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February 3, 2009

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2701
Toronto ON M4P 1E4

Dear Ms. Walli:

Re: EB-2008-0221 Bluewater Power 2009 Rate Application
Supplemental Interrogatory Responses

Please find attached the Interrogatory Responses of Bluewater Power to the VECC supplemental interrogatories.

Two hard copies will follow via courier.

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

A handwritten signature in black ink that reads "L. Dugas".

Leslie Dugas
Manager of Regulatory Affairs
Bluewater Power Distribution Corporation
Email: ldugas@bluewaterpower.com
519-337-8201 ext. 255

cc: All Intervenors

BLUEWATER POWER DISTRIBUTION CORPORATION
Responses to Supplementary Information Requests of
Vulnerable Energy Consumers Coalition (VECC)

VECC Supplementary Question 1

(VECC Question #2)

Reference: Exhibit 1/Schedule 2/Tab 5

a) Provide the following actual 2007 and projected 2009 metrics for all business units of BPC, including Corporate and BPDC:

Preamble:

The information for GenCo, Blackwell and Electek and SHSC. is relevant to the assessment of shared services among affiliates. If the information is confidential/commercially sensitive, then filing under the Board's Confidentiality Guidelines is available to BPDC.

a) Provide the requested information for all affiliates as of the end of either 2007 or 2008

Response:

	Bluewater Power Distribution Corporation		Bluewater Power Corporation	
	2007	2009	2007	2009
# of Board Members	6	6	4	4
# of Officers - affiliation	2 Directors 3 Staff of BPDC	2 Directors 3 Staff of BPDC	2 Directors 3 Staff of BPDC	2 Directors 3 Staff of BPDC
Capital Deployed	4,858,800	8,285,800	NIL	NIL
Fulltime Employees (FTEs)	93	99	NIL	NIL
Contract Employees (FTEs)	3	NIL	NIL	NIL
Operating Revenues	20,094,800	19,520,300	7,007,100	770,200
Operating Costs	18,732,800	17,208,800	NIL	NIL

	Bluewater Power Generation Corporation		Blackwell Renewable Energy Inc.	
	2007	2009	2007	2009
# of Board Members	4	4	4	4
# of Officers - affiliation	2 Directors 3 Staff of BPDC	2 Directors 3 Staff of BPDC	2 Directors 3 Staff of BPDC	2 Directors 3 Staff of BPDC
Capital Deployed	NIL	NIL	3,965,000	200,000
Fulltime Employees (FTEs)	NIL	2	0.5	1
Contract Employees (FTEs)	NIL	NIL	NIL	1
Operating Revenues	13,100	387,100	6,300	1,140,900
Operating Costs	10,500	294,900	20,300	864,300

	Bluewater Power Services Corporation (formerly SHESC)		Electek Power Services Inc.	
	2007	2009	2007	2009
# of Board Members	4	4	2	4
# of Officers - affiliation	2 Directors 3 Staff of BPDC	2 Directors 3 Staff of BPDC	2	2 Directors 3 Staff of BPDC
Capital Deployed	NIL	402,000		
Fulltime Employees (FTEs)	NIL	9	4	5
Contract Employees (FTEs)	NIL	0.5	1	1
Operating Revenues	NIL	1,631,500		
Operating Costs	800	1,457,300		

NOTE: As agreed during the conference call on January 29, 2009, the financial information for Electek Power Services Inc. has not been included in the above analysis as it was not required for the purposes of the analysis that VECC intends to undertake.

- b) For SHESC provide estimates before/after the transfer of functions and assets/
resources for non-core activities (Exhibit 1, Tab 2, Schedule 6, Page 3),

Response:

As discussed during the conference call January 29th, 2009, the answer to Question 1(a) provides the requested information since the transfer took place as of January 1, 2009. The years 2007 and 2008 were inactive years for Bluewater Power Services Corporation (Formerly SHESC). The year 2009 is the first year post-transfer of activities.

VECC Supplementary Question 2

(VECC Question 5 (b))

With regard to the SAP upgrade please provide a copy of the benefits realization assessment/plan, including quantification of annual OM&A cost reductions.

Preamble: The response provides qualitative benefits but does not provide the OM&A cost/benefit requested

Reference Attachment 5A to VECC Question 5

- a) For each of the categories of cost reductions listed in the SJH report at pages 20-21 indicate if BPDC agrees with the savings expected as being applicable to its SAP Upgrade. If not indicate its own estimate for each category

Response:

The following table has been prepared showing the cost reductions listed in the SJH report under the first column below. The second column shows SJH's estimated savings expressed as a percentage taken directly from the SJH report. The dollar figure in parentheses in the second column is the dollar equivalent for the savings – it is important to note that we have included dollar figures as the estimated savings, but that does not necessarily mean that Bluewater Power agrees that the cost reduction will be realized at the utility. That issue is addressed in the third column which contains Bluewater Power's comment on whether the estimated reductions can be realized.

SJH Report	Percentage (BPDC equivalent)	BPDC Comment
Reduced Customer Service Costs due to reduced errors	15-25% (\$1000)	We agree that this benefit will be realized, however, the anticipated savings in OM&A are minimal. BPDC does not formally track its error rate, but we would estimate the error rate is less than 1% so any improvements in efficiency would be minimal. The importance of the upgrade cannot be fully quantified in dollar values, however, because any reduction to the error rate will ensure continued and improved customer confidence in the services of BPDC. That is a non-tangible benefit to customers and the corporation.

