Cost of Capital**									
	Capital Structure:									
	Long-term debt Capitalization Ratio (%)	56.0%				56.0%				
	Short-term debt Capitalization Ratio (%)	4.0%	(8)			4.0%	(8)			(8)
	Common Equity Capitalization Ratio (%)	40.0%				40.0%				
	Prefered Shares Capitalization Ratio (%)									
		100.0%				100.0%				
	Cost of Capital									
	Long-term debt Cost Rate (%)	4.18%				4.00%				
	Short-term debt Cost Rate (%)	2.08%				2.07%				
	Common Equity Cost Rate (%)	9.12%				8.98%				
	Prefered Shares Cost Rate (%)									
	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS ($)		(11)				(11)			(11)

Notes:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Revenue Requirement Workform

Rate Base and Working Capital

Rate Base

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

Allowance for Working Capital - Derivation

(1)

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
6	Controllable Expenses		$13,302,742	$147,232	$13,449,974	$ -	$13,449,974
7	Cost of Power		$89,374,845	($1,104,556)	$88,270,289	$ -	$88,270,289
8	Working Capital Base		$102,677,587	($957,324)	$101,720,263	$ -	$101,720,263
9	Working Capital Rate %	(2)	13.00%	0.00%	13.00%	0.00%	13.00%
10	Working Capital Allowance		$13,348,086	($124,452)	$13,223,634	$ -	$13,223,634

Notes

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

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

Revenue Requirement Workform

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$21,876,690	$63,985	$21,940,675	$ -	$21,940,675
2	Other Revenue	(1)	$1,080,249	($10,000)	$1,070,249	$ -	$1,070,249
3	Total Operating Revenues		$22,956,939	$53,985	$23,010,924	$ -	$23,010,924
	Operating Expenses:						
4	OM+A Expenses		$13,078,828	$98,732	$13,177,560	$ -	$13,177,560
5	Depreciation/Amortization		$5,011,623	$140,343	$5,151,966	$ -	$5,151,966
6	Property taxes		$223,914	$48,500	$272,414	$ -	$272,414
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$18,314,365	$287,575	$18,601,940	$ -	$18,601,940
10	Deemed Interest Expense		$1,619,166	($73,832)	$1,545,334	$68,890	$1,614,224
11	Total Expenses (lines 9 to 10)		$19,933,531	$213,743	$20,147,275	$68,890	$20,216,164
12	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS		$ -	$ -	$ -	$ -	$ -
13	**Utility income before income taxes**		$3,023,408	($159,758)	$2,863,649	($68,890)	$2,794,760
14	Income taxes (grossed-up)		$586,513	($114,648)	$471,865	$ -	$471,865
15	**Utility net income**		$2,436,895	($45,111)	$2,391,784	($68,890)	$2,322,894

Notes

Other Revenues / Revenue Offsets

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

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application	Interrogatory Responses	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$2,436,894	$2,392,161	$2,429,455
2	Adjustments required to arrive at taxable utility income	($892,023)	($966,781)	($892,023)
3	Taxable income	$1,544,871	$1,425,380	$1,537,432
	Calculation of Utility income Taxes			
4	Income taxes	$444,375	$358,429	$358,429
6	Total taxes	$444,375	$358,429	$358,429
7	Gross-up of Income Taxes	$142,138	$113,436	$113,436
8	Grossed-up Income Taxes	$586,513	$471,865	$471,865
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$586,513	$471,865	$471,865
10	Other tax Credits	$69,984	$125,231	$125,231
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	9.23%	9.04%	9.04%
13	Total tax rate (%)	24.23%	24.04%	24.04%

Notes

Revenue Requirement Workform

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$37,408,457	4.18%	$1,563,588
2	Short-term Debt	4.00%	$2,672,033	2.08%	$55,578
3	**Total Debt**	60.00%	$40,080,490	4.04%	$1,619,166
	Equity				
4	Common Equity	40.00%	$26,720,327	9.12%	$2,436,894
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$26,720,327	9.12%	$2,436,894
7	**Total**	100.00%	$66,800,816	6.07%	$4,056,060
		Interrogatory Responses			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$37,294,270	4.00%	$1,490,192
2	Short-term Debt	4.00%	$2,663,876	2.07%	$55,142
3	**Total Debt**	60.00%	$39,958,146	3.87%	$1,545,334
	Equity				
4	Common Equity	40.00%	$26,638,764	8.98%	$2,392,161
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$26,638,764	8.98%	$2,392,161
7	**Total**	100.00%	$66,596,910	5.91%	$3,937,495
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$37,294,270	4.18%	$1,558,815
9	Short-term Debt	4.00%	$2,663,876	2.08%	$55,409
10	**Total Debt**	60.00%	$39,958,146	4.04%	$1,614,224
	Equity				
11	Common Equity	40.00%	$26,638,764	9.12%	$2,429,455
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$26,638,764	9.12%	$2,429,455
14	**Total**	100.00%	$66,596,910	6.07%	$4,043,679

