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December 19, 2008

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

Dear Ms. Walli:

Re: <u>EB-2008-0221 Bluewater Power 2009 Rate Application</u>
<u>Interrogatory Responses from Applicants</u>

Please find attached the Interrogatory Responses of Bluewater Power to the OEB Board Staff interrogatories.

Two hard copies will follow via courier.

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

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
Response to Board Staff Interrogatories
2009 Electricity Distribution Rates
EB-2008-0221

OPERATING COSTS

Question 1.1 - General – Historical OM&A Expenses Data

Ref: http://www.oeb.gov.on.ca/OEB/_Documents/EB-2006-0268/Comparison_of_Distributors_with_2007_data.xls

The figures in Table 1 below are taken directly from the public information filing of Bluewater Power Distribution Corporation (Bluewater) as part of the Reporting and Record-keeping Requirements ("RRR") initiative of the OEB. The figures are available on the OEB's public website.

Table 1

	2003	2004	2005
Operation	*$344,513*	*$285,083*	*$296,163*
Maintenance	*$327,735*	*$307,800*	*$253,056*
Billing and Collection	*$402,872*	*$267,358*	*$237,490*
Community Relations	*$39,998*	*$29,005*	*$136,458*
Administrative and General Expenses	*$7,668,211*	*$7,726,269*	*$7,990,281*
Total OM&A Expenses	***$ 8,783,329***	***$ 8,615,515***	***$ 8,913,448***

Question 1.1

Please confirm Bluewater's agreement with the numbers for Total OM&A Expenses that are summarized in Table 1. If Bluewater does not agree with any figures in Table 1, please explain why not and provide amended tables with a full explanation of all changes.

1.1 Response

Bluewater Power has reviewed the data presented in the reference document ("Comparison table"):

http://www.oeb.gov.on.ca/OEB/_Documents/EB-2006-0268/Comparison_of_Distributors_with_2007_data.xls

and presents the table below as the appropriate Total OM&A costs.

Table 1.1

Note	Description	Accounts	2003	2004	2005
1	Operation	5005-5096	$ 344,513	$ 285,083	$ 296,163
2	Maintenance	5105-5175	$ 327,735	$ 307,800	$ 253,056
3	Billing & Collection	5305-5340	$ 402,872	$ 267,358	$ 237,490
4	Community Relations	5405-5425	$ 39,998	$ 29,005	$ 136,458
5	Administrative and General Exp	5605-5680	$ 7,668,211	$ 7,726,269	$ 7,990,281
6	**Total O&M per Board Staff IR 1.1**		**$ 8,783,329**	**$ 8,615,515**	**$ 8,913,448**
	Changes to above totals:				
7	Add: Other Distribution Expenses	5505, 5510, 5520, 6105, 6215, 6225	$ 269,829	$ 258,283	$ 285,628
8	Less: Charitable Donations	6205	$ (6,069)	$ (16,071)	$ (26,202)
9	**REVISED OM&A**		**$ 9,047,089**	**$ 8,857,727**	**$ 9,172,874**

The total revised OM&A (row 9) for the years 2003 and 2004 agrees with the values presented in the above referenced Comparison table.

For 2005, the comparison table presents OM&A of $9,068,325. Bluewater Power presents a revised OM&A of $9,172,874 for 2005 (row 9). This includes an amount of $104,549 related to account 5415, Energy Conservation which was not included in the total presented in the Comparison document.

Line 7 includes amounts that the Board has included in the above-noted Comparison report therefore Bluewater Power has included them in Table 1.1. In Bluewater Power's case, these costs relate to account 6105 – Taxes other than Income Taxes.

Line 8 represents Charitable Donations which typically is not considered an OM&A expense item, therefore Bluewater Power has removed this item.

With these adjustments, the total on Line 9 is comparable to what Bluewater Power has filed for the 2009 rate application OM&A expenses.

Question 1.2 - General – OM&A Expenses

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

Board staff took the figures from the evidence provided in Exhibit 4 of Bluewater's application and prepared Table 2 below as a summary of Bluewater's OM&A expenses. Please note that rounding differences may occur, but are not material to the questions that follow.

Table 2

	2006 Board Approved	2006 Actual	2007	2008 Bridge	2009 Test
Operation	$ 280,776	$ -	$ 2,206,991	$ 2,258,862	$ 3,535,352
Maintenance	$ 256,425	$ -	$ 122,553	$ 140,410	$ 157,640
Billing and Collection	$ 267,288	$ -	$ 1,277,336	$ 1,370,749	$ 1,497,443
Community Relations	$ 189,005	$ -	$ 94,640	$ 175,409	$ 216,871
Administrative and General Expenses	$ 8,187,189	$ -	$ 5,213,650	$ 5,550,385	$ 5,951,113
Total OM&A Expenses	**$ 9,180,683**	**$ -**	**$ 8,915,170**	**$ 9,495,815**	**$ 11,358,419**

Board staff took the figures from the evidence provided in Exhibit 4 of Bluewater's application and prepared Table 3 below which summarizes Bluewater's OM&A forecasted expenses. Please note that rounding differences may occur, but are not material to the questions that follow.

Table 3

	2006 Board Approved		2006 Actual		2007 Actual		2008 Bridge		2009 Test	Variance 2009/2007
Operation	280,776	-280,776	0	2,206,991	2,206,991	51,871	2,258,862	1,276,490	3,535,352	1,328,361
		-100.0%		-		*2.4%*		*56.5%*		***60.2%***
Maintenance	256,425	-256,425	0	122,553	122,553	17,857	140,410	17,230	157,640	35,087
		-100.0%		-		*14.6%*		*12.3%*		***28.6%***
Billing & Collections	267,288	-267,288	0	1,277,336	1,277,336	93,413	1,370,749	126,694	1,497,443	220,107
		-100.0%		-		*7.3%*		*9.2%*		***17.2%***
Community Relations	189,005	-189,005	0	94,640	94,640	80,769	175,409	41,462	216,871	122,231
		-100.0%		-		*85.3%*		*23.6%*		***129.2%***
Administrative and General Expenses	8,187,189	-8,187,189	0	5,213,650	5,213,650	336,735	5,550,385	400,728	5,951,113	737,463
		-100.0%		-		*6.5%*		*7.2%*		***14.1%***
Total OM&A Expenses	**9,180,683**	**-9,180,683**	**0**	**8,915,170**	**8,915,170**	**580,645**	**9,495,815**	**1,862,604**	**11,358,419**	**2,443,249**
		-100.00%		-		6.51%		19.61%		**27.41%**

Question 1.2 (a)

Please confirm that Bluewater agrees with the figures presented in Table 2 and Table 3. If Bluewater does not agree with any figures in the tables, please explain why not and provide amended tables with a full explanation of all changes.

1.2 (a) Response:

Bluewater Power has included 'Taxes other than Income Taxes' in its definition of OM&A expenses for rebasing purposes. Therefore, Bluewater Power agrees with the figures presented in Tables 2 and 3 below, which have been adjusted accordingly. The 2006 actual data, which was not presented previously has also been included in the revised tables.

Revised Table 2

Account Grouping	2006 EDR Approved	2006 Actual	2007 Actual	2008 Projection	2009 Projection
3500-Distribution Expenses – Operation	280,776	4,004,809	2,206,991	2,258,862	3,535,352
3550-Distribution Expenses - Maintenance	256,425	161,650	122,553	140,410	157,640
3650-Billing and Collecting	267,288	1,616,760	1,277,336	1,370,749	1,497,443
3700-Community Relations	189,005	93,842	94,640	175,409	216,871
3800-Administrative and General Expenses	8,187,189	3,687,412	5,213,650	5,550,385	5,951,113
3950-Taxes Other Than Income Taxes	139,687	286,380	278,911	290,000	297,750
TOTAL	**9,320,370**	**9,850,853**	**9,194,081**	**9,785,815**	**11,656,169**

Revised Table 3

Account Grouping	2006 EDR Approved		2006 Actual		2007 Actual		2008 Projection		2009 Projection	*Variance 2009/2007*
3500-Distribution Expenses - Operation	280,776	*3,724,033*	4,004,809	*(1,797,818)*	2,206,991	*51,871*	2,258,862	*1,276,490*	3,535,352	*1,328,361*
		1326%		*-44.9%*		*2.4%*		*56.5%*		*60.2%*
3550-Distribution Expenses - Maintenance	256,425	*(94,775)*	161,650	*(39,097)*	122,553	*17,857*	140,410	*17,230*	157,640	*35,087*
		-37%		*-24.2%*		*14.6%*		*12.3%*		*28.6%*
3650-Billing and Collecting	267,288	*1,349,472*	1,616,760	*(339,424)*	1,277,336	*93,413*	1,370,749	*126,694*	1,497,443	*220,107*
		505%		*-21.0%*		*7.3%*		*9.2%*		*17.2%*
3700-Community Relations	189,005	*(95,163)*	93,842	*798*	94,640	*80,769*	175,409	*41,462*	216,871	*122,231*
		-50%		*0.9%*		*85.3%*		*23.6%*		*129.2%*
3800-Administrative and General Expenses	8,187,189	*(4,499,777)*	3,687,412	*1,526,238*	5,213,650	*336,735*	5,550,385	*400,728*	5,951,113	*737,463*
		-55%		*41.4%*		*6.5%*		*7.2%*		*14.1%*
3950-Taxes Other Than Income Taxes	139,687	*146,693*	286,380	*(7,469)*	278,911	*11,089*	290,000	*7,750*	297,750	*18,839*
		105%		*-2.6%*		*4.0%*		*2.7%*		*6.8%*
TOTAL	**9,320,370**	*530,483*	**9,850,853**	*(656,772)*	**9,194,081**	*591,734*	**9,785,815**	*1,870,354*	**11,656,169**	*2,462,088*
		6%		*-6.7%*		*6.4%*		*19.1%*		*26.8%*

Question 1.2 (b)

In its application, Bluewater did not provide 2006 actual figures for its operating costs.

Please provide a table that:

i) Lists all the accounts and sub-accounts related to the categories listed in Table 3 above.

ii) Includes 2006 actuals, 2007 actuals, 2008 bridge amounts, and 2009 test year amounts for each account and sub-account.

iii) Includes a year-to-year variance analysis.

1.2 (b) Response:

Please see the attached file below which addresses all three parts of question 1.2 (b).

Attachment: "Board Staff 1.2 Gen OM&A – table b"

OEB Question 1.2 (b) : General - OM&A Expenses

		2006 Actual	2007 Actual	07 vs 06	2008 Bridge	08 vs 07	2009 Test	09 vs 08
Admin & Gen Expense								
5515	Advertising Expense	6,508		(6,508)		-		-
5605	Executive Salaries and Expenses	1,044,819	734,123	(310,696)	738,263	4,140	962,527	224,264
5610	Management Salaries and Expenses	368,849	310,953	(57,896)	180,016	(130,937)	209,019	29,003
5615	General Administrative Salaries and Expenses	1,836,884	1,121,758	(715,126)	1,176,414	54,656	1,713,680	537,266
5620	Office Supplies and Expenses	14,971	6,178	(8,793)	2,000	(4,178)	2,860	860
5625	Administrative Expense Transferred/Credit	(1,190,433)		1,190,433		-	(543,487)	(543,487)
5630	Outside Services Employed	71,756	327,672	255,916	212,442	(115,230)	178,675	(33,767)
5635	Property Insurance	140,538	146,548	6,010	161,843	15,295	166,076	4,233
5645	Employee Pensions and Benefits	(0)	1,590,751	1,590,752	2,053,952	463,201	1,986,471	(67,481)
5655	Regulatory Expenses	261,241	221,247	(39,995)	281,665	60,418	437,711	156,046
5660	General Advertising Expenses	22,154	12,363	(9,790)	10,000	(2,363)	21,000	11,000
5665	Miscellaneous General Expenses	877,583	660,566	(217,016)	652,365	(4,682)	724,793	72,428
5675	Maintenance of General Fleet	235,392	84,914	(150,478)	81,424	(3,490)	91,788	10,363
5680	Electrical Safety Authority Fees	3,660	-	(3,660)		-		-
Admin & Gen Expense Total		3,693,920	5,217,074	1,523,154	5,550,384	336,830	5,951,113	400,728
Billing & Collecting								
5305	Supervision	123,711	107,336	(16,375)	109,522	2,187	124,802	15,279
5310	Meter Reading Expense	147,740	112,856	(34,884)	129,817	16,961	148,146	18,329
5315	Customer Billing	1,005,689	746,719	(258,969)	813,915	67,196	887,684	73,768
5320	Collecting	275,536	216,441	(59,095)	232,243	15,802	233,138	896
5330	Collection Charges	540	975	435	750	(225)	788	38
5335	Bad Debt Expense	63,517	93,011	29,494	84,500	(8,511)	102,885	18,385
5340	Miscellaneous Customer Account Expenses	35		(35)		-		-
Billing & Coll Total		1,616,767	1,277,338	(339,429)	1,370,748	93,409	1,497,443	126,695
Community Relations								
5410	Community Relations - Sundry	30,530	57,142	26,612	36,400	(20,742)	52,000	15,600
5415	Energy Conservation	56,804	12,029	(44,775)	35,376	23,347	45,540	10,163
5420	Community Safety Program		25,469	25,469	103,633	78,164	119,331	15,698
Community Relations Total		87,334	94,640	7,306	175,409	80,769	216,870	41,461
Distribution Expenses - Maintenance								
5114	Maintenance of Distribution Station Equipment	29,635	8,537	(21,098)	4,500	(4,037)	7,275	2,775
5120	Maintenance of Poles, Towers and Fixtures	11,706	11,354	(352)	12,000	646	14,300	2,300
5125	Maintenance of Overhead Conductors and Devices	74,442	67,908	(6,534)	75,470	7,562	83,520	8,050
5145	Maintenance of Underground Conduit	137	69	(68)		(69)		-
5150	Maintenance of Underground Conductors and Devices	16,045	18,988	2,943	16,000	(2,988)	16,900	900
5155	Maintenance of Underground Services	1,849	4,582	2,733	4,900	318	5,145	245
5160	Maintenance of Line Transformers	19,429	8,796	(10,633)	24,000	15,204	26,000	2,000
5165	Maintenance of Street Lighting and Signal Systems	1,637		(1,637)		-		-
5175	Maintenance of Meters	7,210	2,319	(4,891)	3,540	1,221	4,500	960
Dist Exp - Mtce Total		162,089	122,553	(39,535)	140,410	17,857	157,640	17,230

OEB Question 1.2 (b) : General - OM&A Expenses

		2006 Actual	2007 Actual	07 vs 06	2008 Bridge	08 vs 07	2009 Test	09 vs 08
Distribution Expenses - Operation								
5005	Operation Supervision and Engineering	706,876	498,118	(208,758)	648,444	150,326	944,384	295,940
5010	Load Dispatching	269,449	197,013	(72,436)	197,415	402	208,989	11,574
5012	Station Buildings and Fixtures Expense	108	1,223	1,115	-	(1,223)	100	100
5014	Transformer Station Equipment - Operation Labour			-	-	-	26,000	26,000
5015	Transformer Station Equipment - Operation Supplies and Expenses	3,757	592	(3,165)		(592)		-
5017	Distribution Station Equipment - Operation Supplies and Expenses	855	6,835	5,980	400	(6,435)	420	20
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expe	175,250	266,361	91,112	229,370	(36,991)	231,369	1,999
5035	Overhead Distribution Transformers - Operation	2,367	1,859	(508)	1,300	(559)	1,965	665
5040	Underground Distribution Lines and Feeders - Operation Labour	1,665,585	284,584	(1,381,002)	260,994	(23,590)	899,617	638,623
5045	Underground Distribution Lines and Feeders - Operation Supplies and E:	36,543	260,449	223,906	231,929	(28,520)	306,371	74,443
5055	Underground Distribution Transformers - Operation	3,727	1,824	(1,903)		(1,824)		-
5060	Street Lighting and Signal System Expense	189,445		(189,445)		-		-
5065	Meter Expense	534,201	221,593	(312,608)	273,300	51,707	437,516	164,216
5070	Customer Premises - Operation Labour	78,875	60,287	(18,588)	56,379	(3,908)	-	(56,379)
5075	Customer Premises - Materials and Expenses		20,655	20,655	30,171	9,516	43,220	13,049
5085	Miscellaneous Distribution Expense	324,101	356,259	32,158	299,785	(56,474)	404,711	104,926
5095	Overhead Distribution Lines and Feeders - Rental Paid	13,230	29,335	16,105	29,376	41	30,690	1,314
Dist Exp - Operations Total		4,004,370	2,206,987	(1,797,383)	2,258,862	51,875	3,535,351	1,276,490
Taxes								
6105	Taxes Other Than Income Taxes	286,380	275,492	(10,889)	290,000	10,989	297,750	7,749
Tax Total		286,380	275,492	(10,889)	290,000	10,989	297,750	7,749
Grand Total		9,850,860	9,194,084	(656,775)	9,785,813	591,729	11,656,166	1,870,353
variance threshold				132,457		130,420		138,311
total of highlighted				(483,091)		482,590		1,472,868

<u>Question 1.2 (c)</u>

Please complete Table 4 below by identifying and listing the key cost drivers that are contributing to the overall increase of 27% in total 2009 OM&A expenses over 2007 historical actuals. Please include the actual 2006 figures for both opening and closing balances in Table 4 below. Please add additional rows to Table 4 if necessary. Some examples of specific costs drivers include items such as increase in staff compensation, hiring staff, increase in cost of contractors, increase in inflation, etc.

<u>1.2 (c) Response:</u>

The Table has been completed to reconcile year-over-year variances, with the variance from 2005 to 2006 shown under 2006Actual, the variance from 2006 to 2007 shown under 2007, etc. The main drivers of the variance are listed, and it is worth noting that the drivers of the variance do not fall within the same category each year. The variances in Table 4 are provided at a high level (ie. Payroll Related), but a detailed analysis of that variance amount is provided in answer to OEB IR 1.2(d) below (ie. Cost of Living, new staff, etc.).

We have limited the years 2006, 2007 and 2008 to the more material differences. A more extensive list of variance drivers is provided for the year 2009, partly to match the variance analysis for 2007 to 2009 provided in the rate application (Exhibit 4, Tab 2, Schedule 2 at page 2) and partly because 2009 is the test year and further information was warranted.

The Opening Balance for each year is the net OM&A for the prior year. The individual variances that contribute to arrive at the Closing Balances are identified in each year.

As explained in the pre-filed evidence, the data for 2006 and prior years is not properly allocated in two respects (i) not all costs were allocated to the appropriate Account Groups, and (ii) costs related to Non-Core Distribution Activities were not fully allocated in 2006 and not allocated at all in 2005. With that note, high level variances were able to be identified by a closer examination of the data for those years and those variance explanations are provided below.

Table 4

	2006 Actual	2007	2008	2009
Opening Balances	**$9,172,874 Opening Balances**	**$9,850,860 Closing Balances from 2006 Actual**	**9,194,083**	**9,785,815**
Capitalized labour	**263,502**	**(455,645)**	**(305,672)**	**170,552**
Payroll related (not including cap. labour or OMERs)	**49,487**		**622,278**	**1,260,747**
Billable material		**(189,770)**		
C&DM		**(152,993)**		
OMERS	**289,653**	**162,163**		
Employee future benefit			**324,902**	**(153,579)**
Employee costs				**124,987**
Regulatory costs	**98,040**			**122,148**
Third party costs				**69,102**
Fleet costs				**57,266**
Consulting				**48,225**
I.T.				**34,779**
Advertising				**31,700**
Other	**(22,696)**	**(20,532)**	**(49,776)**	**104,427**
Closing Balances	**$9,850,860**	**9,194,083**	**9,785,815**	**11,656,169**

Please note that the opening/closing balances in Table 4 include account grouping 3950 “Taxes Other Than Income Taxes” in order to agree with Bluewater Power’s evidence as submitted. The information in Tables 2 and 3 of OEB IR #1.2 do not include account grouping 3950.

As is evidence above, the major driver for OM&A increase are new staff in 2008 and 2009. A very detailed explanation and justification of these variances in provided in at Exhibit 4, Tab 2, Schedule 2, page 6-20.

Question 1.2 (d)

For the period 2006 to 2009, please provide detailed and specific explanations for each cost driver in Table 4 above.

1.2 (d) Response:

The detailed variance explanations are provided below organized by year

2006 (2005 to 2006 Variance)

(1) **Capitalized Labour**: The change in capitalized labour from year to year is dependent on the nature, timing and completion of capital projects. The positive variance of $263,502 reflects the fact that capitalized labour in 2006 was less than the amount capitalized in 2005.

(2) **Payroll Related Costs**: The net variance for this cost driver is minimal, but it is comprised of components worth noting.

$156,089	cost of living increases
$170,509	progressions and net positions added/removed in 2006
($277,111)	Costs were reallocated to Account 4380 for the first time
$ 49,487	

(3) **OMERS**: The year 2006 includes 8 months of OMERs expense, but the entire amount of OMERs in 2005 was recorded to a deferral account. This drives a variance of $289,653.

(4) **Regulatory Costs**: OEB assessment costs in 2005 were partially recorded to a deferral account in 2005, thereby creating a positive variance of $98,040.

(5) **Other**: Miscellaneous costs are higher and lower by immaterial amounts, the net of which is a negative variance of ($22,696).

2007 (2006 to 2007 Variance)

(1) **Capitalized Labour**: The change in capitalized labour from year to year is dependent on the nature, timing and completion of capital projects. The negative variance of ($455,645) reflects the fact that capitalized labour in 2007 was greater than the amount capitalized in 2006.

(2) **Payroll Related Costs**: The variance for 2007 would be comprised of both positive and negative variance, but the net variance is negligible.

(3) **Billable Materials:** A negative variance is created in 2007 of ($189,770) with respect to billable materials, not because less was spent on materials for billable work, but because all material costs related to Non-Core Distribution Activities were reallocated to Account 4380. In fact, we know 2007 was an extremely busy year for billable work so the variance is entirely driven by this reallocation issue.

(4) **C&DM:** In 2006, C&DM activities took place with third tranche funding, whereas 2007 was funded by OPA programs. The level of activity in 2007 exceeded 2006, however all costs were reallocated to Account 4380 in 2007 whereas no reallocation took place in 2007. This drives a negative variance of ($152,993).

(5) **OMERS**: The year 2007 includes 12 months of OMERs, whereas 2006 includes only 8 months of OMERs expense. This drives a variance of $162,163.

(6) **Other**: Miscellaneous costs are higher and lower by immaterial amounts, the net of which is a negative variance of ($20,532).

2008 (2007to 2008 Variance)

(1) **Capitalized Labour**: The change in capitalized labour from year to year is dependent on the nature, timing and completion of capital projects. The negative variance of ($305,672) reflects the fact that capitalized labour in 2008 was greater than the amount capitalized in 2007.

(2) **Payroll Related Costs**: The net variance for this cost driver is significant and is driven by the following:

$321,000	cost of living increase, minor job progressions and misc. changes
$332,000	reduction in Non-Core Distribution Activities (2007 was very high)
($65,000)	reduction in overtime
$75,000	vacant positions in 2007 that were filled in 2008
($40,000)	net positions added/removed in 2008 (versus 2007)
$623,000	

(3) **Employee Future Benefits**: The increase of $324,902 in 2008 is due to a one-time adjustment relating to an actuarial error. A full explanation is provided in Bluewater Power's evidence in Exhibit 4, Tab 2, Schedule 3, pages 8-9. This amount is the difference between $523,092 (2007) and $847,994 (2008).

(4) **Other**: Miscellaneous costs are higher and lower by immaterial amounts, the net of which is a negative variance of ($49,776).

2009 (2008 to 2009 Variance)

(1) **Capitalized Labour**: The change in capitalized labour from year to year is dependent on the nature, timing and completion of capital projects. The negative variance of $170,552 reflects the fact that capitalized labour in 2009 is projected to be less than the amount capitalized in 2008.

(2) **Payroll Related Costs**: The net variance for this cost driver is comprised of components described as follows:

$335,000	cost of living increase, minor job progressions and misc. changes
$510,000	net increase in new positions (equates to approx. 6 new positions)
$99,000	net increase in benefits (equates to approx. 24% on new positions)
$114,000	increase in overtime
$208,000	net change in payroll accrual
($257,000)	removal of civil department to affiliate (additional amount not already reallocated in 2008)
$252,000	elimination in 2009 of non-core reallocations to non-utility accounts
$1,261,000	

(3) **Employee Future Benefits**: The decrease of $153,579 in 2009 is due to the difference between $847,994 (2008) and $694,415 (2009), which is a variance that is explained in Exhibit 4, Tab 2, Schedule 3, pages 8-9.

(4) **Employee Costs**: The increase of $124,987 in 2009 is due mainly to the following: travel $34,000; training $32,000; cell phones and blackberry $10,000; fire-retardant and traffic- safety clothing $9,000; with the remainder made up of other employee costs such as meals, various allowances, education assistance, and memberships.

(5) **Regulatory Costs**: The increase in regulatory costs is primarily driven by the costs of this 2009 Rebasing application, which have been included for recovery on the basis of one-third of the projected total costs. The variance is $122,148.

(6) **Third Party Costs**: The increase of $69,102 in 2009 is mainly due to the contracted services budget of $52,000 for a Protection and Control specialist. For a further explanation of this position, see Exhibit 4, Tab 2, Schedule 3, page 4, paragraph 1. Also see the answer to OEB interrogatory #1.12.

(7) **Fleet Costs**: The increase of $57,266 in 2009 is primarily due to an increase in fuel costs of $35,000, an increase in vehicle maintenance costs of $10,900, and the reduction in the amount of non-distribution related costs being reallocated to non-utility accounts in 2009 of $9,300.

(8) **Consulting:** The increase of $48,225 in 2009 is primarily due to $17,000 for regulatory-related issues, $10,000 for environmental issues, and $10,000 for unknown issues that may occur.

(9) **IT:** The increase of $34,779 in 2009 is primarily due to $27,000 for various software maintenance items (DigSmart, ITIL, Cyme, and SAP). Another $7,400 is due to computer infrastructure supplies.

(10) **Advertising:** The increase of $31,700 in 2009 is primarily due to $24,500 for regulatory related items and $6,000 for C&DM programs. See Exhibit 4, tab 2, schedule 3, page 6 for further information on these items.

(11) **Other**: Miscellaneous costs are higher and lower by immaterial amounts, the net of which is a positive variance of $104,427.

Question 1.3 - General – Cost Efficiency Programs

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

Question 1.3

Please describe and quantify the benefits of any cost efficiency programs that Bluewater has undertaken, e.g. cost reduction, contract negotiations, system automation, cost savings or other programs that are either in place now or are contemplated at some future time.

1.3 Response:

Bluewater Power has initiated extensive cost efficiency programs that are traditional cost containment like those listed by OEB staff in the question above. The nature of those programs is to contain or reduce gross O&M, and some examples of those efforts are enumerated below.

However, cost efficiency programs have also been initiated by Bluewater to reduce net O&M by creating opportunities to share costs (ie. reallocate costs to Account 4380 through an increase in Non-Core Distribution Activities). These efforts are more appropriately described as the pursuit of economies of scope. These efforts have been successful and, despite the corporate restructuring required by the OEB and discussed throughout the rate application, those programs will continue to reduce net O&M in 2009 and, thereby benefit ratepayers. This answer, therefore, will address both types of cost efficiency programs.

1. Non-Core-Distribution Activities:

Any effort in the area of Non-Core Distribution Activities has the effect of introducing economies of scope to Bluewater Power. In other words, fixed costs are able to be shared (allocated to Account 4380 or charged to an affiliate), thereby reducing the financial burden on ratepayers.

For example, as shown in Table 4.2.7.1 (Exhibit 4, Tab 2, Schedule 7, Page 3) Water Billing and OPA programs allowed certain costs to be removed from O&M that would otherwise form part of revenue requirement for ratemaking purposes. Some of the costs removed are more direct in nature, but a significant portion of the costs reallocated are fixed costs. The following table shows the breakdown of reallocated costs by fixed costs and direct costs for the test year.

	Total Cost reallocated to Account 4380	**Fixed Costs**	**Direct and Other Costs**
Water Billing	$557,042	$283,488	$273,554
OPA Programs	$54,156	$54,156	$0
TOTAL contribution to fixed costs		$337,644	

In 2009, Bluewater Power will lose the opportunity to reallocate costs associated with Affiliate Activities (i.e. Street light, Traffic light, Civil Construction and miscellaneous on-demand line work). In 2007 and 2008, those efforts contributed significantly to reducing Bluewater Power's net O&M as seen in the graph labelled as Table 1.1.3.5 (Exhibit 1, Tab 1, Schedule 3, Page 7). In 2009 ratepayers continue to benefit from those activities as the Corporate Restructuring permanently removes significant costs from the utility's O&M in 2009 and beyond. In fact, Table 1.2.6.1 (Exhibit 1, Tab 2, Schedule 6) demonstrates that ratepayers are not materially impacted by the Corporate Restructuring; they continue to benefit.

In addition, and more to the point of continuing efficiencies, Bluewater Power has budgeted to earn $134,310 from affiliates in the form of management fees; rent of office space and rent of vehicles (see Table 3.3.4.2 in Exhibit 3, Tab 3, Schedule 4, Page 2). These revenues are pure contribution to fixed costs, as no new staff, building space or vehicles have been added to accommodate these affiliates.

Therefore, in 2009 Bluewater Power will see a total of $471,954 of its fixed costs covered by its efforts to create economies of scope through Non-Core Distribution Activities and the provision of services to affiliates.

2. Traditional Cost Containment Programs

Bluewater Power has aggressively and consistently pursued cost containment programs. Some examples already in place are as follows:

1. Diligent purchasing policies and practices have resulted in savings in all areas. Some highlights would include banking services (approximately $2,500 saved per year), insurance costs (during the period from 2005 to 2009, insurance costs have only increase from $164,000 to $166,000) and normalized benefit premiums have decreased by 3% over the same period, after-hour call-centre costs were reduced by $3000 in 2007.

2. Customer service savings have been achieved over the years and some examples include:
    a. Eliminating cashier services in 2001 (staff were redeployed, but the restructuring saved a position worth approximately $40,000 per year);
    b. Eliminating return envelope in 2002 has saved $3000 per year.

3. Control Room costs have been reduced twice in recent years:
    a. First, the control room was reduced from 24 hours/7 days coverage to 12 hours/7 days coverage in 2001, resulting in savings of $150,000. Due to cross-training of our staff, some of those employees were redeployed.
    b. Second, the control room hours were further reduced to 8 hours/5days coverage in 2008 with the retirement of an operator. The position was not replaced resulting in savings of approximately $75,000

4. Certain services have been brought in-house at a reduced cost. For example
    a. Legal services was brought in-house in 2003 at roughly the same dollar amount previously spent on outside legal counsel; however, more legal time was gained which allowed greater efficiencies in other areas and resulted in savings through avoided costs in the regulatory area in particular.
    b. Meter reading services were brought in-house at a cost that was approximately $5,000 less per year than the contracted services previously utilized.
    c. Web design was brought in-house, thereby avoiding a $20,000 per annum cost with no incremental increase in staff costs.
    d. Altered our lawn care and maintenance program since 2001 at savings per year of approximately $8,000.

5. Vehicle costs have been managed in numerous ways, and some highlights include:
    a. in 2004, we strictly limited vehicles taken home by employees to on-call employees resulting in reduced fuel costs, wear and tear on vehicles;
    b. Bluewater Power has consciously reduced its fuel costs by driving our fleet toward more fuel efficient vehicles (normalized fleet fuel consumption has been reduced by approximately $20,000 per year)

6. The costs paid for the Board of Director has been reduced through a reduced number of directors and careful management of the number of meetings held annually; total costs in 2009 are $100,000 compared to 2002 when they were $135,000.

7. Bluewater Power union employees were able to negotiate health and life insurance benefits past retirement (those benefits are also enjoyed by non-union staff). Post retirement benefits have been eliminated for any employee hired after January 1, 2006. This will save significant dollars in the future and has had a positive impact on Employee Future Benefit cost.

8. Early retirement program introduced in 2005 at a cost of $166,000 encouraged the early retirement of four employees, only one of whom was replaced. The savings to the utility were $188,000 per year.

9. Bluewater Power has led by example in energy conservation, with capital investments in lighting and equipment, as well as behavioural change. Energy consumption at the utility has been reduced by 10%. Another example is the movement from CRT based PC monitors to LCD flat panel monitors which decreases power consumption by an average of 60 to 80% per unit. Over the last four years, all monitors have been changed to LCD.

Bluewater Power is also currently either initiating or assessing the potential of other cost saving initiatives. One example is as follows:

Procurement Policies: Regular and disciplined purchasing processes are in place at Bluewater Power and we have confirmed through routine consultations with neighbouring LDCs that we are obtaining competitive costs on our inventory. We are currently evaluating the opportunity to join the Southwest Ontario Utility Buying Group that we expect could lead to savings of 2-5% on certain inventory items. This could equate to savings of between $20-50,000 per year.

Question 1.4 - General – Cost Efficiency Programs

Ref: Exhibit 4/Tab 2/Schedule 8/page 4
Ref: Exhibit 2/Tab 3/Schedule 6/page 48
Ref: Exhibit 2/Tab 3/Schedule 6/page 65

In Exhibit 2/Tab 3/Schedule 6, page 48, Bluewater stated the following:

> "*Bluewater Power is currently engaged in a multi-year Application Maintenance Outsourcing (AMO) agreement with Deloitte Consulting. The purpose of this agreement is for Deloitte to provide development expertise to assist Bluewater Power in the ongoing sustainability of SAP. Under this agreement, Deloitte works with Bluewater Power IT and Business functional staff to develop and maintain the SAP asset*."

…

> *"This agreement is planned to expire in 2008. Subsequently it is not budgeted for in 2009 with the expectation that most development in this area will be managed through the SAP upgrade project."*

Question 1.4 (a)

Please explain whether Bluewater intends to outsource any of its internal functions, eg, customer service, etc.