Increased customer service/call centre capacity	20-30% (\$100,000)	We agree that improved efficiencies in the range of 20% would be available within the call centre given the upgrade to certain key components of SAP. However, these savings will not likely reduce OM&A at BPDC in either 2010 or 2011. Firstly, although Bluewater Power attains the minimum required performance standards of the OEB on an overall basis, the call centre does fail to meet those standards on occasion (based on monthly reporting); accordingly, the upgrade will improve customer service without incurring additional costs. Secondly, the completion of the upgrade will be followed by Smart Meter implementation which will place increased demand on the call centre staff; accordingly, the call centre efficiencies created by the SAP upgrade will not reduce OM&A in 2010 or 2011, but will serve as cost avoidance as new staff will not be required in the call centre for the Smart Meter implementation. Therefore, in both regards, the cost savings are in the nature of cost avoidance.
Improved 1 st call resolution	4-5% (\$nil)	We do not track 1 st call resolution, so it would be difficult to comment.
Reduced repeat calls	20-30% (\$1,000)	We agree that this benefit will be realized, but we anticipate that the savings would be minimal.
Improved Technical Utilization	10% (\$4800)	We agree that this benefit will be realized. The benefit that will be realized in 2010 and beyond is anticipated to be savings on the order of magnitude of \$4800.
Reduced Bad Debt	20-30% (\$20,000)	We agree that this benefit will be realized, but we would anticipate being closer to a 20% improvement due to processes already in place at the utility. Given the anticipated trend in bad debt due to the recent economic downturn, we would anticipate the savings will be offset by increased bad debt likely to impact the budget in 2010. Therefore, the savings are in the nature of cost avoidance.

Improve Days outstanding	14-42% (\$2500)	We agree that this benefit will be realized, but we would anticipate that the impact is minimal. If payments on debt past due accounts were sped up by 2.5 days on average the improvements in cash flow would be approximately \$2500 annually.
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- b) Based on savings estimated and 2009 budgets, provide an estimate of the annual OM&A cost reductions for each category and a total (may include other savings).

Response:

The estimated savings are included in the table provided in response to #2(a) above, as well as in response to OEB Supplementary IR #2 under the heading SAP Upgrade. In the summary below, it is important to differentiate between true reductions in OM&A and reductions that are more in the nature of avoided future costs. Accordingly, the table below will provide both types of savings separately prior to totaling the reductions.

True Reductions in OM&A:		
Reduced error (see above)	\$ 1,000	
Reduced repeated calls (see above)	\$ 1,000	
Improved Technical utilization (see above)	\$ 4,800	
Improved days outstanding (see above)	\$ 2,500	
Annual saving in reduced routine upgrade costs (see OEB Supp.IR#2)	\$ 8,000	
Annual saving in programming efficiencies (see OEB Supp.IR#2)	\$ 15,000	
TOTAL		\$ 32,300
Cost Avoidance:		
Improved Call Centre Capacity (see above)	\$100,000	
Improved Bad Debts (see above)	\$ 20,000	
One-time avoided incremental cost of IFRS implementation in current version of SAP	\$ 50,000	
One-time avoided incremental cost of Smart Meter implementation in current version of SAP	\$250,000	
TOTAL		\$420,000
TOTAL COST AVOIDANCE AND REDUCTIONS		\$452,300

VECC Supplementary Question 3

(VECC Question 8 (c))

Response:

A schedule showing the age distribution by major asset class is not available. Although the 1999 Report prepared by Elecsar Engineering is, in part, an asset condition assessment, there is not sufficient detail to satisfy the question.

Reference: Exhibit 2, Tab 3, Schedule 9

- a) Does BPDC have a Document that describes the development of the Sustaining Capital Budget? If so please provide a copy

Response:

Bluewater Power has described its budgeting process within its Asset Management Plan found at Exhibit 2, Tab 3, Schedule 9. The process described includes:

- bi-weekly meetings during which Engineering and Operation groups discuss on-going capital projects, O&M projects, system reports, and future system planning.
- Budget planning begins in August of each year
- Final review of Capital Budget in September
- Review by Senior Management Team in November
- Board Approval in November/December

Although the process is comprehensive and well-disciplined, there is no separate document that deals with the development of the Sustaining Capital Budget.

- b) If not, provide a description of the process by which Sustaining Capital priorities are set for each major asset class (e.g. substations, feeders, distribution lines, poles, property and equipment) with particular to reference to the 2009 budget.

Response:

Bluewater Power bases its sustaining capital planning on three priorities, reliability, public safety and system integrity.

By way of summary, the Sustaining Capital projects within the Operations categories for the year 2009 are as follows:

UT2	Substation Building Improvement	\$ 106,970
UT4	Street Widening	\$ 53,274
UT8	Alvinston/Oil Springs	\$ 19,576
UT10	Pt. Edward upgrades	\$ 48,940
UT11	Tools	\$ 44,000
UT12	Vehicle Replacements	\$ 528,000
UT13	New Connections	\$ 978,799
UT14	Strategic Transformer Inventory	\$ 163,485
UT16	Safety Related Projects	\$ 11,000
UT17	CrossArm/Cap & Pin Insulator Replacement	\$ 97,880
UT18	Wood Pole Replacement Program	\$ 97,880
UT23	Watford	\$ 77,334
UT24	Load Balancing	\$ 47,425
UT25	CEO Contingency Fund	\$ 212,425
UT28	Service Centre	\$ 53,485
UT35	Transformer Cover Replacements	\$ 24,470
UT38	Storm Restoration	<u>\$ 146,820</u>
		\$ 2,711,762

Before providing the information requested, we should point out that priorities between major asset classes are irrelevant with respect to UT4 (Street Widenings), UT13 (New Connections) and UT38 (Storm Restoration) because those projects are externally driven and because those projects affect all asset classes (for example, a storm can impact poles, transformers, buildings, etc.). Those three capital projects together represent \$1,178,893, or 43% of the total Sustaining Capital projects within Operations.

Spending on the remaining \$1,532,869 of sustaining capital spending is based on three guiding principles, service reliability, public safety and system integrity. As one might expect, when Bluewater Power performs planning to sustain its system, service reliability is of foremost concern. Public safety and system integrity are generally related to service reliability but are considered separately.

Our priorities in terms of spending on major asset classes are determined as set out below. For the purposes of this analysis we have describe the natural asset classes as set out below, followed by a general description of the planning process for those assets.

- 27.6 KV Primary Feeders
- 4kV and 8kV distribution lines
- Underground
- Low Voltage Distribution Circuits.
- Substation Relaying, breakers, underground feeds.