Notes

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

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Interrogatory Responses: At Current Approved Rates	Interrogatory Responses: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$3,456,032		$3,664,502		$3,782,489
2	Distribution Revenue	$18,420,657	$18,420,658	$18,420,657	$18,276,173	$18,420,657	$18,158,186
3	Other Operating Revenue Offsets - net	$1,080,249	$1,080,249	$1,070,249	$1,070,249	$1,070,249	$1,070,249
4	**Total Revenue**	$19,500,906	$22,956,939	$19,490,906	$23,010,924	$19,490,906	$23,010,924
5	Operating Expenses	$18,314,365	$18,314,365	$18,601,940	$18,601,940	$18,601,940	$18,601,940
6	Deemed Interest Expense	$1,619,166	$1,619,166	$1,545,334	$1,545,334	$1,614,224	$1,614,224
7	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	$ - **(2)**	$ -	$ - **(2)**	$ -	$ - **(2)**	$ -
8	**Total Cost and Expenses**	$19,933,531	$19,933,531	$20,147,275	$20,147,275	$20,216,164	$20,216,164
9	**Utility Income Before Income Taxes**	($432,625)	$3,023,408	($656,369)	$2,863,649	($725,258)	$2,794,760
10	Tax Adjustments to Accounting Income per 2013 PILs model	($892,023)	($892,023)	($966,781)	($966,781)	($966,781)	($966,781)
11	**Taxable Income**	($1,324,648)	$2,131,385	($1,623,150)	$1,896,868	($1,692,039)	$1,827,979
12	Income Tax Rate	24.23%	24.23%	24.04%	24.04%	24.04%	24.04%
13	**Income Tax on Taxable Income**	($321,021)	$516,529	($390,205)	$456,007	($406,766)	$439,446
14	**Income Tax Credits**	$69,984	$69,984	$125,231	$125,231	$125,231	$125,231
15	**Utility Net Income**	($181,588)	$2,436,895	($391,394)	$2,391,784	($443,723)	$2,322,894
16	**Utility Rate Base**	$66,800,816	$66,800,816	$66,596,910	$66,596,910	$66,596,910	$66,596,910
17	Deemed Equity Portion of Rate Base	$26,720,327	$26,720,327	$26,638,764	$26,638,764	$26,638,764	$26,638,764
18	Income/(Equity Portion of Rate Base)	-0.68%	9.12%	-1.47%	8.98%	-1.67%	8.72%
19	Target Return - Equity on Rate Base	9.12%	9.12%	8.98%	8.98%	9.12%	9.12%
20	Deficiency/Sufficiency in Return on Equity	-9.80%	0.00%	-10.45%	0.00%	-10.79%	-0.40%
21	Indicated Rate of Return	2.15%	6.07%	1.73%	5.91%	1.76%	5.91%
22	Requested Rate of Return on Rate Base	6.07%	6.07%	5.91%	5.91%	6.07%	6.07%
23	Deficiency/Sufficiency in Rate of Return	-3.92%	0.00%	-4.18%	0.00%	-4.31%	-0.16%
24	Target Return on Equity	$2,436,894	$2,436,894	$2,392,161	$2,392,161	$2,429,455	$2,429,455
25	Revenue Deficiency/(Sufficiency)	$2,618,482	$1	$2,783,555	($377)	$2,873,178	($106,561)
26	**Gross Revenue Deficiency/(Sufficiency)**	$3,456,032 **(1)**		$3,664,502 **(1)**		$3,782,489 **(1)**	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

(2) Treated as an adjustment pre-tax to avoid an impact on taxes/PILs and hence on revenue sufficiency deficiency

(3)

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application		Interrogatory Responses		Per Board Decision	
1	OM&A Expenses	$13,078,828		$13,177,560		$13,177,560	
2	Amortization/Depreciation	$5,011,623		$5,151,966		$5,151,966	
3	Property Taxes	$223,914		$272,414		$272,414	
5	Income Taxes (Grossed up)	$586,513		$471,865		$471,865	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$1,619,166		$1,545,334		$1,614,224	
	Return on Deemed Equity	$2,436,894		$2,392,161		$2,429,455	
	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	$ -		$ -		$ -	
8	**Service Revenue Requirement (before Revenues)**	$22,956,938		$23,011,301		$23,117,485	
9	Revenue Offsets	$1,080,249		$1,070,249		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$21,876,689		$21,941,052		$23,117,485	
11	Distribution revenue	$21,876,690		$21,940,675		$21,940,675	
12	Other revenue	$1,080,249		$1,070,249		$1,070,249	
13	**Total revenue**	$22,956,939		$23,010,924		$23,010,924	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$1	**(1)**	($377)	**(1)**	($106,561)	**(1)**

Notes

(1) Line 11 - Line 8

File Number:	EB-2012-0107
Exhibit:	
Tab:	
Schedule:	
Page:	2 of 27
Date:	