1.4 (a) Response:

Several functions that would typically be internal functions for an electrical utility the size of Bluewater Power are already outsourced:

1. Certain IT services are outsourced where the utility lacks internal resources or a particular technical expertise that would be difficult to replicate in-house.
2. Tree trimming is provided by an outside service provider secured through a competitive bidding process.
3. Insulator washing and thermography scanning services are provided by third parties.
4. Numerous engineering services are outsourced on a case-by-case basis where the utility lacks internal resources or a particular technical expertise that would be difficult to replicate in-house.
5. Civil work has been outsourced to a third party in each of 2007 and 2008 in order to respond to increased demand; this has allowed the civil crew to be staffed at reasonable levels and thereby reducing the risk of "downtime" should the demand for work not exist. In 2009, the civil crew will be relocated to Bluewater

Power's affiliate and the affiliate will provide service to Bluewater Power on a fully-allocated cost basis. Depending upon demand, there remains the possibility that a third party will also be required to provide services if demand for civil work is strong in 2009.

No further outsourcing is envisioned at this time.

<u>Question 1.4 (b)</u>

In Exhibit 2/Tab 3/Schedule 6/page 48, Bluewater identifies the following amounts regarding the Application Maintenance Outsourcing (AMO) agreement with Deloitte Consulting:

2007 Actual - $70,483
2008 Budget - $144,000
2009 Budget - $0

i) Please provide an explanation of these costs.
ii) Provide a breakdown of these costs and identify whether these amounts have been capitalized or expensed.
iii) Please describe the benefits realized by the Application Maintenance Outsourcing project as compared to the total costs of $214,483 incurred over 2007 and 2008.

<u>1.4 (b) Response:</u>

i) These costs represent an agreement by Bluewater Power to purchase support for, and development of SAP by Deloitte Consulting. The agreement is an Application Maintenance Outsourcing contract or AMO. Under the agreement, Bluewater Power agrees to purchase a minimum number of hours per month in exchange for a reduced hourly rate. In addition to the cost of the outsourcing effort, there is some internal labour costs reflected in this budget line item for staff time required to coordinate efforts under the AMO as part of capital projects.

ii) The agreement with Deloitte has been to purchase 55 hours of support and development per month at a cost of $9,900 plus taxes. All of this effort has been capitalized. The agreement is flexible in that any unused hours in a given month can be carried forward for use in future support and development needs. In 2007, the overall amount in this AMO budget line was impacted downward because of an Ontario Power Authority (OPA) conservation project for which purchased AMO hours were utilized. As a non-core distribution activity funded by the OPA and, the costs were reallocated and are not reflected in the 2007 actuals. (as shown above) In 2008, the full $9,900 plus taxes for 12 months is budgeted in addition to some internal effort that is being captured as capitalized labour.

iii) In 2007 and 2008, Bluewater Power engaged Deloitte, as part of the Application Maintenance Outsourcing agreement, on a significant number of issues. Because of the complexity of the SAP ERP System, Bluewater makes use of outsourced expertise in order to support, change and further develop the asset. Some of the issues that were resolved and/or where benefit was received include the following.

- Implementation of Wholesale Settlement into SAP. This eliminated a third party software package and significantly streamlined the settlement process by moving from manual and tedious processes into fully automated processes.
- The function of Complex Billing for large volume customers was brought into SAP. This eliminated manual billing and reporting processes.
- As part of on-going industry development of the Retail Settlement process, a number of tweaks and changes were made to accommodate the requirements. Some of these include Meter Change Retail Settlement Usage Docs, Retail Customers with Multiple Devices, 'Zero Kilowatt Hour' IBR values, and Credit IBR values.
- The Billing Statistics Report was further developed for more accurate accounting.
- A number of revisions and corrections were carried out on various functions and programs to better meet requirements including Meter Changes for General Service and General Service Retail Customers.
- The Ontario Power Authority Summer Savings Program requirements were developed within SAP making the program more cost-effective in the future.
- Assistance was provided for a number of SAP technical issues where in-house expertise was not available.
- SAP was developed to accommodate regulations for Net Metering and Standard Offer Generation Customers
- Development has been undertaken to accommodate compliance with the Affiliate Relationship Code.

Question 1.4 (c)

In Exhibit 4/Tab2/Schedule 8/page 4, Bluewater indicates that it spent $126,341 in 2007 for annual maintenance of its SAP system.

- *i) Please explain the nature of the SAP system annual maintenance costs.*
- *ii) What has Bluewater budgeted for its SAP system annual maintenance in 2008 and 2009?*
- *iii) Please provide a further breakdown of the SAP system annual maintenance costs for 2007, 2008, and 2009.*

1.4 (c) Response:

i) As with many software licensing agreements, SAP charges a percentage of the original software purchase on an annual basis for the provision of software technical support and to make available any patches and upgrades. SAP currently charges 17% of original software licensing.

ii) 2008 - $125,350
2009 - $130,000

iii) Bluewater Power pays SAP an annual maintenance fee for technical support, patches and software code upgrades. The fees are based on a percentage of the owned licenses. In 2007 and 2008, the rate is 17%. In 2009, this increases to 22%, but is phased in over 4 years.

Question 1.4 (d)

Please file the case study, including a cost-benefit analysis, undertaken by Deloitte that explains the purpose of the multi-year Application Maintenance Outsourcing (AMO) agreement.

1.4 (d) Response:

In 2003, Bluewater Power recognized that the potential cost to maintain and continue developing SAP would require careful management in order to control costs. The initial experience following implementation was that maintenance of a fully-integrated SAP system which included billing and all other business functions (excluding Payroll), was that multiple disciplines were required creating the need to search for and hire different consultants depending upon the project. Each time a consultant came on board, a significant amount of time would be spent familiarizing the consultant with Bluewater Power's systems. This made for high cost, low value resolutions. This was untenable in an electrical distribution sector subject to ever changing rules and requirements.

As a result, a 'service bureau' type of solution was sought out whereby a consistent group of SAP experts would regularly work on the Bluewater Power system. These relationships are not typically available for a company the size of Bluewater Power, but Deloitte was offering such a solution and Bluewater Power in order to develop a new market for their service. Bluewater Power was able to negotiate a multi-year contract for those services at a very reasonable cost.

A formal case study with a cost-benefit analysis was not completed because, frankly, the solution would offer better service at a substantially reduced cost compared to the status-quo. This opportunity was brought before the Bluewater Power Board of Directors for approval in a letter dated June 18, 2003. The attached memo to the benefits of the AMO and includes the recommendation to the Board of Directors to proceed.

INTERNAL MEMO

TO: Chairman Firman Bentley,
Bluewater Power Board of Directors

FROM: Tim Vanderheide, VP Client Services

DATE: June 18, 2003

RE: **Deloitte AMO**

In order to remain compliant and in order to realise efficiencies, all LDC systems require regular maintenance and configuration changes. In addition to system maintenance, LDC staff requires continuous training and upgrading. In fact Bluewater Power budgeted approximately $260,000 for such maintenance and training in 2003.

Application Maintenance Offerings (AMOs) provide a consistent and accountable level of maintenance services that meet these requirements. The biggest benefit of an AMO is the access to a wide variety of skills sets on an as needed basis. AMO's are typically only available to company's with IT requirements (and budgets) larger then Bluewater Power's. For example most AMOs require an minimum of 300-500 hours of service per month and require a large up-front commitment in order to train the AMO staff on your particular system. In addition to the large commitments, most AMOs are not flexible, typically training and project work is not included in the AMO, plus normally you are not allowed to carry over hours from one month to the next.

As a result of the relationship we have developed with Deloitte, I was able to negotiate a very flexible and affordable AMO service for Bluewater Power. This AMO service will allow Bluewater Power to manage our IT spending and system changes in much more effective and efficient manner. Bluewater Power's AMO service will allow maintenance, training and project work to be carried out. In addition, the minimum number of hours per month is 55 ($9900.00) and they can be carried over or accumulated for up to three months. Bluewater Power and Deloitte will share the up-front training costs for a maximum to Bluewater of $10,000. I believe this AMO service combined with the complimentary upgrade will prove to be instrumental in positioning Bluewater Power as an industry leader.

I am requesting that the Board approve in principle a three year commitment to Deloitte Consulting for AMO services as outlined above.

<u>Question 1.4 (e)</u>

In Exhibit 2/Tab 3/Schedule 6/page 65, Bluewater has identified $185,000 in expenses for the SAP upgrade.

i) Please provide an explanation and breakdown of these expenses.

ii) Please explain why Bluewater has proposed to capitalize these costs and not expense them.

<u>1.4 (e) Response:</u>

i) These expenses relate to consultant travel, accommodation, meals, or per diem costs. The project is expected to last approximately six months. During that time as many as six external consultants will be on-site at various points in time. This account will also cover other out-of-pocket expenses related to the upgrade.

ii) These costs include the consultant expenses that will form part of the invoice received from the consultant. Hence, these costs will be capitalized.

Question 1.4 (f)

In Exhibit 2/Tab 3/Schedule 6/page 65, Bluewater has identified $75,000 in SAP licensing for the SAP upgrade. Please explain why this cost is being capitalized and not expensed.

1.4 (f) Response:

The $75,000 is for the one time purchase of additional software called ‘SAP Business Objects’ which is required for the SAP upgrade. Bluewater Power has used the term ‘licensing’ to mean the software itself.

Although the terminology ‘licensing’ would suggest it is an OM&A item, this expenditure is in fact a capital item as this cost meets the definition of a capital asset.

Question 1.5 - General – Cost Savings due to Amalgamation

Ref: Exhibit 1/Tab 2/Schedule 1/page 1

On October 30, 2000, Bluewater incorporated when the former Sarnia Hydro-Electric Commission, Petrolia Public Utilities Commission, Point Edward Public Utilities Commission, Watford Public Utilities Commission, Alvinston Public Utilities Commission, and Oil Springs Hydro-Electric Commission merged into one company.

Question 1.5 (a)

Please file with the Board any plan that was developed outlining quantitative cost saving objectives that were envisioned as a result of the merger.

1.5 (a) Response:

No cost saving plans were developed at the time of the merger of the hydro-electric commissions of Sarnia ("Majority Shareholder") and Petrolia, Point Edward, Watford, Alvinston and Oil Springs (the "Minority Shareholders").

It is important to keep in perspective two facts. First, the Majority Shareholder represents an 86% partner in the new merged utility. Second, Sarnia Hydro Electric Commission had already been providing management services for four of the five commissions that eventually merged with Sarnia.

Therefore, there were very few opportunities for synergies that were not already realized prior to 2000. The primary driver of the merger in 2000 was to maintain those efficiencies as well as the desire of the Minority Shareholders to avoid costs associated with market opening and the regulatory environment. The merger allowed those new costs to be shared across a larger customer base.

<u>Question 1.5 (b)</u>

If cost savings and efficiency gains were among the objectives leading to the formation of Bluewater, please provide evidence demonstrating that it has realized cost savings and gained efficiencies from 2000 to 2008.

<u>1.5 (b) Response:</u>

The merger was driven by cost avoidance. The cost savings would be difficult to quantify, but it is fair to say that the cost increases that were brought about due to the regulatory environment and market opening were able to be shared over a greater number of customers. The merged entity and all of its customers benefitted from the sharing of those costs.

Question 1.6 - CEO Contingency Fund – OM&A

Ref: Exhibit 2/Tab 3/Schedule 1/Attachment 1
Exhibit 2/Tab 3/Schedule 6, p.16

In Exhibit 2/Tab 3/ Schedule 1/Attachment 1, Bluewater makes reference to Project UT25 "CEO Contingency Fund" for which an expenditure of $212,425 is budgeted in 2009.

In Exhibit 2/Tab 3/Schedule 6, p.16, it is stated that:

"The CEO Contingency Fund has been created to capture unforeseen capital costs that arise during the course of the year that require an immediate response. The fund has been used, for example, to make major repairs to power line vehicles that have been required within the budget year. The budget has also been utilized to purchase job-specific equipment that has been required within the budget year.

Having the contingency fund has allowed the Bluewater Power senior management team to provide more conservative and accurate capital budget figures during the annual budget processes knowing that funds for unforeseen expenditures can be accessed with the approval from the President and CEO. The fund was utilized almost in its entirety in 2007 and is on track to be fully utilized in 2008"

Question 1.6 (a)

Bluewater states that the CEO Contingency Fund as been created to capture unforeseen capital costs that arise during the course of the year that require an immediate response. Please clarify whether Bluewater has included a Contingency Fund for its 2009 OM&A.

1.6 (a) Response:

There is no CEO Contingency Fund in Bluewater's 2009 OM&A.

Question 1.6 (b)

If Bluewater has not created a Contingency Fund for 2009 OM&A, please explain how contingencies were dealt with in the past to capture unforeseen OM&A costs that might have arisen during the course of the year that required an immediate response.

1.6 (b) Response:

An unforeseen circumstance that requires an immediate response, the value of which is material, would almost certainly be a capital item. As such, the financial consequence of that response would be accommodated within the CEO Contingency Fund within the capital budget. Capitalizing a one-time cost that presumably has a long-term benefit is generally an appropriate capital item. Therefore, Bluewater Power does not believe that a CEO Contingency Fund for OM&A is necessary.

If the situation we are being asked to address by this question is a situation where an O&M item simply comes in over budget, the cost would be incurred and it would have the affect of decreasing the budgeted profitability of the company in that year.

Question 1.7 - Contracted Services

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

Question 1.7 (a)

From 2006 through 2009, please identify the portion of total OM&A expenses that is related to contracted services.

1.7 (a) Response:

The table below details the portion of O&M related to contracted services.

Service Provider	Type of Service	Year Contractor was selected	09 Test Year Projected	08 Bridge Year Projected	2007 Actual	2006 Actual
Spectrum	answering service	2006	5,775	5,500	3,934	5,743
KPMG	audit fees	2002	37,400	29,950	21,275	33,825
Deloitte	SAP consulting	2003	100,000	120,000	168,130	380,476
Sarnia Credit Recovery	collection charges	2001	39,508	37,870	27,763	21,472
Badger daylighting	Hydrovac pole installations	2006	3,500	3,000	2,294	4,380
K-line	Water washing	2006	31,000	31,421	28,548	31,257
J. Carpenter	Design & control specialist	2008	52,000	0	0	0
Spi	EBT Hub services	2002	29,000	29,000	26,953	27,133
Erie-Thames	Meter Re-verification	2003	150,000	151,852	148,287	0
ADP	payroll services	2002	10,200	8,856	8,849	7,403
Electek	Substation maintenance	2006	8,725	5,000	5,000	5,000
Pachecos	Trenching and civil	2003	200,000	208,496	274,328	42,431
Guardian	tree trimming	2006	151,670	160,000	193,796	110,214
		TOTAL	**818,778**	**790,945**	**909,157**	**669,334**

<u>Question 1.7 (b)</u>

For each of the years, 2006 through 2009, please identify the selection process for the contracted services.

<u>1.7 (b) Response:</u>

Bluewater Power's purchasing policy is detailed in Exhibit 4, Tab 2, Schedule 8, pages1-4. The selection process for contracted services involves asking two or more pre-qualified contractors for a quotation whenever possible. Consideration is always given to quality, experience, past performance, safety record, price, availability of contractor to complete the service, meeting of specifications, warrantees and follow-up service.

Early in 2008, Bluewater Power began implementing a process of pre-qualifying contractors. This involves a detailed review of the contractor including some of the items listed below. This pre-qualification allows the quotation process to proceed more quickly as the detailed reviews have already taken place.

- Company safety records,
- training,
- WSIB standing
- Past work experience and references
- Financial stability, years in business, number of employees
- Affiliation with related associations

The contracted services set out in the response to 1.7(a) above were acquired pursuant to Bluewater Power's purchasing policy.

Those items for which there were multiple qualified service providers, the awarding of the contract was subject to a competitive bidding process. Some of the service providers who were selected as a result of a competitive process are as follows:

- Banking – switch to CIBC
- Tree trimming – awarded to Guardian Trees
- Answering service – switch to Spectrum Communications
- Trenching – awarded to Pachecos
- Audit services – switch to KPMG
- Insulator Washing – awarded to K-LIne

- **Question 1.7 (c)**

For each contracted service, please identify the year in which the selection process was used to select a particular contractor.

1.7 (c) Response:

Please see Table 1 in part (a) and (b) of Interrogatory 1.7.

Question 1.7 (d)

Please provide examples of contracted services for the period of 2006 through 2009 in which Bluewater negotiated cost savings or contemplates achieving costs savings. Regarding contracted services, please provide evidence, if any that demonstrates that Bluewater has implemented cost efficiency initiatives or it is contemplating undertaking initiatives that help Bluewater achieve savings at some future time.

1.7 (d) Response:

Bluewater Power is always striving for cost savings on both small purchases and larger purchases and services. We are currently looking to join a Utility Purchasing Group in our area with the purpose to achieve greater cost savings given more bulk purchasing Some examples of successes to-date are listed below:

1. *Insulator washing*. In 2006 a RFP was issued for a three year contract, and the submission received back indicated an increase of 3 to 5% over the 2005 pricing level. To avoid this increase, a one year contract was negotiated and the price remained at the 2005 level, with an increase of 2% in the subsequent years. The result was a 4% increase over a three year period instead of the 9-15% increase indicated in the original RFQ submission.

2. *Property Insurance* – In 2005, property insurance was put out to tender resulting in a competitive process that reduced in premiums from $33,130 to $26,877, a savings of almost $6,000.

3. *Answering services* – In 2006, Bluewater Power initiated a competitive process for our after-hours phone answering needs. This resulted in 10% savings compared to the previous vendor and with far superior service with the new vendor.

4. Benefits – Bluewater Power has negotiated costs savings to its benefits package through its benefits consultant of approximately 3%, when the benefit costs are normalized for the number of employees. The savings have been achieved by our benefits consultant approaching the market.

5. *Scrap Removal* – In 2008 Bluewater Power issued a RFQ for the removal and reimbursement of transformers and associated scrap metal. At the time we were receiving $1.20 - $1.80/kva for transformers from our former contractor; however, we are now receiving $4.20/kva from the new contractor as a result of the RFQ. With other scrap such as copper and aluminum, we continually source the dealers in our area to determine who will give the best price for it.

Question 1.8 - Maintenance Programs and Projects

Ref: http://www.oeb.gov.on.ca/documents/minfilingrequirements_report_141106.pdf
Ref: Exhibit 4/Tab 1/Schedule 1
Ref: Exhibit 4/Tab 2/Schedule 1/Attachment 1

Asset management consists of processes and systems that help evaluate, prioritize, and select the distributor's maintenance and capital plans to maximize the benefits to its customers and shareholder.

For the purpose of providing the information regarding its maintenance and capital plans, Bluewater should use its identified materiality threshold items.

Question 1.8

In regards to Bluewater's 2009 maintenance plans:

i) *Please provide a list of criteria and rationale that Bluewater has utilized in the prioritization and selection of its 2009 maintenance projects.*

ii) *Please complete the following Table 5 and provide ranking and the description of the maintenance projects using the threshold test that is outlined above. Please note that the rating "1" is the highest priority, rating "2" is the second highest priority, rating "3" is the third highest priority etc. Please use additional rows, if necessary.*

iii) *Please explain and file with the Board necessary evidence, if any, how the priorities of these maintenance projects are determined and their expenditures are justified by the distributor's management using the criteria identified in part "a(i)", e.g. reliability statistics, customer complaints, cost information, etc.*

1.8 Response:

i) List of criteria and rationale:

Bluewater Power's description of its Asset Management Plan is provided in detail at Exhibit 2, Tab 3, Schedule 9 of the pre-filed evidence. Seven specific maintenance programs for operational distribution assets are listed in that document. In addition, the remainder of this answer also speaks to maintenance programs involving software and non-operational assets such as buildings.

Understandably, the criteria and rational vary depending upon whether the maintenance program relates to an operational asset or other assets. Operational asset maintenance programs are prioritized on the following basis. We have ranked these items in order of importance, but it would be overly simplistic to suggest that a mechanistic application of these criteria is possible with every program. Nevertheless, programs are viewed with these criteria in mind.

1) **Power reliability**: The primary motivation for most maintenance programs is to reduce the number of outages. Within power reliability, priority is based on:
   i) **Environmental sensitivity:** Bluewater Power has customers in the petrochemical industry and power failures have the potential for significant environmental impact. Therefore, these customers have priority in maintenance planning.
   ii) **Size of customers:** Large customers require increased priority due to the number of people impacted and the economic impact of outages.
   iii) **Number of customers:** Large and well utilized feeders also require priority.
   iv) **Other:** All customers are important, but where Bluewater Power is aware of a particular concerns, the utility is small enough to keep that information "in mind" during maintenance planning.
2) **Cost containment**: Maintenance programs typically reduce the likelihood of expensive repairs, and those programs that better allow cost containment are given priority. A good example would be maintenance required as part of Bluewater Power's leading indicator program (ie. Animal Contacts)
3) **Safety**: Public safety and employee safety are always priority in any planning, and that includes maintenance planning.
4) **Compliance**: as a regulated utility, Bluewater Power is subject to numerous regulatory regimes.
5) **Power Quality**: modern electrical equipment in homes and industry are driving power quality to become a primary concern for maintenance programs.

With respect to non-operational assets, the maintenance programs are prioritized on the following basis:

1. **Systems reliability**: Bluewater Power provides an essential service to its customers, so all systems (building, software, phones, computer infrastructure, etc.) must be maintained in a reliable manner.
2. **Cost Containment**: Certain maintenance programs are designed to avoid future costs. An example includes maintenance
3. **Safety**: As an electrical distributor, safety is important in all aspects of the business.
4. **Legal requirements**: falling in the realm of non-discretionary, certain maintenance programs are driven by legislative or contractual requirements.

ii) Compete Table 5:

The sheet that follows contains the completed Table 5. Bluewater Power's materiality threshold for expense items is approximately $130,000, however we have presented programs that exceed $100,000 in annual costs.

iii) Evidence of use of priorities:

Evidence can be seen in Bluewater Power's description of its Asset Management Plan is provided at Exhibit 2, Tab 3, Schedule 9. In addition, Table 5 below contains a summary of the application of each priority to the maintenance programs listed.

Table 5 – 2009 Maintenance Programs or Projects

Department	Priority Ranking	Name of Program or Project	Ongoing or One-time	Type of Program (Reactive, Preventive or Predictive)	Description of Project	Maintenance Expenditure ($)	Rationale for Priority Selection
Operations	1	Tree Trimming	On Going	Preventive	Tree trimming	$ 151,670	Four year cycle designed to cover all BWP service territory. Program is driven by public safety and power reliability. Also justified as costs containment by decreasing outages.
Operations	1	Vehicle maintenance	On Going	Preventive	Fleet maintenance	$ 115,724	BWP aerial fleet annual dielectric, mechanical testing, resulting in maintenance repairs. BWP small fleet has regular maintenance schedule. Imperative to employee/public safety; maintenance also delays cost of replacements.
Operations	2	Service centre property maintenance	On-going	Some reactive, some predictive (ie. HVAC)	On going maintenance on building	$ 119,554	This includes plumbing, HVAC, electrical repairs, janitorial, and lawn care. Maintenance is driven by employee safety. Maintenance also delays cost of replacements.
Total Operations						**$ 386,948**	
IT	1	IT Software Maintenance - Corporate / Customer Services	Ongoing	Predictive	Software Maintenance including Finance, Materials Mgmt., Work Mgmt., Supply Chain, and Customer Information / Billing	$ 129,957	These costs are for annual software maintenance. In order to remain compliant with agreements and to get support for break/fix, security patches and future upgrades, payment is necessary.
Total IT		**Software Maintenance**				**$ 129,957**	
Total for Maintenance Programs Greater than $100,000						**$ 516,905**	
Total Prioritized Programs % of Overall 2009 Maintenance Programs						**54%**	

Question 1.9 - Employee Costs

Ref: Exhibit 4/Tab 2/Schedule 2/ p.2/ Table 4.2.2.1

Bluewater has forecasted employee costs at $536,627.

Question 1.9 (a)

Please provide a description for the "Employee Costs" category referenced in the Table 4.2.2.1 of the above evidence.

1.9 (a) Response:

The "Employee Costs" category includes the following items: training, travel, car allowance, meals, fitness allowance, education assistance, boot allowance, clothing allowance, cell phones, and memberships.

<u>Question 1.9 (b)</u>

Please provide a listing of all accounts including dollar amounts that form the "Employee Costs" category.

<u>1.9 (b) Response:</u>

Please see the attached file below.

Attachment: "Board Staff 1.9 b – Employee Costs"

OEB STAFF: Question #1.9 (b) : Employee Costs

Account	Description	2006 Actual	2007 Actual	07 vs 06	2008 Bridge	08 vs 07	2009 Test	09 vs 08
Distribution Expenses - Operation								
5005	Operation Supervision and Engineering	$ -	$ 20,973	$ 20,973	$ 35,651	$ 14,678	$ 40,191	$ 4,540
5010	Load Dispatching	-	7,169	7,169	5,970	(1,199)	6,691	721
5040	Underground Distribution Lines and Feeders - Operation Labour	-	(34)	(34)	-	34	-	-
5045	Underground Distribution Lines and Feeders - Operation Supplies/Expenses	-	88,179	88,179	60,354	(27,825)	96,541	36,187
5065	Meter Expense	-	11,532	11,532	15,390	3,858	22,260	6,870
5070	Customer Premises - Operation Labour	-	1,394	1,394	-	(1,394)	-	-
5075	Customer Premises - Materials and Expenses	-	4,941	4,941	3,630	(1,311)	5,300	1,670
5085	Miscellaneous Distribution Expense	-	2,544	2,544	7,520	4,976	8,273	753
Distribution Expenses - Maintenance								
5155	Maintenance of Underground Services	-	-	-	-	-	-	-
Billing & Collecting								
5305	Supervision	-	11,702	11,702	11,290	(412)	12,400	1,110
5310	Meter Reading Expense	-	3,590	3,590	4,783	1,193	5,300	517
5315	Customer Billing	-	9,310	9,310	9,931	621	15,964	6,033
5320	Collecting	-	1,026	1,026	1,077	51	1,950	873
Community Relations								
5415	Energy Conservation	-	267	267	2,450	2,183	2,350	(100)
5420	Community Safety Program	-	4,110	4,110	13,485	9,375	15,925	2,440
Admin & Gen Expense								
5605	Executive Salaries and Expenses	170,311	129,740	(40,570)	95,742	(33,998)	126,154	30,412
5610	Management Salaries and Expenses	16,827	26,241	9,414	15,795	(10,446)	17,215	1,420
5615	General Administrative Salaries and Expenses	251,572	156,124	(95,449)	110,065	(46,059)	139,380	29,315
5630	Outside Services Employed	-	527	527	185	(342)	300	115
5645	Employee Pensions and Benefits	6,802	7,123	321	7,592	469	8,603	1,011
5655	Regulatory Expenses	3,081	8,876	5,795	8,950	74	9,850	900
5665	Miscellaneous General Expenses	-	-	-	1,780	1,780	1,980	200
Grand Total		$ 448,593	$ 495,333	$ 46,740	$ 411,640	$ (83,693)	$ 536,627	$ 124,987

Question 1.10 - Personnel Management

Ref: Exhibit 4/Tab 2/Schedule 9/Attachment 1

Question 1.10

Please provide a description of plans (if any) to address the issue of an aging workforce.

1.10 Response:

Like all companies in Ontario dependent on skilled trades, Bluewater Power is significantly affected by the issue of an aging workforce. In order to ensure that Bluewater Power has the necessary skills and expertise to continue providing a high standard of distribution services, Bluewater Power proactively engages in succession planning and recruitment.

Our plan is an annual plan, with a five year view. Each year Managers and Supervisors are advised of people within their department who are eligible to retire within the next 5 years. Depending on the need to replace eligible retirees, and the time required to train replacements, Bluewater Power will either train internal staff, or recruit and train new staff in preparation for the pending retirement.

Examples of how this proactive succession planning works can be found in the justifications provided for the new positions or replacements set out in the pre-filed evidence as follows:.

- Exhibit 4, Tab 2, Schedule 2, Page 18 of 26 Line 3, "*Finally*, *this position (Accountant) is critical to succession planning as Bluewater Power faces a likely retirement from the Finance Department at some point beyond 2010."*

- Exhibit 4, Tab 2, Schedule 2, Page 19 of 26, Line 15, "*For the purpose of both succession planning and increased workload, a new supervisor will be added for 2009."*

- Exhibit 4, Tab 2, Schedule 2, Page 16 of 26, Line 17, *"The effort to train and retain young staff is critical to Bluewater Power's attempt to manage and sustain its workforce."*

Question 1.11 - Operating Costs – External Costs

Ref: Exhibit 4 Tab 2 Schedule 2 Page 3
Ref: Exhibit 4 Tab 2 Schedule 3 Page 10

In E4/T2/S2/p.3, Bluewater forecasted an increase of approximately $20,000 in legal fees in recognition of the fact that the in-house legal counsel will be primarily involved in the 2009 Rebasing application in the first quarter of 2009.

In addition, Bluewater has identified that its rebasing costs included $125,000 for legal fees.

Question 1.11

Please provide justification for legal costs of $125,000 as a part of the cost for Bluewater's rebasing application.

With reference to the information in the above referenced evidence of the application, please indicate whether in-house legal counsel costs of $20,000 are included in the $125,000 legal costs for rebasing. If not, please provide further explanation for this expenditure.

1.11 Response:

Bluewater Power's in-house legal counsel has been actively involved in this rate proceeding, and therefore has had to rely on external counsel for matters unrelated to the rate proceeding that he would have otherwise dealt with in the normal course. The $20,000 budget figure represents this incremental cost. Had Bluewater Power's in-house counsel not been actively involved in the rate proceeding (i.e. thereby avoiding the $20,000 cost), Bluewater Power would have had to rely more heavily on external counsel for its legal support in preparing the application, which would have resulted in the legal budget for the rate application exceeding the current level of $125,000.

For greater certainty, the $20,000 cost is in addition to the $125,000 cost, and there is no double counting.

In regard to the magnitude of the $125,000 budget for legal fees associated with the rate proceeding, the legal budget includes the preparation, review and provision of advice on the pre-filed evidence, the preparation, review and provision of advice on interrogatory responses, witness preparation, preparation for and attendance at a technical conference or oral hearing, and preparation, review and advice on final submissions and reply submissions.

Question 1.12 - Operating Costs – External Costs

Ref: Exhibit 4 Tab 2/ Schedule 2/ Page 4

Bluewater has identified one-time costs of approximately $14,000 for increased overtime and $26,000 for consulting fees as well as $26,000 for an increase in engineering consulting fees.

Question 1.12 (a)

Has Bluewater amortized the above one-time costs in its 2009 rebasing application? If not, why not.

1.12 (a) Response:

Bluewater Power has not amortized these costs in its 2009 rebasing application.

The $14,000 for increased overtime is planned to be a recurring operating expense in future years due to the permanent reduction of one employee in the control room.

The $26,000 for increased consulting fees for the control room and the $26,000 for increased engineering consulting fees are related. Both are planned to be a recurring operating expense in future years. The combined $52,000 in consulting fees relates to using an external Power Quality Specialist to assist various operational areas of Bluewater Power to address ongoing power quality issues with customers. Please also refer to Bluewater Power's answer to OEB interrogatory 3.15.

Question 1.12 (b)

If Bluewater has amortized one-time costs, please explain and justify the amortization period.

1.12 (b) Response:

Not applicable as Bluewater Power has not amortized these costs.

<u>Question 1.12 (c)</u>

Please identify all other one-time costs that Bluewater has not amortized and provide an explanation of why Bluewater is seeking full recovery of these costs in the 2009 rates.

<u>1.12 (c) Response:</u>

Bluewater Power has made every effort to identify in its evidence the applicable "one-time" operating expenses that are proposed to be amortized over three years - being the expected duration until the next rebasing. Those include rate application costs and employee future benefit costs. There are no other "one-time" costs that require amortization.

Question 1.13 - Operating Costs – Employee Compensation

Ref: Exhibit 4 Tab 2 Schedule 9 Attachment 1

Question 1.13 (a)

Please complete table 5 and 6 below.

1.13 (a) Response:

Please see the attachment indicated below. The table in this attachment includes the requested information for both tables 5 and 6 in the question.

Attachment: "Board Staff 1.13 a – Operating Costs – Employee Compensation"

OEB Question 1.13(a) : Operating Costs - Employee Compensation

	(2006 EDR) 2004 Actual	2006 Actual	2007Actual	2008 Bridge	2009 Test
Number of employees (FTEs)					
Executive CEO, COO, VP/Directors	-	8	8	7	8
Management & Supervisors	15	5	6	6	7
Non Union - non supervisor	19	24	20	21	27
Union	51	61	59	59	57
Total - a	85	98	93	93	99
Number of part time employees					
Executive CEO, COO, VP/Directors	-	-	-	-	-
Management & Supervisors	-	-	-	-	-
Non Union - non supervisor	-	-	-	-	-
Union	-	-	-	-	-
Total - b	-	-	-		-
Total Compensation					
Executive CEO, COO, VP/Directors	-	857,127	919,552	819,880	987,376
Management & Supervisors	1,300,035	372,375	471,695	537,608	595,652
Non Union - non supervisor	1,096,167	1,313,641	1,268,541	1,450,167	1,750,594
Union	2,682,294	2,918,188	3,192,536	3,371,912	3,358,816
Total - c	5,078,496	5,461,331	5,852,324	6,179,567	6,692,438
Compensation - Average Yearly Base Wages					
Executive CEO, COO, VP/Directors	-	107,141	114,944	117,126	123,422
Management & Supervisors	86,669	74,475	78,616	89,601	85,093
Non Union - non supervisor	57,693	54,735	63,427	69,056	64,837
Union	52,594	47,839	54,111	57,151	58,927
Total - d = c/a	59,747	55,728	62,928	66,447	67,600
Compensation - Yearly Overtime					
Executive CEO, COO, VP/Directors		1,923	-	-	-
Management & Supervisors	35,250	15,991	13,486	11,500	13,220
Non Union - non supervisor	10,659	14,080	8,355	7,000	9,000
Union	348,228	361,756	370,895	310,830	421,228
Total - e	394,137	393,749	392,736	329,330	443,448
Compensation - Yearly Incentive					
Executive CEO, COO, VP/Directors	-	72,270	89,089	67,157	124,175
Management & Supervisors	-	15,924	21,828	33,674	26,952
Non Union - non supervisor	-	31,038	42,858	32,590	45,141
Union	-	39,265	46,052	50,548	50,597
Total - f	-	158,497	199,827	183,969	246,865
Compensation - Yearly Benefits					
Executive CEO, COO, VP/Directors		176,925	186,542	156,637	191,375
Management & Supervisors	235,125	85,697	120,066	129,662	154,802
Non Union - non supervisor	268,432	301,251	276,870	374,498	416,281
Union	646,935	719,547	775,706	833,511	801,488
Total - g	1,150,492	1,283,420	1,359,184	1,494,308	1,563,946
Grand Total = c+e+f+g	6,623,125	7,296,997	7,804,071	8,187,174	8,946,697

<u>Question 1.13 (b)</u>

Please provide the rationale for Bluewater's compensation structure(s) for its executive CEO, COO, VP/Directors, Management, and Supervisors positions and file with the Board supporting documentation.