The asset classes listed above receive first priority when planning sustaining capital budgets. The primary consideration in that regard is service reliability based on the assessment that these assets classes are critical to system reliability. In project planning, the health of these assets is generally determined by age and design. They are the backbone of our distribution system and represent approximately 800 kms of overhead and underground plant exposure; exposure to the public, to the elements and our customers. The Bluewater Power capital planning process prioritizes projects within the above asset classes with emphasis on age of plant, documented inspection reports, system load reports and open dialogue. In addition, Substation Relaying and Breakers are a key component to customer reliability, and Bluewater Power has a program to upgrade substation relaying.

- Vehicles

The second priority in the Bluewater Power budget process is vehicles. This priority is based on service reliability and public safety, including employees. An LDC must have a modern, well maintained fleet of vehicles to deliver a reliable supply of electricity to customers. Bluewater Power crews work on 27.6 KV high voltage circuits energized on a daily basis and the margin for human or equipment error is extremely narrow. The most devastating result of equipment or human error is serious injury. With so much emphasis on customer reliability and conversion to high voltage circuits, the trend to live line work will only increase.

- Substations
- Buildings and Facilities

The third priority in the Bluewater Power budget process is capital spending on Substations. Bluewater Power owns 17 - 4 KV substations. Nine are bungalow style substations or buildings and 8 are outdoor substations. Bluewater Power has a solid, documented substation inspection program; that combined with building, fence, grounding and other associated capital upgrades allows us to keep this asset in a reliable and safe condition.

The main service centre for Bluewater Power office staff, trade staff and vehicles is located at 855 Confederation St. in Sarnia. Bluewater Power has replaced and maintained the core infrastructure at this facility to keep it in good physical shape. The main limitation at the service centre is the lack of garage space and square footage for offices. To the extent that the lack of garage space limits efficiencies, that individual project has become a higher priority as that can impact reliability and safety.

Buildings and substations provide Bluewater Power with a relatively small geographic footprint. We can continuously monitor to ensure the workplace is safe and the infrastructure properly maintained.

VECC Supplementary Question 4

(VECC Question 9 (b))

Response indicates (in part) "We have budgeted to change expired meters in order to maintain compliance. For budgeting and planning purposes, we cannot anticipate that the dispensation from Measurement Canada will be granted".

References:

Exhibit 2/Tab 3/Schedule 1, page 5 of 6 & Attachment 1, page 2

Exhibit 5/Tab 1/Schedule 4, page 1

- a) provide a copy of the correspondence with Measurement Canada

Response:

The original request for information was delivered by e-mail dated November 25, 2008. That e-mail and the chain of response is attached.

A follow-up meeting was initiated by Bluewater Power's Manager of Metering Services via a phone call on January 7, 2009. A meeting was arranged with a representative of Measurement Canada for January 27, 2009. There is no written correspondence following from these more detailed discussions, but a summary is found in response to the next question.

b) Indicate the status of the requested dispensation.

Response:

A meeting was held with Luc Van Overberghe from Measurement Canada on January 27, 2009 to discuss the dispensation policy. It is our understanding from that conversation that dispensation is not available on the basis of financial hardship (ie. inefficient use of resources to replace meters to be replaced with Smart Meters within one year). Dispensation may be available where there is a demonstrated lack of resources at the utility to achieve compliance (ie. staff shortages or unanticipated number of meters requiring replacement).

As suggested in our answer to VECC's original IR#9(b), we plan to reseal meters rather than replace; the cost difference being \$22.50 installed versus \$50 installed. A solution was presented by Measurement Canada for those meters within sample groups because representative sampling can allow the seal period of meters within the sample to be extended without individual testing. Bluewater Power has 1189 meters in six such sample groups, but the remaining 1500 meters that are overdue from 2008 are not within any sample group. Therefore, this is only a partial solution.

However, we believe a complete solution to the challenge of replacing expired meters unnecessarily can be achieved. At this point in time, Bluewater Power's Smart Metering Team has selected its preferred meter. We are confident that any residential meters that require replacement in 2009 can be replaced with smart meters (once a contract is signed with the preferred supplier).

- c) Provide an estimate of the \$ impact of dispensation on 2009 residential meter costs (resealing vs. replacement) if dispensation is granted by each of Q1-Q4 respectively

Response:

Not applicable given the response to part (b).

- d) Explain clearly why replacement of expired standard meters with smart meters cannot be standard practice (other than requiring MC approval).

Response:

Once a contract is signed with the selected smart meter provider, the plan is to purchase only smart meters when required to replace residential meters.

VECC Supplementary Question 5

Reference: VECC #13 b)

- a) The original question requested the LV charges embedded in the “rates” for 2008 and 2009, i.e., what is the LV adder included in each customer class’ variable rates for each of those years. Please provide.

Response:

The LV rate applicable to 2008 is the current rate that was established in the 2006 EDR proceeding, and is displayed in the table below. The 2009 rate would be determined by dividing the revenue allocated to each customer class by the 2009 forecast (kWh or kW) and is also displayed below. The amount of revenue allocated to each class is determined by the methodology described in response to VECC Supplemental Interrogatory #13 (b)

Customer Class Name	LV Rate per 2006 EDR, applicable to 2008 \$/kWh	2009 Proposed LV rate \$/kWh
Residential	0.0002	0.0002
General Service <50 kW	0.0002	0.0002
General Service 50 to 999 kW	0.0813	0.0684
General Service 1,000 to 4,999 kW	0.0862	0.0750
Large	0.0815	0.0858
Unmetered Scattered Load	0.0002	0.0002
Sentinel Lighting	0.0556	0.0540
Street Lighting	0.0531	0.0529

VECC Supplementary Question 6

Reference: VECC #14 c) and e)

- a) Please provide a schedule that for 2008 and 2009 set out how much of the Interest and Dividend Income in each year is attributable to a) net carrying charges on regulatory accounts and b) interest income.

Response:

The amounts included in Account 4405 can be broken down as follows.