Appendix 2-W
Bill Impacts

Customer Class: Residential

Consumption 800 **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 13.8000	1	$ 13.80	$ 16.4400	1	$ 16.44	$ 2.64	19.13%
Smart Meter Rate Adder	Monthly	$ 1.9400	1	$ 1.94	$ -	1	$ -	-$ 1.94	-100.00%
Rate Rider for Tax change	kWh	-$ 0.0005	800	-$ 0.40	$ -	800	$ -	$ 0.40	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kWh	$ 0.0188	800	$ 15.04	$ 0.0224	800	$ 17.92	$ 2.88	19.15%
Smart Meter Disposition Rider				$ -			$ -	$ -	
LRAM 2011	kW	$ 0.0004	800	$ 0.32	$ -	800	$ -	-$ 0.32	-100.00%
LRAM 2012	kW	$ 0.0002	800	$ 0.16	$ 0.0002	800	$ 0.16	$ -	
LRAM 2013 (for 2011/12 persisten	kW	$ -	800	$ -	$ 0.0004	800	$ 0.32	$ 0.32	
LRAMVA 2013 (for 2011 programs	kWh	$ -	800	$ -	$ 0.0001	800	$ 0.08	$ 0.08	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ 1.4700	1	$ 1.47	$ 1.47	
Sub-Total A				$ 31.11			$ 36.64	**$ 5.53**	**17.78%**
Rate Rider for Deferral/Variance Account Disposition 2011	kW	$ 0.0012	800	$ 0.96	$ -	800	$ -	-$ 0.96	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kW	-$ 0.0017	800	-$ 1.36	-$ 0.0017	800	-$ 1.36	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kW	$ -	800	$ -	-$ 0.0013	800	-$ 1.04	-$ 1.04	
Low Voltage Service Charge	kWh	$ 0.0002	800	$ 0.16	$ 0.0002	800	$ 0.16	$ -	
Smart Meter Entity Charge						800	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 30.87**			**$ 34.40**	**$ 3.53**	**11.44%**
RTSR - Network	kWh	$ 0.0068	828	$ 5.63	$ 0.0064	834	$ 5.34	-$ 0.30	-5.30%
RTSR - Line and Transformation Connection	kWh	$ 0.0057	828	$ 4.72	$ 0.0054	834	$ 4.50	-$ 0.22	-4.67%
Sub-Total C - Delivery (including Sub-Total B)				**$ 41.23**			**$ 44.24**	**$ 3.01**	**7.30%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	828	$ 4.31	$ 0.0052	834	$ 4.33	$ 0.03	0.62%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	828	$ 0.91	$ 0.0011	834	$ 0.92	$ 0.01	0.62%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	600	$ 44.40	$ 0.0740	600	$ 44.40	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0870	228	$ 19.88	$ 0.0870	234	$ 20.33	$ 0.45	2.26%
TOU - Off Peak	kWh	$ 0.0630	530	$ 33.40	$ 0.0630	534	$ 33.61	$ 0.21	0.62%
TOU - Mid Peak	kWh	$ 0.0990	149	$ 14.76	$ 0.0990	150	$ 14.86	$ 0.09	0.62%
TOU - On Peak	kWh	$ 0.1180	149	$ 17.60	$ 0.1180	150	$ 17.71	$ 0.11	0.62%
Total Bill on RPP (before Taxes)				**$ 116.32**			**$ 119.82**	**$ 3.49**	**3.00%**
HST		13%		$ 15.12	13%		$ 15.58	$ 0.45	3.00%
Total Bill (including HST)				$ 131.45			$ 135.39	$ 3.95	3.00%
Ontario Clean Energy Benefit 1				-$ 13.14			-$ 13.54	-$ 0.40	3.04%
Total Bill on RPP (including OCEB)				**$ 118.31**			**$ 121.85**	**$ 3.55**	**3.00%**
Total Bill on TOU (before Taxes)				**$ 117.81**			**$ 121.26**	**$ 3.45**	**2.93%**
HST		13%		$ 15.32	13%		$ 15.76	$ 0.45	2.93%
Total Bill (including HST)				$ 133.13			$ 137.03	$ 3.90	2.93%
Ontario Clean Energy Benefit 1				-$ 13.31			-$ 13.70	-$ 0.39	2.93%
Total Bill on TOU (including OCEB)				**$ 119.82**			**$ 123.33**	**$ 3.51**	**2.93%**

Loss Factor (%)	3.56%	4.21%

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

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

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

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

Appendix 2-W
Bill Impacts

Customer Class: General Service < 50 kW

Consumption 2000 **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 23.7100	1	$ 23.71	$ 28.2400	1	$ 28.24	$ 4.53	19.11%
Smart Meter Rate Adder	Monthly	$ 5.9400	1	$ 5.94	$ 5.9400	1	$ 5.94	$ -	
Rate Rider for Tax change	kWh	-$ 0.0003	2000	-$ 0.60	$ -	2000	$ -	$ 0.60	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Distribution Volumetric Rate	kWh	$ 0.0166	2000	$ 33.20	$ 0.0198	2000	$ 39.60	$ 6.40	19.28%
Smart Meter Disposition Rider				$ -			$ -	$ -	
LRAM 2011	kW	$ 0.0001	2000	$ 0.20	$ -	2000	$ -	-$ 0.20	-100.00%
LRAM 2012	kW	$ 0.0002	2000	$ 0.40	$ 0.0002	2000	$ 0.40	$ -	
LRAM 2013 (for 2011/12 persisten	kW	$ -	2000	$ -	$ 0.0004	2000	$ 0.80	$ 0.80	
LRAMVA 2013 (for 2011 programs	kWh	$ -	2000	$ -	$ 0.0001	2000	$ 0.20	$ 0.20	
Stranded Meters Recovery	Monthly	$ -	1	$ -	$ 4.6600	1	$ 4.66	$ 4.66	
Sub-Total A				$ 63.10			$ 80.09	**$ 16.99**	**26.93%**
Rate Rider for Deferral/Variance Account Disposition 2011	kW	$ 0.0012	2000	$ 2.40	$ -	2000	$ -	-$ 2.40	-100.00%
Rate Rider for Deferral/Variance Account Disposition 2012	kW	-$ 0.0016	2000	-$ 3.20	-$ 0.0016	2000	-$ 3.20	$ -	
Rate Rider for Deferral/Variance Account Disposition 2013 (for 2011 balances)	kW	$ -	2000	$ -	-$ 0.0012	2000	-$ 2.40	-$ 2.40	
Low Voltage Service Charge	kWh	$ 0.0002	2000	$ 0.40	$ 0.0002	2000	$ 0.40	$ -	
Smart Meter Entity Charge						2000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 62.70**			**$ 74.89**	**$ 12.19**	**19.44%**
RTSR - Network	kWh	$ 0.0063	2071	$ 13.05	$ 0.0060	2084	$ 12.50	-$ 0.54	-4.17%
RTSR - Line and Transformation Connection	kWh	$ 0.0050	2071	$ 10.36	$ 0.0047	2084	$ 9.80	-$ 0.56	-5.41%
Sub-Total C - Delivery (including Sub-Total B)				**$ 86.10**			**$ 97.19**	**$ 11.09**	**12.87%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	2071	$ 10.77	$ 0.0052	2084	$ 10.84	$ 0.07	0.62%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0011	2071	$ 2.28	$ 0.0011	2084	$ 2.29	$ 0.01	0.62%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0740	750	$ 55.50	$ 0.0740	750	$ 55.50	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0870	1321	$ 114.94	$ 0.0870	1334	$ 116.07	$ 1.12	0.98%
TOU - Off Peak	kWh	$ 0.0630	1326	$ 83.51	$ 0.0630	1334	$ 84.03	$ 0.52	0.62%
TOU - Mid Peak	kWh	$ 0.0990	373	$ 36.91	$ 0.0990	375	$ 37.14	$ 0.23	0.62%
TOU - On Peak	kWh	$ 0.1180	373	$ 43.99	$ 0.1180	375	$ 44.27	$ 0.27	0.62%
Total Bill on RPP (before Taxes)				**$ 283.60**			**$ 295.89**	**$ 12.29**	**4.33%**
HST		13%		$ 36.87	13%		$ 38.47	$ 1.60	4.33%
Total Bill (including HST)				$ 320.47			$ 334.35	$ 13.89	4.33%
Ontario Clean Energy Benefit 1				-$ 32.05			-$ 33.44	-$ 1.39	4.34%
Total Bill on RPP (including OCEB)				**$ 288.42**			**$ 300.91**	**$ 12.50**	**4.33%**
Total Bill on TOU (before Taxes)				**$ 277.56**			**$ 289.76**	**$ 12.19**	**4.39%**
HST		13%		$ 36.08	13%		$ 37.67	$ 1.58	4.39%
Total Bill (including HST)				$ 313.65			$ 327.42	$ 13.78	4.39%
Ontario Clean Energy Benefit 1				-$ 31.36			-$ 32.74	-$ 1.38	4.40%
Total Bill on TOU (including OCEB)				**$ 282.29**			**$ 294.68**	**$ 12.40**	**4.39%**