<u>1.13 (b) Response:</u>

Bluewater Power salaries for executive and management in 2008 are consistent with the average (see definition below) for comparable industries. The 2009 Budget has been prepared assuming a 3% increase for all employees, including executive and management, as well as an allocation for progression increases across the executive and management of approximately $20,000. Therefore, salaries for executive and management in 2009 are expected to remain in-line with industry averages.

As discussed in Exhibit 4, Tab 2, Schedule 2, page 7, Bluewater Power's compensation for executive and management is determined by the Compensation Committee of the Board of Directors. The committee relies upon data presented from the Hay Group. The Hay Group is a consulting firm well recognized as a leader in the area of compensation.

The Committee looks at each position's actual salary compared to the Base Salary for comparable positions within two relevant categories within the Hay Group's data base – "Industrial Organizations with Revenue < $125M" and "Utilities with Revenue <$1B". In making that comparison, actual salaries in 2008 were compared to base salaries for comparable positions. Base Salary under the Hay Group system is the mid-range of the salary grid for a given position. Therefore, the conclusions reached by this method of comparison are conservative because Bluewater Power's actual compensation is compared to the mid-range for comparable positions.

The analysis is shown in Attachment 1- Compensation Report, which is an excerpt from the report of the Vice President of Human Resources to the Compensation Committee in December of 2008. The report demonstrates the following:

- When compared to Industrial Organizations, three of the nine positions considered by the Compensation Committee do not meet the average compensation even using the more conservative approach.

- When compared to the Utilities, seven of the nine positions do not meet the average compensation even using the more conservative approach
- Incentives are well below the Industrial Organizations and below Utilities for most positions
- Total Compensation (salary plus incentive) are below average for Industrial Organizations
- Total Compensation (salary plus incentive) are below average for Utilities, with the exception of two positions which exceed average by less than 10%.

Also provided in response to this question are the Hay Group analyses based on comparing the Base Salary for each position at Bluewater Power with the 50th percentile of Base Salaries for comparable positions. Attachments 2 and 3 have been produced using data collected and presented by the Hay Group. The attachment labelled 'Base Salary Policy' show Base Salaries for the executive members of Bluewater Power's team compared to two relevant categories within the Hay Group's data base – "Industrial Organizations with Revenue < $125M" and "Utilities with Revenue <$1B". The data has been presented in this response in a modified format; the actual salary information for each position has been removed to protect private information. What remains is as follows:

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

The analysis shows that comparing Base Salaries to the 50th percentile of Base Salaries, the compensation for our executive and management falls well below the 75th percentile. In fact, the market position for our Base Salaries falls between the 10th and the 30th percentiles.

The attachment labelled ‘Supplementary Table, Market Actual and Target Incentive Pay’, is the Hay Group evaluation of Bluewater Power’s Incentive Pay. Bluewater Power’s compensation structure also includes an incentive program designed to incent superior performance in the four key areas of spending, reliability/service, financial results and safety (this program is discussed in detail at Exhibit 4, Tab 2, Schedule 2, page 9). The Hay Group analysis attached shows that “target” and “actual” bonuses for Bluewater Power are 20% to 200% less than the “Industrial Organizations with Revenue < $125M” category. The Hay Group analysis attached also shows that the incentives are less than the target and actual for “Utilities with Revenue <$1B” category, with the exception of three positions.

Attachments:

Board Staff 1.13.b.Compensation Report

1. Board Staff 1.13.b. Base Salary Policy
2. Board Staff 1.13.b Supplementary Table

COMPENSATION REPORT

of the

VICE PRESIDENT
of
HUMAN RESOURCES

HAY SURVEY

Hay Data

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

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

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

Analysis: Two positions are well below the average for Industrial Organizations (CEO & VP, Human Resources). One position is just below the Average (VP, Operations). All other positions are above the Average. In the Utility comparison only one position is above the 75 Percentile (VP, Corporate Services & Legal Counsel) and one position is above the Average (COO of BWP Generation). All others are below the Average.

Base Salary

Industrial Organizations

Comparison to Industrial Organizations

Base Salary

Bluewater Power Benchmark Job Title	Current Salary	Industrial Organizations Base Salaries						Variance from P75	Variance from AVG	Variance from P25
		P90	P75	AVG	P50	P25	P10			
President & Chief Executive Officer								-23.5%	-15.4%	0.9%
Vice-President Corporate Services & Gen								-11.2%	0.7%	17.0%
Chief Operating Officer								-9.8%	1.3%	15.0%
VP Operations & COO								-11.6%	-0.3%	13.6%
Vice-President Human Resources								-22.1%	-10.0%	4.7%
Controller								-2.7%	6.8%	17.4%
Director - Information Technology								-5.0%	4.9%	16.0%
Director - Client Services								-4.7%	4.3%	14.7%
Manager - Design Services								-6.9%	2.3%	12.9%

Data Information as of: **May 1, 2008**

Base Salary

Utilities

Comparison to Utilities

Base Salary

Bluewater Power Benchmark Job Title	Base Salary Policy	Utilities Base Salaries P90	P75	AVG	P50	P25	P10	Variance from P75	Variance from AVG	Variance from P25
President & Chief Executive Officer		*					*	-25.5%	-9.2%	7.2%
Vice-President Corporate Services & Gen		*					*	0.7%	3.4%	10.6%
Chief Operating Officer		*					*	-2.8%	0.2%	7.9%
VP Operations & COO		*					*	-4.5%	-1.5%	6.4%
Vice-President Human Resources		*					*	-16.0%	-12.3%	-3.4%
Controller		*					*	-10.3%	-2.6%	9.2%
Director - Information Technology		*					*	-7.5%	-0.5%	11.4%
Director - Client Services		*					*	-7.8%	-2.4%	10.3%
Manager - Design Services		*					*	-10.1%	-4.5%	8.5%

** Denotes insufficient data*

Data Information as of: **May 1, 2008**

Incentives

Comparison to Industrial Organizations & Utilities

Incentives

		Average of Industrial Organizations				Average of Utilities Organizations			
Bluewater Power Benchmark Job Title	**Target**	**Actual Incentive**	**% Difference**	**Target Incentive**	**% Difference**	**Actual Incentive**	**% Difference**	**Target Incentive**	**% Difference**
President & Chief Executive Officer			-66.0%		-91.5%		-39.5%		-21.0%
Vice-President Corporate Services & Gen			-28.6%		-33.7%		32.0%		24.6%
Chief Operating Officer			-21.3%		-40.7%		6.7%		8.0%
VP Operations & COO			-21.3%		-40.7%		6.7%		8.0%
Vice-President Human Resources			-73.0%		-105.0%		-42.0%		-38.0%
Controller			-96.0%		-126.7%		-40.0%		-57.3%
Director - Information Technology			-102.7%		-134.7%		-46.7%		-64.0%
Director - Client Services			-80.0%		-110.7%		-24.0%		-38.7%
Manager - Design Services			-170.0%		-216.0%		-86.0%		-108.0%

Data Information as of: **May 1, 2008**

Total Compensation

Industrial Organizations

Comparison to Industrial Organizations
Total Compensation

Bluewater Power Benchmark Job Title	Total Compensation	Industrial Organizations Total Compensation						Variance from P75	Variance from AVG	Variance from P25
		P90	P75	AVG	P50	P25	P10			
President & Chief Executive Officer								-42.3%	-33.0%	-14.2%
Vice-President Corporate Services & Gen								-16.8%	-4.3%	12.8%
Chief Operating Officer								-15.6%	-3.9%	10.5%
VP Operations & COO								-17.5%	-5.7%	9.0%
Vice-President Human Resources								-33.8%	-20.5%	-4.4%
Controller								-11.8%	-1.5%	10.1%
Director - Information Technology								-14.9%	-4.0%	8.2%
Director - Client Services								-12.8%	-3.1%	8.1%
Manager - Design Services								-17.8%	-7.7%	3.9%

Data Information as of: **May 1, 2008**

Total Compensation

Utilities

Comparison to Utilities
Total Compensation

Bluewater Power Benchmark Job Title	Total Compensation	Utilities Total Compensation						Variance from P75	Variance from AVG	Variance from P25
		P90	P75	AVG	P50	P25	P10			
President & Chief Executive Officer		*					*	-29.9%	-13.0%	3.9%
Vice-President Corporate Services & Gen		*					*	4.3%	6.9%	13.9%
Chief Operating Officer		*					*	-1.7%	1.2%	8.9%
VP Operations & COO		*					*	-3.4%	-0.4%	7.4%
Vice-President Human Resources		*					*	-20.0%	-16.2%	-6.9%
Controller		*					*	-14.7%	-6.7%	5.5%
Director - Information Technology		*					*	-12.3%	-4.9%	7.4%
Director - Client Services		*					*	-10.8%	-5.2%	7.9%
Manager - Design Services		*					*	-15.8%	-9.9%	3.7%

** Denotes insufficient data*

Data Information as of: **May 1, 2008**

Comparison to Market Using Bluewater Power Base Salary Policy

Base Salary Policy **May 1, 2008**

Bluewater Power Benchmark Job Title	Total Points	Base Salary Policy	Industrial Organizations with Revenue < $125MM							
			P90	P75	AVG	P50	P25	P10	Variance from P50	Market Position
President & Chief Executive Officer	1566								-26.4%	P13
Vice-President Corporate Services & Gen	954								-10.9%	P26
Chief Operating Officer	830								-13.0%	P22
VP Operations & COO	830								-14.4%	P20
Vice-President Human Resources	800								-22.4%	<P10
Director - Information Technology	677								-9.9%	P24
Controller	657								-8.2%	P27
Manager - Design Services	611								-12.5%	P19
Director - Client Services	611								-10.7%	P22

*Note: * indicates data insufficient to report*

Comparison to Market Using Bluewater Power Base Salary Policy

Base Salary Policy **May 1, 2008**

Bluewater Power Benchmark Job Title	Total Points	Base Salary Policy	Utilities with Revenue < $1B							
			P90	P75	AVG	P50	P25	P10	Variance from P50	Market Position
President & Chief Executive Officer	1566		*					*	-27.5%	<P25
Vice-President Corporate Services & Gen	954		*					*	-10.9%	<P25
Chief Operating Officer	830		*					*	-13.5%	<P25
VP Operations & COO	830		*					*	-14.9%	<P25
Vice-President Human Resources	800		*					*	-22.9%	<P25
Director - Information Technology	677		*					*	-12.6%	<P25
Controller	657		*					*	-11.4%	<P25
Manager - Design Services	611		*					*	-16.7%	<P25
Director - Client Services	611		*					*	-15.0%	<P25

*Note: * indicates data insufficient to report*

Supplementary Table
Market Actual and Target Incentive Pay as % of Salary
(Includes bonus eligible only)

May 1, 2008

Bluewater Power Benchmark Job Title	Total Points	Average of Industrial Organizations with Revenue less than $125 Million			
		Actual Bonus	Target Bonus	Variance From Actual	Variance from Target
President & Chief Executive Officer	1566			-66.0%	-91.5%
Vice-President Corporate Services & Gen	954			-28.6%	-33.7%
Chief Operating Officer	830			-21.3%	-40.7%
VP Operations & COO	830			-21.3%	-40.7%
Vice-President Human Resources	800			-73.0%	-105.0%
Director - Information Technology	677			-96.0%	-126.7%
Controller	657			-102.7%	-134.7%
Manager - Design Services	611			-80.0%	-110.7%
Director - Client Services	611			-170.0%	-216.0%

*Note: * indicates data insufficient to report*

Bluewater Power Benchmark Job Title	Total Points	Average of Utilities Organizations with Revenue less than $1 Billion			
		Actual Bonus	Target Bonus	Variance From Actual	Variance From Target
President & Chief Executive Officer	1566			-39.5%	-21.0%
Vice-President Corporate Services & Gen	954			32.0%	24.6%
Chief Operating Officer	830			6.7%	8.0%
VP Operations & COO	830			6.7%	8.0%
Vice-President Human Resources	800			-42.0%	-38.0%
Director - Information Technology	677			-40.0%	-57.3%
Controller	657			-46.7%	-64.0%
Manager - Design Services	611			-24.0%	-38.7%
Director - Client Services	611			-86.0%	-108.0%

*Note: * indicates data insufficient to report*

Question 1.14 - Operating Costs – All Other Costs

Ref: Exhibit 4 Tab 2 Schedule 2 Page 2 Table 4.2.2.1

Bluewater has forecasted an amount of $1,937,998 for "All other costs". This represents an increase of $224,614 since 2007.

Question 1.14

Please provide a listing of all accounts that form the "All Other Costs" category including the dollar amounts for each account from 2006 to 2009.

1.14 Response:

Please see the attachment below.

Attachment: "Board Staff 1.14 – All Other Costs"

OEB STAFF: Question 1.14 : Operating Costs - All Other Costs

		2006 Actual	2007 Actual	2008 Bridge	2009 Test
Distribution Expenses - Operation					
5005	Operation Supervision and Engineering		13,021	15,702	32,506
5010	Load Dispatching		11,004	11,320	11,886
5012	Station Buildings and Fixtures Expense	108	416	-	100
5015	Transformer Station Equipment - Operation Supplies and Expenses	3,757	592		
5017	Distribution Station Equipment - Operation Supplies and Expenses	855	6,835	400	420
5025	Overhead Distribution Lines/Feeders - Operation Supplies and Exp	60,455	68,162	65,270	74,319
5035	Overhead Distribution Transformers - Operation	2,367	1,274	1,300	1,365
5045	Underground Distribution Lines/Feeders - Operation Supplies and Exp	36,543	172,078	171,575	209,830
5055	Underground Distribution Transformers - Operation	3,727	1,824		
5060	Street Lighting and Signal System Expense	110,471			
5065	Meter Expense	248	4,333	10,576	13,352
5070	Customer Premises - Operation Labour		768		
5075	Customer Premises - Materials and Expenses		15,714	26,541	37,920
5085	Miscellaneous Distribution Expense	6,692	39,630	37,588	41,306
5095	Overhead Distribution Lines and Feeders - Rental Paid		15,756	15,800	16,990
Distribution Expenses - Maintenance					
5114	Maintenance of Distribution Station Equipment	9,055	7,299	4,500	6,025
5120	Maintenance of Poles, Towers and Fixtures	11,706	11,354	12,000	14,300
5125	Maintenance of Overhead Conductors and Devices	74,442	67,810	75,470	83,420
5145	Maintenance of Underground Conduit	137	69		
5150	Maintenance of Underground Conductors and Devices	16,045	18,988	16,000	16,900
5155	Maintenance of Underground Services	1,452	2,230	2,500	2,625
5160	Maintenance of Line Transformers	18,256	8,031	24,000	25,200
5165	Maintenance of Street Lighting and Signal Systems	1,637			
5175	Maintenance of Meters	7,210	2,319	3,540	4,500
Billing and Collecting					
5310	Meter Reading Expense	736	14,640	13,630	19,680
5315	Customer Billing	140,806	134,999	138,099	141,935
5320	Collecting		119	-	150
5335	Bad Debt Expense	63,517	93,011	84,500	102,885
5340	Miscellaneous Customer Account Expenses	35			
Community Relations					
5410	Community Relations - Sundry	30,530	57,142	36,400	52,000
5415	Energy Conservation	56,804	21,310	100	600
5420	Community Safety Program		471	18,700	21,240
Administration and General Expenses					
5605	Executive Salaries and Expenses	1,491	5,352	7,300	8,100
5610	Management Salaries and Expenses		120	-	-
5615	General Administrative Salaries and Expenses	5,944	5,658	16,085	20,810
5620	Office Supplies and Expenses	14,971	6,178	2,000	2,860
5630	Outside Services Employed			(174)	(180)
5635	Property Insurance			(84)	(78)
5655	Regulatory Expenses	99,994	109,147	121,400	128,041
5665	Miscellaneous General Expenses	656,526	438,724	430,420	459,026
5675	Maintenance of General Fleet	234,076	81,517	79,924	90,213
Taxes					
6105	Taxes Other Than Income Taxes	286,380	275,492	290,000	297,750
Grand Total		1,956,971	1,713,386	1,732,382	1,937,995

Question 1.15 - Shared Services / Corporate Cost Allocation

Ref: http://www.oeb.gov.on.ca/documents/minfilingrequirements_report_141106.pdf

Pursuant to section 2.5 (Exhibit 4 Part A and D) of the Filing Requirements for Transmission and Distribution Applications (see reference above), applicants are to file the following information:

Question 1.15 (a)

The type of shared service and the total annual expense by service.

1.15 (a) Response:

The budgeted figures for 2008 are set out below.

Table 7

Name of Company		Type of Service Offered	Pricing Methodology	Price for the Service ($)	Cost for the Service ($)	% Allocation	Explanation
From	To						
Bluewater Power Distribution Corporation	Electek Power Services Inc	Management Fee	Fully allocated costing	20,000	20,000	100	Management services such as Financial (treasury, controllership, audit) and Corporation Services (HR, IT and other), charges hourly on a fully-allocated cost basis.
Bluewater Power Distribution Corporation	Bluewater Power Generation Corporation	Office Space	Fully allocated costing	7,200	6,850	>100	Approximately 500 sq ft of office space rented for two staff and charged as an estimate of market value, which is less than the fully-allocated cost.
Bluewater Power Distribution Corporation	Bluewater Power Generation Corporation	Management Fee	Fully allocated costing	15,000	15,000	100	Management services such as Financial (treasury, controllership, audit) and Corporation Services (HR, IT and other), charges hourly on a fully-allocated cost basis.
Bluewater Power Distribution Corporation	Blackwell Renewable Inc.	Management Fee	Fully allocated costing	7,500	7,500	100	Management services such as Financial (treasury, controllership, audit) and Corporation Services (HR, IT and other), charges hourly on a fully-allocated cost basis.

The Projected figures for 2009 are set out below.

Table 7

Name of Company		Type of Service Offered	Pricing Methodology	Price for the Service ($)	Cost for the Service ($)	% Allocation	Explanation
From	To						
Bluewater Power Distribution Corporation	Electek Power Services Inc.	Management Fee	Fully allocated costing	33,750	33,750	100	Management services such as Financial (treasury, controllership, audit) and Corporation Services (HR, IT and other), charges hourly on a fully-allocated cost basis.
Bluewater Power Distribution Corporation	Bluewater Power Generation Corporation	Management Fee	Fully allocated costing	8,000	8,000	100	Management services such as Financial (treasury, controllership, audit) and Corporation Services (HR, IT and other), charges hourly on a fully-allocated cost basis.
Bluewater Power Distribution Corporation	Bluewater Power Generation Corporation	Office Space	Fully allocated costing	7,200	6,850	>100	Approximately 500 sq ft of office space rented for two staff and charged as an estimate of market value, which is less than the fully-allocated cost.
Bluewater Power Distribution Corporation	Blackwell Renewable Inc.	Management Fee	Fully allocated costing	6,000	6,000	100	Management services such as Financial (treasury, controllership, audit) and Corporation Services (HR, IT and other), charges hourly on a fully-allocated cost basis.
Bluewater Power Distribution Corporation	Bluewater Power Services Corporation	Management Fee	Fully allocated costing	46,560	46,560	100	Management services such as Financial (treasury, controllership, audit) and Corporation Services (HR, IT and other), charges hourly on a fully-allocated cost basis.
Bluewater Power Distribution Corporation	Bluewater Power Services Corporation	Office Space	Fully allocated costing	12,000	6,500	>100	Office space and facilities, including storage, rented at a largely retired Substation and charged as an estimate of market value, which is less than the fully-allocated cost.
Bluewater Power Distribution Corporation	Bluewater Power Services Corporation	Vehicle Costs	Fully allocated costing	20,800	20,800	100	Bucket trucks and smaller vehicles are rented on an as-needed basis and charged at the fully-allocated cost.
Bluewater Power Services Corporation	Bluewater Power Distribution Corporation	Trenching/Excavating/Installation of Distribution underground plant, project support	Fully allocated costing	343,386	343,386	100	The civil crew being transferred to the affiliate performs distribution work which will be purchased back from the affiliate on a fully-allocated cost basis.

*NOTE: The name change for the affiliate from Sarnia Hydro Energy Services Corporation to Bluewater Power Services Corporation

Question 1.15 (b)

A detailed description of the assumptions underlying the corporate cost allocation as well as provide documentation of the overall methodology and policy.

1.15 (b) Response:

This information was provided in some detail at Exhibit 3, Tab 3, Schedule 4 of the pre-filed evidence.

The assumptions underlying the corporate costs allocation for Management Fees are as follows:

1. Costs are allocated on the basis of hours spent providing service to an affiliate;
2. Hours are charged on a fully-allocated cost basis, which means hourly equivalent salary plus benefits and overhead.

The assumptions underlying the allocation of office space is that an estimate of market value was determined based on current market conditions in the Sarnia-Lambton region The fully-allocated cost was prepared for comparison, and represented Return on Invested Capital and O&M costs related to the building allocated on the basis of FTEs.

The assumptions underlying the allocation of costs for trenching/excavating/other from the affiliate to the utility are as follows:

1. Costs are allocated on the basis of hours spent providing service;
2. Hours are charged on a fully-allocated cost basis, which means hourly equivalent salary plus benefits and overhead.

Question 1.16 - Purchase of Services

Ref: http://www.oeb.gov.on.ca/documents/minfilingrequirements_report_141106.pdf

Question 1.16

Pursuant to section 2.5 (Exhibit 4 Operating & Maintenance and Other Costs, Section A) of the Filing Requirements, please file the necessary information relating to the purchase of services or products for 2006 to 2009.

1.16 Response:

Please see the attached file below which provides a listing of the more significant purchases of services or products for 2006 to 2009. Please note that the amounts for 2009 are estimates only.

Attachment: "Board Staff 1.16 Purchase of Services"

BOARD STAFF 1.16

PURCHASE OF SERVICES

Vendor	Description of Service	2006 Purchases	2007 Purchases	2008 YTD Sept	2009 Estimate
ABB INC.	Transformers	204,853	-	-	-
ANIXTER CANADA INC.	Wire	63,047	81,612	45,467	50,000
BADGER DAYLIGHTING	Hydrovac Pole Installation	43,651	36,098	30,455	35,000
BAYVIEW CHRYSLER DODGE LTD.	Dodge Ram & Caravan & Repairs	42,798	55,957	357	-
BELL CANADA	Telephone System	41,728	39,687	38,766	40,000
CANADA POST CORP.	Bulk Letter Posting	129,138	121,200	115,500	120,000
CANADA POWER PRODUCTS CORP.	Transformer	-	113,863	162	-
CANNON TECHNOLOGIES INC.	Conservation Load Control	-	165,802	-	-
CARTE INTERNATIONAL INC.	Transformer	94,869	-	-	-
CCSI TECHNOLOGY SOLUTIONS CORP.	Support System	193,571	110,951	51,917	50,000
CLEAN AIR FOUNDATION	Cool Shop Program	71,837	-	-	-
CONEXSYS	Professional Services	52,092	13,077	1,385	-
CORP CITY OF SARNIA	Fuel	83,227	83,097	129,445	130,000
DELL CANADA INC.	Computers & Supplies	77,644	46,725	52,863	45,000
DELOITTE INC.	Support Service	380,476	168,130	94,500	100,000
ELECTROZAD SUPPLY	Electric Supply	97,245	60,613	40,235	40,000
ELENCHUS RESEARCH ASSOCIATES	Review of BWP cost allocation	1,385	-	68,885	-
ERIE THAMES SERVICES	Meter Re-verification		148,287	151,852	150,000
ESRI CANADA LTD	Support for software	34,932	30,350	30,163	30,000
DAVID GILCHRIST ARCHITECT	Office Renovation	-	2,076	30,638	10,000
GOOD CENTS INTERNATIONAL	Peaksaver Program Expenses	-	59,105	71,228	70,000
GUARDIAN TREE SYSTEMS INC.	Tree Trimming Service	118,254	176,343	114,046	125,000
GUELPH UTILITY POLE COMPANY LTD.	Wood Poles	41,940	59,300	81,399	70,000
GUILLEVIN INTERNATIONAL CO.	Electrical Supply	63,136	89,281	44,266	50,000
HD SUPPLIY UTILITIES	Cable, Wire, Transformer Line, Hardware	452,589	501,902	454,224	450,000
IBM CANADA LTD.	Tape library, Storage, Maintenance	31,696	41,538	41,801	41,000
IMPERIAL OIL	2004 Electrical Boom Truck	-	-	41,000	-
IMPERIAL ROOFING	Service Centre Roof & repairs	68,708	72,393	83,360	55,000
INNIVITY MARKETING GROUP	Marketing services	1,428	11,552	30,487	10,000
ITRON CANADA INC.	Meters	83,109	43,338	27,489	30,000
ITRON INC.	Hardware & software support, PC Base	63,901	14,244	-	-
K-LINE MAIN & CONSTRUCTION	Water washing contract	31,257	28,548	31,421	31,000
KPMG LLP	Auditors	16,642	33,605	104,584	40,000
LAFARGE CANADA INC.	Sand & Gravel Supply	41,138	40,372	7,686	8,000
LAKEPORT POWER LTD.	Cable	90,845	-	7,124	-
LAMBTON MOTORS	2005 & 2007 Ford Focus	27,513	311	30,955	-
LIFTOW	Toyota Forklift	39,498	-	-	-
LINEMAN TESTING	Testing of line equipment, Gloves	19,750	21,822	31,570	30,000
LOCKHART ELECTRIC	Office Renovation	-	-	40,041	-
MANLEY'S	Office supplies, Toner, Furniture	41,115	36,401	39,193	40,000
MOLONEY ELECTRIC	Transformers	451,879	687,802	382,039	400,000
OGILVY RENAULT	Professional Services	111,555	18,915	78,344	25,000
PACHECOS CONTRACTORS	Civil Contractor	42,431	274,328	208,496	200,000
POSI PLUS	Freight liner Truck	319	234,855	462,064	-
POSTAGE BY PHONE	Postage	32,449	26,500	23,600	25,000
ROGERS	Blackberries & Cell Phones	-	37,539	34,606	35,000
RUDDY	Electrical Supply Distributor	307,351	248,949	381,116	300,000
SAP CANADA INC	Annual Maintenance	131,164	126,341	9,765	120,000
SCHWEITZER ENGINEERING LABS	Protection Relay	32,936	17,486	17,307	17,000
SHURGARD GROUP INC.	Office Renovation, Petrolia substation	-	-	190,101	-
SOFTCHOICE CORP.	Software Vendor	2,581	177,084	27,178	25,000
STRESS CRETE LTD	Mounting Plate	-	28,399	110,740	-
SUMMERHILL GROUP	BWP Fixed & Variable expenses	-	122,625	119,382	120,000
UNIS LUMIN	WI-FI	-	26,769	39,616	30,000
WAJAX INDUSTRIES	Telelect & labour to install, Inspections	48,459	9,620	386,740	-
WALLIS MOTORS	2 Pontiac Vibes, GMC Sierra	86,869	66	-	-
WHARTON SALES CO. LTD.	Street lights	-	-	149,953	-
XEROX CANADA INC.	Copier, Copies, Toner	41,956	5,171	4,313	5,000
GRAND TOTAL		$ 4,134,961	$ 4,550,029	$ 4,789,824	$ 3,152,000

Question 1.17 - Corporate Cost Allocation

Ref: EB-2005-0001 Decision with Reason for Enbridge Gas Distribution Inc. Chapter 10 p.69-91

The five principles listed below formed the basis of the Board's acceptance of Enbridge's corporate cost allocations in EB-2005-0001.

1. *The service is specifically required by the utility;*
2. *The level of service provided is required by the utility;*
3. *The costs are allocated based on cost causality and cost drivers;*
4. *The cost to provide the service internally would be higher and the cost to acquire the service externally on a stand-alone basis would be higher; and*
5. *There are scale economies.*

Question 1.17

Please provide information as to how Bluewater's corporate cost allocation policy meets each of these principles.

1.17 Response:

Bluewater Power Distribution Corporation does not receive corporate services from its affiliates. The test outlined in the Enbridge decision (EB-2005-0001) is not applicable where corporate services are provided by the utility to its affiliates, as is the case with Bluewater Power.

COST OF CAPITAL, CAPITAL STRUCTURE, AND WEIGHTED AVERAGE COST OF CAPITAL

Question 2.1 - Long Term Debt Rate

Ref: Exhibit 6/Tab 1/Schedule 2
Ref: Exhibit 1/Tab 3 Schedule 2," Financial Statements (2007)", Note 5.
Ref: Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors December 20, 2006, page 14 - http://www.oeb.gov.on.ca/documents/cases/EB-2006-0088/report_of_the_board_201206.pdf

Note 5 of Bluewater's 2007 Audited Financial Statements makes reference to the following debt:

"Subordinate promissory note payable to shareholders, bearing interest at 7.25%, with interest payable in quarterly instalments, with no specific repayment terms for principal amounts. Shareholders can demand payment with twelve months written notice."

On Long-Term Debt, Section 2.2.1 of the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors - December 20, 2006 states, in part:

*"**For all variable-rate debt and for all affiliate debt that is callable on demand the Board will use the current deemed long-term debt rate.** When setting distribution rates at rebasing these debt rates will be adjusted regardless of whether the applicant makes a request for a change." [Emphasis in original]*

Beginning on Line 25 of Exhibit 6 Tab 1 Schedule 2 Page 2, Bluewater states the following in support of its use of a 7.25% rate for this debt:

"The OEB Cost of Capital Report permits certain forms of callable debt to be considered long-term debt recovered at its face value, but purports to distinguish between debt that is callable by an affiliate and debt that is callable by a third party. There is no jurisdictional basis to make that distinction. Moreover, there is no factual basis in the case of the debt of Bluewater Power because the Promissory Notes have been treated at all times as if they were third party debt."

<u>Question 2.1 (a)</u>

Please elaborate on what is meant by the statement that "There is no jurisdictional basis to make that distinction."

<u>2.1 (a) Response:</u>

Before answering this question, Bluewater Power points out that the issue of debt rate may be moot as current economic conditions point to a deemed debt rate closely approximately the 7,.25% rate under the Promissory Note.

The Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation, dated December 20, 2006 (the "OEB Report") seeks to distinguish between a note callable on demand on the basis of whether it is held by a third party or whether it is held by an affiliate. Therefore, if two distinct OEB panels were to consider two promissory notes negotiated at the same time and leading to identical terms, the OEB Report would cause those Board panels to decide differently if one promissory note was held by a third party and the other was held by an affiliate. It seems obvious to suggest that result is inappropriate and yet that is exactly the consequence of a mechanistic application of the OEB Report.

The OEB has an obligation to approve just and reasonable rates. It also has a duty under section 1(1) of the *Ontario Energy Board Act* to carry out is responsibilities while guided by two objectives:

(1) "To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity services"
(2) "To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry".

Neither of those objectives is achieved by permitting recovery through rates of the face-value of notes callable on demand only when they are held by third parties. Neither of those objectives is achieved by a mechanistic application by an OEB panel of rule in an OEB Staff Report.

That is not to suggest the OEB does not have the jurisdiction to inquire as to the terms of the Promissory Note or whether the Promissory Note entered into with an affiliate represents the market rate at the time the note was negotiated. To the contrary, that is an important role for the OEB. What we are suggesting is that the OEB lacks jurisdiction to take a mechanistic approach based on a test outlined in an OEB Staff Report.

Question 2.1 (b)

With reference to the statement that "there is no factual basis in the case of the debt of Bluewater because the Promissory Notes have been treated at all times as if they were third party debt," please state why Bluewater believes this to be the case. Please explain why Bluewater takes the position that negotiating a debt rate with an affiliate is the same as negotiating it with a non affiliate. Please reference any efforts that were made at the time the debt was negotiated to ensure that the rate was equivalent to that which would have been obtained from a third party.

2.1 (b) Response:

Bluewater Power does not take the position that "negotiating a debt with an affiliate is the same as negotiating it with a non affiliate". The process may be different, but if the end result is a prudent debt instrument at market-based rates, then the OEB ought to permit recovery of that debt through rates.

We would like to point out that we agree with the underlying assumption in the question that the test is whether the interest rate represented a market rate at the time it was negotiated. With respect to independent efforts to determine the market rate for the debt in the year 2000, we were unable to locate any such efforts. We do note, however, that consultations were ongoing with OEB Staff regarding the appropriate debt rate and that debt rate was specifically approved for recovery in rates as part of the 2001 RUD Application.

RATE BASE AND CAPEX

Question 3.1 - Consistency of Information Provided

Ref: Exhibit 2/Tab 1/Schedule 2, p .1
Exhibit 2/Tab 2/Schedule 1, p. 1

In Exhibit 2/Tab 1/Schedule 2, p.1 ending net capital asset balances for the years 2007, 2008 and 2009 are shown as follows:

2007: $37,626,977

2008: $37,944,816

2009: $41,145,335

In Exhibit 2/Tab 2/Schedule 1, the Fixed Asset Continuity Statements show net book values for the years 2007, 2008 and 2009 as follows:

2007: $36,908,359

2008: $37,226,198

2009: $40,426,717

Question 3.1

Please provide a reconciliation of the two above sets of numbers.

3.1 Response:

Exhibit 2/Tab 1/Schedule 2, p.1 presents the correct ending net capital asset balances for the years 2007, 2008 and 2009 as follows:

2007: $37,626,977
2008: $37,944,816
2009: $41,145,335

There was a numerical error in the Accumulated Amortization line for the asset class 1930, Transportation Equipment in the Fixed Asset Continuity Statements. This error affected the Continuity Statements only, and did not affect any calculations. A correct version of the continuity statements is attached.

Attachment: Board Staff 3.1 Updated Fixed Asset Continuity Statements.