For 2008:

\$100,320	- interest revenue
<u>(\$223,924)</u>	- carrying charges
<u>(\$123,604)</u>	

For 2009:

\$ NIL	- interest revenue
<u>(\$243,636)</u>	- carrying charges
<u>(\$243,636)</u>	

VECC Supplementary Question 7

Reference: VECC #15 d)

- a) The response stated that February to December 2007 data was not excluded from the analysis. However, the original Application clearly states “Weather correction and forecasting for general service class kWh is based on data from January 2004 to January 2007” {paragraph 2, page 2}. Please reconcile and explain the exclusion of the February –December 2007 data if not used.

Response:

Page 2, paragraph 2 of the ERA Report contains the following sentence:

“Weather correction and forecasting for general service class kWh volumes is based on data from January 2004 to January 2007, due to anomalous monthly consumption in 2003.”

The above sentence contains a typographical error and should have read:

“Weather correction and forecasting for general service class kWh volumes is based on data from January 2004 to December 2007, due to anomalous monthly consumption in 2003.”

VECC Supplementary Question 8

(VECC Question #20)

Response refers to Board Staff IR #1.13 (b).including Hay Report.

Reference: Board Staff Interrogatory 1.13.b Attachment 1 Hay Compensation Report

- a) With respect to the position of Vice President Corporate Services and General Manager, please provide, in the context of utility comparators, explanations why this position is compensated at or above P75 or above average in terms of
- i. Base Salary
 - ii. Incentives
 - iii. Total Compensation

Response:

The title of the position in question is VP Corporate Services and General Counsel, rather than VP Corporate Services and General Manager. That is significant because the person holding this position is not only an executive member of the management team but also a legal professional. Therein lies one possible explanation as discussed further below.

Although the question asks for an explanation within the context of utility comparators only, it is inappropriate to limit the scope of the explanation in that manner because the Compensation Committee considers comparisons with both the Utility group and the Industrial organizations. Although the position of VP Corporate Services and General Counsel is marginally above the 75th percentile in the utility comparison, the position is further below the 75th percentile than four other positions at the utility in the comparison with the Industrial organizations. This disparity in results suggests one of two possible explanations.

Firstly, it is possible that the sample size for utilities with legal professionals was too small to rely upon on its own. We certainly do know anecdotally that there are few in-house legal counsels in Ontario utilities. The Hay group methodology of utilizing a point-based system for ranking positions should largely correct for this sample size issue. Nevertheless, this issue with the utility data points out the importance of carrying out more than one comparison.

Secondly, the disparity in results would seem to suggest that utilities place less value on legal professionals than the industrial sector. The positions that surpass the VP

Corporate Services and General Counsel in relative compensation in the comparison with Industrial Organizations are the Controller, Director of IT, Director of Client Services and Manager Design Services; the results for the VP Operations & COO are almost identical to that of the VP Corporate Services and General Counsel. In other words, that the legal profession would appear to be less valued within the Utility sector than it is within the Industrial Organizations. Given the fact that utilities have only recently become regulated entities, it is not surprising that technical and operational positions would continue to be more valued.

Finally, determining compensation is a twofold process. The position must be assessed and classified, but then the individual holding the position must also be assessed. Bluewater Power and its Compensation Committee have recognized that this individual serves as the Acting CEO when required and plays a critical role within the Senior Management Team.

- b) Is the Compensation Committee aware of the compensation for this position being a “outlier” and if so has any action been taken to levelize compensation among executive positions?

Response:

The documentation provided in response to the original Board Staff IR # 1.13(b) is precisely the information provided to the Compensation Committee. The information provided was modified only to remove personal information. Therefore, the Compensation Committee is aware that the position of VP Corporate Services and General Counsel is marginally above the 75th percentile for the Utility group.

That is not to say that the Compensation Committee would agree that the compensation for this position is an “outlier”. First, as a pure statistical analysis the statement appears to be false even if we look at the Utility comparisons only. Second, the Compensation Committee would not look at the Utility comparison only without also looking to the Industrial comparison.

- c) Estimate the change to 2009 payroll costs if the position was compensated at the P50 level for base pay, incentives and total compensation.

Response:

For all of the reasons discussed above, we believe that this question contains a false premise that the position is an “outlier”. It also sets as its objective a goal to compensate this position at the P50 level which is inappropriate given the discussion of the conservative nature of the comparison methodology (see OEB IR #1.13(b)) and the fact that the result would not be consistent with relative compensation for the other positions at the utility. We believe that it would be inappropriate to provide the information requested.

We can provide, for the comfort of the OEB, that even if we were to look at the Utility group analysis only, the dollar value required to bring the total compensation for the VP Corporate Service and General Counsel to be in line with the nearest positions in this relative comparison would be less than \$5,000.

VECC Supplementary Question 9

VECC Question 20 (g)

Response: The application assumes that the six new positions will be in place as full FTEs in 2009.

Clarification re impact.

- a) Please provide a schedule showing the time that each new hire will be on payroll in 2009. List all relevant assumptions (hire date etc)

Response:

Accountant	-	March 1, 2009	-	interviews in progress
HR Administrator	-	February 16, 2009	-	confirmed start date
Line Technician	-	January 1, 2009	-	hired in 2008
Line Supervisor	-	April 1, 2009	-	job posting pending
Lineman #1	-	January 1, 2009	-	existing (not moved to affiliate)
Lineman #2	-	March 1, 2009	-	interviews in progress

- b) Calculate the difference in 2009 total compensation for the 6 new hires, assuming full year compensation as filed and compensation per the schedule provided in part a)

Response:

The difference in 2009 total compensation for the four applicable new hires above is \$46,800.

- c) Assume all hires are delayed 3 months from the schedule provided in part a) and calculate the total 2009 compensation. Compare to the 2009 total compensation in the prefiled evidence and the total resulting from the schedule provided in part a)

Response:

The information sought by this question can only be provided with respect to the three positions that do not already have a firm start date. That would include the accountant, line supervisor and lineman #2. The difference in 2009 total compensation caused by further delaying these three positions by three months is \$90,700. The net increase in the potential savings above those identified in answer to 9(b) above is, therefore, \$43,900.

Within the next month two of those three positions (accountant and Lineperson #2) are likely to be filled. Those positions simply cannot be delayed any further in the opinion of Bluewater Power's management.