Loss Factor (%) 3.56% 4.21%

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

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

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

5.0 - EP 46 - Infrastructure Ontario

Ref: 5.0-Energy Probe-30

a) Please show the calculation of the 4.24% as stated in part (c) of the response using a table similar to that shown in Appendix 2-OB in the original evidence.

Table 1 – Updated Weighted Average Long Term Debt Rate

Year 2013 | Rate Base 66,596,910

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)
1	Promissory Note to Shareholder	Village of Point Edward	Affiliated	Fixed Rate	Oct 30, 2000	-	$ 655,187	4.41%	$ 28,894
2	Promissory Note to Shareholder	Town of Petrolia	Affiliated	Fixed Rate	Oct 30, 2000	-	$ 1,430,914	4.41%	$ 63,103
3	Promissory Note to Shareholder	Village of Alvinston	Affiliated	Fixed Rate	Oct 30, 2000	-	$ 139,981	4.41%	$ 6,173
4	Promissory Note to Shareholder	Township of Warwick	Affiliated	Fixed Rate	Oct 30, 2000	-	$ 421,886	4.41%	$ 18,605
5	Promissory Note to Shareholder	City of Sarnia	Affiliated	Fixed Rate	Oct 30, 2000	-	$ 16,729,636	4.41%	$ 737,777
6	Debenture	Infrastructure Ontario	Third-Party	Fixed Rate	Sep 15, 2011	10.00	$ 6,177,576	3.37%	$ 208,184
8	Unfunded deemed portion						$ 11,739,090	4.41%	$ 517,694
Total							$ 37,294,270	4.24%	$1,580,431

b) What is the impact on the revenue requirement for 2013 of the decision to fully repay the $2.2 million of advances? Please include the impact on the cost of debt and the reduction in interest income.

The impact on the cost of long term debt is an increase of $21,878 as compared to the original application which is a direct impact to revenue requirement. This impact was assessed using the data from the original application (ie. rate base and cost of capital parameters), and removing the portion of debt related to the $2.2 million.

Table 2 – Long Term Debt Cost

	Original Application	Updated to remove $2.2M debt	Variance from Original Application
Long Term Debt Annual Cost	$ 1,563,588	$1,585,466	$ 21,878

In addition, Bluewater Power's response to 5.0 – Energy Probe -30, indicated that the Interest Income is expected to reduce by approximately $10,000 per year based on an assumed interest rate of 0.5%. (Average annual balance in 2013 of $2.1 million * 0.5% = $10,500). A reduction in interest income reduces revenue requirement.

Therefore the net impact on the revenue requirement by repaying the $2.2 million is an increase of approximately $11,878.

c) Please explain why Bluewater Power decided to pay down $2.2 million on the IO loan at a rate of 3.37% rather than a portion of the affiliate debt, at a rate of 7.25%?

At the end of 2012, Bluewater Power's construction loan with IO expired and the utility faced the choice between converting the loan to a long-term debenture or to repay the loan amount. Based on our cash forecast, we determined that we were in a position to repay the loan.

As similar option to repay the Promissory Notes with our municipal shareholders was not available to Bluewater Power. The Promissory Notes (disclosed at Exh.5-1-1, Attachment 3) are callable upon demand by the municipal holders of the notes only on eighteen months' notice.

d) Please explain why Bluewater Power is not forecasting the use of long-term debt to finance capital expenditures in 2012 and 2013 that total approximately $18 million on a CGAAP basis. How are these capital expenditures going to be financed?

Bluewater Power has historically funded its capital spending through its operating cash flow. The capital expenditures are funded through depreciation recovered through rates, shareholder retained earnings. In the event that timing creates a need for external funding, then the utility would turn to short-term borrowing. Bluewater Power currently has a $5M line of credit with the CIBC.

5.0 - EP 47 - Cost of Capital and all adjustments

Ref: Board Letter dated February 14, 2013 - Cost of Capital Parameter Updates for 2013 Cost of Service Applications for Rates Effective May 1, 2013 & 1.0-Staff-2

Please update the cost of capital to reflect the figures in the Board's letter noted above. Please also provide an updated RRWF (including the live Excel version) that incorporates these changes, along with the changes adopted in the response to 1.0-Staff-2 along with any other changes that may be made by Bluewater as a result of the supplemental interrogatories. Please also provide an updated Table of Adjustments as was provided in Attachment 2 to 1.0-Staff-2.