Capital Asset Continuity Statements

** Asset retirements and other changes*	2006 EDR Approved	Variance to 2006 Actual Additions	Ret./Other *	Amortization	2006 Balance
1805-Land					
Gross Assets	445,817				445,817
Accumulated Amortization					
Net Book Value	445,817				445,817
1806-Land Rights					
Gross Assets	283,160				283,160
Accumulated Amortization	(221,619)			(29,507)	(251,125)
Net Book Value	61,541			(29,507)	32,035
1808-Buildings and Fixtures					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1810-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1815-Transformer Station Equipment - Normally Primary above 50 kV					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	4,421,144	247,437	646,111		5,314,692
Accumulated Amortization	(2,251,875)			(275,789)	(2,527,663)
Net Book Value	2,169,269	247,437	646,111	(275,789)	2,787,029

Capital Asset Continuity Statements

** Asset retirements and other changes*	2006 EDR Approved	Variance to 2006 Actual			2006 Balance
		Additions	Ret./Other *	Amortization	
1830-Poles, Towers and Fixtures					
Gross Assets		203,424	103,114		306,538
Accumulated Amortization				(13,471)	(13,471)
Net Book Value		203,424	103,114	(13,471)	293,067
1835-Overhead Conductors and Devices					
Gross Assets	22,528,705	788,215	1,118,943		24,435,863
Accumulated Amortization	(10,746,858)			(2,262,108)	(13,008,965)
Net Book Value	11,781,847	788,215	1,118,943	(2,262,108)	11,426,898
1840-Underground Conduit					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1845-Underground Conductors and Devices					
Gross Assets	16,336,461	367,560	1,068,742		17,772,763
Accumulated Amortization	(6,971,481)			(1,617,703)	(8,589,184)
Net Book Value	9,364,980	367,560	1,068,742	(1,617,703)	9,183,579
1850-Line Transformers					
Gross Assets	10,514,427	665,389	711,204		11,891,020
Accumulated Amortization	(5,079,269)		(6)	(1,080,906)	(6,160,181)
Net Book Value	5,435,158	665,389	711,198	(1,080,906)	5,730,839
1855-Services					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1860-Meters					
Gross Assets	5,625,800	186,909	410,359		6,223,068
Accumulated Amortization	(3,212,663)			(506,092)	(3,718,755)
Net Book Value	2,413,137	186,909	410,359	(506,092)	2,504,313

Capital Asset Continuity Statements

** Asset retirements and other changes*	2006 EDR Approved	Variance to 2006 Actual			2006 Balance
		Additions	**Ret./Other ***	**Amortization**	
1905-Land					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1906-Land Rights					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1908-Buildings and Fixtures					
Gross Assets	3,737,050	176,607	136,305		4,049,962
Accumulated Amortization	(1,426,051)			(158,883)	(1,584,934)
Net Book Value	2,310,999	176,607	136,305	(158,883)	2,465,028
1910-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1915-Office Furniture and Equipment					
Gross Assets	539,755	56,181	88,218		684,154
Accumulated Amortization	(472,937)			(58,839)	(531,776)
Net Book Value	66,818	56,181	88,218	(58,839)	152,378
1920-Computer Equipment - Hardware					
Gross Assets	1,985,558	372,081	546,346		2,903,985
Accumulated Amortization	(1,410,824)			(584,266)	(1,995,091)
Net Book Value	574,734	372,081	546,346	(584,266)	908,894
1925-Computer Software					
Gross Assets	1,868,201	525,770	1,550,889		3,944,860
Accumulated Amortization	(511,803)			(1,302,288)	(1,814,091)
Net Book Value	1,356,398	525,770	1,550,889	(1,302,288)	2,130,769

Capital Asset Continuity Statements

** Asset retirements and other changes*	2006 EDR Approved	Variance to 2006 Actual			2006 Balance
		Additions	Ret./Other *	Amortization	
1930-Transportation Equipment					
Gross Assets	2,585,010	269,708	263,305		3,118,023
Accumulated Amortization	(2,278,476)		342,051	(389,038)	(2,325,463)
Net Book Value	306,534	269,708	605,355	(389,038)	792,560
1935-Stores Equipment					
Gross Assets	42,591	37,420	593		80,604
Accumulated Amortization	(31,169)			(11,243)	(42,413)
Net Book Value	11,422	37,420	593	(11,243)	38,191
1940-Tools, Shop and Garage Equipment					
Gross Assets	546,958	53,192	50,762		650,911
Accumulated Amortization	(447,580)			(56,776)	(504,356)
Net Book Value	99,377	53,192	50,762	(56,776)	146,555
1945-Measurement and Testing Equipment					
Gross Assets	194,133	14,464	20,802		229,399
Accumulated Amortization	(185,753)			(14,281)	(200,034)
Net Book Value	8,380	14,464	20,802	(14,281)	29,366
1950-Power Operated Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1955-Communication Equipment					
Gross Assets	142,724	2,480	15,192		160,396
Accumulated Amortization	(110,071)			(15,222)	(125,293)
Net Book Value	32,653	2,480	15,192	(15,222)	35,103
1960-Miscellaneous Equipment					
Gross Assets	493,304	93,071	73,501		659,876
Accumulated Amortization	(452,651)			(63,687)	(516,338)
Net Book Value	40,653	93,071	73,501	(63,687)	143,538

Capital Asset Continuity Statements

** Asset retirements and other changes*	2006 EDR Approved	Variance to 2006 Actual			2006 Balance
		Additions	**Ret./Other ***	**Amortization**	
1965-Water Heater Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1970-Load Management Controls - Customer Premises					
Gross Assets	418,852		46,065		464,917
Accumulated Amortization	(379,695)			(48,633)	(428,328)
Net Book Value	39,157		46,065	(48,633)	36,589
1975-Load Management Controls - Utility Premises					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1980-System Supervisory Equipment					
Gross Assets	985,837	5,184	185,199		1,176,220
Accumulated Amortization	(440,001)			(108,692)	(548,694)
Net Book Value	545,836	5,184	185,199	(108,692)	627,527
1985-Sentinel Lighting Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1990-Other Tangible Property					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1995-Contributions and Grants - Credit					
Gross Assets	(2,049,843)		(1,000,923)		(3,050,765)
Accumulated Amortization				504,861	504,861
Net Book Value	(2,049,843)		(1,000,923)	504,861	(2,545,904)

Capital Asset Continuity Statements

** Asset retirements and other changes*	2006 EDR Approved	Variance to 2006 Actual			2006 Balance
		Additions	Ret./Other *	Amortization	
2005-Property Under Capital Leases					
Gross Assets					
Accumulated Amortization					
Net Book Value					
TOTAL					
Gross Assets	**71,645,644**	**4,065,093**	**6,034,725**		**81,745,463**
Accumulated Amortization	**(36,630,775)**		**342,045**	**(8,092,563)**	**(44,381,292)**
Net Book Value	**35,014,869**	**4,065,093**	**6,376,771**	**(8,092,563)**	**37,364,171**

Capital Asset Continuity Statements

* Asset retirements and other changes	2006 Balance	2007 Changes Additions	Ret./Other *	Amortization	2007 Balance
1805-Land					
Gross Assets	445,817				445,817
Accumulated Amortization					
Net Book Value	445,817				445,817
1806-Land Rights					
Gross Assets	283,160				283,160
Accumulated Amortization	(251,125)			(11,448)	(262,574)
Net Book Value	32,035			(11,448)	20,586
1808-Buildings and Fixtures					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1810-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1815-Transformer Station Equipment - Normally Primary above 50 kV					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	5,314,692	89,774	0		5,404,466
Accumulated Amortization	(2,527,663)			(125,677)	(2,653,340)
Net Book Value	2,787,029	89,774	0	(125,677)	2,751,126

Capital Asset Continuity Statements

** Asset retirements and other changes*	2006 Balance	2007 Changes Additions	Ret./Other *	Amortization	2007 Balance
1830-Poles, Towers and Fixtures					
Gross Assets	306,538	384,496	1		691,035
Accumulated Amortization	(13,471)			(19,035)	(32,506)
Net Book Value	293,067	384,496	1	(19,035)	658,529
1835-Overhead Conductors and Devices					
Gross Assets	24,435,863	650,518	(0)		25,086,381
Accumulated Amortization	(13,008,965)			(920,856)	(13,929,821)
Net Book Value	11,426,898	650,518	(0)	(920,856)	11,156,560
1840-Underground Conduit					
Gross Assets		71,215	0		71,215
Accumulated Amortization				(2,849)	(2,849)
Net Book Value		71,215	0	(2,849)	68,366
1845-Underground Conductors and Devices					
Gross Assets	17,772,763	575,045	0		18,347,808
Accumulated Amortization	(8,589,184)			(684,423)	(9,273,607)
Net Book Value	9,183,579	575,045	0	(684,423)	9,074,201
1850-Line Transformers					
Gross Assets	11,891,020	803,622	(0)		12,694,642
Accumulated Amortization	(6,160,181)			(478,622)	(6,638,803)
Net Book Value	5,730,839	803,622	(0)	(478,622)	6,055,839
1855-Services					
Gross Assets		143,665	0		143,665
Accumulated Amortization				(3,162)	(3,162)
Net Book Value		143,665	0	(3,162)	140,503
1860-Meters					
Gross Assets	6,223,068	524,711	0		6,747,779
Accumulated Amortization	(3,718,755)			(220,086)	(3,938,841)
Net Book Value	2,504,313	524,711	0	(220,086)	2,808,938

Capital Asset Continuity Statements

** Asset retirements and other changes*	2006	2007 Changes			2007
	Balance	**Additions**	**Ret./Other ***	**Amortization**	**Balance**
1905-Land					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1906-Land Rights					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1908-Buildings and Fixtures					
Gross Assets	4,049,962	189,714	0		4,239,676
Accumulated Amortization	(1,584,934)			(60,043)	(1,644,977)
Net Book Value	2,465,028	189,714	0	(60,043)	2,594,699
1910-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1915-Office Furniture and Equipment					
Gross Assets	684,154	27,251	(0)		711,405
Accumulated Amortization	(531,776)			(30,141)	(561,917)
Net Book Value	152,378	27,251	(0)	(30,141)	149,488
1920-Computer Equipment - Hardware					
Gross Assets	2,903,985	353,265	0		3,257,250
Accumulated Amortization	(1,995,091)			(336,821)	(2,331,912)
Net Book Value	908,894	353,265	0	(336,821)	925,338
1925-Computer Software					
Gross Assets	3,944,860	451,110	1		4,395,971
Accumulated Amortization	(1,814,091)			(725,420)	(2,539,512)
Net Book Value	2,130,769	451,110	1	(725,420)	1,856,459

Capital Asset Continuity Statements

** Asset retirements and other changes*	2006	2007 Changes			2007
	Balance	**Additions**	**Ret./Other ***	**Amortization**	**Balance**
1930-Transportation Equipment					
Gross Assets	3,118,023	292,958	(17,258)		3,393,723
Accumulated Amortization	(2,325,463)		17,258	(207,679)	(2,515,885)
Net Book Value	792,560	292,958	0	(207,679)	877,838
1935-Stores Equipment					
Gross Assets	80,604				80,604
Accumulated Amortization	(42,413)			(6,493)	(48,905)
Net Book Value	38,191			(6,493)	31,699
1940-Tools, Shop and Garage Equipment					
Gross Assets	650,911	41,396	(0)		692,307
Accumulated Amortization	(504,356)			(26,189)	(530,545)
Net Book Value	146,555	41,396	(0)	(26,189)	161,762
1945-Measurement and Testing Equipment					
Gross Assets	229,399				229,399
Accumulated Amortization	(200,034)			(3,527)	(203,560)
Net Book Value	29,366			(3,527)	25,839
1950-Power Operated Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1955-Communication Equipment					
Gross Assets	160,396				160,396
Accumulated Amortization	(125,293)			(5,649)	(130,942)
Net Book Value	35,103			(5,649)	29,454
1960-Miscellaneous Equipment					
Gross Assets	659,876	124,656	(0)		784,532
Accumulated Amortization	(516,338)			(45,872)	(562,211)
Net Book Value	143,538	124,656	(0)	(45,872)	222,321

Capital Asset Continuity Statements

** Asset retirements and other changes*	2006 Balance	2007 Changes Additions	Ret./Other *	Amortization	2007 Balance
1965-Water Heater Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1970-Load Management Controls - Customer Premises					
Gross Assets	464,917				464,917
Accumulated Amortization	(428,328)			(14,264)	(442,592)
Net Book Value	36,589			(14,264)	22,325
1975-Load Management Controls - Utility Premises					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1980-System Supervisory Equipment					
Gross Assets	1,176,220	25,190	(0)		1,201,410
Accumulated Amortization	(548,694)			(47,342)	(596,035)
Net Book Value	627,527	25,190	(0)	(47,342)	605,375
1985-Sentinel Lighting Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1990-Other Tangible Property					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1995-Contributions and Grants - Credit					
Gross Assets	(3,050,765)		(637,880)		(3,688,645)
Accumulated Amortization	504,861			127,697	632,558
Net Book Value	(2,545,904)		(637,880)	127,697	(3,056,087)

Capital Asset Continuity Statements

** Asset retirements and other changes*	2006 Balance	2007 Changes Additions	Ret./Other *	Amortization	2007 Balance
2005-Property Under Capital Leases					
Gross Assets					
Accumulated Amortization					
Net Book Value					
TOTAL					
Gross Assets	**81,745,463**	**4,748,586**	**(655,136)**		**85,838,913**
Accumulated Amortization	**(44,381,292)**		**17,258**	**(3,847,902)**	**(48,211,936)**
Net Book Value	**37,364,171**	**4,748,586**	**(637,878)**	**(3,847,902)**	**37,626,977**

Capital Asset Continuity Statements

** Asset retirements and other changes*	2007 Balance	2008 Changes Additions	Ret./Other *	Amortization	2008 Balance
1805-Land					
Gross Assets	445,817				445,817
Accumulated Amortization					
Net Book Value	445,817				445,817
1806-Land Rights					
Gross Assets	283,160				283,160
Accumulated Amortization	(262,574)			(1,193)	(263,767)
Net Book Value	20,586			(1,193)	19,393
1808-Buildings and Fixtures					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1810-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1815-Transformer Station Equipment - Normally Primary above 50 kV					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	5,404,466	231,747			5,636,213
Accumulated Amortization	(2,653,340)			(130,291)	(2,783,631)
Net Book Value	2,751,126	231,747		(130,291)	2,852,582

Capital Asset Continuity Statements

** Asset retirements and other changes*	2007	2008 Changes			2008
	Balance	Additions	Ret./Other *	Amortization	Balance
1830-Poles, Towers and Fixtures					
Gross Assets	691,035	517,118			1,208,153
Accumulated Amortization	(32,506)			(38,033)	(70,539)
Net Book Value	658,529	517,118		(38,033)	1,137,614
1835-Overhead Conductors and Devices					
Gross Assets	25,086,381	1,051,321			26,137,702
Accumulated Amortization	(13,929,821)			(948,992)	(14,878,813)
Net Book Value	11,156,560	1,051,321		(948,992)	11,258,889
1840-Underground Conduit					
Gross Assets	71,215	75,759			146,974
Accumulated Amortization	(2,849)			(4,364)	(7,213)
Net Book Value	68,366	75,759		(4,364)	139,761
1845-Underground Conductors and Devices					
Gross Assets	18,347,808	412,052			18,759,860
Accumulated Amortization	(9,273,607)			(709,385)	(9,982,992)
Net Book Value	9,074,201	412,052		(709,385)	8,776,868
1850-Line Transformers					
Gross Assets	12,694,642	378,444			13,073,086
Accumulated Amortization	(6,638,803)			(502,061)	(7,140,864)
Net Book Value	6,055,839	378,444		(502,061)	5,932,222
1855-Services					
Gross Assets	143,665	138,840			282,505
Accumulated Amortization	(3,162)			(8,524)	(11,686)
Net Book Value	140,503	138,840		(8,524)	270,819
1860-Meters					
Gross Assets	6,747,779	251,908			6,999,687
Accumulated Amortization	(3,938,841)			(228,463)	(4,167,304)
Net Book Value	2,808,938	251,908		(228,463)	2,832,383

Capital Asset Continuity Statements

** Asset retirements and other changes*

	2007	2008 Changes			2008
	Balance	Additions	Ret./Other *	Amortization	Balance
1905-Land					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1906-Land Rights					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1908-Buildings and Fixtures					
Gross Assets	4,239,676	398,023			4,637,699
Accumulated Amortization	(1,644,977)			(65,146)	(1,710,123)
Net Book Value	2,594,699	398,023		(65,146)	2,927,576
1910-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1915-Office Furniture and Equipment					
Gross Assets	711,405	8,522			719,927
Accumulated Amortization	(561,917)			(30,811)	(592,728)
Net Book Value	149,488	8,522		(30,811)	127,199
1920-Computer Equipment - Hardware					
Gross Assets	3,257,250	143,621			3,400,871
Accumulated Amortization	(2,331,912)			(348,948)	(2,680,860)
Net Book Value	925,338	143,621		(348,948)	720,011
1925-Computer Software					
Gross Assets	4,395,971	938,835			5,334,806
Accumulated Amortization	(2,539,512)			(856,415)	(3,395,927)
Net Book Value	1,856,459	938,835		(856,415)	1,938,879

Capital Asset Continuity Statements

** Asset retirements and other changes*	2007 Balance	2008 Changes Additions	Ret./Other *	Amortization	2008 Balance
1930-Transportation Equipment					
Gross Assets	3,393,723	504,440	(504,979)		3,393,184
Accumulated Amortization	(2,515,885)		309,940	(177,184)	(2,383,129)
Net Book Value	877,838	504,440	(195,039)	(177,184)	1,010,055
1935-Stores Equipment					
Gross Assets	80,604				80,604
Accumulated Amortization	(48,905)			(6,218)	(55,123)
Net Book Value	31,699			(6,218)	25,481
1940-Tools, Shop and Garage Equipment					
Gross Assets	692,307	38,763			731,070
Accumulated Amortization	(530,545)			(26,233)	(556,778)
Net Book Value	161,762	38,763		(26,233)	174,292
1945-Measurement and Testing Equipment					
Gross Assets	229,399				229,399
Accumulated Amortization	(203,560)			(3,527)	(207,087)
Net Book Value	25,839			(3,527)	22,312
1950-Power Operated Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1955-Communication Equipment					
Gross Assets	160,396				160,396
Accumulated Amortization	(130,942)			(5,592)	(136,534)
Net Book Value	29,454			(5,592)	23,862
1960-Miscellaneous Equipment					
Gross Assets	784,532	50,506			835,038
Accumulated Amortization	(562,211)			(47,276)	(609,487)
Net Book Value	222,321	50,506		(47,276)	225,551

Capital Asset Continuity Statements

** Asset retirements and other changes*

	2007 Balance	2008 Changes Additions	Ret./Other *	Amortization	2008 Balance
1965-Water Heater Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1970-Load Management Controls - Customer Premises					
Gross Assets	464,917				464,917
Accumulated Amortization	(442,592)			(13,112)	(455,704)
Net Book Value	22,325			(13,112)	9,213
1975-Load Management Controls - Utility Premises					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1980-System Supervisory Equipment					
Gross Assets	1,201,410				1,201,410
Accumulated Amortization	(596,035)			(48,054)	(644,089)
Net Book Value	605,375			(48,054)	557,321
1985-Sentinel Lighting Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1990-Other Tangible Property					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1995-Contributions and Grants - Credit					
Gross Assets	(3,688,645)	(581,752)			(4,270,397)
Accumulated Amortization	632,558			154,553	787,111
Net Book Value	(3,056,087)	(581,752)		154,553	(3,483,286)

Capital Asset Continuity Statements

** Asset retirements and other changes*	2007	2008 Changes			2008
	Balance	Additions	Ret./Other *	Amortization	Balance
2005-Property Under Capital Leases					
Gross Assets					
Accumulated Amortization					
Net Book Value					
TOTAL					
Gross Assets	**85,838,913**	**4,558,147**	**(504,979)**		**89,892,081**
Accumulated Amortization	**(48,211,936)**		**309,940**	**(4,045,269)**	**(51,947,265)**
Net Book Value	**37,626,977**	**4,558,147**	**(195,039)**	**(4,045,269)**	**37,944,816**

Capital Asset Continuity Statements

* Asset retirements and other changes	2008 Balance	2009 Changes Additions	Ret./Other *	Amortization	2009 Balance
1805-Land					
Gross Assets	445,817				445,817
Accumulated Amortization					
Net Book Value	445,817				445,817
1806-Land Rights					
Gross Assets	283,160				283,160
Accumulated Amortization	(263,767)			(14,292)	(278,059)
Net Book Value	19,393			(14,292)	5,101
1808-Buildings and Fixtures					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1810-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1815-Transformer Station Equipment - Normally Primary above 50 kV					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	5,636,213	130,491			5,766,704
Accumulated Amortization	(2,783,631)			(141,591)	(2,925,222)
Net Book Value	2,852,582	130,491		(141,591)	2,841,482

Capital Asset Continuity Statements

** Asset retirements and other changes*	2008 Balance	2009 Changes Additions	Ret./Other *	Amortization	2009 Balance
1830-Poles, Towers and Fixtures					
Gross Assets	1,208,153	733,494			1,941,647
Accumulated Amortization	(70,539)			(62,282)	(132,821)
Net Book Value	1,137,614	733,494		(62,282)	1,808,826
1835-Overhead Conductors and Devices					
Gross Assets	26,137,702	1,109,429			27,247,131
Accumulated Amortization	(14,878,813)			(853,578)	(15,732,391)
Net Book Value	11,258,889	1,109,429		(853,578)	11,514,740
1840-Underground Conduit					
Gross Assets	146,974	96,978			243,952
Accumulated Amortization	(7,213)			(7,704)	(14,917)
Net Book Value	139,761	96,978		(7,704)	229,035
1845-Underground Conductors and Devices					
Gross Assets	18,759,860	570,078			19,329,938
Accumulated Amortization	(9,982,992)			(728,401)	(10,711,393)
Net Book Value	8,776,868	570,078		(728,401)	8,618,545
1850-Line Transformers					
Gross Assets	13,073,086	445,502			13,518,588
Accumulated Amortization	(7,140,864)			(522,231)	(7,663,095)
Net Book Value	5,932,222	445,502		(522,231)	5,855,493
1855-Services					
Gross Assets	282,505	163,459			445,964
Accumulated Amortization	(11,686)			(14,360)	(26,046)
Net Book Value	270,819	163,459		(14,360)	419,918
1860-Meters					
Gross Assets	6,999,687	698,030			7,697,717
Accumulated Amortization	(4,167,304)			(248,155)	(4,415,459)
Net Book Value	2,832,383	698,030		(248,155)	3,282,258

Capital Asset Continuity Statements

* Asset retirements and other changes	2008	2009 Changes			2009
	Balance	Additions	Ret./Other *	Amortization	Balance
1905-Land					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1906-Land Rights					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1908-Buildings and Fixtures					
Gross Assets	4,637,699	1,067,317			5,705,016
Accumulated Amortization	(1,710,123)			(73,139)	(1,783,262)
Net Book Value	2,927,576	1,067,317		(73,139)	3,921,754
1910-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1915-Office Furniture and Equipment					
Gross Assets	719,927	4,036			723,963
Accumulated Amortization	(592,728)			(29,182)	(621,910)
Net Book Value	127,199	4,036		(29,182)	102,053
1920-Computer Equipment - Hardware					
Gross Assets	3,400,871	465,762			3,866,633
Accumulated Amortization	(2,680,860)			(360,020)	(3,040,880)
Net Book Value	720,011	465,762		(360,020)	825,753
1925-Computer Software					
Gross Assets	5,334,806	2,167,170			7,501,976
Accumulated Amortization	(3,395,927)			(1,082,787)	(4,478,714)
Net Book Value	1,938,879	2,167,170		(1,082,787)	3,023,262

Capital Asset Continuity Statements

* Asset retirements and other changes	2008 Balance	2009 Changes Additions	Ret./Other *	Amortization	2009 Balance
1930-Transportation Equipment					
Gross Assets	3,393,184	565,599	(230,139)		3,728,644
Accumulated Amortization	(2,383,129)		230,139	(200,330)	(2,353,320)
Net Book Value	1,010,055	565,599		(200,330)	1,375,324
1935-Stores Equipment					
Gross Assets	80,604				80,604
Accumulated Amortization	(55,123)			(48,254)	(103,377)
Net Book Value	25,481			(48,254)	(22,773)
1940-Tools, Shop and Garage Equipment					
Gross Assets	731,070	68,473			799,543
Accumulated Amortization	(556,778)			(29,590)	(586,368)
Net Book Value	174,292	68,473		(29,590)	213,175
1945-Measurement and Testing Equipment					
Gross Assets	229,399				229,399
Accumulated Amortization	(207,087)			(3,527)	(210,614)
Net Book Value	22,312			(3,527)	18,785
1950-Power Operated Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1955-Communication Equipment					
Gross Assets	160,396				160,396
Accumulated Amortization	(136,534)			(8,987)	(145,521)
Net Book Value	23,862			(8,987)	14,875
1960-Miscellaneous Equipment					
Gross Assets	835,038				835,038
Accumulated Amortization	(609,487)			(50,873)	(660,360)
Net Book Value	225,551			(50,873)	174,678

Capital Asset Continuity Statements

** Asset retirements and other changes*	2008 Balance	2009 Changes Additions	Ret./Other *	Amortization	2009 Balance
1965-Water Heater Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1970-Load Management Controls - Customer Premises					
Gross Assets	464,917				464,917
Accumulated Amortization	(455,704)			(11,739)	(467,443)
Net Book Value	9,213			(11,739)	(2,526)
1975-Load Management Controls - Utility Premises					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1980-System Supervisory Equipment					
Gross Assets	1,201,410				1,201,410
Accumulated Amortization	(644,089)			(48,054)	(692,143)
Net Book Value	557,321			(48,054)	509,267
1985-Sentinel Lighting Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1990-Other Tangible Property					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1995-Contributions and Grants - Credit					
Gross Assets	(4,270,397)	(727,190)			(4,997,587)
Accumulated Amortization	787,111			180,967	968,078
Net Book Value	(3,483,286)	(727,190)		180,967	(4,029,509)

Capital Asset Continuity Statements

** Asset retirements and other changes*	2008 Balance	2009 Changes Additions	Ret./Other *	Amortization	2009 Balance
2005-Property Under Capital Leases					
Gross Assets					
Accumulated Amortization					
Net Book Value					
TOTAL					
Gross Assets	**89,892,081**	**7,558,628**	**(230,139)**		**97,220,570**
Accumulated Amortization	**(51,947,265)**		**230,139**	**(4,358,109)**	**(56,075,235)**
Net Book Value	**37,944,816**	**7,558,628**		**(4,358,109)**	**41,145,335**

Question 3.2 - Capital Program Increase

Ref: Exhibit 2/Tab 3/Schedule 1

In this Schedule, Bluewater lays out its actual capital additions for the year 2007 and its planned capital additions for 2008 and 2009. The size of the program increases considerably in 2009 from the 2008 level rising from $5.1 million in 2008 to $8.3 million in 2009.

Question 3.2 (a)

Please provide the breakdown for each of 2006 through 2009 showing the total of capital expenditures that are "one-time programs" vs. "ongoing programs".

3.2 (a) Response:

The Capital Schedule has been updated with 2006 actual data and is presented below. Bluewater has used the term 'Sustaining & Ongoing (S)' to represent "ongoing programs", and has used the term 'Non-routine (N)' to represent "one-time programs". Each project in the schedule is labelled with 'N' or 'S', and totalled.

ATTACHMENT: Board Staff 3.2.a.Capital Plan with 2006 Programs

BLUEWATER POWER CAPITAL PLAN BY PROJECT

Project ID	Project Name	Sustaining & Ongoing (S), Non-Routine (N)	2009 Budget	2008 Budget	2007 Actuals	2006 Actuals
	Operations/Design Services					
UT1	Furniture	N	-	2,000	2,000	1,024
UT2	Substation Building Improvement Program	S	106,970	60,000	37,732	37,144
UT3	27.6 Load Break Switch Replacement	N	48,940	50,000	47,555	39,991
UT4	Street Widening	S	53,274	60,000	12,833	16,664
UT5	27.6kV Neutral Program	N	146,820	40,000	24,512	41,202
UT6	Sub #2 Conversion - Phase III	N	-	100,000	48,208	108,221
UT7	27.6 Feeder - Petrolia Program	N	97,880	125,000	32,623	15,860
UT8	Alvinston/Oil Springs Capital Items	S	19,576	20,000	12,814	13,058
UT9	4KV Load Conversion	N	97,880	80,000	91,861	87,727
UT10	Pt Edward upgrades	S	48,940	40,000	47,610	26,258
UT11	Tools	S	44,000	20,000	22,417	18,826
UT12	Vehicle Replacements	S	528,000	450,000	261,891	197,841
UT13	New Connections	S	978,799	800,000	1,166,879	877,619
UT14	Strategic Transformer Inventory	S	163,485	150,000	232,686	175,740
UT15	5kV Protective Relay Replacement	N	81,940	80,000	52,354	49,541
UT16	Safety Related Projects	S	11,000	5,000	6,884	6,718
UT17	Cross Arm/Cap & Pin Insulator Replacement	S	97,880	80,000	72,047	32,437
UT18	Wood Pole Replacement Program	S	97,880	100,000	108,219	111,054
UT19	Transformer Replacements (PCB Units)	N	-	50,000	94,146	79,993
UT20	SCADA Projects	N	-	10,000	17,954	21,652
UT21	27.6kV Lines Upgrades	N	97,880	100,000	102,828	99,522
UT22	Perch DS Conversion	N	-	-	68,958	110,154
UT23	Watford	S	77,334	30,000	31,357	19,114
UT24	Load Balancing	S	47,425	20,000	17,542	10,753
UT25	CEO Contingency Fund	S	212,425	200,000	194,899	130,280
UT26	Fault Indicators - Underground	N	18,970	20,000	15,984	16,017
UT27	Manhole Structure Re-builds	N	51,970	30,000	20,700	5,589
UT28	Service Centre	S	53,485	97,000	87,112	132,799
UT29	Animal Protection	N	103,940	50,000	22,421	23,587
UT30	Overhead Line - Back Lot Rebuild	N	97,880	80,000	62,556	
UT31	18M11 Recloser	N	-	-	4,951	
UT32	27.6 Kv Feeder Extensions	N	122,350	150,000	-	
UT33	Reclosers (other types)	N	-	-	129,336	
UT34	8 kv Load Conversion	N	73,410	50,000	32,140	17,773
UT35	Transformer Cover Replacements	S	24,470	20,000	24,157	19,513
UT36	Harbour Rd. & Seaway Rd. Upgrades	N	-	-	71,561	
UT37	Vault 'K'-Riser installation	N	-	-	40,362	
UT38	Storm Restoration	S	146,820	150,000	67,594	
UT39	Remote Load Break Switches	N	75,880	60,000	-	
UT40	Asset Condition Assessment	N	163,485	-	-	
UT41	Elimination of Load Transfers	N	-	150,000	-	
UT42	Cyme Gateway	N	-	100,000	-	
UT43	Management Labour	S	-	194,000	-	
UT44	Substation Transformer #9 Replacement	N	126,137	-	-	115,491
UT45	Geographical Information System (GIS)	N	160,189	-	-	3,116
UT46	Substation Cable Replacement Program	N				54,911
UT47	27.6 Lightening Prtotection Program	N				24,322
UT48	Fault Indicators - Overhead Lines	N				9,673
UT49	Primary Underground Cable Replacement	N				16,379
UT50	Construction Equipment	N				59,222
	Total Operations/Design Services		**4,277,313**	**3,823,000**	**3,387,683**	**2,826,785**
		S	**2,711,762**	**2,496,000**	**2,404,673**	**1,825,819**
		N	**1,565,550**	**1,327,000**	**983,010**	**1,000,966**
			4,277,313	**3,823,000**	**3,387,683**	**2,826,785**

Project ID	Project Name	Sustaining & Ongoing (S), Non-Routine (N)	2009 Budget	2008 Budget	2007 Actuals	2006 Actuals
	Metering					
M1	Single Phase Meters	S	96,706	100,000	114,558	78,827
M2	Poly Phase Meters	S	55,365	60,000	66,535	100,265
M3	St. Andrews Meter Upgrade	N	-	-	313,813	0
M4	New Meters	S	27,500	20,000	19,321	7,816
M5	Traffic Room Organization	N	-	-	3,736	
M6	Metering Tools	S	6,600	5,000	3,881	6,850
M7	Trans Station Meter Upgrade - Modeland	N	525,074	-	-	
	Total Metering		**711,245**	**185,000**	**521,844**	**193,759**
		S	**186,171**	**185,000**	**204,295**	**193,759**
		N	**525,074**	**-**	**317,549**	**-**
			711,245	**185,000**	**521,844**	**193,759**
	Information Technology					
IT1	Corporate IT Security	S	48,462	40,000	37,069	29,513
IT2	Customer Self-Service	N	-	-	12,780	
IT3	Data Centre Lifecycle	S	265,379	202,500	212,938	198,939
IT4	Deloitte/SAP AMO	S	-	144,000	70,483	183,150
IT5	Computer Infrastructure Lifecycle	S	118,777	60,000	58,741	81,402
IT6	Recurring Systems Developments & Enhancements	S	60,267	100,000	125,228	61,970
IT7	Legislated Business Application Upgrades	S	198,625	140,000	76,113	144,827
IT8	Software-Upgrades and Additions	S	107,036	75,000	74,172	5,061
IT9	GIS Developments	S	-	2,500	-	
IT10	Microsoft SQL	N	-	-	37,503	
IT11	Server OS Upgrades	N	-	-	24,826	
IT12	Blackberry	N	-	-	20,756	
IT13	SAP Performance Optimization	N	-	-	1,478	
IT14	GIS - (Various)	N		-	24,822	1,133
IT15	Data Backup and Restore	S	-	47,000	-	
IT16	Document Management	S	15,018	37,000	-	
IT17	IT Management Tools	S	-	45,000	-	
IT18	SAP Upgrade	N	1,445,145	-	-	
IT19	Data Center Network Lifecycle Replacement	N	173,036	-	-	
IT20	IT Office Updates	N				1,252
IT21	MV-90xi	N				34,798
IT22	Photocopiers	N				33,883
	Total Information Technology		**2,431,744**	**893,000**	**776,909**	**775,928**
		S	**813,563**	**893,000**	**654,744**	**704,861**
		N	**1,618,180**	**-**	**122,165**	**71,067**
			2,431,744	**893,000**	**776,909**	**775,928**
	Other Projects					
O1	Other Projects (all below $100,000)	N	2,202	53,900	144,239	46,003
O5	Building Renovations/Expansion	N	863,315	185,000	28,154	
	C&DM - Third Tranche projects	N				255,415
	Total Other Projects	**N**	**865,517**	**238,900**	**172,393**	**301,417**
	Grand Total		**8,285,818**	**5,139,900**	**4,858,829**	**4,097,889**
		S	**3,711,497**	**3,574,000**	**3,263,712**	**2,724,438**
		N	**4,574,321**	**1,565,900**	**1,595,117**	**1,373,450**
			8,285,818	**5,139,900**	**4,858,829**	**4,097,889**

The projects highlighted are discussed at Exhibit 2, Tab 3, Schedule 6 - Materiality Analysis on Capital Additons.