The third position (line supervisor) could be delayed a further three months, but we do not believe that would be appropriate. If this were the only position delayed by a further three months, then that would reduce the incremental savings from the \$43,900 figure identified above to \$20,400.

VECC Supplementary Question 10

VECC Question 24 (b)

Response: The assets being transferred to the affiliate include a backhoe, compact wheel loader, excavator, freightliner truck and a flatbed trailer. The approximate net book value at December 31, 2008 is \$195,000, which also closely approximates fair market value.

Clarification questions re use of BPDC vehicles and garage space

Preamble

(ii) Equipment Bay Space

The equipment needs of Bluewater Power have also grown over the years as the company has evolved. In addition, similar to the personnel impact of the merger, Bluewater Power assumed responsibility for all equipment bay storage requirements for the trucks and other equipment absorbed as part of the merger. In addition, in 2004 Bluewater Power also made a strategic decision to move its meter reading services in-house and this decision resulted in an additional four vehicles. In total, the vehicle base of Bluewater Power has increased by 18 units over the last 10 years.

- a) Was the Freightliner double bucket material handler truck purchased in 2008 for \$425,000 transferred to the affiliate? If not, is it rented to the affiliate for either core (outsourced) or non core activities.

Response:

No, the vehicles transferred to the affiliate did not include the Freightliner double budget material handler truck purchased in 2008. Given the size and nature of this vehicle, it is very unlikely that it will be outsourced to the affiliate.

b) Provide the hourly rental rate calculation

Response:

Large Trucks

Bluewater Power charges customers, including affiliates, \$30 per hour for large trucks. This rate is well in excess of the average costs per hour that Bluewater Power incurs calculated as follows:

\$364,400	- total annual costs (operating expenses, amortization, insurance, etc)
<u>15</u>	- divide by number of large trucks in fleet
\$ 24,300	- total average annual cost per large truck
<u>1,560</u>	- divide by conservative estimate that trucks are used 75%x2,080 hours
<u>\$ 15.58</u>	- estimated average cost per hour per large truck

This rate is based on 2008 actual costs incurred. The costs for the 2009 test year are consistent.

Small Vehicles (Trucks, Vans, Cars)

Bluewater Power charges customers, including affiliates, \$10 per hour for small vehicles. This rate is well in excess of the average costs per hour that Bluewater Power incurs calculated as follows:

\$214,500	- total annual costs (operating expenses, amortization, insurance, etc)
<u>30</u>	- divide by number of small vehicles in fleet
\$ 7,150	- total average annual cost per small vehicle
<u>1,560</u>	- divide by conservative estimate that vehicles are used 75%x2,080 hours
<u>\$ 4.58</u>	- estimated average cost per hour per large truck

This rate is based on 2008 actual costs incurred. The costs for the 2009 test year are consistent.

- c) How much of the garage equipment storage space was used by the affiliate in 2008 . How will this change after the transfer of functions and assets in 2009?

Response:

The vehicles used for Non-Core Distribution Activities can be divided into two groups:

- (1) **Civil Equipment:** equipment used for civil work (such as excavators, dump trucks, backhoe and the transport truck for moving equipment) has been stored off-site since 2006. The vehicles were relocated to previously abandoned garage space and yard facilities located at Main Substation #1 in Sarnia ("MS#1"). Therefore, none of the garage space at 855 Confederation Street was utilized in 2008 or will be utilized in 2009 for the Civil Fleet.
- (2) **Line Vehicles:** There is no one vehicle used exclusively for streetlight, traffic light work, or any other work to be carried out by the affiliate in 2009. Vehicles are utilized on an as-needed basis and the affiliate is charged an hourly rental rate as discussed above. Based on 2008 actual hours recorded to Account 4380 for line vehicles used in pursuit of Non-Core Distribution Activities, Bluewater Power's large vehicles are utilized for Non-Core Distribution activities approximately 5% of the time available in the year. Bluewater Power's small vehicles are utilized for Non-Core Distribution activities approximately 1% of the time available in the year. Since garage space is primarily occupied by large vehicles, we could conclude that less than 5% of the garage space at 855 Confederation Street was utilized in 2008 or will be utilized in 2009 for storage of vehicles used in pursuit of Non-Core Distribution Activities.

d) Are the transferred vehicles/equipment housed in the BPDC Garage?

Response:

No, the vehicles being transferred have been housed at MS#1 since 2006.

- e) For these and BPDC vehicles rented by the affiliate, what charge is made for garage space?

Response:

There is no specific charge for garage space. Given that no one vehicles is exclusively used by the affiliate, the only way to charge for garage space would be to include the charge as part of the hourly rental rate. Vehicles are charged out to affiliates at the same rate they are charged to third parties. It is reasonable to say that a charge for garage space could be considered as included in the hourly charge-out rate for vehicles since the charge out rate significantly exceeds the fully-allocated cost of the vehicles (as shown in answer to VECC Supplementary IR #10(b) above).

f) If the facilities expansion proceeds what how will these charges change?

Response:

Given the answer to 10(e), there is no specific charge to be modified.

- g) Given the need to expand the equipment storage in the garage facilities why cannot the affiliate find alternative garage/storage space?

Response:

As discussed above all vehicles exclusively dedicated to affiliate activities are already stored offsite. By way of reminder, the rent charged by Bluewater Power to the affiliate for the use of the garage and yard space at MS#1 in 2009 is \$12,000.

h) Has this option been examined and what were the conclusions in terms of proceeding with /deferring the facilities expansion?

Response:

Yes, this option was examined and has already been implemented as discussed above.

VECC Supplementary Question 11

(VECC Questions 27a-27c LRAM/SSM)

Clarification/follow up questions based on attachments provided

References: Exhibit 5 Tab 1 Schedule 3 Attachment 1 and Exhibit 5 Tab1 Schedule 3 Attachment 2 ERA report Pages 10 and 12

Preamble: ERA Report states "All reviews included a check for internal consistency, integrity of the calculations and consistency with published OEB or OPA approved values"

- a) Please provide Copies of the OPA Every Kilowatt Counts (EKC) Program Calculators for
 - i. 2006 spring/summer fall campaigns
 - ii. 2007 spring and summer/fall campaigns

Response:

Below is the output of the OPA Every Kilowatt Counts (EKC) Program Calculators for the 2006 Spring/Summer and Fall campaigns. Note that the fall 2006 program calculator assumed a coupon:unit ratio higher than the 1:1 assumption that Bluewater Power utilized.