Please see response to 5.0-Staff-76 for the updated information.

In regard to a Table of Adjustments, the only update made was the changes as a result of the updated cost of capital parameters. This affected the value of ratebase, PILs, revenue requirement and resulting rates. All other data is as presented in response to 1.0-Staff-2 in the first round of interrogatories.

Table 1 below summarizes the progression from the original application to the current status.

1 **Table 1 – Summary of Revenue Requirement Changes**

	2013 Original Application	2013 Test Year with results from Interrogatories Round 1	2013 Test Year after Cost of Capital Changes
Cost of Capital			
Rate Base	66,800,816	66,596,910	66,596,910
Cost of Capital	6.07%	6.10%	5.91%
Return on Rate Base	3,691,179	3,700,413	3,572,614
Plus: IFRS Adjustment	364,881	364,881	364,881
Total Return on Rate Base	4,056,060	4,065,294	3,937,495
Cost of Service			
Operations, Maintenance & Admin	13,302,742	13,449,974	13,449,974
Depreciation	5,011,623	5,151,966	5,151,966
Income Taxes	586,513	484,823	471,488
Service Revenue Requirement	**22,956,938**	**23,152,058**	**23,010,924**
Other Revenue	1,080,249	1,070,249	1,070,249
Base Revenue Requirement	**21,876,689**	**22,081,809**	**21,940,675**

2

3

5.0 - SEC 59 - Infrastructure Ontario loan

[5.0 EP-30] Please explain why the lower interest Infrastructure Ontario loan was repaid rather than higher interest debt.

Please see response to 5-EP-46(c).

BLUEWATER POWER DISTRIBUTION CORPORATION

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Exhibit 6 - Revenue Deficiency

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Exhibit 7 - Cost Allocation

7.0 - Staff 77 - Weighting factor

Ref: 9.2-7-Staff-42

The objective of the interrogatory was to examine the weighting factor for services for non-residential customers. However, the response provided information related to residential customers. Please provide the response for non-residential customers.

The policy quoted at Ex 7/1/1 page 4, of the original application does not apply to capital contribution. Capital contribution would apply for all customers (residential and non-residential) if a system expansion is required. Capital contributions get allocated under CGAAP to Account 1995 (until Dec 31, 2012), and as of January 1, 2013 to Account 2440 (under MIFRS) in accordance with the USoA, and not to account 1855 Services.

In regard to 'any subsequent related OM&A expenses', the above referenced policy would not apply to either residential or non-residential customers. Bluewater Power could only envision possible OM&A expenses applying subsequent to a service installation, such as a repair to a utility owned service line. In this case the repair would be made and the costs allocated to the respective OM&A accounts, and no charges would be allocated to customers.

7.0 - EP 48 - Service Factor

Ref: 7.0-Staff-42

a) Please confirm that the policy to charge customers other than residential customers for the cost of their service, such that there are no service costs being booked to account 1855 for non-residential customers, has been in place for at least the life of services used for depreciation purposes. If this cannot be confirmed, would it be possible that some historical service costs for non-residential classes remain in account 1855? If yes, what percentage would be non-residential costs?

Confirmed. There has never been non-residential service costs booked to account 1855.

Bluewater Power would like to clarify the policy in order to assist the understanding of this concept. The reason there are no service costs booked to account 1855 for non-residential customers is because non-residential customers are required to install their own service wire to Bluewater Power's point of demarcation, therefore they own their service. Bluewater Power would only charge for the service connection cost, which is the labour and vehicle costs required to connect the service and set the meter and these costs do not get booked to account 1855.

b) Does the policy noted above apply to new services, replacement services (end of life situations) and/or capitalized portions of repair costs?

Yes, the policy applies to new services, replacement services and capitalized portion of repair costs.

7.0 - VECC 74 - Billing and Collecting Factors

Reference: Staff #43 / VECC #62

a) With respect to VECC #62 c), please explain how the fact that the IESO/SME processes and validates Bluewater's Residential and GS<50 TOU meter data for billing purposes is taken into account in the derivation of the billing & collecting weighting factors.

Bluewater Power did not specifically incorporate the IESO/SME processes in the derivation of the billing & collecting weighting factors. As noted in response to 7.0 Staff 43, our approach to calculating the factor was mainly based on assessing the overall complexity of the bill, and what specific factors or billing determinants were relevant for each rate class.

b) Please indicate which classes are billed based on the HOEP and hourly data and explain on how the increased complexity of billing for hourly use for these classes as opposed to TOU period use for Residential and GS<50 customers is reflected in the billing & collecting weighting factors.

The following rate classes are billed on HOEP pricing using hourly data:

- A small portion of GS>50 rate class
- General Service – Intermediate
- Large Use
- Streetlighting

We assessed the above noted rate classes using HOEP pricing to be more complex than TOU pricing therefore allocated a higher weighting for 'billing', however, these rate classes are deemed to have lower collections and call center weightings than the residential and GS<50 rate classes which led to an overall lower weighting for the General Service>50 and Intermediate rate classes as compared to the residential rate class.

c) Do any of the GS>50 customers have interval or smart meters? If yes, how is the meter data processed in order to establish billing quantities for commodity sales?

Approximately 7% of the customers in the GS>50 rate class have interval meters, and none of the customers in this rate class have smart meters. For the customers that have interval meters, the billing system calculates the commodity cost by multiplying the customer's hourly data by the hourly price.

d) Does Bluewater undertake periodic audits of the number and nature of the connections associated with those classes that are not metered? If not, why not?

Yes, Bluewater Power undertakes periodic audits of the number and nature of unmetered connections. For the streetlighting accounts, each month the number of connections is monitored and adjusted for billing if required. For the sentinel connections, audits are undertaken typically upon determination of an inconsistency in the field or upon a customer's request for confirmation.

e) If the response to part (d) is affirmative, then with respect to Staff #43, how do the billing & collecting weighting factors for Sentinel Lighting (as well as Street Lights and USL) account for the cost of these periodic audits?