Question 3.2 (b)

Please provide an overview of why Bluewater believes that such a large increase in its capital program is justified in 2009 in light of the considerably lower CAPEX levels in the 2007/2008 period.

3.2 (b) Response:

The increase in CAPEX from 2008 to 2009 of $3.7M is primarily driven by three one-time non-routine capital investments. Those three projects are justified individually in Exhibit 2, Tab 3, Schedule 6.

Each of those three capital projects can generally be described as non-discretionary, except perhaps as to timing. Therefore, we will address those projects in more detail in answer to question 3.2(c) below which inquires as to the possibility of phasing capital projects.

Apart from those one-time increases, CAPEX is relatively constant for Sustaining Capital Investments. Looking to Exhibit 2, Tab 3, Schedule 1, Attachment 1, the breakdown of CAPEX across the utility broken down by sustaining and non-routine is as follows:

	2006	2007	2008	2009
Sustaining Capital Investments	$2,724,438	$3,263,712	$3,574,000	$3,711,497
Non-Routine Capital Investments	$1,373,450	$1,595,117	$1,565,900	$4,574,321
TOTAL	$4,097,889	$4,858,829	$5,139,900	$8,285,818

The chart demonstrates that Non-Routine Capital Investments have been fairly consistent at approximately $1.5M, until 2009 driven by the three capital projects discussed below.

The chart also demonstrates relatively stable spending in Sustaining Capital Investments. Sustaining Capital Investments are forecast to increase by approximately $448,000 from 2007 to 2009. This increase reflects a general increase in the cost of doing business (both materials and labour), as well as the introduction of new sustaining capital programs or increased spending on existing sustaining capital programs during the 2007-2009 period. For example:

- Substation Building Improvement Program (UT2) [Exhibit 2, Tab 3, Schedule 6, Page 4]: Bluewater Power typically spends $37,000/year on this program. However in 2009 Bluewater Power proposed to increase spending to $106,970 to repair two substations with deteriorating exteriors.

- Vehicle Replacements (UT12) [Exhibit 2, Tab 3, Schedule 6, Pages 5-9]: 2009 expenditures on this program are forecast to increase from the 2007 spending level due to the need to replace or purchase specific vehicles. Justification for each vehicle required is set out in the evidence.

- Storm Restoration (UT38) [Exhibit 2, Tab 3, Schedule 6, Page 17]: Proposed spending in 2008 and 2009 is higher than 2007 based on weather patterns experienced in 2008, as explained in the evidence.

Question 3.2 (c)

Please discuss the extent to which Bluewater considered a phased approach to its capital program and if a phased approach was considered, why it was not adopted. If a phased approach was not considered, please explain why not.

3.2 (c) Response:

Many of Bluewater Power's Non-Routine Capital Programs have been undertaken through a phased approach. In fact, of the 40 Non-Routine Capital Programs in 2009, 15 of those programs are part of a multi-year program.

In regard to the three Non-Routine Capital Programs that are the primary drivers for the increase in capital spending from 2008 to 2009, the phasing-in of those projects is discussed below:

(1) SAP upgrade IT-18

Software upgrades are inevitable regardless of the nature of the software. Support for Bluewater Power's current version (4.7) of SAP expires in 2010. Complicating the decision on timing is the upcoming Smart Meter implementation which must take place in 2010. Bluewater Power lacks the resources to carry out both upgrades, and delaying the upgrade until after 2010 would result in higher overall costs for Smart Meter.

If the suggestion of the question is that the SAP upgrade could be broken into phases, we do not believe that would be prudent. It is possible to perform a technical upgrade one year followed by a functional upgrade the next year. However, splitting the project into two phases would not be efficient; testing time would be doubled and overall costs would likely be 15% to 30% higher if broken into phases. The other consideration is that it would place a significant drain on internal staff that could be minimized with a full-implementation.

(2) Building Expansion - O5

The Building expansion is described at Exhibit 2, Tab 3, Schedule 6, pages 67-70 as a phased project involving five different phases. The expenditure contributing to CAPEX in 2009 is Phase II of that expansion, which involves the creation of six additional vehicle bays and equipment storage space. Consideration has been given to delaying Phase II outside of the test year, however, Bluewater Power believes that it would not be prudent to delay this investment. A very detailed discussion of efficiencies and costs savings to be achieved through the expansion is included in answer to VECC #6 and, more particular, VECC IR #10(d).

(3) Transmission Station Meter Upgrade – Modeland - M7

As explained at Exhibit 2, Tab 3, Schedule 6, Page 46, Hydro One agreed to allow Bluewater Power to keep its meters in Hydro One's Modeland Road transmission station until 2009. Upon removal, there must be uninterrupted metering in accordance with the IESO's Market Rules. Therefore, Bluewater Power must install metering installations outside the Modeland Road transmission station in 2009 in order to comply with the Market Rules. This project can not be phased-in.

<u>Question 3.2 (d)</u>

Please state why Bluewater believes that it has the capacity to complete such a large capital program in 2009. In this context, please provide an update as to where the 2008 capital program stands on a completion basis as of September 30, 2008. Please also discuss whether or not Bluewater anticipates having any carryover projects from 2008 and if so what their impact would be in 2009.

<u>3.2 (d) Response:</u>

See attachment named "Board Staff 3.2 d – Capital YTD Sep. 2008" which provides an update of our 2008 year to date capital project results.

Bluewater Power anticipates carrying forward UT 41 – Elimination of Load Transfers - $150,000 as all necessary documentation from Hydro One and the OEB is not expected to be in place until early 2009. We also anticipate carrying forward UT 30 Overhead Line – Back Lot Rebuild - $80,000 due to time constraints. Both are not expected to be accommodated within the 2009 capital projects.

The 2009 capital program is larger than previous years due to the following non-recurring projects:

M 7 – Transmission Station Meter Upgrade – Modeland $525,074

IT 18 – SAP Upgrade - $1,445,145

O 5 – Building Renovations/Expansion $863,315

Without these projects, the remaining capital projects are in-line with previous years and are expected to be completed in 2009. All three of these projects will be outsourced and managed externally. The only project with material capitalized labour is the SAP Upgrade, but the labour being capitalized is not the Operations Department but staff that are not typically involved in capital projects (ie. billing, CSR, Finance, Materials Management will all be involved in testing).

ATTACHMENT: Board Staff 3.2.d – Capital YTD Sept 2008

Bluewater Power Distribution Corporation
2008 Capital Expenditures Detail by Project
As of September 30, 2008

Project ID	Project Name	2008 Budget	2008 Actual	2008 Variance	Comments Regarding 2008 Project Status and/or Variance
UT 1	Furniture	2,000	1,123	877	Still underway.
UT 2	Substation Building Improvement Program	60,000	12,972	47,028	All building work currently underway.
UT 3	27.6 Load Break Switch Replacement	50,000	24,539	25,461	Projects are in progress
UT 4	Street Widening	60,000	18,151	41,849	Projects are ongoing.
UT 5	27.6kV Neutral Program	40,000	22,454	17,546	Project underway
UT 6	Sub #2 Conversion - Phase III	100,000	70,920	29,080	Project complete awaiting final invoicing
UT 7	27.6 Feeder - Petrolia Program	125,000	114,391	10,609	Project complete
UT 8	Alvinston/Oil Springs Capital Items	20,000	17,952	2,048	Alvinston work is complete. Oil Springs work is complete
UT 9	4KV Load Conversion	80,000	49,430	30,570	Projects underway, projects scheduled for Nov/Dec
UT 10	Pt Edward upgrades	40,000	14,122	25,878	Work orders have been issued. Work to be scheduled
UT 11	Tools	20,000	15,586	4,414	Tools on order
UT 12	Vehicle Replacements	450,000	451,898	(1,898)	Complete
UT 13	New Connections	800,000	520,683	279,317	Demand driven expenditures
UT 14	Strategic Transformer Inventory	150,000	153,786	(3,786)	Transformers to be purchased
UT 15	5kV Protective Relay Replacement	80,000	61,948	18,052	Scheduled for December
UT 16	Safety Related Projects	5,000	500	4,500	For safety related expenditures
UT 17	Cross Arm/Cap & Pin Insulator Replacement Program	80,000	39,062	40,938	Project underway, Multi- phase project
UT 18	Wood Pole Replacement Program	100,000	43,415	56,585	Project underway, Multi- phase project
UT 19	Transformer Replacements (PCB Units)	50,000	39,722	10,278	Complete, awaiting final costs
UT 20	SCADA Projects	10,000	6,550	3,450	Project is underway
UT 21	27.6kV Lines Upgrades	100,000	24,043	75,957	Work orders have been issued, work to be scheduled
UT 22	Perch DS Conversion	-	-	-	Not applicable
UT 23	Watford	30,000	1,664	28,336	Work orders issued, work to be scheduled
UT 24	Load Balancing	20,000	1,472	18,528	Project is on-going
UT 25	CEO Contingency Fund	200,000	126,050	73,950	CEO-approved unforeseen expenditures.
UT 26	Fault Indicators - Underground	20,000	11,334	8,666	Scheduled for Nov/Dec
UT 27	Manhole Structure Re-builds	30,000	20,405	9,595	In progress
UT 28	Service Centre	97,000	10,725	86,275	Roofing work currently underway and paving scheduled.
UT 29	Animal Protection	50,000	9,777	40,223	Project ongoing
UT 30	Overhead Line - Back Lot Rebuild	80,000	1,752	78,248	Project deferred
UT 31	Reclosers (18M11)	-	-	-	Not applicable
UT 32	27.6 Kv Feeder Extensions	150,000	141,120	8,880	Project is complete.
UT 33	Reclosers (other types)	-	-	-	Not applicable
UT 34	8 kv Load Conversion	50,000	28,824	21,176	Project complete, awaiting final costs
UT 35	Transformer Cover Replacements	20,000	3,065	16,935	Material ordered, to be scheduled
UT 36	Harbour Rd. & Seaway Rd. Upgrades	-	-	-	Not applicable
UT 37	Vault 'K'-Riser Installation	-	-	-	Not applicable
UT 38	Storm Restoration	150,000	62,628	87,372	As required
UT 39	Remote Load Break Switches	60,000	4,102	55,898	Work to be scheduled for December.
UT 40	Asset Condition Assessment	-	-	-	Not applicable
UT 41	Elimination of Load Transfers	150,000	-	150,000	Awaiting responses from Hydro One and the OEB. Work will not start until all documentation is in place. Will likely be a project for 2009.
UT 42	CYME Gateway	100,000	10,950	89,050	Project is underway, work to be completed by year end
UT 43	Management Labour	194,000	130,379	63,621	Management time that will be reallocated to specific projects at a later date.
	TOTAL OPERATIONS/DESIGN	**3,823,000**	**2,267,494**	**1,555,506**	

Bluewater Power Distribution Corporation 2008 Capital Expenditures Detail by Project As of September 30, 2008					
Project ID	**Project Name**	**2008 Budget**	**2008 Actual**	**2008 Variance**	**Comments Regarding 2008 Project Status and/or Variance**
M 1	Single Phase Meters	100,000	76,155	23,845	In progress
M 2	Poly Phase Meters	60,000	29,179	30,821	In progress
M 3	St. Andrews Meter Upgrade	-	-	-	not applicable
M 4	New Meters	20,000	-	20,000	In progress
M 5	Traffic Room Organization	-	-	-	not applicable
M 6	Metering Tools	5,000	608	4,392	In progress
	Total Metering	**185,000**	**105,942**	**79,058**	
IT 1	Corporate IT Security	40,000	34,844	5,156	Complete
IT 2	Customer Self-Service	-	-	-	not applicable
IT 3	Data Centre Lifecycle	202,500	106,236	96,264	Continues throughout the year
IT 4	Deloitte/SAP AMO	144,000	88,650	55,350	Continues throughout the year
IT 5	Computer Infrastructure Lifecycle	60,000	47,454	12,546	Continues throughout the year
IT 6	Recurring Systems Developments & Enhancements	100,000	130,153	(30,153)	Continues throughout the year
IT 7	Legislated Business Application Upgrades	140,000	9,104	130,896	Various projects in progress
IT 8	Software-Upgrades and Additions	75,000	24,266	50,734	Various projects in progress
IT 9	GIS Developments	2,500	670	1,830	Complete
IT 10	Microsoft SQL	-	-	-	not applicable
IT 11	Server OS Upgrades	-	-	-	not applicable
IT 12	Blackberry	-	-	-	not applicable
IT 13	SAP Performance Optimization	-	-	-	not applicable
IT 14	GIS - Various	-	-	-	not applicable
IT 15	Data Backup and Restore	47,000	3,035	43,965	Project in progress
IT 16	Document Management	37,000	9,722	27,278	Project in progress
IT 17	IT Management Tools	45,000	532	44,468	Project in progress
	TOTAL IT	**893,000**	**454,666**	**438,334**	
O 1	Other Projects (all below $100,000)	53,900	4,114	49,786	Various projects in progress
O 5	Building Renovations	185,000	185,000	-	Building renovations are complete
	Total Other	**238,900**	**189,114**	**49,786**	
	GRAND TOTAL	**5,139,900**	**3,017,216**	**2,122,684**	

Question 3.2 (e)

Please provide an explanation on the measures that Bluewater has taken or will undertake, e.g. use of tendering process and deploying the lowest bid contractor, negotiations with suppliers on purchase of material and equipment, etc. to execute capital program projects in the most cost-effective way. Please file any evidence that demonstrates Bluewater's effort in undertaking and implementing measures that would achieve cost savings for Bluewater's capital programs.

3.2 (e) Response:

Bluewater Power follows a disciplined purchasing approach that favours tendering as opposed to direct negotiations with preferred suppliers. This process generally achieves the best product at the best available price. In that regard, price is typically the primary driver, however, quality of product and ability to deliver the product on time are also significant considerations.

Bluewater Power has provided a summary of its purchasing policy at Exhibit 4, Tab 2, Schedule 8. We have also provided a list of some of our success stories in purchasing that have resulted in lower prices in answer to OEB Staff IR #1.3. That answer also speaks to an initiative to participate with the South-western Ontario Utility Buying Group, which is projected to achieve savings of $20,000 to $50,000 per year which will primarily benefit Capital Programs, if successful. With respect to those Capital Programs that will require outside consultants or service providers, we provide the following general description of the processes that will be put in place.

(1) IT18 - SAP Upgrade: This major project will be undertaken in accordance with a tender for services. Bluewater Power has identified five potential vendors. Our goal will be to tender this project in sufficient detail to allow vendors to provide reliable and reasonable fixed-price proposals. The tender will be awarded to the lowest priced vendor capable of demonstrating their ability to complete the project on time. The project will be managed by the successful proponent, but an internal team from IT, Customer Service, Finance, Purchasing and Operations will be assembled to ensure the project is closely monitored and managed.

(2) O5 - Building Expansion/Upgrade: The capital budget is based on the estimate provided by our third party architect. The building itself will be built under the direction of the architect, who will prepare and execute the tender, as well as evaluate the bids submitted. The project will be professionally managed by the architect to ensure there are limited opportunities for extras under the contract.

(3) M7- Meter: Bluewater Power has an existing Meter Service Provider. This particular provider was selected following discussions and negotiations with multiple parties. We have been pleased with service, safety and price. It is our intention to enter into negotiations with the MSP for the M7 capital project.

Question 3.3 - Capital Expenditure Forecasts

Ref: Exhibit 2/Tab 3/Schedule 1

Question 3.3

Please provide the CAPEX forecasts for 2010, 2011, and 2012.

3.3 Response:

Please see the attachment below.

Attachment: "Board Staff 3.3 – Capital 2010 to 2012"

Bluewater Power Distribution Corporation

OEB Question 3.3: Capital Expenditures Detail by Project - 2007 to 2012

Project Name	2007 Actuals	2008 Budget	2009 Budget	2010 Budget	2011 Budget	2012 Budget
OPERATIONS/DESIGN Services						
Furniture	2,000	2,000	-	2,000	2,000	2,000
Substation Building Improvement Program	37,732	60,000	106,970	100,000	100,000	100,000
27.6 Load Break Switch Replacement	47,555	50,000	48,940	50,000	50,000	50,000
Street Widening	12,833	60,000	53,274	40,000	40,000	40,000
27.6kV Neutral Program	24,512	40,000	146,820	150,000	-	-
Sub #2 Conversion - Phase III	48,208	100,000	-	-	-	-
27.6 Feeder - Petrolia Program	32,623	125,000	97,880	100,000	100,000	100,000
Alvinston/Oil Springs Capital Items	12,814	20,000	19,576	20,000	20,000	20,000
4KV Load Conversion	91,861	80,000	97,880	100,000	100,000	100,000
Pt Edward upgrades	47,610	40,000	48,940	40,000	50,000	50,000
Tools	22,417	20,000	44,000	25,000	25,000	25,000
Vehicle Replacements	261,891	450,000	528,000	450,000	450,000	450,000
New Connections	1,166,879	800,000	978,799	800,000	800,000	800,000
Strategic Transformer Inventory	232,686	150,000	163,485	150,000	150,000	150,000
5kV Protective Relay Replacement	52,354	80,000	81,940	50,000	-	-
Safety Related Projects	6,884	5,000	11,000	10,000	10,000	10,000
Cross Arm/Cap & Pin Insulator Replacement	72,047	80,000	97,880	120,000	120,000	120,000
Wood Pole Replacement Program	108,219	100,000	97,880	100,000	100,000	100,000
Transformer Replacements (PCB Units)	94,146	50,000	-	-	-	-
SCADA Projects	17,954	10,000	-	30,000	30,000	30,000
27.6kV Lines Upgrades	102,828	100,000	97,880	-	-	-
Perch DS Conversion	68,958	-	-	-	-	-
Watford	31,357	30,000	77,334	100,000	80,000	100,000
Load Balancing	17,542	20,000	47,425	25,000	25,000	25,000
CEO Contingency Fund	194,899	200,000	212,425	200,000	200,000	200,000
Fault Indicators - Underground	15,984	20,000	18,970	20,000	-	-
Manhole Structure Re-builds	20,700	30,000	51,970	30,000	-	-
Service Centre	87,112	97,000	53,485	50,000	50,000	60,000

Bluewater Power Distribution Corporation						
OEB Question 3.3: Capital Expenditures Detail by Project - 2007 to 2012						
Project Name	**2007 Actuals**	**2008 Budget**	**2009 Budget**	**2010 Budget**	**2011 Budget**	**2012 Budget**
Animal Protection	22,421	50,000	103,940	50,000	-	-
Overhead Line - Back Lot Rebuild	62,556	80,000	97,880	100,000	100,000	100,000
18M11 Recloser	4,951	-	-	-	-	-
27.6 Kv Feeder Extensions	-	150,000	122,350	125,000	150,000	150,000
Reclosers (other types)	129,336	-	-	-	-	-
8 kv Load Conversion	32,140	50,000	73,410	75,000	100,000	100,000
Transformer Cover Replacements	24,157	20,000	24,470	25,000	25,000	25,000
Harbour Rd. & Seaway Rd. Upgrades	71,561	-	-	-	-	-
Vault 'K'-Riser installation	40,362	-	-	-	-	-
Storm Restoration	67,594	150,000	146,820	150,000	150,000	150,000
Remote Load Break Switches	-	60,000	75,880	80,000	80,000	80,000
Asset Condition Assessment	-	-	163,485	150,000	150,000	200,000
Elimination of Load Transfers	-	150,000	-	-	-	-
Cyme Gateway	-	100,000	-	-	-	-
Management Labour	-	194,000	-	194,000	194,000	194,000
Substation Transformer #9 Replacement	-	-	126,137	-	-	-
Geographical Information System (GIS)	-	-	160,189	-	-	150,000
Primary Underground Cable Replacements	-	-	-	150,000	200,000	200,000
Remote Terminal Unit Upgrades	-	-	-	50,000	50,000	50,000
TOTAL OPERATIONS/DESIGN	**3,387,683**	**3,823,000**	**4,277,314**	**3,911,000**	**3,701,000**	**3,931,000**
Metering						
Single Phase Meters	114,558	100,000	96,706	100,000	100,000	100,000
Poly Phase Meters	66,535	60,000	55,365	60,000	60,000	60,000
St. Andrews Meter Upgrade	313,813	-	-	-	-	-
New Meters	19,321	20,000	27,500	25,000	25,000	25,000
Traffic Room Organization	3,736	-	-	-	-	-
Metering Tools	3,881	5,000	6,600	6,000	6,000	6,000

Bluewater Power Distribution Corporation						
OEB Question 3.3: Capital Expenditures Detail by Project - 2007 to 2012						
Project Name	**2007 Actuals**	**2008 Budget**	**2009 Budget**	**2010 Budget**	**2011 Budget**	**2012 Budget**
Trans Station Meter Upgrade - Modeland	-	-	525,074			
Total Metering	**521,844**	**185,000**	**711,245**	**191,000**	**191,000**	**191,000**
Information Technology						
Corporate IT Security	37,069	40,000	48,462	50,000	50,000	50,000
Customer Self-Service	12,780	-	-			
Data Centre Lifecycle	212,938	202,500	265,379	235,000	235,000	235,000
Deloitte/SAP AMO	70,483	144,000	-	150,000	150,000	150,000
Computer Infrastructure Lifecycle	58,741	60,000	118,777	100,000	100,000	100,000
Recurring Systems Developments & Enhanc.	125,228	100,000	60,267	100,000	100,000	100,000
Legislated Business Application Upgrades	76,113	140,000	198,625	155,000	155,000	155,000
Software-Upgrades and Additions	74,172	75,000	107,036	75,000	75,000	85,000
GIS Developments	-	2,500	-	-	-	-
Business Technology Improvements	-	-	-	100,000	100,000	100,000
Microsoft SQL	37,503	-	-	-	-	-
Server OS Upgrades	24,826	-	-	-	-	-
Blackberry	20,756	-	-	-	-	-
SAP Performance Optimization	1,478	-	-	-	-	-
GIS - (Various)	24,822	-	-	2,500	2,500	2,500
Data Backup and Restore	-	47,000	-	-	-	-
Document Management	-	37,000	15,018	-	-	-
IT Management Tools	-	45,000	-	-	-	-
SAP Upgrade	-	-	1,445,145	-	-	-
Data Center Network Lifecycle Replacement	-	-	173,036	-	-	-
TOTAL IT	**776,909**	**893,000**	**2,431,745**	**967,500**	**967,500**	**977,500**
Other Projects						
Other Projects (all below $100,000)	144,239	53,900	2,202	2,000	2,000	2,000
Building Renovations/Expansion	28,154	185,000	863,315	400,000	4,000,000	-

Bluewater Power Distribution Corporation						
OEB Question 3.3: Capital Expenditures Detail by Project - 2007 to 2012						
Project Name	**2007 Actuals**	**2008 Budget**	**2009 Budget**	**2010 Budget**	**2011 Budget**	**2012 Budget**
Total Other	**172,393**	**238,900**	**865,517**	**402,000**	**4,002,000**	**2,000**
Grand Total	**4,858,828**	**5,139,900**	**8,285,821**	**5,471,500**	**8,861,500**	**5,101,500**

Question 3.4 - CEO Contingency Fund

Ref: Exhibit 2/Tab 3/Schedule 1/Attachment 1
Exhibit 2/Tab 3/Schedule 6, p.16

In Exhibit 2/Tab 3/ Schedule 1/Attachment 1, Bluewater makes reference to Project UT25 "CEO Contingency Fund" for which an expenditure of $212,425 is budgeted in 2009.

In Exhibit 2/Tab 3/Schedule 6, p.16, it is stated that:

"The CEO Contingency Fund has been created to capture unforeseen capital costs that arise during the course of the year that require an immediate response. The fund has been used, for example, to make major repairs to power line vehicles that have been required within the budget year. The budget has also been utilized to purchase job-specific equipment that has been required within the budget year.

Having the contingency fund has allowed the Bluewater Power senior management team to provide more conservative and accurate capital budget figures during the annual budget processes knowing that funds for unforeseen expenditures can be accessed with the approval from the President and CEO. The fund was utilized almost in its entirety in 2007 and is on track to be fully utilized in 2008"

Question 3.4 (a)

Please provide a full justification as to why the CEO Contingency Fund was created including an explanation as to how contingencies were dealt with in Bluewater's planning process before the CEO Contingency Fund was created and what motivated the decision by Bluewater management to adopt this approach.

3.4 (a) Response:

The CEO Contingency Fund allows for a budgeted allotment of funds for prudent Capital Projects which are unplanned and yet invariably arise during the calendar year. This fund allows for better cash and financial planning for the calendar year. Bluewater Power has always historically had projects "come up" during the year which are not foreseen at budget time. Prior to the creation of the CEO Contingency Fund these projects would still proceed as required but as an "unbudgeted expenditure". To budget for the contingency allows a more accurate cash, rate base and capital forecast for the year. Although not an item which exceeds Bluewater Power's materiality threshold, the contingency fund represents approximately 2.5% of the total budget for 2009, this fund has resulted in an improved budget planning process.

Question 3.4 (b)

Please state why Bluewater believes that the contingency fund allows the senior management team to, as stated above, "provide more conservative and accurate figures during the annual budget processes". Please provide copies of any internal assessments that may have been undertaken that would support this statement.

3.4 (b) Response:

The contingency fund allows for more accurate budgeting during the annual forecast process for two main reasons:

i. There is no need for a "contingency" to be built into other individual budget project/areas to ensure capital is available during the year.

ii. Bluewater Power can more accurately forecast cash levels and thus financing requirements by incorporating an allowance for the unforeseen projects.

Question 3.5 - Vehicle Replacements

Ref: Exhibit 2/Tab 3/Schedule 1/Attachment 1

Exhibit 2/Tab 3/Schedule 6, pp. 5-9

In Exhibit 2/Tab 3/Schedule 1/Attachment 1, Bluewater states that it expects to incur expenditures of $528,000 in 2009 on Project UT12 "Vehicle Replacements." This proposed expenditure follows similar expenditures on vehicle replacement of $450,000 in 2008 and $261,891 in 2007.

On Page 5 of Exhibit 2/Tab 3/Schedule 6, Bluewater states that:

"Bluewater Power works from a five year capital plan to prepare for vehicle budgeting. For the purpose of large fleet vehicles a team comprised of users, a mechanic and a management supervisor is created to review the products of different manufacturers and request estimated costs early in a budget year. Following budget approval from the Bluewater Power Board of Directors the team moves into deeper analysis, utilizing demonstration vehicles, visiting and discussing reliability, warrantee response and overall vehicle satisfaction with other LDCs who have purchased similar equipment.

The Materials Management Department prepares an RFP based on team results and sends it out to the chosen manufacturers who have met the desired vehicle criteria. The contract is awarded based on the manufacturer meeting the required specifications, cost and overall support from the team"

Question 3.5 (a)

Please provide the referenced "five year capital plan to prepare for vehicle budgeting."

3.5 (a) Response:

The five year capital plan is a schedule which lists the vehicles that are targeted to be replaced in the following year. The attached schedule includes the planned and actual purchases from 2005 to the 2009 projection.

ATTACHMENT: Board Staff 3.5.a.Vehicle Plan

Bluewater Power Fleet Five Year Capital Plan

Year	Vehicle Number	Department	Description	Comment	Forecast Cost	Actual Cost	Total Forecasted Cost	Total Actual Annual Cost
2005	39	Client Services	2005 Echo	New Vehicle	$ 20,000	$ 18,338	$ 281,000	$ 302,413
	5	Operations	2006 Chrysler Van	Replacing 1997 Chev Van	$ 21,000	$ 20,531		
	11	Operations	2005 Bucket Truck	Replacing 1994 Bucket	$ 240,000	$ 263,544		
2006	4	Operations	New Van	Replacing 1994 Dodge 150 Van	$ 28,000	$ 21,134	$ 199,000	$ 197,841
	1	Engineering	2001 Dodge Pickup	Move from Engineering to Operations to replace #9	$ -	$ -		
	9	Operations	1998 GMC 4 X 4	Replaced by 2001 Dodge from Engineering Dept.	$ -	$ -		
	10	Engineering	1995 Ford Van	Sell & replace with subcompact - sold, not replaced	$ 25,000	$ 23,310		
	6	Engineering	1994 Chevrolet Passenger Van	Replace with Car or Sub-compact	$ 28,000	$ 23,310		
	14	Operations	2002 Ford F150		$ -	$ 26,973		
	20	Operations	1999 Ford Pickup	Trade in	$ 45,000	$ 36,231		
	32	Client Services	1995 Chevrolet Pickup	Replace	$ 28,000	$ 22,550		
	34	Operations	1999 Ford Pickup	Trade in-cancelled	$ 45,000	$ -		
	65	Operations	2006 Ford F150 Pickup	Replace 34 that went to civil crew	$ -	$ 25,419		
	66	Operations	2005 Chevrolet Pickup	New vehicle	$ -	$ 18,915		
2007	27	Meter Services	1995 Dodge Van	Replace	$ 30,000	$ 19,813	$ 291,891	$ 278,631
	47	Operations	2007 Trailer		$ -	$ 16,740		
	48	Operations	2007 Dump Trailer		$ 10,041	$ 9,563		
	67	Operations	2007 Freightliner		$ 243,210	$ 223,874		
	69	Operations	2007 Kubota lawn mower		$ 8,640	$ 8,640		
2008	33	Operations	1998 Bucket	Replace-improved instead	$ 200,000	$ -	$ 650,000	$ 451,898
	70	Meter Services	2007 Ford Focus Wagon		$ 25,000	$ 16,263		
	18	Operations	1994 Freightliner double bucket	Replace	$ 425,000	$ 435,634		
2009		Operations	2000 Freightliner	Replace	$ 286,000		$ 528,000	$ -
		Meter Services	1995 Dodge Van	Replace	$ 27,500			
		Service Rep	2000 Dodge Van	New Vehicle	$ 27,500			
		Engineering	2001 Dodge Pickup	Replace	$ 22,000			
		Operations	Combo Boom/Dump Truck	New Vehicle	$ 165,000			

<u>Question 3.5 (b)</u>

Please provide Bluewater's level of capital expenditures on vehicle replacement for the 2001 to 2006 period.

<u>3.5 (b) Response:</u>

Year	Fleet Purchases
2001	$ 57,826
2002	$ 5,055
2003	$ 47,756
2004	$ 240,000
2005	$ 302,271
2006	$ 197,841

Question 3.5 (c)

Please provide any quantitative analyses that were undertaken that support the proposed 2008 and 2009 level of expenditures on vehicle replacements.

3.5 (c) Response:

The information provided at Exhibit 2, Tab 3, Schedule 6, Pages7-9 does contain quantitative analyses. For vehicle replacements, forecasting end-of-useful-life is based on quantitative analysis such as age of vehicle, number of kilometres, number of engine hours and number of PTO (Power Take Off) hours. When a vehicle reaches end-of-useful-life, further maintenance investment is not cost effective, driver safety is jeopardized and the vehicle reliability is questionable.

In summary Bluewater Power considers all of the following qualitative and quantitative factors when preparing long range forecasts to replace fleet vehicles:

Small Fleet

1 - The age of the vehicle and associated maintenance costs are taken into consideration. Bluewater Power maintains a comprehensive data base to track all maintenance efforts for each vehicle.

2 – Vehicle mileage is another consideration. For example the vehicle used for the 24/7 Stand-By is replaced more frequently given the high mileage.

3– Fuel efficiency has been a goal in Bluewater Power fleet. Bluewater Power's fleet database allows tracking of fuel economy for all vehicles. As a result Bluewater Power has made a concerted effort to move from pick-up trucks to compact and sub compact cars depending on the job requirement. As a result of these actions Bluewater Power witnessed a savings of approximately $20,000 in fuel during 2008 from a fleet of 4 Toyota Echo's, 2 Pontiac Vibes, 2 Ford Focus, 1 Mercedes Smart car over pickup trucks that would have been purchased prior to this fuel efficiency initiative. Additionally, there were substantial savings from lower capital costs on the compact vehicles.

4 – Bluewater Power purchases used vehicles instead of new which leads to additional cost savings. Bluewater Power started purchasing small vehicles being returned from one year lease agreements in 2007. We were able to get almost full warranty coverage and substantial savings off list price for similar new vehicles. To date we have purchased 1 Ford ½ ton, 1 Chev 1/2 ton, two Ford Focus. We have estimated savings of $40,000 from list price. We have experienced no mechanical problems.

Bluewater Power's efforts to curb idling, to reduce the size of our small fleet and save on fuel costs was a key element in receiving the EDA "Environmental Excellence Award" in 2005.

Large Fleet

1 - Safety – Truck design and the right truck for the right job are important factors in determining timing for truck purchases and the required specifications. As an example, Bluewater Power experience a boom failure in 2008 (lease see photo attached below). No known cause has been established by the manufacturer for the boom failure other than it was not operator error; fortunately, no one was injured. The truck had all necessary inspections and data sheets. The boom in the photo was versatile and used in a number of work situations and we had contemplated replacing the truck one year earlier due to the heavier than normal work load, and the high number of Power Take Off ("PTO"). This incident reinforces the importance of design, good documentation and a solid multiyear program to replace aerial devises. Number of km and age is not always the key indicator of when the vehicle needs to be replaced, so the number of hours, work load, working conditions, etc. are relied upon as well.

2 - The age of the vehicle, road miles, engine hours and associated maintenance costs. Bluewater Power has a comprehensive data base to track all maintenance items.