Bluewater Power did not make a claim for the 2007 EKC Program, thus no output is provided.

Also filed are the excel versions of the 2006 and 2007 program calculators.

Attachments:

- 1. Spring/summer 2006 EKC Calculator
- 2. Fall 2006 EKC Calculator



TOTAL RESOURCE COST TEST CALCULATOR
2006 Summer Every KiloWatt Counts Campaign

Part 1. Enter Data Here (in yellow shaded area: cells C22 and C26:C30)

LDC Information	
Discount Rate	6.82%
Products Sold	
CFLs	3,447
Ceiling Fans	119
Timers	112
Program Thermostats	149
Program Costs	\$0

Part 2. Results by Technology

Total Resource Cost Test Results by Technology (2007 \$'s)							
Technology	TRC Benefits	TRC Costs	TRC Net Benefits	TRC Benefit Cost Ratio	Summer Peak kW Savings	Net Annual kWh Savings	Net Lifecycle kWh Savings
CFLs	\$73,741	\$6,980	\$66,760	10.56	-	322,801	1,291,202
Ceiling Fans	\$14,944	\$2,678	\$12,267	5.58	1.53	15,058	301,165
Timers	\$17,560	\$1,260	\$16,300	13.94	-	18,396	367,920
Programmable Thermostats	\$30,244	\$8,717	\$21,527	3.47	6.71	29,235	526,224

Part 3. Program Results

Total Resource Cost Test Results for Program (2007 \$'s)	
TRC Benefits	\$136,488
TRC Costs	\$19,634
TRC Net Benefits	\$116,854
Benefit Cost Ratio	6.95
Total Summer Peak kW Savings	8.23
Total Annual kWh Savings	385,489
Total Lifecycle kWh Savings	2,486,511

Instructions for Calculating Total Resource Cost Test Results
2006 Fall Every KiloWatt Counts Campaign

Part 1

a. Enter Discount Rate (refer to page 5 of the Ontario Energy Board Total Resource Cost Test Guide, Revised October 2, 2006.)

Discount Rate 6.82%

b. Enter number of coupons redeemed by technology.

Products	Number of Coupons
Baseboard Programmable Thermostats	33
Dimmers	198
Energy Star CFL's	4044
Motion Sensor Light Switch	69
Programmable Thermostat	382
Seasonal LED Lights	4749

c. Enter program dollars (refer to page 10 of the Ontario Energy Board Total Resource Cost Test Guide, Revised October 2, 2006.)

Program Costs: \$ -

Part 2

Program Total Resource Cost Test Results

Calculation of Program TRC Benefits
Sum of TRC Benefits for all technologies

Calculation of Program TRC Costs
Sum of TRC Costs for all technologies plus Program Costs

Calculation of Program TRC Net Benefits
= TRC Benefits - TRC Costs

Fall EKC		
Technology	Number of Participants	Free Ridership
Compact Fluorescent Bulbs	11566	10.00%
LED Christmas Lights (indoor or outdoor) Replacing 5w Christmas Lights C-7 (25 Lights)	2375	5.00%
LED Christmas Lights (indoor or outdoor) Replacing Incandescent Mini Lights	2375	5.00%
Programmable Thermostat - Space Heating, Existing Single Family Detached	66	10.00%
Programmable Thermostat - Space Cooling, Existing Single Family Detached	172	10.00%
pStat Baseboard	8	10.00%
Dimmer	198	10.00%
Motion Sensor	69	10.00%

Fall EKC					
Technology	Summer Peak kW Savings	Winter Peak kW Savings	Annual kWh Savings in Year	Measure Life	Lifecycle kWh Savings
Compact Fluorescent Bulbs	0	239.41	1,086,726	4	4,346,905.31
LED Christmas Lights (indoor or outdoor) Replacing 5w Christmas Lights C-7 (25 Lights)	0.00	42.86	95098.73	30	2,852,961.75
LED Christmas Lights (indoor or outdoor) Replacing Incandescent Mini Lights	0.00	15.79	36329.85	30	1,089,895.50
Programmable Thermostat - Space Heating, Existing Single Family Detached	0.00	10.29	87211.71	18	1,569,810.81
Programmable Thermostat - Space Cooling, Existing Single Family Detached	25.22	0.00	24614.36	18	443,058.50
pStat Baseboard	0.00	7.43	10887.28	18	195,971.00
Dimmer	0.00	16.04	24769.80	10	247,698.00
Motion Sensor		8.38	12978.90	20	259,578.00
Total	25.22	340.20	1,378,617		11,005,879

Fall EKC					
Technology	TRC Benefits	Incremental Equipment Costs	Program Costs	TRC Net Benefits	TRC B/C Ratio
Compact Fluorescent Bulbs	\$248,372.24	\$18,736.66		\$229,636	13.26
LED Christmas Lights (indoor or outdoor) Replacing 5w Christmas Lights C-7 (25 Lights)	\$124,574	\$4,512		\$120,062	27.61
LED Christmas Lights (indoor or outdoor) Replacing Incandescent Mini Lights	\$47,474	\$4,512		\$42,963	10.52
Programmable Thermostat - Space Heating, Existing Single Family Detached	\$73,640	\$3,569		\$70,072	20.64
Programmable Thermostat - Space Cooling, Existing Single Family Detached	\$36,957	\$9,283		\$27,674	3.98
pStat Baseboard	\$10,005	\$446		\$9,560	22.46
Dimmer	\$13,684	\$3,564		\$10,120	3.84
Motion Sensor	\$8,819	\$435		\$8,385	20.29
Utility Program Costs			\$ -		
Total	\$563,526	\$45,055	\$0	\$518,471	#DIV/0!