Bluewater Power has assigned an administrative factor to each of the unmetered categories to account for the manual tracking of the connections. The USL category was deemed to have the highest administration given that the connections relate to traffic lights, cable boosters, bus shelters etc., which require more monitoring than the sentinel connections. We do not currently add any new sentinel connections therefore the administration only deals with removing connections at a customer's request, and therefore was weighted less than the USL category.

f) With respect to Staff #43 (pg. 2), please confirm that the 2013 test year costs will include maintenance and licencing cost for all billing software in use. If so, please respond to the issue raised by Board Staff.

Maintenance and licensing costs for billing software are included in the 2013 test year OM&A costs. Bluewater Power's response to Staff 43 indicated that billing software costs were not specifically incorporated into the weighting factor analysis. We do not have a mechanism to breakdown any software capital costs by rate class, and allocating the maintenance and licensing costs has been accomplished through the regular functionality of the cost allocation model.

Bluewater Power utilizes a full ERP software system (SAP) which integrates billing, finance, purchasing, device management, customer service, credit and collections, plant maintenance etc. The maintenance/licensing costs for SAP are allocated to the USoA accounts according to nature of the costs as much as possible. It is Bluewater Power's opinion that this adequately captures cost causality for maintenance/licensing costs.

It should be noted that in response to 7.0 – SEC 38 in the first set of Interrogatories, Bluewater Power provided Tables 1,3 and 4 which detailed the impact of changing the billing and collecting weighting factors from the previous OEB default values. All rate classes with the exception of the USL category were within the OEB target ranges for both scenarios. That is, Table 1 details the R/C ratio's as provided in the application, and Table 3 details the R/C ratio's if the billing and collecting weighting factors used were the prior OEB default values. The results show that the R/C ratios are within the OEB range in both cases with the exception of the USL. Therefore by utilizing Bluewater Power's derived billing and collecting weighting factors (as opposed to the OEB default values), there is no impact on rates other than for the USL rate category and the GS – Intermediate category whereby adjustments were made as detailed in Ex 7/1/1.

7.0 - VECC 75 - Load Profiles

Reference: AMPCO #12 e)

a) Please confirm that for customer classes other than intermediate and large use, the load profiles used to "scale to the 2013 forecasted energy" were based on those developed by Hydro One using 2004 data. If not, on what year's data were the profiles based and where/how were the profiles developed?

Confirmed, for all customer classes other than the intermediate and large use, the load profiles developed by Hydro One using 2004 data was used to scale to the 2013 forecasted energy.

7.0 - AMPCO 16 - Large Use Study

Reference 1: 7.0-AMPCO 12, Tab 9, Schedule 5
Reference 2: 7.0-AMPCO 13, Tab 9, Schedule 6

As part of the Settlement Agreement in Bluewater Power's last COS application, it was agreed to by all Parties that Bluewater Power would undertake a study of its costs to serve its customers in the Large Use Rate classes. . The study will assist both in determining the costs to serve customers in this rate class and determining the balance of rates among all rate classes in the future.

a) Please confirm it is Bluewater Power's position that it has undertaken a study of its costs to serve its customers in the Large Use Rate Classes as per the Settlement Agreement.

Confirmed. As stated in Ex 7/1/1, Attachment 2, page 2, Section 3:

> "*Elenchus is of the view that by using the OEB's unaltered cost allocation model, the intent of the study of costs to serve customers in the Large User customer class as per the Settlement Agreement has been met and no separate study is required.*
>
> *If a separate study would have been conducted to allocate assets and expenses to the Large User customer class, the cost causality principles that would have been used in a separate study would have been the same principles as applied in the OEB's cost allocation model. Bluewater has used its best available information in the Cost Allocation model and the same information would have been applied in a separate study for the Large User class. The same cost causality parameters: energy, demand, number of customers, used in the OEB's cost allocation model would have been used in a separate study for the Large User class.*"

b) Please comment on the quality of the cost data for the Large User class and discuss any limitations.

Bluewater Power has used the most accurate data available as inputs to the cost allocation model. For the Large Use class this includes accurate hourly load data, customer count, meter cost, financial data, and weighting factors developed to the best of our knowledge.

c) In Bluewater Power's opinion, do the costs assigned to the Large User class represent full cost causality?

The costs assigned to the Large User class follow the OEB's approved Cost Allocation Methodology to be used by distributors in Ontario and the outcome reflects cost causality as determined by this approved methodology.

d) Based on the cost study, please discuss why Bluewater Power has not assigned a revenue to cost ratio of 100% for the Large User class to reflect the results of the study and full cost causality.

As per the Board's guidelines contained in the Board Report "Application of Cost Allocation for Electricity Distributors" in proceeding EB-2007-0667 dated November 28, 2007, the appropriate range for the revenue to cost ratio for the Large User class is 0.85 to 1.15[i]. In that report the Board identified influencing factors in developing the Board's policy on revenue to cost ratios, and particularly the creation of, and continued maintenance of revenue to cost ratio 'ranges' as opposed to a revenue to cost ratio of 1.0 for each rate class. The influencing factors included:

i. Quality of data

ii. Limited modeling experience
iii. Status of current rate classes
iv. Managing the movement of rates closer to allocated costs

The Board in the above noted report states: "*As the influencing factors are addressed over time, the Board expects that these bands will narrow and move closer to one*."