3– Annual testing of aerial devices gives a historic trend. Historical trends will show if something is deteriorating quicker than expected. Trends also assist in making decisions on which vehicle needs to be replaced next.

Boom failure discussed above.

Question 3.5 (d)

Please provide a summary of the RFP process results leading to the 2008 and 2009 budgeted vehicle replacement amounts including the competing bids that were considered and how they were scored to determine the winning bidders.

3.5 (d) Response:

In 2008, Bluewater Power purchased two vehicles; a double bucket material handler and a station wagon with a total actual price of $451,898.

The bucket truck was purchased through an RFP process. The RFP was sent to three vendors well known in the industry, with one response. Consideration is always given to price, terms & conditions, quality, availability, specifications and service. The vendor who responded met all criteria and specifications provided for in the RFP, thus was selected.

Please see the attached RFP #432-07 for the 2008 vehicle purchase.

The RFP's for the projected 2009 vehicle purchases have not yet been issued. Further evidence on each proposed purchase is detailed in Exhibit 2, Tab 3, Schedule 6, page 8-9.

Attachment: Board Staff 3.5.d RFP

Bluewater Power Distribution Corporation
855 Confederation Street
PO Box 2140 Sarnia, ON N7T 7L6
Telephone: (519) 337-8201
Fax: (519) 332-3878

Request for Proposal
R.F.P. #432-07

This is not a Purchase Order
Information to Vendor

Vendor:

Please submit a proposal to furnish Bluewater Power with a new Tandem Axle 156" C.T. Heavy Duty Cab & Chassis with a Fiberglass Utility Line Body and a 83' Articulating over-center Aerial Device, with all of the necessary conversions, as described in the attached specifications, all in accordance with this Request for Proposal #432-07, including Bluewater Power technical specifications.

CLOSING DATE: Friday, October 5th, 2007

ALL REQUEST FOR PROPOSALS ARE SUBJECT TO THE TABLE OF CONTENTS BELOW

TABLE OF CONTENTS

The following sections marked with an "x" are part of this Request for Proposal:

Bill validity to be sixty (60) days from Proposal Closing Date.

Bluewater Power
By: Becky Bellavance

Document List

- Request for Proposal including:
  - Instructions to Vendors
  - Blank Proposal Form
  - General Terms and Conditions
  - Supplementary Terms and Conditions
  - Technical Specifications
  - Drawings as listed below

- Standard Drawings:

THE FOLLOWING IS A SUMMARY OF INFORMATION WHICH MUST ACCOMPANY THE COMPLETED BLANK PROPOSAL FORM:

- Copies of Insurance Certificates together with valid Clearance Certificates from the Workplace Safety and Insurance Board for Vendor and any proposed subcontractors
- Construction schedule
- List of proposed sub-contractors
- References and experience in this work

Instructions to Vendor

R.F.P. #431-06

Instructions to Vendor

1. Proposal Preparation

1.1 Proposals shall be submitted upon the blank proposal form contained herein as an **original.** Proposals shall be typewritten or written in ink. Proposals are solicited for the Scope of Work in its entirety. Exceptions and/or clarifications shall be covered in a separate letter attached to the base proposal. If exceptions are not itemized by the Vendor, it shall be assumed that the base proposal conforms in all respects with the proposal documents.

1.2 Each copy of the proposal shall contain information requested, together with sufficient supporting information and technical data to permit an understanding of the proposal.

1.3 Original proposal plus copies shall be submitted in a sealed envelope referring to Request for Proposal number at all times and addressed to:

Becky Bellavance, Materials Manager
Bluewater Power Distribution Corporation
855 Confederation Street, PO Box 2140
Sarnia, Ontario
N7T 7L6

**Note: Faxed or email proposals acceptable with original to follow within two (2) days of closing date.
Bluewater Power will not assume any responsibility for the receipt of faxed or email proposals.**

2. Signed Proposals

2.1 All proposals must be signed by Vendor's duly authorized signing authority.

3. Variations in Proposal Documents

3.1 The Vendor shall carefully examine the specifications and other documents incorporated with the Request for Proposal. Any errors, omissions, discrepancies or clauses requiring clarification shall be reported to Bluewater Power in writing not less than four (4) working days prior to the proposal closing date.

4. Proposal Acceptance

4.1 Bluewater Power reserves the right to accept any proposal and not necessarily the lowest proposal and to reject any or all proposals.

4.2 Bluewater Power reserves the right to award in whole or in part, by item, or class.

4.3 No commitment shall be made by Bluewater Power in respect of the proposal until such time that the Vendor receives written notification of acceptance from Bluewater Power Purchasing.

4.4 Proposals having any erasures or corrections therein may be rejected unless explained or noted over the signature of the Vendor.

4.5 Proposal evaluation will include the following criteria:

- the extent to which the proposal is appropriately received and details required are accurately submitted;
- the extent to which the proposal meets all mandatory requirements of this solicitation'
- deemed capabilities, understanding the requirements, integrity, reliability and financial stability of the supplier to meet the requirements of Bluewater Power;
- pricing;
- quality of product and samples (where requested) submitted;
- range and scope of services, resources, available to Bluewater Power;
- delivery, capabilities to ensure deadlines are met;
- quality of past performance, based of references;
- environmental responsibility;
- absence of both conflict of interest and potential or perceived conflict of interest.
- Each criterion above is listed randomly and does not necessarily reflect priority in the actual evaluation process.

4.6 Late proposals shall be returned unopened.

5. Documentation of Communication with Vendor

5.1 Purpose and Scope

The purpose of this clause is to identify the correspondents for this proposal package at Bluewater Power with the object of gaining maximum efficiency in communications.

5.2 Identification

All communications regarding this proposal package will show the Request for Proposal number.

5.3 Direction and Routing

All communications regarding Technical or Commercial matters will be addressed in writing only.
Our fax number for this purpose is (519)332-3878.

Commercial:	Technical:
Becky Bellavance (ext. 242)	Terry Warren (ext. 260)
Materials Manager	Mechanic

Email : bbellavance@bluewaterpower.com

Note: Bluewater Power will not be responsible for any verbal communications.

6. Freedom of Information

6.1 All proposals received will be subject to the regulations stated in the Freedom of Information and Protection of Privacy Act.

7. Ability and Experience

7.1 It is not the purpose of BPDC to award a contract to any Vendor who does not furnish satisfactory evidence that he has the ability and experience in this class of work, and that he has sufficient capital and plant to enable him to execute and complete the same successfully and to complete it in accordance with this Request for Proposal.

8. Site Inspection

8.1 Each Vendor shall make whatever arrangements are necessary to become fully informed regarding all existing and expected site conditions which could affect performance of the Work in any way. Submission of a proposal will constitute an acknowledgement by the Vendor of its awareness of the conditions to be encountered at the Site and of the requirements for performing the Work.

The Vendor shall conform with BPDC's requirements regarding permission, personnel access and safety while visiting the Site. BPDC assumes no responsibility for oral statements made during the Site Visit.

Vendors are advised that all personnel entering a BPDC construction site, must comply with site safety regulations which require a C.S.A. approved Hardhat, Safety Glasses and Workboots.

9. Vendor's Liability Insurance

See Supplementary Terms and Conditions.

10. Bonds

See Supplementary Terms and Conditions.

11. Prices

11.1 Price proposed on Blank Proposal Form must be firm for the duration of the contract.

12. Special Instructions

12.1 It is the Vendor's responsibility to provide a complete, detailed response to both the Commercial and Technical sections of this Request for Proposal that require the Vendor's direct input. Failure to address this completely may result in automatic disqualification. Bluewater Power will no longer accept the responsibility of advising the Vendor that the information provided by the Vendor is incomplete, nor will Bluewater Power advise the Vendor of any disqualification. Should the Vendor not fully understand the foregoing, contact with Bluewater Power shall be made via telephone. Arrangements will then be made the have the Vendor's project manager or qualified representative **and** the Vendor's estimator meet at the Bluewater Power site to clarify all areas of concern (the estimator must be present at any meetings). Vendor must copy Bluewater Power Purchasing on all Technical queries pertaining to this Request for Proposal.

Blank Proposal Form

R.F.P. #432-07

Blank Proposal Form

1. The successful Vendor shall perform the work as defined in the Request for Proposal Documents (herein referred to as the "work") and fulfill all other requirements of the work.

2. The Vendor hereby represents to Bluewater Power that it:

   2.1 has carefully examined the Request for Proposal Documents as listed in the Request for Proposal;

   2.2 has the resources, skills and abilities to perform the work in accordance with the stated requirements.

3. The Vendor understands and agrees that:

   3.1 Bluewater Power reserves the right to increase, decrease, delete or vary any portion of the work, and the Vendor agrees to comply with any such change in the work subject to valuation and adjustment as provided in the order.

   3.2 The quantities and/or values, if any, listed by Bluewater Power herein are estimates based upon historical information. No claim will be allowed for any loss of anticipated profits resulting from any excess or deficiency in the quantities/values shown.

   3.3 The Vendor represents and warrants to Bluewater Power that the several declarations and matters stated in this proposal are true and binding in all respects, and that this proposal has been compiled by the Vendor with full knowledge and understanding of all matters and things called for insofar as they relate to the Request for Proposal Documents.

Blank Proposal Form

DESCRIPTION: Please submit a proposal to furnish Bluewater Power with a new Tandem Axle 156" C.T. Heavy Duty Cab & Chassis with a Fiberglass Utility Line Body and a 83' Articulating over-center Aerial Device ,with all of the necessary conversions, all in accordance with this Request for Proposal #432-07, including Bluewater Power technical specifications (attached).

SCHEDULE: Preliminary, pre-order consultation with vendor (to be arranged immediately, following award of contract). On-site Inspection by BWP Mechanic/staff, to take place 3 – 4 times during assembly. Commence tentative with completion.

FIRM/FIXED
ADDENDA: Specify addendums included in Total Price (if applicable)
Addendum No. 1______; No. 2 ______; No. 3 ______; No. 4

Prices must be firm lump sum. P.S.T. & G.S.T. shown as Extra.

1. Cab & Chassis (as per attached specifications) $ _________
2. Fiberglass Utility Line Body

G.S.T. Applicable $ _________
P.S.T. Applicable $ _________

Total firm and binding price including all taxes and bonds and Addendums specified herein $ __________

I/we the undersigned, herewith agree to provide a new Tandem Axle 156" C.T. Heavy Duty Cab & Chassis with a Fiberglass Utility Line Body and a 83' Articulating over-center Aerial Device ,with all of the necessary conversions, all in accordance with this Request for Proposal #432-07, including all technical specifications and drawings and at the price and schedule stated herein.

Delivery Date of above: ________________________

Submitted by: (company name) ____

Name of Signing Officer: ____

Title: ____

Address: ____

Telephone: _______________________ Date: ______________________________

CLOSING DATE: Friday, October 5th, 2007

Signature of Signing Officer: ____

General Terms And Conditions

General Terms and Conditions

1. <u>Applicability</u>

1.1 Unless specifically stated to the contrary on the face of the purchase order, the terms and conditions contained in the order shall apply to all purchases by Bluewater Power Distribution Corporation ("BPDC") from the Vendor ("Vendor") of the goods and/or services which are the subject of the order. As used herein, the term "goods" shall mean and include goods or services or any combination thereof. As used herein, the term "order" shall mean and include the face of the purchase order, the within terms and conditions, any plans, specifications and other documents incorporated by reference on the face of the purchase order and such additional terms as are approved in writing by Bluewater Power Distribution Corporation. No understanding, agreement, term, condition or trade custom at variance with the order shall be binding on Bluewater Power Distribution Corporation. The order shall be deemed to be accepted by the Vendor upon Vendor's execution and return to Bluewater Power Distribution Corporation the attached acknowledgment copy of the order or by Vendor's shipment of some or all of the goods or, if the goods are specially manufactured for Bluewater Power Distribution Corporation, upon Vendor's commencement of the engineering, design, procurement or manufacture of the goods. Any proposal by Vendor for additional or different terms and conditions ("variation") shall be deemed an "immaterial alteration" of the order, in which event the order shall be deemed accepted by Vendor without such "variation" unless such "variation" is with respect to the description, quantity, price, or delivery schedule of the goods (collectively referred to herein as a "material alteration"), in which event the order shall be deemed rejected by Vendor unless Bluewater Power Distribution Corporation provides Vendor with prior written approval of such "material alteration."

2. <u>Change Orders</u>

2.1 Bluewater Power Distribution Corporation shall have the right, through the issuance of change orders, to make changes in the drawings, designs, specifications, time and place of delivery and method of shipment or packing with respect to the goods or in the quantity of goods to be delivered. No change order shall be effective unless authorized in writing by Purchasing Department. If any change order causes a material increase or decrease in Vendor's cost of, or the time required for, performance of the order, Vendor shall, within five (5) calendar days of receipt of such change order, notify Bluewater Power Distribution Corporation in writing of Vendor's request for an equitable adjustment of the terms of the order. In the event Bluewater Power Distribution Corporation and Vendor are unable, within twenty (20) days of Bluewater Power Distribution Corporation's receipt of such notice of

Request or such longer period as may be authorized in writing by Bluewater Power Distribution Corporation, to agree on the terms of such equitable adjustment, Vendor shall, if directed in writing by Bluewater Power Distribution Corporation, proceed diligently to comply such change order. Bluewater Power Distribution Corporation shall pay compensation in the amount of the sum of Vendor's direct, verifiable, out-of-pocket costs incurred, and reasonable profit margin earned, in connection with such change order.

3. Price

3.1 The price set forth in the order (the "Price") shall include all charges with respect to the purchase of the goods, including those for insurance, packing, boxing, cartage and storage, and freight, hauling and transportation to the point of delivery. All applicable taxes relating to the manufacture, sale and delivery of the goods should be quoted separately. Payment of the Price shall be due thirty (30) calendar days after the latest to occur of (a) the date of delivery, (b) the date of receipt of Vendor's invoice or (c) the date of settlement of any dispute or claim with respect to a material term of the order. Vendor agrees that any price reduction with respect to the goods made by Vendor for the benefit of other customers subsequent to the issuance of the order but prior to when payment is due hereunder will be applicable to the order. Vendor warrants that for a period of three (3) months prior to the date hereof, it has not offered goods similar to those purchased under the order to any other customer on terms more favourable to such customer than those contained herein.

4. Delivery

4.1 Time is of the essence with respect to any delivery or completion date set forth in the order (the "Specified Date"). Bluewater Power Distribution Corporation reserves the right to require the Vendor to alter its planned transportation methodology if, in the opinion of Bluewater Power Distribution Corporation, the specified date is jeopardized. All cost associated with this alteration shall be to the account of the Vendor. Without Bluewater Power Distribution Corporation's prior written consent, no delivery shall be made more than seven (7) calendar days prior to the applicable specified date. Any goods delivered at a time or in a manner not in accordance with the order may, at Bluewater Power Distribution Corporation's option, be returned to Vendor or stored by Bluewater Power Distribution Corporation and all costs incurred as a result thereof shall be at the expense of Vendor. Partial shipments by Vendor will not be accepted without prior written authorization by Bluewater Power Distribution Corporation. Unless otherwise set forth in the order, payments based on delivery or completion will not be made until all goods are delivered or completed.

In the event that a carrier specified in the order by Bluewater Power Distribution Corporation is not used by Vendor, all excess costs as a result thereof will be at the expense of the Vendor. Except for shipments sent by courier, billable freight must be accompanied by paid freight bills. Freight charges are subject to audit and payment at corrected rates.

5. Force Majeure

5.1 Neither Bluewater Power Distribution Corporation nor Vendor shall be liable to the other for loss, damage, delay in the work or nonperformance of any contractual obligation caused by war, riot, the act or order of any competent civil or military authority, fire, flood, strike, lockout or other labour dispute or by any other cause which is unavoidable and beyond the party's reasonable control. Both parties shall be prompt in restoring normal conditions, re-establishing schedules and resuming operations as soon as the interruptions have ceased. In the event of a situation of force majeure, Vendor shall give written notice and full particulars of the cause or causes thereof as soon as reasonably possible after the occurrence of any such cause. In no event shall Vendor be entitled to any increase in the price as a result of any event of force majeure.

6. Expediting

6.1 In order to ensure compliance with the Specified Date(s), Vendor acknowledges that the order is subject to expediting of all raw and finished materials by Bluewater Power Distribution Corporation or a third party designated by Bluewater Power Distribution Corporation at either Vendor's plant or Vendor's source of supply. Vendor shall note this provision on all purchase agreements it enters into with its Vendors. In the event that Vendor is unable or unwilling to expedite the material, Bluewater Power Distribution Corporation reserves the right to contact Vendor's source of supply to attempt to effect same.

7. Shipping Documents

7.1 Vendor shall at all times comply with all packaging, handling and storage procedures set forth in the order or, if such procedures are not so set forth, with the procedures customarily used in Vendor's industry, and shall, where necessary, tag the goods with Bluewater Power Distribution Corporation's part, matchmark or other identification set forth in attached and/or referenced drawings, specifications or bills of material. Unless otherwise provided in the order, Vendor shall (a) place on each package an itemized list of all components contained therein; (b) display Bluewater Power Distribution Corporation's order number on each such document. Vendor shall provide notice of shipment of the goods at least three (3) working days prior thereto.

8. Drawings and Data

8.1 Vendor shall supply drawings, manufacturing schedules, progress reports and other appropriate data by the dates specified in the order. Bill of material, part, matchmark, tag and/or I.D. numbers must appear on all documents, and final drawings shall be certified correct for the order. Bluewater Power Distribution Corporation reserves the right to withhold payments due under the order until all such drawings, schedules, reports and data have been received by Bluewater Power Distribution Corporation in proper form and quantity.

9. Drawing Review

9.1 Any review or comments on Vendor's drawings and/or specifications by Bluewater Power Distribution Corporation shall in no way relieve the Vendor of his responsibility for proper design and full compliance with all Purchase Order documents and shall in no way result in any responsibility on the part of Bluewater Power Distribution Corporation for adequacy or correctness of the Vendor's design.

10. Warranties

10.1 Vendor expressly warrants that (a) the goods shall be: new, merchantable, fit and suitable for the purposes expressed in, or reasonably inferred from, the description of the goods set forth in the order (it being understood that Bluewater Power Distribution Corporation is relying on Vendor's skill and judgement in selecting and providing the proper goods for Bluewater Power Distribution Corporation's particular use); free from all liens, claims and encumbrances; in conformity with the specifications, drawings, instructions, data, samples, codes and any other description of the goods set forth or referred to in the order and any customary quality control inspections; and in accordance with any warranties or conditions which are statutory or implied by law; and (b) the goods which are services shall be performed in a competent and workmanlike manner and according to high professional standards (collectively referred to herein as the "Warranties"). Vendor covenants that the Warranties will survive for a reasonable period following acceptance of the goods and payment therefore by Bluewater Power Distribution Corporation, but in no event for a period shorter than one year. If any of the Warranties is breached, Vendor shall promptly repair or replace the goods upon Bluewater Power Distribution Corporation's notice to Vendor of Bluewater Power Distribution Corporation's desire to have Vendor so repair or replace the goods affected by such breach. In the event the Vendor fails to cure such breach within a reasonable period after receiving such notice, Bluewater Power Distribution Corporation may, at Vendor's expense, take all necessary steps to cure such breach. In the event any of the goods does not conform with any of the Warranties, Bluewater Power

Distribution Corporation reserves the right to reject or revoke its acceptance of such goods. Bluewater Power Distribution Corporation's payment for or inspection or receipt of the goods shall not constitute a waiver of Bluewater Power Distribution Corporation's right to claim any breach of any of the Warranties.

11. Save Harmless and Indemnification

11.1 The Vendor hereby agrees to save harmless and indemnify Bluewater Power in relation to any and all actions, causes of action, damages, losses, costs and expenses incurred by Bluewater Power that may arise or be related to the services and materials and the performance of the Vendor, whether the Vendor is in fact in default or not in default under the terms and provisions of this Order, Agreement or Proposal. This remedy shall be in addition to any and all other remedies that Bluewater Power may be entitled to in law or pursuant to the terms of this Order, Agreement or Proposal. Notwithstanding any termination of this Order, Agreement or Proposal, this provision shall remain in full force and effect for so long as may be necessary.

12. Patent Matters

12.1 Vendor warrants that its manufacture, and the purchase, sale and use of the goods do not and will not infringe any patent, copyright or trademark. Vendor shall indemnify, defend and hold harmless Bluewater Power Distribution Corporation and its officers, employees, agents, customers and any other subsequent owners from and against all liability, costs and expenses, including, without limitation, the incurrence of reasonable attorneys' fees, arising out of any claim that the manufacture, sale, purchase or use of the goods infringes or contributes to the infringement of any Canadian patent, or patent or registered design of any other country. In the event of such claim, Vendor shall, promptly upon receipt of written notice thereof from Bluewater Power Distribution Corporation, obtain for Bluewater Power Distribution Corporation and its customers the right to continued use of the goods or replace the goods with non-infringing goods which conform, in all material respects, to the requirements of the order. In the event the order is with respect to materials, machinery, equipment or manufacturing apparatus developed or designed or paid for by Bluewater Power Distribution Corporation based on a concept suggested by Bluewater Power Distribution Corporation, all patent and other intellectual property rights incident thereto shall automatically become the exclusive property of Bluewater Power Distribution Corporation, and Vendor shall cooperate with Bluewater Power Distribution Corporation in obtaining such rights thereto.

13. <u>Inspection and Tests</u>

13.1 All goods (and materials incorporated therein and work in progress) will be subject to inspection and testing at Vendor's expense by Bluewater Power Distribution Corporation and its agents, employees and customers at all reasonable times and places, including during manufacture at Vendor's plant or the Vendor's subvendor's plant. Bluewater Power Distribution Corporation shall at all times have access to Vendor's Quality Assurance program to ensure and maintain the quality of the goods. Vendor will, upon Bluewater Power Distribution Corporation's request, provide Bluewater Power Distribution Corporation with representative samples and/or documentation necessary to assess compliance of the goods with the terms of the order. It is expressly agreed that the making of or the failure to make any inspection and/or test will not impair Bluewater Power Distribution Corporation's right to reject any nonconforming or defective goods, constitute acceptance of nonconforming or defective goods, or be construed as a waiver or approval of any such defects or non-conformities. If any inspection or test is made on Vendor's premises, Vendor shall furnish, without additional charge, all reasonable facilities and assistance for safe and convenient inspections and tests required by the inspectors in the performance of their duty. All inspections and tests shall be performed in such a manner as will not unreasonably delay delivery of the goods. Bluewater Power Distribution Corporation shall have the right to charge to Vendor any additional costs when goods are not ready at the time Vendor advises that the goods are ready for inspection. Vendor shall work within, and inspect to, tolerances and limitations, and shall make such tests specified in the order unless deviation therefrom is authorized in writing by Bluewater Power Distribution Corporation's Purchasing Department. All shipments may be subject to final inspection after receipt by Bluewater Power Distribution Corporation at destination. Whether or not such inspection is performed, if goods, supplies or work performed by Vendor is found to be defective or incomplete, Bluewater Power Distribution Corporation shall have the right to require the proper correction thereof, either by Vendor, at Vendor's risk and expense, or, upon authorization from Vendor, by Bluewater Power Distribution Corporation or a third party authorized by Bluewater Power Distribution Corporation. Bluewater Power Distribution Corporation may backcharge Vendor for the cost of any such corrections. If correction of such work is impracticable, Vendor shall bear all the risk after notice of rejection and shall, if so requested by Bluewater Power Distribution Corporation, promptly make all necessary replacements at Vendor's own expense. If Vendor fails to make such replacements promptly, Bluewater Power Distribution Corporation may by contact or otherwise, make the same and backcharge to Vendor the cost occasioned to Bluewater Power Distribution Corporation thereby. Replacements shall not be made except and upon receipt of specific written instructions from Bluewater Power Distribution Corporation's Purchasing Department. Bluewater Power Distribution Corporation's rights under this paragraph shall be in addition to and shall in no way limit any rights of Bluewater Power Distribution Corporation arising out of any other paragraph of the order or any applicable law, statute or regulation.

14. Title and Risk of Loss

14.1 Unless otherwise provided in the order, title shall not pass to Bluewater Power Distribution Corporation and Vendor shall bear all risk of loss or damage to the goods until the goods have been delivered to Bluewater Power Distribution Corporation at the destination and in the manner indicated in the order and in conformity with the Warranties.

15. Confidentiality

15.1 All data, designs, drawings, processes, specifications, reports and other technical or proprietary information submitted by Bluewater Power Distribution Corporation to the Vendor and the features of all parts, equipment, tools, patterns and other items furnished or disclosed to the Vendor by Bluewater Power Distribution Corporation in connection with the order (the "Confidential Data") are to be considered confidential, the sole property of Bluewater Power Distribution Corporation, and shall not be used except in connection with Vendor's provision of the goods to Bluewater Power Distribution Corporation in accordance with the order and shall not be published or disclosed to any third party without Bluewater Power Distribution Corporation's prior written authorization, unless the Confidential Data or any relevant part thereof is or becomes generally available to the public other than as a result of disclosure by Vendor, or is or becomes available to Vendor on a non-confidential basis from a source (other than Bluewater Power Distribution Corporation) which is entitled to disclose the same. Upon completion, termination or cancellation of the order, or upon Bluewater Power Distribution Corporation's request, Vendor shall return to Bluewater Power Distribution Corporation all such Confidential Data, including all copies thereof made by Vendor. Vendor shall not, without receipt of Bluewater Power Distribution Corporation's prior written authorization, advertise or publish any matter relating to the order.

16. Bluewater Power Distribution Corporation Related Materials

16.1 Title to any materials, tooling and equipment, including all patterns, molds, dies or templates (collectively referred to as "Bluewater Power Distribution Corporation Related Materials") supplied by Bluewater Power Distribution Corporation to Vendor or specifically acquired or produced for the order at Bluewater Power Distribution Corporation's expense shall remain with Bluewater Power Distribution Corporation. Vendor shall make no use of the Bluewater Power Distribution Corporation Related Materials except in the performance of the order and shall, to the extent not incorporated in delivered end goods, return the Bluewater Power Distribution Corporation Related Materials to Bluewater Power Distribution Corporation, FOB Bluewater Power Distribution Corporation's site, at the completion or termination of the order in good condition subject to ordinary wear and tear and normal manufacturing losses. If so directed, Vendor shall retain the Bluewater Power Distribution Corporation Related Materials pending further disposition instructions from Bluewater Power Distribution Corporation. Bluewater Power Distribution Corporation shall have the right to remove such Bluewater Power Related Materials at any time for any reason Bluewater Power deems necessary and shall have reasonable rights of access to Vendor's premises to protect its rights to such materials. Vendor shall ensure that all distinctive markings placed on any such material by Bluewater Power shall remain intact until such time as such material is incorporated into the goods. Vendor further warrants that when any such Bluewater Power Related Materials are in Vendor's possession, Vendor shall take the necessary precautions to ensure that they do not sustain damage of any nature whatsoever. Vendor assumes all risk of loss of, damage to, or liability resulting from the Bluewater Power Related Materials from whatever cause while in Vendor's custody or control and Vendor shall indemnify, defend and hold harmless Bluewater Power from and against all liabilities, costs and expense arising from Vendor's failure to comply with its obligations under this section.

17. Termination for Convenience

17.1 In addition and without prejudice to any other rights of Bluewater Power Distribution Corporation hereunder or otherwise in the event of Vendor's default, Bluewater Power Distribution Corporation may, by written notice to Vendor, terminate for any reason all or any part of the order, including all or any part of installments thereof not yet delivered, at any time prior to the delivery of all of the goods. In such event, Vendor shall, immediately upon receipt of such notice of termination, stop all work in connection with the order except as other otherwise directed by Bluewater Power Distribution Corporation and shall make every reasonable effort to procure cancellation of all existing orders or contracts on terms satisfactory to Bluewater Power Distribution Corporation, and shall thereafter do only such work as may be necessary to preserve and protect the work already in progress.

If Vendor (a) is not, at the time of such termination, in default hereunder; (b) has not filed a petition in bankruptcy, been the subject of any involuntary petition in bankruptcy which remains undismissed for more than sixty (60) days, suffered a receivership or other similar petition to be filed for or against it, or made a general assignment for the benefit of its creditors ("Indications of Insolvency"); or (c) cannot use the goods to satisfy an obligation to another buyer, (a) Bluewater Power Distribution Corporation shall pay and Vendor shall accept as full compensation Vendor's direct verifiable, out-of-pocket costs to the date of such notice in connection with the order, including any reasonable expenses incurred by Vendor in connection with Vendor's termination of any of Vendor's Purchase Agreements required by such cancellation, and Vendor's customary profits earned in connection therewith (the "Cancellation Charges"); provided, however, that in no event shall the total amount of such Cancellation Charges plus payments previously made, exceed the proportionate part of the price attributable to the goods produced hereunder prior to the date of Vendor's receipt of Bluewater Power Distribution Corporation's notice of termination; and (b) the completed goods and any uncompleted portion of the goods shall be the property of Bluewater Power Distribution Corporation and the Vendor shall safely hold the same subject to receipt of Bluewater Power Distribution Corporation's written shipping or other disposition instructions. Vendor shall submit its claim for such termination payment together with all substantiating documentation within thirty (30) days after receiving Bluewater Power Distribution Corporation's notice of termination and shall take prompt action to minimize the Cancellation Charges. If the order covers goods or parts thereof which are standard or stock merchandise, Bluewater Power Distribution Corporation shall have no obligation to pay the Cancellation Charges hereunder except to make payment, subject to other applicable terms hereof, for the goods actually shipped or in transit prior to such notice of termination and for any other goods under the order not included within such notice of terminations. In no event shall Bluewater Power Distribution Corporation be liable for loss of anticipated profits on the cancelled portion or portions of the work.

18. Vendor's Default

18.1 If Vendor defaults in the performance of the order or any of the Indications of Insolvency occur, Bluewater Power Distribution Corporation may, in addition to any other remedies available to Bluewater Power Distribution Corporation at law or in equity and without any liability to Bluewater Power Distribution Corporation, cancel the order in whole or in part.

19. Right to Set-Off

19.1 Bluewater Power Distribution Corporation may set-off any claims by Vendor for monies due hereunder against any claim Bluewater Power Distribution Corporation may have against Vendor arising out of this or any other transaction with Vendor.

20. Governing Law

20.1 The order shall be interpreted and enforced in accordance with the laws of the Province of Ontario, including the laws of Canada applicable therein.

21. Compliance with Laws

21.1 Vendor warrants that performance of the work hereunder and all goods to be delivered hereunder shall be in accordance with any and all applicable executive orders, and federal, provincial, municipal and local laws and rules, orders, requirements and regulations promulgated thereunder, including the Occupational Health and Safety Act.

22. Assignment

21.1 The order and the rights and obligations arising hereunder may not be assigned by Vendor in whole or in part without the prior written consent of Bluewater Power Distribution Corporation. Vendor shall not, except in the case of obtaining raw materials or standard commercial items or except as otherwise agreed in writing by Bluewater Power Distribution Corporation's Purchasing Department, delegate or assign all or any part of the work on any of the goods to be furnished under the order. The terms of the order shall be binding upon and shall inure to the benefit of any and all authorized assignees or permissible subvendors of Vendor and any and all assignees of Bluewater Power Distribution Corporation.

23. Non-Waiver

23.1 The failure of Bluewater Power Distribution Corporation to insist upon strict performance of any of the terms and conditions herein shall not be deemed a waiver of any rights or remedies that Bluewater Power Distribution Corporation shall have and shall not be deemed a waiver of any subsequent default of the terms and conditions hereof. The shipping, receiving or acceptance of goods hereunder shall not be deemed a waiver by Bluewater Power Distribution Corporation of any rights Bluewater Power Distribution Corporation wishes to assert in response to any failure of Vendor to comply with any of the provisions of the order.

24. Integration

24.1 The order contains the entire agreement between Vendor and Bluewater Power Distribution Corporation. The order supersedes any prior or contemporaneous understandings or agreements not set forth herein. No subsequent modification of the order shall be of any force or effect unless it is in writing and executed by the parties to be bound thereby.

25. Severability

25.1 In the event that any provision of the order is determined to be unlawful or invalid, only that specific provision shall be severed from the order and all other terms and conditions shall remain in full force and effect.

26. Hazardous Materials

26.1 Vendor must comply with all requirements of the Transportation of Dangerous Goods Act and all amendments and regulations thereto.

26.2 Products containing asbestos and/or PCB’s are unconditionally prohibited material.

26.3 The Vendor shall advise Bluewater Power Distribution Corporation of any and all hazardous products or chemicals (as defined by the Occupational Health and Safety Act) incorporated in or to be supplied with the equipment. Material Safety Data Sheets for these products must accompany each shipment to site.

26.4 Workplace Hazardous Materials Information System (WHMIS) - Vendor’s personnel providing installation advisory services at Bluewater Power Distribution Corporation’s site must be trained in accordance with the requirements of WHMIS legislation.

27. Notice

27.1 Any notice required to be given hereunder shall be in writing and sent by registered or overnight mail or by facsimile copy, addressed to the other party as set forth on the face of the order. Any change of address by either of the parties will be submitted in writing to the other party hereto. Any notice shall be deemed received within three (3) days of mailing.

28. Arbitration

28.1 Any claims which the Vendor may have against Bluewater Power Distribution Corporation arising out of the Order shall be presented, in writing, to Bluewater Power Distribution Corporation no later than twenty-five (25) days after the circumstances which gave rise to the claim have first taken place. Any work in dispute shall be kept readily accessible and shall not be covered up without the express permission of Bluewater Power Distribution Corporation. The claim shall contain a concise statement of the question or dispute together with the relevant facts and other data in support of the claim. Vendor may be required to furnish such additional information as Bluewater Power Distribution Corporation may require to enable it to render its decision. Claims not presented within the said twenty-five (25) day period may be disallowed. The presentation of any claim questions or differences which persist after reference thereof to Bluewater Power Distribution Corporation and the receipt of its decision thereof shall be referred to arbitration in accordance with The Arbitrations Act of Ontario. Vendor hereby agrees that any arbitration may include by consolidation or joinder or by any other means parties other than Bluewater Power Distribution Corporation and Vendor who are substantially involved in a common question of fact or law and whose presence is required if complete relief is to be accorded in the arbitration proceeding.