- b) Provide a comparison table showing the following input assumptions in each of the OPA 2006 and 2007 EKC Program calculators with the OEB TRC Guide.
- a. Annual saving kwh/unit
 - b. Peak demand reduction kw/unit
 - c. Estimated useful life
 - d. Free ridership
- For the following Measures:
- i. Energy Star CFL 15w
 - ii. LED Xmas lights
 - iii. Outdoor Motion Sensor
 - iv. Dimmer Switch

Response:

Table 1 below compares the input assumptions for the 2006 EKC programs and Table 2 is presents the 2007 assumptions using the 2007 EKC Calculator. Table 2 is presented for information only, as Bluewater Power did not make a claim for 2007 results.

Table 1 - 2006 Comparison

	Energy Star CFL 15w	LED Xmas lights	Outdoor Motion Sensor	Dimmer Switch
EKC Calculator Annual Savings (kWh)	104	Note 1	209	139
OEB TRC Guide (kWh)	104	19	209	139
EKC Calculator peak Demand	0	Note 2	0.135	0.09
OEB TRC Guide peak Demand	0	0.008	0.135	0.09
EKC Calculator Useful Life	4	30	20	10
OEB TRC Guide Useful Life	4	30	10	10
EKC Calculator Free Ridership	10%	5%	10%	10%
OEB TRC Guide Free Ridership	10%	5%	10%	10%

Note 1: The value is unknown since the EKC calculator splits the lights between 5w and mini.

Note 2: Unknown

Table 2 – 2007 Comparison

Technology	Energy Star CFL 15w	LED Xmas lights	Outdoor Motion Sensor	Dimmer Switch
EKC Calculator Annual Savings (kWh)	44.3	13.7	161.1	23.7
OEB TRC Guide (kWh)	104	19	209	139
EKC Calculator peak Demand	0.0017	0	0	0.001
OEB TRC Guide peak Demand	0	0.008	0.135	0.09
EKC Calculator Useful Life	6	5	10	10
OEB TRC Guide Useful Life	4	30	10	10
EKC Calculator Free Ridership	30%	30%	30%	30%
OEB TRC Guide Free Ridership	10%	5%	10%	10%

- c) Comment on the differences between the OPA EKC 2007 Program Calculator and the OEB TRC Guide regarding the input assumptions for the following measures
- i. Energy Star CFL 15 w
 - ii. Outdoor Motion Detector
 - iii. LED Xmas lights
 - iv. Dimmer Switch

Response:

The differences between the 2007 EKC program calculator and the OEB TRC Guide are a reduction in energy savings and peak demand. Free ridership increased to 30% compared to the 5-10% contained in the OEB Assumptions and Measures List. The measure life increased from 4 years to 6 years on a CFL 15w while the Seasonal LED decreased from 30 years to 5 years. The measure life remained the same on motion sensors and dimmers.

- d) Confirm the total coupons and number of units for Energy Star CFL 15w for OPA 2006 and 2007 campaigns respectively

Response:

Bluewater Power treated coupons:lamps purchased conservatively on a 1:1 basis. Therefore the number of coupon/lamps was 3447 in the Spring 2006 and 4044 in the Fall 2006. As mentioned previously Bluewater Power did not make a claim for the 2007 coupons. The tables below detail the number of coupons which were included in the report provided in response to VECC Interrogatory Question 27(a) Attachments 2 and 3.

In comparison to Bluewater Power's assumption of a 1:1 coupon to unit ratio, the 2006 Fall EKC Calculator factored a 1:2.86 coupon to lamps ratio and the 2007 EKC Calculator factored a 1:3.86 coupon to lamp ratio.

Table 1 – 2006 Spring/Summer Campaign

	CFL 15w	Timers	Programmable Thermostat
Direct Mail	547	68	46
Sarnia	2578	43	77
Point Edward	1	0	24
Petrolia	321	0	2
Watford	0	1	0
Oil Springs	0	0	0
Alvinston	0	0	0
Totals	3447	112	149

Table 2 – 2006 Fall Campaign

	Dimmer Switch	CFL 15w	Motion Sensor	Programmable Thermostat	LED Xmas lights
Direct Mail	61	637	18	112	360
Sarnia	129	2970	39	250	3460
Point Edward	4	118	2	3	50
Petrolia	4	280	8	16	744
Watford	0	39	2	1	135
Alvinston	0	0	0	0	0
Oil Springs	0	0	0	0	0
Totals	198	4044	69	382	4749

- e) Recalculate the 2007 energy savings and LRAM using the 2007 OPA EKC Program calculator values for
- i. Energy Star CFL 15 w
 - ii. Outdoor Motion Detector
 - iii. LED Xmas lights

Response:

The table below provides the recalculated LRAM results for the three technologies for 2007 which were implemented as part of the 2006 EKC Program and commenced in 2006.

Program	Technology	Year Implemented	# units	Total Energy Savings (kWh)	Total Energy Savings with # units	Free Ridership	Net kWh or kW saved	Rate \$/kWh or \$/kW	Lost Revenue \$
OPA EKC Coupons - fall 2006	CFL	2007	4044	44.3	179,149	30%	125,404	0.0117	\$ 1,467
OPA EKC Coupons - fall 2006	Motion detector	2007	69	161.1	11,116	30%	7,781	0.0117	\$ 91
OPA EKC Coupons - fall 2006	LED lights	2007	4749	13.7	65,061	30%	45,543	0.0117	\$ 533

- f) Apply a Partial Effectiveness factor to the 2007 Savings and LRAM calculation using the OPA EKC Program Campaign timing and the number of Coupons/units in each campaign. Provide the result in tabular form. Provide a revised LRAM schedule as per page 25 of the ERA Report incorporating the “new” OPA EKC input assumption and the PE factor

Response:

A partial effective factor for 2007 is not applicable, as Bluewater Power has not made a claim related to the 2007 EKC programs.

g) Recalculate the SSM with the 2007 OPA EKC input assumptions

Response:

Bluewater Power has recalculated the SSM values by updating the technologies that were part of the 2006 EKC Programs, but with the 2007 EKC assumptions.

Attach SSM PDF.

- h) With respect to the Cool Shops Program, explain the differences in input assumptions used by BWPC's consultants and the 2007 OPA EKC calculator for CFL 15w.