The more recent 'Review of Electricity Distribution Cost Allocation Policy, Issuance of the Report to the Board , EB-2010-0291', dated March 31, 2011, page 36 states:

> *"…the Board expects that with the installation of smart meters and the availability of sufficient smart meter data, better cost allocators for the CA Model will become available and a more comprehensive review of the Board's cost allocation policies will become feasible. The Board anticipates that such a comprehensive review may provide an opportunity to further refine its target ranges. In the meantime, the Board's policy remains that distributors should endeavor to move their revenue-to-cost ratios closer to one if this is supported by improved cost allocations."*

Bluewater Power's proposed revenue to cost ratio of 1.15 for the Large Use class is within the recommended range. Any additional movement in the revenue to cost ratio for the Large Use class to reduce it to a value of 1.0 would have an impact on the revenue to cost ratios and rates for other rate classes. For this reason Bluewater Power is not recommending a lower revenue to cost ratio for the Large Use customer class.

e) Does Bluewater Power believe that a further study of the costs to serve the large use customer is required to determine full cost causality?

Bluewater Power does not expect that a further study in order to determine 'full cost causality' for the Large Use customer class would produce a different result than that obtained using the OEB's Cost Allocation Methodology. This is the best available methodology to determine cost causality by customer class used by distributors in Ontario and accepted by the Board.

f) Please confirm Bluewater Power can propose revenue to cost ratios adjustments to the revenue to cost ratios resulting from the cost allocation study in this application, to better reflect cost causality and reduce cross subsidization between rate classes.

Bluewater Power has no further information to be used in the cost allocation study that would better reflect cost causality than what has been presented in the evidence. It is true that further movement towards a ratio of 1.0 can be made for each rate class, however the Board has not mandated further movement towards unity until further refinements to the factors noted in response to part (d) above warrant such changes.

[i] Page 10, Section 3.5

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Exhibit 8 - Rate Design

8.0 - VECC 76 - LV

Reference: Staff #47 / VECC #57

a) Please provide a schedule setting out the derivation of the revised 2013 LV cost estimate ($189,412).

Please see attachment 1 to this interrogatory for the derivation of the LV cost estimate for 2013.

b) Please provide the total kWh associated with Bluewater's determination of the commodity costs underlying its 2013 working capital calculation.

The total kWh associated with the commodity costs related to the calculation of working capital allowance is presented in Table 1 below. The commodity price underpinning the commodity cost is based on the OEB's Regulated Price Plan dated October 17, 2012.

Table 1 – Derivation of the Commodity Cost

					Commodity Rate	$0.07970
Electricity (Commodity)						
	Class Name	Load Forecast	Uplifted Load Forecast	Less: WMP	Net Volume	$ Amount = Net Volume * Rate
kWh	Residential	255,687,351	266,451,788		266,451,788	21,236,208
kWh	General Service < 50 kW	97,434,167	101,536,145		101,536,145	8,092,431
kWh	General Service > 50 to 999 kW	221,905,974	231,248,216	6,138,657	225,109,558	17,941,232
kWh	General Service 1000 to 4999 kW	156,701,083	161,652,837		161,652,837	12,883,731
kWh	Large Use	247,541,912	249,249,951	116,254,337	132,995,614	10,599,750
kWh	Unmetered Scattered Load	2,238,935	2,333,194		2,333,194	185,956
kWh	Sentinel Lighting	627,674	654,099		654,099	52,132
kWh	Street Lighting	8,991,302	9,369,836		9,369,836	746,776
-	TOTAL	991,128,398	1,022,496,067	122,392,994	900,103,073	$71,738,215

Attachment 1 of 1

8.0 - VECC 76 - Low Voltage

Response to 8.0 VECC - 76

Bluewater Power proposed 2013 LV DELIVERY Charges from Hydro One Networks Inc.