Supplementary
Terms and Conditions

Supplementary Terms and Conditions

1. Definitions

1.1 "BPDC", "Owner" or "Utility" means Bluewater Power Distribution Corporation.

1.2 "Contractor" or "Successful Vendor" means the person, firm or company whose proposal has been accepted by BPDC.

1.3 "Engineer" means any Engineer appointed from time to time by Bluewater Power.

1.4 "BPDC Representative" means any person(s) appointed from time to time by Bluewater Power.

1.5 "Contract" means the document between the Successful Vendor and/or its subcontractors/sub-vendors and Bluewater Power to supply, deliver, install, remove, dispose of goods/services all in accordance with Bluewater Power's Request for Proposal, Technical Specifications, Scope of Work and Drawings.

1.6 "Contract Price" means the sum named in the Blank Proposal Form subject to such additions and deductions as may be made under provisions contained in the contract.

1.7 "Drawings" means the drawings referred to in this specification and any modifications to such drawings approved by BPDC representative and such other drawings as may from time to time be furnished or approved by the BPDC representative.

1.8 "Work" means the work to be executed in accordance with this Request for Proposal.

1.9 "Site" means the land and other places on which the work is to be executed.

2. Subcontracting

2.1 The successful Vendor shall not subcontract the whole of the work. Except where otherwise provided by the contract, the contractor shall not subcontract any part of the work without the written consent of BPDC and such consent, if given, shall not relieve the contractor from any liability or obligation under the contract. The contractor shall be responsible for the acts, defaults and neglects of any subcontractor, his agents or workmen.

3. Cleaning Up

3.1 The Vendor shall at all times keep the site free from accumulations of waste materials or rubbish caused by its employees or work, and at the completion of the work it shall remove all its rubbish and all tools, equipment and surplus materials from and about the work and shall leave the site of the work clean and in a workmanlike condition to the satisfaction of BPDC. In case of dispute, BPDC may remove the above and charge the cost to the contractor.

4. Emergencies

4.1 BPDC has the authority in any emergency to stop the progress of the work whenever in his opinion such stoppage may be necessary to ensure the safety of life, or the structure, or neighbouring property.

5. Working Days

5.1 Normal working days will be Monday to Friday, excluding holidays. The Vendor will observe BPDC holidays on the following days:

Good Friday	Thanksgiving Day
Victoria Day	Christmas Eve
Canada Day	Christmas Day
Civic Holiday	Boxing Day
Labour Day	New Year’s Day

6. Familiarity With Proposed Work

6.1 No plea of ignorance of existing conditions or difficulties which may be encountered during the execution of the work by reason of failure to make necessary inspections and investigations will be accepted as sufficient reason not to fulfill in detail all requirements under this Request for Proposal.

7. Order of Precedence

7.1 All Bluewater Power documents shall govern over Vendor’s proposal including its acknowledgment and terms and conditions.

7.2 Documents of a later date shall govern corresponding documents of an earlier date or change level.

7.3 Figured dimensions shown on drawings shall govern and scaled dimensions shall not be used.

7.4 Drawings of a larger scale shall govern over those of a smaller scale of the same date.

7.5 Technical specifications shall govern over Bills of Material.

7.6 Notes on drawings shall be considered as part of the technical specifications.

7.7 Bills of Material and drawings shall be considered complementary to each other and what is called for on one is considered as being called for on the other.

7.8 The Supplementary Terms and Conditions shall govern over the General Terms and Conditions.

7.9 The Purchase Order contract shall govern over the Supplementary Terms and Conditions.

8. Quantities/Values

8.1 The quantities and/or values shown in this Request for Proposal are estimates only based on historical information. No claim will be allowed for any loss of anticipated profits resulting from any excess or deficiency in the quantities/values shown.

9. Maintenance Period

9.1 **The successful Vendor shall maintain all work all in accordance with this Request for Proposal for a period of twelve (12) months from the date of acceptance by Bluewater Power.** The date of acceptance shall be the date upon which Bluewater Power makes final payment for the work (subject to holdback).

9.2 The successful Vendor shall maintain the works and every part thereof and shall make good in a permanent manner, satisfactory to Bluewater Power's representative, any and all damage or injury to the works which results from faulty workmanship or materials, both during construction and during the specified maintenance period.

9.3 Should the successful Vendor fail to make the necessary repairs, Bluewater Power's representative, after giving three (3) days notice to do so, may proceed to have the repairs carried out.

10. Joint-Use Parties - ***Not applicable

10.1 Some of the work involved in our projects involves installation of either Bell Canada or Cogeco Cable Solutions systems. It is the successful Vendor's responsibility to ensure that he is eligible to do work for these joint-use parties. Should the successful Vendor be deemed as unacceptable by either joint-use party, it is the option of Bluewater Power to terminate or disqualify any successful Vendor. All construction and installations for Bell Canada and/or Cogeco Cable Solutions shall be completed as per the standard work practice of the appropriate joint-use party. Negotiations for payment of exclusive joint-use party items not shown on this proposal shall be the responsibility of the successful Vendor.

11. Drawings

11.1 The Drawings shall remain in the sole custody of BPDC, but three copies thereof shall be furnished to the Vendor free of cost. The Vendor shall provide and make at its own expense any further copies required by it. At the completion of the Contract the Vendor shall return to BPDC one set of marked up drawings as a record of construction (as built).

11.2 One copy of the Drawings furnished to the Vendor as aforesaid shall be kept by the Vendor on the Site and the same shall at all reasonable times be available for inspection and use by BPDC.

11.3 BPDC shall have full power and authority to supply to the Vendor from time to time during the progress of the Work copies of such further drawings and such instructions as shall be necessary for the purpose of the proper and adequate execution and (where specified) maintenance of the Work, and the Vendor shall carry out and be bound by the same.

12. Security

12.1 The Vendor shall provide for the security of its equipment, all materials, and of the site at all times during the execution of the contract.

12.2 The Vendor shall assume all responsibility for loss or damage to owner-supplied equipment after receipt.

13. Damage to Property

13.1 The Vendor shall take all necessary measures to protect existing and all properties of others from damage. In the event that any such service or property is damaged during the course of the work, the contractor shall immediately and at his own expense, make good such damage.

14. Performance Bond – ***Not applicable

14.1 The Proposal shall be accompanied by the commitment of a Surety Company licensed by the Province of Ontario for such purposes, to provide a Performance Bond. The successful Vendor shall furnish the Performance Bond to BPDC Purchasing prior to the execution of the Contract.

14.2 **The Performance Bond** shall be for fifty percent (50%) of the Proposal sum and shall be maintained in good standing until the fulfilment of the Contract.

15. Pricing

15.1 Contract price shall be firm, fixed and not subject to changes in cost of labour, material, travel, living, mileage expense or any other factor.

16. Invoicing and Terms of Payment

16.1 Ninety percent (90%) of the contract price may be invoiced on a progress basis for the value of work performed to the end of the previous month less the sum of all previous payments for that job.

16.2 Ten percent (10%) of the price may be invoiced upon satisfactory completion of the work with payment made forty-five (45) days thereafter.

16.3 All invoices will be paid within thirty (30) days subject to approval by BPDC.

16.4 When work is not progressing on schedule, all payment will be suspended until such time as work is again proceeding on schedule.

16.5 All invoices must reference purchase order number and detail sufficient to understand the work being billed. Taxes must be shown as a separate item on invoice.

16.6 No progress, nor payments will be allowed for the furnishing of bonds.

17. Changes and Extra Work

17.1 Fixed price changes (if applicable) shall include all costs and impacts associated with the work and must include a price breakdown. Unless otherwise directed the breakdown will be in sufficient detail to provide an analysis of all labour, material, equipment, subcontractor costs, as well as overhead and profit and will cover all work involved in modification, whether such work be deleted, added or changed.

17.2 Any and all changes (if applicable) to the firm Proposal contract price must be documented on a Bluewater Power Change Order Form and submitted to Bluewater Power Engineering for approval prior to proceeding.

18. Toxic and Hazardous Material

18.1 Certain material the Vendor uses or generates in the course of the work may be classified as toxic or hazardous according to federal, provincial or municipal laws and regulations.

18.2 The Vendor will monitor all materials and notify BPDC in writing if any of these materials are classified as toxic or hazardous. The contractor will maintain records, and will properly protect, store and/or contain these materials.

18.3 The Vendor will be responsible to instruct its personnel in proper use and handling of this material and of potential hazard and liability of misuse, exposure and environmental contamination.

18.4 The Vendor will be liable for full clean-up and restoration costs resulting from improper use, handling and disposal of toxic or hazardous wastes wherever they may lie.

19. Experience

The contractor must provide references of previous work completed in already existing residential areas.

The selected contractor must have a proven record when it comes to civil construction and restoration in existing residential areas. Documented proof must be provided upon request and shall consist of: photos, before and after, of working areas; letters of recommendation from customers, etc.

20. Penalty Provision

20.1 In the event that the Vendor defaults in the Performance of this Order, Agreement or Proposal and the said default is not corrected by the Vendor, then Bluewater Power, in addition to any and all other remedies that Bluewater Power may be entitled to in law or pursuant to the terms of this Order, Agreement or Proposal, shall also be entitled to claim a penalty against the Vendor in an amount equal to the amount of the value of this Order, Agreement or Proposal. The Vendor acknowledges and agrees that this provision is fair and reasonable. Notwithstanding any termination of this Order, Agreement or Proposal, this provision shall remain in full force and effect for so long as may be necessary.

21. Vendor's Liability Insurance/WSIB Coverage

21.1 The Vendor will provide in the proposal, proof of current Liability Insurance for themselves and also any proposed Subcontractors. The amount of liability protecting the Vendor/Subcontractor against property damage and/or public liability should be as follows:

General Liability - $2,000,000.00 min/occurrence
Automotive Liability - $2,000,000.00 min/3rd party liability

21.2 The Vendor will also include with the proposal, a copy of a valid Workplace Safety Insurance Board Clearance Certificate, for themselves and any proposed Sub Contractors.

THIS SPECIFICATION IS TO SET FORTH THE SPECIFIC REQUIREMENTS FOR A TANDEM AXLE 156" C.T HEAVY DUTY CAB AND CHASSIS

THIS CAB AND CHASSIS SHALL BE TO THE MANUFACTURERS STANDARD IT SHALL BE EQUIPPED WITH THE MANUFACTURERS EQUIPMENT AND ACCESSORIES WHICH ARE INCLUDED AS STANDARD IN THE ADVERTISED LITERATURE FOR THE UNIT. NO SUCH ITEM OR EQUIPMENT OR ACCESSORIES SHALL BE REMOVED OR OMITTED FOR THE REASON THAT IT WAS NOT SPECIFIED IN THE BID.

IF IT IS NECESSARY TO BID ALTERNATIVE EQUIPMENT OR TO TAKE EXCEPTIONS TO THE SPECIFICATIONS AS SET FORTH THIS MUST BE SO STATED IN YOUR BID. FOR EACH ITEM PLACE AN X IN THE APPROPRIATE SPACE (YES NO) TO SIGNIFY WEATHER OR NOT YOU ARE IN COMPLETE COMPLIANCE WITH THE SPECIFICATION. FAILURE TO FOLLOW THE FORMAT OR ANSWER THE SPECIFICATION MAY CAUSE YOUR BID BE DISQUALIFIED. IF YOU NEED EXTRA SPACE TO DESCRIBE YOUR PRODUCT PLEASE FEEL FREE TO ATTACH EXTRA SHEETS. WHEN DOING THIS BE SURE YOUR DESCRIPTION REFERENCES THE APPROPRIATE NUMBER

ITEM		COMPLY YES	NO
	MODEL		
	FREIGHTLINER M2 112 CONVENTIONAL CHASSIS		
	SET BACK FRONT AXLE DESIGN		
	STRAIGHT TRUCK PROVISION		
	PRIMARY STEERING LOCATION LEFT HAND		
	ENGINE		
	MBE 4000 12.8L 410 HP @ 1900 RPM 2000 GOV RPM 1450 LB FT @ 1100 RPM		
	ENGINE TO BE PROGRAMMED AS FOLLOWS FOR PTO PUMP FUNCTIONS		
	HIGH SPEED 1200 RPM		
	LOW SPEED 900 RPM		
	PTO FUNCTION ENABLE		
	2007 EPA CARB EMISSION CERTIFICATION		
	ENGINE EQUIPMENT		
	OIL CHECK AND FILL ENGINE MOUNTED		
	SIX PIECE VALVE COVER		
	SIDE OF HOOD AIR INTAKE WITH FIREWALL MOUNTED DONALDSON AIR CLEANER		
	AIR CLEANER ONE STAGE		
	LN 12 VOLT 200 AMP ALTERNATOR		
	3 ALLIANCE MODEL 1031 GROUP 31 12 VOLT MAINTENANCE FREE 2280 CCA THREADED STUD BATTERIES		
	BATTERY BOX FRAME MOUNTED		
	SINGLE BATTERY BOX FRAME MOUNTED LH SIDE BACK OF CAB		
	FRAME GROUND RETURN FOR BATTERY CABLES		

NON POLISHED BATTERY BOX COVER ____________________

COMPRESSOR WABCO 15.5 CFM ____________________

STEEL AIR COMPRESSOR DISCHARGE LINE WITH INTEGRAL QUICK CONNECT SYSTEM HARGEING VALVE AND ST4 SAFETY VALVE ____________________

ENGINE PROTECTION ELECTRONIC ENGINE INTEGRAL SHUTDOWN PROTECTION SYSTEM ____________________

MERCEDES BENZ STANDARD COMPRESSION TURBO BRAKE WITH 1 ON OFF AND 1 LOW MEDIUM HIGH BRAKING SWITCH ____________________

LH INBOARD FRAME MOUNTED HORIZONTAL AFTER TREATMENT DEVICE WITH LH HORIZONTAL TAILPIPE ____________________

ENGINE AFTER TREATMENT DEVICE AUTOMATIC OVER THE ROAD REGENERATION AND DASH MOUNTED REGENERATION REQUEST SWITCH ____________________

LH STANDARD HORIZONTAL TAILPIPE TO EXIT IN FRONT OF TANDEM AXLE ____________________

BORG WARNER KYSOR K26RA REAR AIR ON OFF ENGINE CLUTCH FAN ____________________

ENGINE HOUR METER OIL PRESSURE ACTIVATED TO BE DASH MOUNTED ____________________

AUTOMATIC FAN CONTROL WITH DASH SWITCH AND INDICATOR LIGHT ____________________

ONE TRIP TYPE HOUR METER IN DRIVER DISPLAY ____________________

MUFFLER SHIELD STAINLESS STEEL ____________________

MBE FUEL FILTER ____________________

FULL FLOW OIL FILTER ____________________

POWER COOL PLAIN COOLANT FILTER ____________________

1500 SQUARE INCH ALUMINUM RADIATOR ____________________

HEAVY DUTY COOLANT ETHYLENE GLYCOL PRE CHARGED SCA TO -34 F ____________________

GATES BLUE STRIPE COOLANT HOSE ____________________

CONSTANT TENSION HOSE CLAMPS FOR COOLANT HOSES ____________________

PHILLIPS TEMRO 1500 WATT 115 VOLT BLOCK HEATER ____________________

CHROME ENGINE HEATER RECEPTACLE MOUNTED UNDER LH DOOR ____________________

FLYWHEEL HOUSING ALUMINUM ____________________

DELCO 12V 39 MT HD STARTER WITH INTEGRATED MAGNETIC SWITCH ____________________

TRANSMISSION AND EQUIPMENT

TRANSMISSION ALLISON 4500 RDS AUTOMATIC WITH PTO PROVISION

WTEC CALIBRATION 6 SPEED RDS TRV PACKAGE 113

VEHICLE INTERFACE WIRING WITH BODY BUILDER CONNECTOR MOUNTED BACK OF CAB

ELECTRONIC TRANSMISSION CUSTOMER ACCESS CONNECTOR FIREWALL MOUNTED

CHELSEA 277 SERIES CUSTOMER INSTALLED PTO WITH REMOTE SOLENOID

PTO MOUNTING LH SIDE OF MAIN TRANSMISSION

MAGNETIC ENGINE DRAIN & REAR AXLE DRAIN AND FILL PLUGS

PUSH BUTTON ELECTRONIC SHIFT CONTROL DASH MOUNTED

TRANSMISSION OIL COOLER WATER TO OIL FRAME MOUNTED

TRANSMISSION OIL CHECK AND FILL WITH ELECTRONIC OIL LEVEL CHECK

TRANSMISSION TO BE PROGRAMMED AS FOLLOWS
PTO TO DISENGAGE IF UNIT IS SHIFTED INTO GEAR WITH PTO ENGAGED
PTO TO HAVE AUTO NEUTRAL

AF 16.0-5 FL1 71.0 KPI/3.74 DROP SINGLE FRONT AXLE

MERITOR 16.5X6 Q+ CAST SPIDER CAM FRONT BRAKES DOUBLE ANCHOR FABRICATED SHOES

FRONT BRAKES LININGS NON ASBESTOS

CONMET CAST IRON FRONT BRAKE DRUMS

CHICAGO RAWHIDE SCOTSEAL PLUS XL FRONT OIL SEALS

FRONT BRAKE DUST SHIELDS

VENTED FRONT HUB CAPS OIL

STANDARD SPINDLE NUTS FOR ALL AXLES

FRONT AUTO SLACK ADJUSTERS MERITOR

POWER STEERING TRW TAS 85

POWER STEERING PUMP

POWER STEERING RESERVOIR 2 QUART

FRONT SUSPENSION FLAT LEAF 16000 LB

GRAPHITE BRONZE BUSHINGS WITH SEALS FRONT SUSPENSION

FRONT HEAVY DUTY SHOCK ABSORBERS

REAR AXLE AND SUSPENSION

RT 46 160P R SERIES TANDEM REA AXLE 46000 LB

IRON REAR AXLE CARRIER WITH STANDARD AXLE HOUSING

FORE AND AFT TRANSVERSE CONTROL RODS

4.89 AXLE RATIO

REAR AXLE CARRIER HOUSING IRON WITH HEAVY DUTY AXLE HOUSING

18N MERITOR MAIN DRIVELINE WITH FULL ROUND YOKES

17N MERITOR INTERAXLE DRIVELINEWITH FULL ROUND YOKES

DRIVER CONTROLLED TRACTION DIFFERENTIAL BOTH TANDEM REAR AXLES

1 DCDL FORWARD AND REAR REAR AXLE VALVE AND 1 INTERAXLE LOCK CONTROL VALVE

BLINKING LAMP WITH EACH MODE SWITCH INTERAXLE UNLOCK DEFAULT WITH IGNITION OFF

BLINKING LAMP WITH EACH MODE SWITCH DIFFERENTIAL UNLOCK WITH IGNITION OFF ACTIVE

CASTROL TRANSYND SYNTHETIC AUTOMATIC TRANSMISSION OIL

MERITOR 16.5X8 Q+ CAST SPIDER CAM REAR BRAKES DOUBLE ANCHOR FABRICATED SHOES

REAR BRAKE LININGS NON ASBESTOS

STANDARD BRAKE CHAMBER LOCATION

CAM BRAKE AUXILIARY SUPPORT BRACKETS

CONMET CAST IRON REAR BRAKE DRUMS

REAR BRAKE DUST SHIELDS

CHICAGO RAWHIDE SCOTSEAL CLASSIC REAR OIL SEALS

HALDEX LONG STROKE 2 DRIVE AXLES SPRING PARKING CHAMBERS

MERITOR AUTOMATIC REAR SLACK ADJUSTERS

AIRLINER 46000 REAR SUSPENSION WITH CHAIN CLEARANCE

AIRLINER HIGH POSITION RIDE HEIGHT

AXLE SEATS WITH RETAINERS

MANUAL DUMP VALVE FOR AIR SUSPENSION WITH INDICATOR LIGHT GAUGE AND BUZZER

REAR AIR SUSPENSION DUMP VALVE AUTOFIL WITH IGNITION OFF OR 5 MPH

DUAL INSTANT RESPONSE REAR SUSPENSION LEVELING VALVES

TRANSVERSE CONTROL RODS

REAR SHOCK ABSORBERS TWO AXLES TANDEM AIR RIDE SUSPENSION

REAR AXLE SPACING 72.5"

BRAKE SYSTEM EQUIPMENT

TRAILER AIR BRAKE PACKAGE C/W GLAD HANDS

WABCO 4S/4M ABS WITHOUT TRACTION CONTROL ENHANCEMENT

REINFORCED NYLON FABRIC BRAID AND WIRE BRAID CHASSIS AIR LINES

STANDARD BRAKE SYSTEM VALVES

RELAY VALVE W / 5-8 PSI CRACK PRESSURE NO REAR PROPORTIONING VALVE

MERITOR WABCO SYSTEM SAVER 1200 HEATED AIR DRYER WITH PRESSURE CONTROL

AIR RESERVOIRS STEEL

AIR TANK DRAIN VALVES CABLES ALL TANKS

AIR CONNECTIONS TO END OF FRAME WITH GLAD HANDS FOR TRUCK

PRIMARY CONNECTOR RECEPTACLE CENTER PIN POWERED THROUGH IGNITION

SAE J560 7 WAY PRIMARY TRAILER CABLE RECEPTACLE MOUNTED END OF FRAME

UPGRADED CHASSIS MULTIPLEXING UNIT

UPGRADED BULKHEAD MULTIPLEXING UNIT

WHEELBASE

222" WHEELBASE

156 CT

FRAME

11/32" X 3-1/2" X 10-15/16" STEEL FRAME

1/4" C CHANNEL INNER FRAME RAIL REINFORCEMENT

104 AF TO BE SUPPLIED

REAR SUSPENSION CROSS MEMBER

END FRAME SQUARE

RBM 2,637,000

SECTION MODULES 22.25

YIELD STRENGTH 120,000 PSI

UNDER SLUNG CROSS MEMBER

STANDARD WEIGHT ENGINE CROSS MEMBER

STANDARD REARMOST CROSS MEMBER

HEAVY DUTY SUSPENSION CREWMEMBER

CHASSIS DIMENSIONS

AF 104" AFTER FRAME

156 CT CAB TO CENTER OF TANDEM

CHASSIS EQUIPMENT

THREE PIECE 14" CHROMED STEEL BUMPER WITH COLLAPSIBLE ENDS

FRONT TOW HOOKS TWO FRAME MOUNTED

LICENSE PLATE MOUNTING BELOW FRONT BUMPER

CLEAR FRAME RAILS FROM BACK OF CAB TO END OF FRAME RAILS

BUMPER MOUNTING FOR SINGLE LICENSE PLATE

REMOVABLE FRONT TOW HOOKS STORED ON CHASSIS FRAME

ALL EQUIPMENT TO BE MOUNTED INBOARD FRAME RAILS

GRADE 8 THREADED HEX HEADED FRAME FASTENERS

FUEL TANKS AND EQUIPMENT

RH FUEL TANK 50 GALLON ALUMINUM

LH FUEL TANK 50 GALLON ALUMINUM

23" DIAMETER FUEL TANKS

FUEL TANK BAND AND FINISH PLAIN TANK W/ PAINTED BANDS

FUEL TANK LOCATION FORWARD

FUEL TANK CAP

ALLIANCE FUEL FILTER / WATER SEPARATOR WITH PRIMER PUMP

FUEL SYSTEM F/L EQUIFLO INBOARD

REINFORCED NYLON FUEL HOSE

385/65R22.5 18 PLY RADIAL FRONT TIRES

MICHELIN XZY-3 385/65R22.5 18PLY RADIAL FRONT TIRES

11R22.5 16 PLY RADIAL REAR TIRES

MICHELIN XDE A/T 11R22.5 16 PLY RADIAL REAR TIRES

CONMET IRON FRONT HUBS

CONMET IRON REAR HUBS

ACCURIDE 29374A 22.5 X 12.25 10 HUB PILOT 4.75 INSERT 10 HAND ALUMINUM DISC FRONT WHEELS

ACCURIDE 29644A 22. X 8 .25 10 HUB PILOT ALUMINUM REAR WHEELS

POLISHED FRONT WHEELS

POLISHED REAR WHEELS

CAB EXTERIOR

112" BBC FLAT ROOF ALUMINUM CONVENTIONAL CAB

AIR CAB MOUNTS

2-1/2" FENDER EXTENSIONS

GRAB HANDLES LH/RH EXTERIOR

HOOD MOUNTED CHROME PLASTIC GRILLE

FIBERGLASS HOOD

HOOD LINER INSULATION WITH SINGLE FIREWALL INSULATION

SINGLE 11" ROUND AIR HORN UNDER DECK

DUAL ELECTRIC HORNS

SINGLE HORN SHIELD

DOOR LOCKS AND IGNITION SWITCH KEYED THE SAME

REAR LICENSE PLATE MOUNT END OF FRAME

INTEGRAL HEADLIGHT/MARKER ASSEMBLY WITH CHROME BEZEL

FREIGHTLINER LED AERODYNAMIC MARKER LIGHTS

RECTANGULAR FOG LIGHTS MOUNTED UNDER BUMPER ____________

DAYTIME RUNNING LIGHTS ____________

INTEGRAL STOP/TAIL/BACKUP LIGHTS ____________

STANDARD FRONT TURN SIGNAL LAMPS ____________

DUAL WEST COAST BRIGHT FINISH HEATED MIRRORS LH RH REMOTE ____________

DOOR MOUNTING OF MIRRORS ____________

102" EQUIPMENT WIDTH ____________

LH AND RH 8" BRIGHT FINISH CONVEX MIRRORS MOUNTED UNDER PRIMARY MIRRORS ____________

DOWN VIEW MIRROR RH ____________

STANDARD SIDE/REAR REFLECTORS ____________

DUAL LEVEL CAB ENTRY STEPS ON BOTH SIDES ____________

COMPOSITE EXTERIOR SUN VISOR ____________

63" X 14" TINTED REAR WINDOW ____________

TINTED DOOR GLASS LH AND RH WITH TINTED OPERATING WING WINDOWS ____________

POWER WINDOWS LH / RH ____________

WINDSHIELD TINTED ____________

8 LITER WINDSHIELD WASHER RESERVOIR WITH FLUID LEVEL INDICATOR ____________

CAB INTERIOR

OPAL GREY VINYL INTERIOR ____________

M2 INTERIOR CONVENIENCE PACKAGE ____________

MOLDED PLASTIC DOOR PANEL WITH ALUMINUM KICK PLATE LOWER DOOR ____________

GRAY VINYL MATS WITH INSULATION ____________

LH UPPER DOOR TRIM GRAY ____________

RH UPPER DOOR TRIM GRAY PATTERNED VINYL ____________

FLOOR MATS BLACK WITH SINGLE INSULATION ____________

DASH MOUNTED ASH TRAYS & LIGHTER ____________

FORWARD ROOF MOUNTED CONSOLE WITH UPPER STORAGE COMPARTMENTS AND ADDITIONAL CENTER COMPARTMENT WITHOUT NETTING ____________

TWO CUP HOLDERS LH AND RH DASH

GRAY/CHARCOAL WING DASH

SMART SWITCH EXPANSION PANEL

HEATER DEFROSTER AND AIR CONDITIONING

STANDARD HVAC DUCTING

MAIN HVAC CONTROLS WITH RECIRCULATION SWITCH

STANDARD PLUMBING WITH SHUTOFF VALVES

SANDEN HEAVY DUTY AIR CONDITIONER COMPRESSOR

BINARY CONTROL R-134A

SILENCER PACKAGE FOR CAB

SOLID STATE CIRCUIT PROTECTION AND FUSES

12V NEGATIVE GROUND ELECTRICAL SYSTEM

WIRING SCHEMATIC CARD UNMOUNTED BASIC WIRING DIAGRAM FOR 12 VOLT NEGATIVE GROUND SYSTEM

DOME DOOR ACTIVATED LH AND RH DUAL READING LIGHTS FORWARD CAB ROOF

ELECTRIC DOOR LOCKS LH AND RH

2- 12VOLT POWER SUPPLY IN DASH CIGAR LIGHTER STYLE

NATIONAL 2000 SERIES HIGH BACK AIR SUSPENSION DRIVER SEAT WITH ACTIVE AIR LUMBAR SUPPORT

NATIONAL 2000 SERIES HIGH BACK AIR SUSPENSION SEAT WITH ACTIVE AIR LUMBAR SUPPORT

DUAL DRIVER AND PASSENGER SEAT ARMRESTS

LH AND RH INTEGRAL DOOR PANEL ARMRESTS

BLACK MORDURA CLOTH DRIVER SEAT COVER

BLACK MORDURA CLOTH PASSENGER SEAT COVER

3 POINT FIXED D-RING RETRACTOR DRIVER AND PASSENGER SEAT BELTS

STEERING COLUMN TILT AND TELESCOPIC

4 SPOKE 18" STEERING WHEEL

INTERIOR SUN VISORS DRIVER / PASS

BLACK GAUGE BEZELS

WOOD GRAIN INSTRUMENT PANEL DRIVER

WOOD GRAIN CENTER INSTRUMENT PANEL

LOW AIR PRESSURE WARNING LIGHT AND BUZZER

SINGLE BRAKE APPLICATION AIR GAUGE

2" PRIMARY AND SECONDARY AIR PRESSURE GAUGES

ENGINE COMPARTMENT MOUNTED AIR RESTRICTION INDICATOR
WITH GRADUATIONS WITH WARNING LIGHT IN DASH

97 DB BACKUP ALARM

CRUISE CONTROL ELECTRONIC ENGINE WITH SWITCHES ON
AUXILIARY GAUGE PANEL

KEY OPERATED IGNITION SWITCH AND INTEGRAL START POSITION
4 POSITION OFF/RUN/START/ACCESSORY

ODOMETER/TRIP/HOUR/DIAGNOSTIC/VOLTAGE DISPLAY 1 X CHARACTER
26 WARNING LAMPS DATA LINKED ICU3

DIAGNOSTIC INTERFACE CONNECTOR 9 PIN SAE J1587/1708/1939 LOCATED
BELOW DASH

2" ELECTRIC FUEL GAUGE

ENGINE ECM CUSTOMER ACCESS CONNECTOR MOUNTED BACK OF CAB
PARK BRAKE AND NEUTRAL INTERLOCK

COOLANT TEMPERATURE GAGE ELECTRIC

TRANSMISSION TEMPERATURE GAGE ELECTRIC

TRIP HOUR METER INTEGRAL WITH DRIVER DISPLAY

ELECTRIC/AIR DASH MOUNTED PTO SWITCH WITH INDICATOR LAMP

ENGINE OIL PRESSURE GAGE

DELPHI AM/FM/WB PREMIUM RADIO WITH CD

RADIO SPEAKER QTY2

RADIO ANTENNA AM/FM ROOF MOUNTED ON FORWARD LEFT CORNER

POWER AND GROUND STUDS IN/UNDER DASH

SPEEDOMETER ELECTRONIC KPH WITH SECONDARY MPH SCALE WITH
ODOMETER

ELECTRONIC KPH SPEEDOMETER WITH SECONDARY MPH SCALE WITHOUT
ODOMETER

ELECTRONIC TACHOMETER 3000 RPM

IGNITION SWITCH CONTROLLED ENGINE STOP ____________

8 EXTRA SWITCHES IN DASH 4 WITH INDICATOR LAMPS AND WIRES TO CHASSIS AT BACK OF CAB 4 WIRED BY BODY BUILDER ____________

BW TRACTOR PROTECTION VALVE ____________

TRAILER BRAKE VALVE HAND CONTROL ____________

DIGITAL VOLTAGE DISPLAY INTEGRAL WITH DRIVER DISPLAY ____________

WIND SHIELD WIPER CONTROL INTERMITTENT ____________

MARKER LAMP SWITCH MARKER LIGHT HEADLIGHT SWITCH WITH INTERRUPTER FOR CLEARANCE LIGHTS ____________

TWO VALVE PARKING BRAKE SYSTEM WITH WARNING INDICATOR ____________

TURN SIGNAL SWITCH SELF CANCELLING WITH INTEGRAL HEADLIGHT BEAM 4 WAY FLASHER ____________

INTEGRAL ELECTRONIC TURN SIGNAL FLASHER WITH HAZARD LAMPS OVERRIDING STOP LAMPS ____________

TURN SIGNAL FLASHER HD MECHANICAL ____________

ONE COLOR DESIGN ____________

CAB COLOR TO MATCH FLEET N0890EA ELITE SS RED ____________

CHASSIS BLACK HIGH SOLIDS POLYURETHANE ____________

2 COPIES OF SHOP PARTS AND MAINTENANCE MANUALS ____________

WARRANTY NOT TO START UNTIL VEHICLE IS PLACED INTO SERVICE ____________

THIS SPECIFICATION IS TO SET FORTH THE SPECIFIC REQUIREMENTS FOR A FIBERGLASS UTILITY LINE BODY SUITABLE FOR MOUNTING ON A TANDEM AXLE 156" CA CAB AND CHASSIS

THIS BODY SHALL BE TO THE MANUFACTURERS STANDARD IT SHALL BE EQUIPPED WITH THE MANUFACTURERS EQUIPMENT AND ACCESSORIES WHICH ARE INCLUDED AS STANDARD IN THE ADVERTISED LITERATURE FOR THE UNIT. NO SUCH ITEM OR EQUIPMENT OR ACCESSORIES SHALL BE REMOVED OR OMITTED FOR THE REASON THAT IT WAS NOT SPECIFIED IN THE BID.