Response:

With respect to the Cool Shops Program, the assumptions used by Bluewater Power for the CFL 15w are the same assumptions used for all CFL 15w programs, which for this technology was based on the OEB Assumptions and Measures List. It was only for the four technologies that were not listed in the OEB Assumptions and Measures list (BR15w, BR16w, PAR 20w, PAR 23w) where we sought measures from the Cool Shops consultant.

The differences in input assumptions for the CFL 15w are displayed in response to part (b) above.

VECC Supplementary Question 12

Reference: VECC #32 a) & b) and #33 a)

- a) Please indicate how Bluewater determined that \$10,708,278 was the cost/revenue requirement allocation to the residential class based on the proposed 2009 Base Revenue Requirement of \$20,707,479 and a 100% revenue to cost ratio.

Response:

Table 32.3 provided in response to VECC Interrogatory 32 (b), is reproduced below.

Outstanding Base Revenue Requirement %			Outstanding Base Revenue Requirement \$		
Cost Allocation	Existing Rates	Rate Application	Cost Allocation	Existing Rates	Rate Application
51.71%	50.37%	51.50%	10,708,278	10,431,093	10,664,352
15.92%	16.44%	16.40%	3,296,423	3,405,078	3,396,027
15.65%	15.28%	15.45%	3,240,448	3,164,210	3,198,270
4.19%	7.24%	5.39%	867,607	1,498,477	1,116,692
7.39%	8.62%	8.42%	1,530,278	1,784,050	1,744,517
0.83%	0.41%	0.58%	172,628	85,102	120,839
0.36%	0.12%	0.16%	73,513	24,118	33,081
3.95%	1.52%	2.09%	818,305	315,351	433,701
100.00%	100.00%	100.00%	20,707,478	20,707,479	20,707,479

The table displays revenue allocation by rate class for two scenario's ('cost allocation' and 'existing rates') which were used as considerations in determining the proposed revenue allocation for the rate application.

1. Cost Allocation. Based on the updated cost allocation results, it was determined that 51.71% of revenue requirement would come from the residential class, which would equate to \$10,708,278. The Table below indicates the results from

Sheet O1 of the updated cost allocation filing, and details how the 51.71% is derived.

Customer Class Name	REVENUE ALLOCATION (sheet O1)						
	Service Revenue Requirement	%	Miscellaneous Revenue (mi)	%	Base Revenue Requirement *	%	Revenue to Expenses %
Residential	9,273,295	52.07%	1,062,684	55.02%	8,210,611	51.71%	99.58%
General Service <50 kW	2,847,037	15.99%	319,493	16.54%	2,527,544	15.92%	107.47%
General Service 50 to 999 kW	2,765,474	15.53%	280,849	14.54%	2,484,625	15.65%	88.44%
General Service 1,000 to 4,999 kW	732,633	4.11%	67,392	3.49%	665,241	4.19%	141.32%
Large	1,277,548	7.17%	104,202	5.40%	1,173,346	7.39%	125.51%
Unmetered Scattered Load	155,882	0.88%	23,519	1.22%	132,363	0.83%	65.02%
Sentinel Lighting	62,483	0.35%	6,117	0.32%	56,366	0.36%	33.01%
Street Lighting	694,555	3.90%	67,117	3.48%	627,438	3.95%	44.42%
TOTAL (from Column C of sheet O1)	17,808,908	100.00%	1,931,373	100.00%	15,877,535	100.00%	100.00%

2. Existing Rates. The second scenario reviewed the amount of revenue derived from each rate class related to existing rates. Tables 9.1.1.3, and 9.1.1.4 in the original submission detail this calculation. The results indicate that 50.37% of revenue or \$10,431,093 is derived from the residential rate class.

3. The final scenario details the revenue allocation proposed in this rate application, which is 51.5% or \$10,664,352. This amount was determined by reviewing scenario's 1 & 2, and striving towards a revenue to cost ratio of 1.0 for the rate classes. The residential rate class had a revenue to cost ratio of .9958 (rounded to 1.) as a result of the updated cost allocation filing, so no alterations were made to the revenue to cost ratio. Therefore 51.5% of the base revenue requirement of \$20,707,479 led to a proposed residential revenue requirement of \$10,664,352.

VECC Supplementary Question 13

Reference: VECC #34 a) & b)

- a) The response to part (a) states that there is no LV adder included in current rates. If this is the case, how does Bluewater determine the LV related revenues for purpose of recording annual additions to Regulatory Asset Account #1550?

Response:

The response to VECC #34 (a) was misstated. Bluewater Power does use the rate adder as calculated in the 2006 EDR model for the purpose of recording revenue to Regulatory Asset Account #1550. The rate adder is displayed in response to VECC Supplementary Question #5.

- b) In response to part (b), Bluewater allocates LV revenues to classes. Please explain how the total LV revenue of \$164,987 was determined. Please also explain in more detail how the revenue allocation to classes was done.

Response:

The LV revenue was assumed to equal the LV cost. The 2008 estimated LV cost of \$164,987 was determined by using actual Hydro One invoice data for the period of Jan 2008 to June 2008, and estimating the remainder of 2008. The amount of LV cost estimated for 2009 is \$189,602 and is detailed at Exhibit 1, Tab 3, Schedule 4, Attachment 2.

The revenue allocation to classes was based on the same methodology as 2006 EDR whereby Transmission Connection Revenue by rate class was used as a proxy for the LV cost estimate/revenue requirement of \$189,602 for 2009.

	Test Year Revenues	Class	Low Voltage
Customer Class Name	Transmission - Connection	Share	Charges
Residential	1,324,414	28.1%	53,360
General Service <50 kW	536,794	11.4%	21,627
General Service 50 to 999 kW	1,008,265	21.4%	40,623
General Service 1,000 to 4,999 kW	742,624	15.8%	29,920
Large	1,050,979	22.3%	42,344
Unmetered Scattered Load	9,747	0.2%	393
Sentinel Lighting	2,195	0.0%	88
Street Lighting	30,944	0.7%	1,247
TOTAL	4,705,961	100.0%	189,602