From Date	To Date	Hydro One Meter Number	Location	KW ON	Total kW	Shared Low Voltage Dist Station (Oil Springs and Alvinston)	Monthly meter charge for cust not owning their meters.	Monthly Service Charge	Common STLines ($/kW)	Total monthly charge
			Actual Rates Jan 1, 2013			$ 1.9650	$ 471.17	$ 295.68	$ 0.675	
12/29/2010	01/28/2011	4192430W1	PME#1				$ 471.17	$ 295.68		
		4103010W1	Oil Springs	763	10,750	$ 1,499.30	$ 471.17	$ 295.68	$ 7,256.25	
		6200430W1	PME #2				$ 471.17	$ 295.68		
		0000840W1	Pet PME3				$ 471.17	$ 295.68		
		4102870W1	Alvinston	948		$ 1,862.82	$ 471.17	$ 295.68		
		6200230W3	WatT-2				$ 471.17	$ 295.68		$ 7,963.22
01/28/2011	03/01/2011	4192430W1	PME#1				$ 471.17	$ 295.68		
		4103010W1	Oil Springs	765	10873	$ 1,503.23	$ 471.17	$ 295.68	$ 7,339.28	
		6200430W1	PME #2				$ 471.17	$ 295.68		
		0000840W1	Pet PME3				$ 471.17	$ 295.68		
		4102870W1	Alvinston	921		$ 1,809.77	$ 471.17	$ 295.68		
		6200230W3	WatT-2				$ 471.17	$ 295.68		$ 7,914.09
03/01/2011	03/30/2011	4192430W1	PME#1				$ 471.17	$ 295.68		
		4103010W1	Oil Springs	681	10794	$ 1,338.17	$ 471.17	$ 295.68	$ 7,285.95	
		6200430W1	PME #2				$ 471.17	$ 295.68		
		0000840W1	Pet PME3				$ 471.17	$ 295.68		
		4102870W1	Alvinston	840		$ 1,650.60	$ 471.17	$ 295.68		
		6200230W3	WatT-2				$ 471.17	$ 295.68		$ 7,589.87
03/30/2011	04/30/2011	4192430W1	PME#1				$ 471.17	$ 295.68		
		4103010W1	Oil Springs	618	9466	$ 1,214.37	$ 471.17	$ 295.68	$ 6,389.55	
		6200430W1	PME #2				$ 471.17	$ 295.68		
		0000840W1	Pet PME3				$ 471.17	$ 295.68		
		4102870W1	Alvinston	746		$ 1,465.89	$ 471.17	$ 295.68		
		6200230W3	WatT-2				$ 471.17	$ 295.68		$ 7,281.36
04/30/2011	06/01/2011	4192430W1	PME#1				$ 471.17	$ 295.68		
		4103010W1	Oil Springs	698	12203	$ 1,371.57	$ 471.17	$ 295.68	$ 8,237.03	
		6200430W1	PME #2				$ 471.17	$ 295.68		
		0000840W1	Pet PME3				$ 471.17	$ 295.68		
		4102870W1	Alvinston	866		$ 1,701.69	$ 471.17	$ 295.68		
		6200230W3	WatT-2				$ 471.17	$ 295.68		$ 7,674.36
06/01/2011	06/30/2011	4192430W1	PME#1				$ 471.17	$ 295.68		
		4103010W1	Oil Springs	812	14566	$ 1,595.58	$ 471.17	$ 295.68	$ 9,832.05	
		6200430W1	PME #2				$ 471.17	$ 295.68		
		0000840W1	Pet PME3				$ 471.17	$ 295.68		
		4102870W1	Alvinston	948		$ 1,862.82	$ 471.17	$ 295.68		
		6200230W3	WatT-2				$ 471.17	$ 295.68		$ 8,059.50
06/30/2011	07/30/2011	4192430W1	PME#1				$ 471.17	$ 295.68		
		4103010W1	Oil Springs	966	14827	$ 1,898.19	$ 471.17	$ 295.68	$ 10,008.23	
		6200430W1	PME #2				$ 471.17	$ 295.68		
		0000840W1	Pet PME3				$ 471.17	$ 295.68		
		4102870W1	Alvinston	1189		$ 2,336.39	$ 471.17	$ 295.68		
		6200230W3	WatT-2				$ 471.17	$ 295.68		$ 8,835.68
07/30/2011	08/31/2011	4192430W1	PME#1				$ 471.17	$ 295.68		
		4103010W1	Oil Springs	828	12375	$ 1,627.02	$ 471.17	$ 295.68	$ 8,353.13	
		6200430W1	PME #2				$ 471.17	$ 295.68		
		0000840W1	Pet PME3				$ 471.17	$ 295.68		
		4102870W1	Alvinston	916		$ 1,799.94	$ 471.17	$ 295.68		
		6200230W3	WatT-2				$ 471.17	$ 295.68		$ 8,028.06
08/31/2011	09/30/2011	4192430W1	PME#1				$ 471.17	$ 295.68		
		4103010W1	Oil Springs	856	13014	$ 1,682.04	$ 471.17	$ 295.68	$ 8,784.45	
		6200430W1	PME #2				$ 471.17	$ 295.68		
		0000840W1	Pet PME3				$ 471.17	$ 295.68		
		4102870W1	Alvinston	971		$ 1,908.02	$ 471.17	$ 295.68		
		6200230W3	WatT-2				$ 471.17	$ 295.68		$ 8,191.16
09/30/2011	10/29/2011	4192430W1	PME#1				$ 471.17	$ 295.68		
		4103010W1	Oil Springs	551	10044	$ 1,082.72	$ 471.17	$ 295.68	$ 6,779.70	
		6200430W1	PME #2				$ 471.17	$ 295.68		
		0000840W1	Pet PME3				$ 471.17	$ 295.68		

From Date	To Date	Hydro One Meter Number	Location	KW ON	Total kW	Shared Low Voltage Dist Station (Oil Springs and Alvinston)	Monthly meter charge for cust not owning their meters.	Monthly Service Charge	Common STLines ($/kW)	Total monthly charge
		4102870W1	Alvinston	746		$ 1,465.89	$ 471.17	$ 295.68		
		6200230W3	WatT-2				$ 471.17	$ 295.68		$ 7,149.71
10/29/2011	11/30/2011	4192430W1	PME#1				$ 471.17	$ 295.68		
		4103010W1	Oil Springs	647	10073	$ 1,271.36	$ 471.17	$ 295.68	$ 6,799.28	
		6200430W1	PME #2				$ 471.17	$ 295.68		
		0000840W1	Pet PME3				$ 471.17	$ 295.68		
		4102870W1	Alvinston	900		$ 1,768.50	$ 471.17	$ 295.68		
		6200230W3	WatT-2				$ 471.17	$ 295.68		$ 7,640.96
11/30/2011	12/31/2011	4192430W1	PME#1				$ 471.17	$ 295.68		
		4103010W1	Oil Springs	730	12017	$ 1,434.45	$ 471.17	$ 295.68	$ 8,111.48	
		6200430W1	PME #2				$ 471.17	$ 295.68		
		0000840W1	Pet PME3				$ 471.17	$ 295.68		
		4102870W1	Alvinston	953		$ 1,872.65	$ 471.17	$ 295.68		
		6200230W3	WatT-2				$ 471.17	$ 295.68		$ 7,908.20
						$ 39,022.94	$ 33,924.24	$ 21,288.96	$ 95,176.35	$ 189,412.49
					Estimated for 2013					**$ 189,412**

Rates Updated January 2013 to reflect Hydro One approved rates.

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Exhibit 9 - Deferral and Variance Accounts

9.0 - Staff 78 - Stranded Meters

Ref: 4.2-2-Staff-5

Ref: 11.3-9-Staff 51

In response to Staff IR 5, Bluewater Power provided 2012 NBV of stranded meters. Please explain why the NBV differs from that used to determine the SMRR in the response to Staff IR 51.

The response to Staff IR 5 is $1,928,303 which is a MIFRS amount. The response to Staff IR 51 is $1,926,645 which is a CGAAP amount. Both of these amounts are found in the pre-filed evidence in Exh 2-2-2 Appendix 2-EB.