IF IT IS NECESSARY TO BID ALTERNATIVE EQUIPMENT OR TO TAKE EXCEPTIONS TO THE SPECIFICATIONS AS SET FORTH THIS MUST BE SO STATED IN YOUR BID. FOR EACH ITEM PLACE AN X IN THE APPROPRIATE SPACE (YES NO) TO SIGNIFY WEATHER OR NOT YOU ARE IN COMPLETE COMPLIANCE WITH THE SPECIFICATION. FAILURE TO FOLLOW THE FORMAT OR ANSWER THE SPECIFICATION MAY CAUSE YOUR BID BE DISQUALIFIED. IF YOU NEED EXTRA SPACE TO DESCRIBE YOUR PRODUCT PLEASE FEEL FREE TO ATTACH EXTRA SHEETS. WHEN DOING THIS BE SURE YOUR DESCRIPTION REFERENCES THE APPROPRIATE NUMBER

ITEM #	REQUIREMENT	COMPLY YES	COMPLY NO
	BODY TO BE OF FIBERGLASS CONSTRUCTION PROTEK		
	BODY TO BE SUPPLIED WITH THE FOLLOWING		
	NON SKID GRIP STRUT ALUMINUM COMPARTMENT TOPS		
	DOUBLE LAMINATED DOORS		
	HIGH PERFORMANCE GELCOAT EXTERIOR		
	SEPARATE WHEEL WELL SECTIONS		
	WHEEL WELLS TO BE LINED		
	AUTOMOTIVE DOOR SEAL		
	L.E.D. EXTERIOR LIGHTS		
	MID SHIP TURN SIGNAL LIGHT		
	PROTECTIVE LOOM FOR ALL WIRING		
	GAS STRUTS ON ALL DOORS		
	STAINLESS STEEL NUTS AND BOLTS THROUGHOUT		
	STAINLESS STEEL DOOR LATCHES		
	DUAL STAGE ROTARY DOOR LATCHES		
	STAINLESS STEEL HARDWARE		
	HEAVY DUTY STAINLESS STEEL HINGES		
	ALL SHELVING TO BE ALUMINUM		
	BODY TO BE PAINTED TO MATCH FLEET COLORS		
	OVERALL DIMENSIONS 225" LONG X 68" HIGH X 18" DEEP X 100" WIDE		

SIDE PACKS TO BE 54 " HIGH

TOP BOXES TO BE 14 " HIGH

STREET SIDE COMPARTMENTS

1- 27" WIDE TO BE WALKUP TO DECK

2 - 24" WIDE TO HAVE THREE ADJUSTABLE SHELVES

3 - 24" WIDE TO HAVE ADJUSTABLE SHELVES & 9 SWIVEL HOOKS

4 - 60" WIDE TWO SHELVES C/W DIVIDERS

5 - 66" WIDE TWO SHELVES C/W DIVIDERS

6 - 24" WIDE TO HAVE 18 SWIVEL HOOKS 3 EACH WALL TOP AND CENTRE

HOTSTICK SHELF TO EXTEND FROM S4 TO REAR

HOTSTICK SHELF TO HAVE HOTSTICK BRACKETS

CURBSIDE COMPARTMENTS

1 - 27" WIDE TO BE WALKUP TO DECK

2 - 24' WIDE TO HAVE ONE SHELF & 4 PULLOUT DRAWERS 6" DEEP
C/W CROSS DIVIDERS

3 - 24" WIDE TO HAVE THREE ADJUSTABLE SHELVES C/W 9 SWIVEL HOOKS

4 - 60" WIDE TO HAVE THREE SHELVES C/W DIVIDERS

5 - 66 WIDE TO HAVE THREE SHELVES C/W DIVIDERS

6 - 24" WIDE TO HAVE 18 SWIVEL HOOKS 3 EACH WALL TOP AND CENTRE

SUPPLY AND INSTALL THE FOLLOWING ACCESSORIES

ONE TUBULAR STEEL REAR BUMPER WITH DOOR ON CURBSIDE

ONE 22 TON ARMY STYLE PINTLE HITCH

ONE SET TOW EYES

ONE TRAILER PLUG TO MATCH FLEET 6 POLE

ONE ELECTRONIC TRAILER BRAKE CONTROL

ACCESS HANDLES AT SIDE AND REAR 3 AT EACH SIDE ENTRANCE

INSTALL TWO WHELAN MODEL R6DXPA MINI LIGHT BARS AT LEFT AND RIGHT
REAR CORNERS OF BODY

INSTALL TWO WHELAN MODEL R6DXPA MINI LIGHTBARS AT RIGHT AND LEFT
HAND CORNERS OF THE CAB GUARD

INSTALL TWO SPARTAN REMOTE CONTROL FLOODLIGHTS AT RIGHT AND LEFT REAR CORNERS OF CAB GUARD

INSTALL PLATFORM ACCESS STEPS ON TOP OF BODY COMPARTMENTS.

INSTALL DECK TO COMPARTMENT TOP ACCESS STEPS C/W HANDLES

INSTALL FLYING BRIDGE C/W PLATFORM SUPPORTS

INSTALL ONE REMOVABLE VICE BRACKET AND 6 " SWIVEL VICE AT REAR

INSTALL OUTRIGGER STORAGE BRACKET AS CLOSE TO OUTRIGGERS AS POSSIBLE. STORAGE BRACKETS ARE TO HOLD TWO PADS EACH

INSTALL WHEEL CHOCK CUTOUTS IN FENDER SKIRTS TWO EACH SKIRT

INSTALL TWO BURNDY GROUND STUDS

INSTALL HEAVY DUTY BOOM REST

INSTALL HEAVY DUTY 3/4 CAB GUARD ALUMINUM

INSTALL FRONT BUMPER TEXAS STYLE CONE HOLDERS QTY2 C/W RETENTION DEVICE

CONTROL PANEL TO INCLUDE THE FOLLOWING FUNCTIONS
PTO ENGAGE / DISENGAGE
REAR WORK LIGHTS ON / OFF
BEACONS ON / OFF
COMPARTMENT LIGHTS ON / OFF
PTO HOUR METER
OUTRIGGER WARNING LIGHTS QTY4
BOOM OUT OF REST LIGHT
SPOT LIGHTS ON / OFF
DECK LIGHTS
STROBE LIGHTS C/W THREE POSITION SWITCH

ALL COMPARTMENTS TO BE EQUIPPED WITH VISTA STYLE LIGHTS

SUPPLY SIGN HOLDER FOR THREE SIGNS

SUPPLY SHOVEL BROOM AND RAKE HOLDER

SUPPLY FIRE EXTINGUISHER AND BRACKET

SUPPLY FIRST AID KIT

SUPPLY TRIANGLE FLARE KIT

ALL COMPARTMENT TOPS TO BE TOP OPENING

ALL TOP OPENING COMPARTMENTS TO HAVE GAS STRUTS

TOP OPENING COMPARTMENTS ARE TO STOP12" FROM REAR TO ALLOW FOR LIGHT BAR INSTALLATION

TOP OPENING COMPARTMENTS ARE NOT TO INTERFERE WITH THE PLATFORMS WHEN THE AERIAL DEVICE IS IN THE STOWED POSITION ______

ALL COMPARTMENT TOPS TO HAVE GRIP STRUT ALUMINUM ______

ALL TOP OPENING COMPARTMENTS TO HAVE POSITIVE MECHANICAL LATCHES ______

CARGO AREA IS TO BE LINED WITH ALUMINUM ______

INSTALL BOSCH WORK LIGHTS AT REAR C/W SWIVEL ARMS ______

INSTALL 8 INCH REAR TAIL SHELF AT REAR ______

INSTALL RECESSED DECK AREA LIGHTING ______

INSTALL RECESSED DECK ACCESS LIGHTING ______

INSTALL RECESSED DECK TRANSFORMER TIE DOWN BRACKETS ______

INSTALL BACK UP ALARM ______

INSTALL LADDER FROM DECK TO CAB GUARD ______

INSTALL SURFACE MOUNT AMBER STROBES ON CHASSIS HOOD ______

INSTALL ROUND AMBER STROBES IN REAR TAIL SHELF ______

INSTALL 6 WHELAN MODEL 810CA0ZR SCENE LIGHTS ______

ALL HORIZONTAL COMPARTMENTS TO HAVE GULL WING STYLE DOORS ______

INSTALL TAILBOARD BRACKETS AT REAR AND SIDE ENTRANCE ______

INSTALL LEVEL ANGLE INDICATOR ______

INSTALL REEL STAND AT REAR C/W ARBOR BAR AND COLLARS ______

INSTALL GUY STEEL REEL HOLDER ______

INSTALL SHORT MATERIAL RAIL AT REAR BOTH SIDES C/W HOOKS AND CHAINS ______

INSTALL WATER JUG HOLDER AT REAR ______

BODY COLOR TO BE N0890EA ELITE SS RED

STATE BODY WARRANTY ______

THIS SPECIFICATION IS TO SET FORTH THE SPECIFIC REQUIREMENTS FOR A 83' HYDRAULIC OPERATED ARTICULATING OVER CENTER AERIAL DEVICE

THIS AERIAL DEVICE SHALL BE TO THE MANUFACTURERS STANDARD IT SHALL BE EQUIPPED WITH THE MANUFACTURERS EQUIPMENT AND ACCESSORIES WHICH ARE INCLUDED AS STANDARD IN THE ADVERTISED LITERATURE FOR THE UNIT. NO SUCH ITEM OR EQUIPMENT OR ACCESSORIES SHALL BE REMOVED OR OMITTED FOR THE REASON THAT IT WAS NOT SPECIFIED IN THE BID.

IF IT IS NECESSARY TO BID ALTERNATIVE EQUIPMENT OR TO TAKE EXCEPTIONS TO THE SPECIFICATIONS AS SET FORTH THIS MUST BE SO STATED IN YOUR BID. FOR EACH ITEM PLACE AN X IN THE APPROPRIATE SPACE (YES NO) TO SIGNIFY WEATHER OR NOT YOU ARE IN COMPLETE COMPLIANCE WITH THE SPECIFICATION. FAILURE TO FOLLOW THE FORMAT OR ANSWER THE SPECIFICATION MAY CAUSE YOUR BID BE DISQUALIFIED. IF YOU NEED EXTRA SPACE TO DESCRIBE YOUR PRODUCT PLEASE FEEL FREE TO ATTACH EXTRA SHEETS. WHEN DOING THIS BE SURE YOUR DESCRIPTION REFERENCES THE APPROPRIATE NUMBER

ITEM #	REQUIREMENT	COMPLY YES	COMPLY NO
	UNIT TO BE DESIGNED AS A HIGH CAPACITY MATERIAL HANDLING AERIAL DEVICE		
	UNIT TO BE A STACKED BOOM DESIGN		
	UNIT IS TO BE MOUNTED WITH BUCKETS AT REAR WITH KNUCKLE MOUNTED OVER CAB		
	KNUCKLE IS NOT TO PROTRUDE PAST FRONT BUMPER		
	55' FROM GROUND TO BOTTOM OF PLATFORM ELEVATOR STOWED		
	60' WORKING HEIGHT ELEVATOR STOWED		
	83' FROM GROUND TO BOTTOM OF PLATFORM ELEVATOR RAISED		
	88' WORKING HEIGHT ELEVATOR RAISED		
	360 DEGREE CONTINUOUS ROTATION		
	LOWER BOOM 0 TO 105 DEGREES		
	UPPER BOOM 210 DEGREES IN RELATION TO LOWER BOOM		
	LOWER BOOM 0 DEGREES UPPER BOOM 180 DEGREES 48.8' REACH @ 11.5' HEIGHT STATE ACTUAL ELEVATOR STOWED		
	LOWER BOOM 105 DEGREES UPPER BOOM PARALLEL TO GROUND 36.2' REACH @ 33.8' HEIGHT STATE ACTUAL ELEVATOR STOWED		
	TOP ELEVATOR RAISED LOWER BOOM 105 UPPER BOOM PARALLEL TOP GROUND 36.2' @ 46.8'		
	LOWER ELEVATOR 90 DEGREE UPPER ELEVATOR PARALLEL TO GROUND LOWER BOOM 105 DEGREE UPPER BOOM PARALLEL TO GROUND 51.2' @ 45.5'		

BOTH ELEVATORS UP LOWER BOOM 105 DEGREE UPPER BOOM PARALLEL TO GROUND 36.2' @ 60.2'

UNIT MUST COMPLY TO THE FOLLOWING STANDARDS
CAN CSA C225-00
ANSI/SIA A92.2-1990
W47.1 - 1983
W59 - M1984
CAN 3 - Z299 4- 85
SAE J343c
OSHA PARAGRAPH 1910.67 & 1926.556

ALL FEDERAL AND PROVINCIAL REQUIREMENTS

ISO 9001 94

STEEL STRUCTURES 3:1 TO YIELD

STEEL STRUCTURES USED IN FABRICATION OF ANY LOAD BEARING ELEMENT MUST HAVE A MINIMUM YIELD STRENGTH OF 50,000 PSI AND A CHARPY IMPACT VALUE OF 20J - 20c

ALL FIBERGLASS TO BE RATED 8:1 TO THE K POINT

SELF ALIGNING BEARINGS ARE TO BE USED THROUGHOUT LOAD BEARING AXIS POINTS

A SINGLE SPEED PTO CONTINUOUS DUTY ELECTRIC SHIFTED IS TO BE MOUNTED ON THE VEHICLE TRANSMISSION

PTO IS TO BE 6 BOLT TYPE

PTO IS TO BE EQUIPPED WITH RED WARNING LIGHT

PTO IS TO PROVIDE 1000 RPM ON ITS OUTPUT SHAFT WITH THE VEHICLE SPEED BETWEEN 900 AND 1200 RPM

PTO SWITCH IS TO BE LOCATED IN WIRE RITE CONTROL PANEL OR CHASSIS SUPPLIED SWITCH PANEL

A VARIABLE VOLUME HYDRAULIC PUMP

PUMP IS TO BE CLOSE COUPLED TO THE PTO

PUMP IS TO BE VICKERS OR EQUIVALENT

PUMP TO BE 3000 PSI STATE ACTUAL

PUMP TO BE 12 GPM STATE ACTUAL

HYDRAULIC SYSTEM TO BE FULL PRESSURE CLOSED CENTER DESIGN

50 GALLON FRAME MOUNT RESERVOIR IS TO BE PROVIDED

RESERVOIR IS TO BE PROVIDED WITH
BREATHER
SUMP
DRAIN PLUG

SIGHT GAGE
THERMOMETER
CLEAN OUT HAND HOLE
MAGNETIC DRAIN PLUG
SHUT OFF VALES TIE WIRED IN THE OPEN POSITION
BAFFLES

100 MESH SUCTION LINE STRAINER

10 MICRON RETURN LINE FILTER WITH RELIEF

GATE VALVES ARE TO BE PROVIDED ON SUCTION AND DRAIN LINES

BOOM CYLINDERS ARE TO BE EQUIPPED WITH PAD MOUNTED PILOT OPERATED ADJUSTABLE HOLDING VALVES

OUTRIGGERS ARE TO BE WELDED TO THE SUB FRAME AND BOLTED TO THE CHASSIS FRAME RAIL

OUTRIGGERS ARE TO BE RADIAL DESIGN

OUTRIGGER FOOT PADS ARE TO MEASURE 14" X 14"

OUTRIGGER FOOT PADS TO BE SUPPLIED WITH FLAG HOLDERS

OUTRIGGERS AR TO FIT A 100" WIDE BODY

OUTRIGGERS ARE TO HAVE 10" OF GROUND PENETRATION

OUTRIGGER / MACHINE SELECTOR VALVE IS TO BE LOCATED AT THE LOWER CONTROL STATION

OUTRIGGER CONTROL VALVES ARE TO BE LOCATED SO TO ALLOW THE OPERATOR CLEAR VIEW OF THE OUTRIGGER OPERATION

OUTRIGGERS ARE NOT TO BIND UNDER FULL LOAD DURING OPERATION

OUTRIGGERS ARE TO BE EQUIPPED WITH HOLDING VALVES

QTY 4 OUTRIGGER WARNING LIGHTS ARE TO BE PROVIDED

SUB FRAME IS TO BE A INTEGRAL PART OF THE AERIAL DEVICE

SUB FRAME IS TO BE 6" X 4" RECTANGULAR HOLLOW HIGH TENSILE STEEL TUBING

SUB FRAME IS TO BE PLATED WITH 3/8" STEEL TOP AND BOTTOM

SUB FRAME IS TO BE PRIMED AND FINISH PAINTED

THE PEDESTAL IS TO BE THOROUGHLY WELDED AND BRACED TO THE SUB FRAME BOLT ON DESIGN IS NOT ACCEPTABLE

THE TURNTABLE BEARING SHALL HAVE A 32 1/8" DIAMETER AND A NOMINAL CAPACITY MOMENT OF 315,600 FT LBS

THE PEDESTAL IS TO BE EQUIPPED WITH A HINGED ACCESS DOOR

THE PEDESTAL IS TO MEASURE 26" X 26" X 5/`16" THICK

THE PEDESTAL IS TO BE MANUFACTURED OF H.S.S. STEEL

THE PEDESTAL TOP PLATE IS TO BE MACHINED AFTER WELDING

ROTATION IS TO BE ACCOMPLISHED THROUGH A PLANTARY GEAR DRIVE TRANSMISSION WORM GEAR DRIVE IS NOT ACCEPTABLE

ROTATION IS TO BE FIELD ADJUSTABLE FOR BACK LASH

AN AUTOMATIC SPRING APPLIED HYDRAULIC RELEASE BRAKE IS TO BE PROVIDED

IN THE EVENT OF A HYDRAULIC FAILURE A MEANS OF MANUAL ROTATIONS TO BE PROVIDED

FIBERGLASS SECTIONS ARE TO BE SANDED SMOOTH AND SPRAY PAINTED TO MATCH FLEET COLORS WITH A NON CONDUCTIVE PAINT

PAINT IS TO BE WATERPROOF

PAINT SHALL NOT CRACK

BOOM IS TO BE DESIGNED TO ALLOW CANDLIGHTING OF A SUSPECTED AREA IF REQUIRED

LOWER BOOM INSERT MANUFACTURED FROM SPIRALLY WOUND FIBERGLASS

LOWER BOOM INSERT TO PROVIDE 58.62" CLEAR GAP INSULATION

LOWER BOOM TO BE RECTANGULAR IN SHAPE

LOWER BOOM TO MEASURE 13.5" X 11.5" X 1.75" THICK

LOWER BOOM TO MEASURE 265.25" PIN TO PIN

LOWER BOOM TO ARTICULATE BY MEANS OF ONE LIFT CYLINDER

LOWER BOOM LIFT CYLINDER TO BE DOUBLE ACTING TYPE

UPPER BOOM TO BE MANUFACTURED FROM SPIRALLY WOUND FIBERGLASS

UPPER BOOM TO BE 33" LONGER THAN LOWER BOOM

UPPER BOOM TO PROVIDE 216.9" CLEAR GAP INSULATION

UPPER BOOM TO MEASURE 295.25" PIN TO SHAFT

UPPER BOOM MEASURE 13.5" X 11.5" X 1" THICK

BOOM DEFLECTION IS TO BE LESS THAN 1/8 TH " PER FOOT

UPPER BOOM TO ARTICULATE BY MEANS OF DUAL BOOM LIFT CYLINDERS THAT WORK IN UNISON

UPPER BOOM LIFT CYLINDERS TO BE DUAL CYLINDER DESIGN

ALL BOOM PINS TO BE CHROMED

ALL BOOM PINS TO BE DRILLED AND THREADED TO FACILITATE EASE OF REMOVAL

RETURN TO ZERO BOOM STOW LIGHT IS TO BE SUPPLIED AT THE BOOM REST TO ALLOW OPERATOR TO SEE WHEN THE LOWER BOOM IS LINED UP WITH THE BOOM REST FOR STORAGE

AN AIR OPERATED BOOM STOW LATCH SYSTEM IS TO BE PROVIDED FOR BOTH UPPER AND LOWER BOOMS

TWO 24" X 30" X 42" DEEP PLATFORMS ARE TO BE PROVIDED

TWO PLATFORM LINERS 50KV RATING ARE TO BE PROVIDED

TWO PLATFORM SCUFF PADS C/W STEPS ARE TO BE PROVIDED

TWO HEAVY DUTY VINYL PLATFORM COVERS ARE TO BE PROVIDED

PLATFORM CAPACITY TO BE 300LBS

PLATFORMS ARE TO BE SUPPLIED WITH MOLDED IN STEPS

OPERATORS PLATFORM IS TO ROTATE 90 DEGREES

PASSENGER PLATFORM IS TO ROTATE 90 DEGREES

PASSENGER PLATFORM TO BE QUICK RELEASE DESIGN

PLATFORMS ARE TO SUPPLIED WITH HYDRAULIC TILT CONTROL LOCATED AT THE UPPER CONTROL STATION

A D RING ATTACHMENT IS TO BE PROVIDED AT THE PLATFORM AREA FOR LANYARD ATTACHMENT

UNIT TO BE EQUIPPED WITH A COMBINATION FLYING BRIDGE AND PLATFORM SUPPORT

PLATFORM LEVELING IS TO BE POSITIVE THROUGH A PARALLELOGRAM OF NUMBER 100 ROLLER CHAIN

LEVELING CHAIN SHALL HAVE AN AVERAGE TENSILE STRENGTH OF 30,000 LBS

FIBERGLASS RODS ARE TO BE USED TO MAINTAIN RATED DIELECTRIC STRENGTH

THE LEVELING SYSTEM IS TO BE ENCLOSED WITHIN THE BOOMS

ACCESS IS TO BE PROVIDED FOR INSPECTION

THE LEVELING SYSTEM IS TO HAVE A LIFETIME WARRANTY AND IS TO REQUIRE INSPECTION ONLY DURING THE LIFE OF THE AERIAL DEVICE THERE IS TO BE NO MANDATORY CHANGE REQUIRED FOR THE LEVELING SYSTEM

HYDRAULIC CONTROLS ARE TO BE LOCATED AT THE PLATFORMS AND BELOW ROTATION AT THE RIGHT REAR CORNER OF THE BODY

LOWER CONTROL VALVE TO BE DANFOSS PVG32 PROPORTIONAL VALVE WITH INDIVIDUAL ADJUSTMENT FOR

LO (START) SPEED BOTH DIRECTIONS OF OPERATION
HI (MAXIMUM) SPEED BOTH DIRECTIONS OF OPERATION
RAMP UP BOTH DIRECTIONS OF OPERATION
RAMP DOWN BOTH DIRECTIONS OF OPERATION
MID RANGE "SLOW" MODE BOTH DIRECTIONS OF OPERATION

AERIAL DEVICE IS TO BE CAPABLE OF MULTIPLE BOOM FUNCTIONS FROM THE UPPER CONTROL STATION

BOOM FUNCTIONS ARE TO BE CONTROLLED BY A 4 AXIS HYCOTEC MODEL M22019-00015-01 PISTOL GRIP STYLE JOYSTICK

AXES TO BE AS FOLLOWS
X AXIS ROTATION CW/CCW
Y AXIS UPPER BOOM FOLD UNFOLD
Z AXIS PUSH PULL LOWER BOOM RAISE AND LOWER
W AXIS PROPORTIONAL THUMB ROCKER UPPER AND LOWER ELEVATOR RAISE LOWER

ELEVATOR FUNCTION TO HAVE PROVISION TO OPERATE UPPER OR LOWER ELEVATOR OR BOTH SIMULTANEOUSLY

BOOM JOYSTICK TO BE EQUIPPED WITH A DEADMAN TRIGGER
NO BOOM FUNCTIONS TO BE POSSIBLE UNLESS THE JOYSTICK IS IN NEUTRAL BEFORE THE JOYSTICK TRIGGER IS PULLED

THE FOLLOWING ACCESSORY FUNCTIONS ARE TO BE AVAILABLE AT THE BUCKET CONTROL STATION
ENGINE START
ENGINE STOP
EMERGENCY STOP
TOOLS ON/OFF
ENGINE THROTTLE HIGH/LOW
EMERGENCY PUMP
BOOM FUNCTION RESPONSE FAST/SLOW
BRIGHT WHITE LED LIGHT TO ILLUMINATE UPPER CONTROL STATION

WINCH CONTROLLER AT PLATFORM TO BE SUPPLIED WITH SEPARATE DEADMAN ENABLE

BOOM/ELEVATOR/WINCH AND ACCESSORY FUNCTION COMMAND SIGNALS TO BE TRANSMITTED AND PROCESSED VIA HYCOTEC FIBER OPTIC CANBUS SYSTEM

PILOT OPERATED SYSTEMS ARE NOT ACCEPTABLE

CANBUS SYSTEM INPUT/OUTPUT BOARDS TO BE EPOXY POTTED

RATED FOR -40 TO + 85 C

OPERATIONAL LIMITATIONS /LOGIC PRIORITY SELECTION TO BE PERFORMED VIA CANBUS SYSTEM SOFTWARE TO LIMIT THE AMOUNT OF EXTERNAL RELAYS WIRING

LOWER CONTROLS ARE TO BE LOCATED AT THE CURBSIDE REAR TAIL SHELF

LOWER CONTROLS ARE TO INCLUDE THE FOLLOWING FUNCTIONS
TWO SPEED THROTTLE
D/C LOWERING
ENGINE STOP / START

LIGHT FOR NIGHT TIME OPERATION
AERIAL DEVICE / OUTRIGGER / EMERGENCY STOP
OUTRIGGER CONTROLS CURBSIDE
TOOL OUTLETS AND CONTROL SELECTOR
LOWER BOOM RAISE / LOWER
UPPER BOOM RAISE / LOWER
ROTATION LEFT / RIGHT
WINCH RAISE / LOWER
WINCH ON/OFF KEY SWITCH
UPPER ELEVATOR RAISE AND LOWER
LOWER ELEVATOR RAISE AND LOWER

CONTROLS FOR STREET SIDE OUTRIGGERS ARE TO BE LOCATED AT STREET SIDE REAR OF THE BODY

UPPER CONTROLS ARE TO INCLUDE THE FOLLOWING FUNCTIONS
TWO SPEED THROTTLE
ENGINE STOP / START
D/C LOWERING
PLATFORM ROTATION TO BE CONTROLLED VIA FULL PRESSURE OPEN CENTRE VALVE
UPPER BOOM RAISE / LOWER
LOWER BOOM RAISE / LOWER
ROTATION LEFT / RIGHT
WINCH UP / DOWN
JIB ROTATE UP / DOWN TO BE CONTROLLED VIA FULL PRESSURE OPEN CENTRE VALVE
JIB EXTEND / RETRACT TO BE CONTROLLED VIA FULL PRESSURE OPEN CENTRE VALVE
TOOLS ON / OFF
EMERGENCY STOP
BOOM SPEED FAST / SLOW
ELEVATOR UP/DOWN

UNIT IS TO BE DESIGNED AND TESTED AS PER CSA 225-00

UNIT TO BE STABILITY TESTED TO CSA C225-M88

UNIT TO BE RATED AS A CLASS B MACHINE 69 KV AS PER CSA C225-00

UNIT TO BE SUPPLIED WITH CURRENT LEAKAGE MONITORING SYSTEM C/W METER CABLE AND CASE.

AMPHENOL CONNECTOR TO BE LOCATED AT UPPER BOOM BASE END IN BOOM INSPECTION COVER

LOWER BOOM INSERT IS TO BE JUMPERED OUT WITH A COPPER BAR AND STUDS

UNIT TO BE SUPPLIED WITH VACUUM FLASHOVER PROTECTION

THE AERIAL DEVICE IS TO BE TESTED AT THE FACTORY BY QUALITY CONTROL PERSONNEL

AN APPLICABLE CHECK LIST IS TO BE USED AND AVAILABLE FOR REVIEW IF REQUIRED

ALL COMPONENTS ARE TO BE GIVEN A VISUAL INSPECTION UNDER OPERATION AT SHAFT CAPACITY

HYDRAULIC COMPONENTS ARE TO BE ADJUSTED AND TESTED

ALL HOLDING VALVES ARE TO BE CHECKED AND ADJUSTED
TO RATED LOAD

ALL TESTING IS TO BE DOCUMENTED AND A COPY AVAILABLE
IF REQUESTED

THE FOLLOWING WARNING LIGHTS ARE TO BE SUPPLIED IN THE CAB
PTO
OUTRIGGER WARNING LIGHTS QTY4
BOOM STOW
PTO HOUR METER

A HEAVY DUTY BOOM REST IS TO BE SUPPLIED

BOOM REST IS TO BE LOCATED BETWEEN THE CAB AND THE BODY

TWO SETS OF TOOL OUTLETS ARE REQUIRED AT THE BOOM TIP

ONE SET OF TOOL OUTLETS ARE TO BE PROVIDED AT THE LOWER
CONTROL STATION

TOOL OUTLETS ARE TO MATCH EXISTING FLEET

TOOL OUTLETS TO BE SET AT 5 GPM 2000 PSI

A NINE FOOT RECTANGULAR IN SHAPE JIB BOOM IS TO BE SUPPLIED

IT IS TO BE MADE OF PULTRUSION FIBERGLASS AND MOUNTED ON
THE LEVELING SHAFT

A CONTINUOUS ROTATION HYDRAULIC DEVICE IS TO BE LOCATED
INSIDE THE UPPER BOOM

MAXIMUM OUTPUT TORQUE CAPACITY SHALL BE 39,000 IN POUNDS

A DOUBLE ACTING HYDRAULIC EXTENSION IS TO BE SUPPLIED

MAXIMUM VERTICAL EXTENSION CAPACITY 2,400 LBS

24" STROKE

MUST BE ABLE TO EXTEND AND RETRACT UNDER FULL RATED LOAD

JIB MUST BE REPINNABLE UNDER LOAD

JIB MUST ROTATE 250 DEGREES IN ALL BOOM POSITIONS

JIB MUST ROTATE UNDER FULL RATED LOAD

A DOUBLE ACTING HYDRAULIC WINCH IS TO BE SUPPLIED

WINCH TO HAVE 4,000 LB BARE DRUM RATING

WINCH TO HAVE 2,000 FULL DRUM RATING

WINCH TO BE INSTALLED BELOW JIB BOOM HOLDER

WINCH LINE TO BE YALE MAXIBRAID 0.5" X 80'

WINCH LINE TO HAVE 7 TO 1 SAFETY FACTOR

WINCH LINE TO HAVE EYE SPLICE AND THIMBLE AT WORKING END

WINCH LINE TO BE SPLICED BY A CERTIFIED SPLICER

A REMOVABLE DOUBLE ROLLER SHEAVE HEAD IS TO BE SUPPLIED

A TOP OPENING TILTING CONDUCTOR HOLDER IS TO BE SUPPLIED

CONDUCTOR HOLDER IS TO HAVE A 825 LB RATING IN ALL POSITIONS

A COMPLETE SET OF FIBERGLASS GUARDS ARE TO BE SUPPLIED ON THE MATERIAL HANDLING PACKAGE

GREASE ZERKS FOR OUTRIGGER AND BOOM LUBRICATION ARE TO LOCATED IN EASY TO REACH LOCATIONS

ALL HIGH HOSE TO BE COLORED ORANGE AND BE USED ABOVE AND BELOW ROTATION

HIGH PRESSURE HOSE TO MEET SAE 100R7

MAIN PRESSURE AND RETURN LINE BELOW ROTATION TO BE NON COLLAPSIBLE SAE 100R2 WITH OIL AND WEATHER RESISTANT COVER

ALL HOSE TO BE RATED TO 4:1 MINIMUM

ALL HOSES ROUTED CLOSE TO EXHAUST TO BE SHIELDED

ALL HIGH PRESSURE TUBING O SAE J524A

ALL TUBE FITTINGS TO SAE J514D

ALL HYDRAULIC PIPE FITTING TO SAE J926

HOSES TO BE IDENTIFIED AT BOTH ENDS AS TO FUNCTION

HOSES TO HAVE CODING SHEET INCLUDED IN MANUAL

LOWER BOOM ARTICULATION TO BE ACCOMPLISHED WITH A SINGLE BOOM LIFT CYLINDER

UPPER BOOM ARTICULATION TO BE ACCOMPLISHED BY MEANS OF TWO CYLINDERS AND A DELTA DRIVE CHAINS AND CABLES ARE NOT ACCEPTABLE

INCLUDE TWO SETS OF OPERATORS PARTS AND MAINTENANCE MANUALS

INCLUDE COPY OF WARRANTY STATEMENT

ELEVATOR TO PROVIDE 0 TO 90 DEGREE ARTICULATION

ROTATION IS TO BE LOCATED AT THE TOP OF THE ELEVATOR

ELEVATOR TO PROVIDE AN ADDITIONAL 28 FEET OF HEIGHT

UNIT TO BE EQUIPPED WITH QTY 2 9 VOLT BATTERY CHARGERS IN CAB

BOOM STEEL N0890EA ELITE SS RED

BOOM FIBERGLASS WHITE

PLATFORMS WHITE

OUTRIGGERS N0890EA ELITE SS RED

SUB FRAME N0890EA ELITE SS RED

JIB WHITE

PLEASE FILL IN THE FOLLOWING CHART WITH YOUR NET JIB LIFT CAPACITIES. CAPACITIES ARE TO ASSUME THAT THE PLATFORMS ARE FULLY LOADED TO CAPACITY AND ALL DEDUCTIONS HAVE BEEN MADE FOR ALL EQUIPMENT AT THE BOOM TIP. BARE SHAFT CAPACITIES AND NET SUPPLEMENTAL CAPACITIES WILL NOT BE CONSIDERED. FAILURE TO COMPLETE THE CHART WILL WILL CAUSE YOUR TENDER TO BE DISQUALIFIED.

NET UPPER JIB CAPACITIES REQUIRED
FULL MATERIAL HANDLING JIB 600LB PLATFORM CAPACITY
PLEASE FILL IN THE BLANKS WITH YOUR CORRESPONDING CAPACITIES

LOWER BOOM ANGLE DEGREES	UPPER BOOM ANGLE DEGREES	REACH" 12" CAPACITY REQUIRED	***STATE ACTUAL CAPACITY***		REACH 36" CAPACITY REQUIRED	***STATE ACTUAL CAPACITY***		REACH 48" CAPACITY REQUIRED	***STATE ACTUAL CAPACITY***
90	-90	2000			1333			1000	
90	-85	2000			1333			1000	
90	-80	2000			1333			1000	
90	-75	2000			1333			1000	
90	-70	2000			1333			1000	
90	-65	2000			1333			1000	
90	-60	2000			1333			1000	
90	-55	2000			1333			1000	
90	-50	2000			1333			1000	
90	-45	2000			1333			1000	
90	-40	2000			1333			1000	
90	-35	1950			1333			1000	
90	-30	1745			1333			1000	
90	-25	1584			1333			1000	
90	-20	1461			1333			1000	
90	-15	1369			1333			1000	
90	-10	1306			1333			1000	
90	-5	1269			1175			1000	
90	0	1256			1163			1000	
90	5	1267			1173			1000	
90	10	1303			1205			1000	
90	15	1364			1260			1000	
90	20	1454			1333			1000	
90	25	1575			1333			1000	
90	30	1733			1333			1000	
90	35	1937			1333			1000	
90	40	2000			1333			1000	
90	45	2000			1333			1000	
90	50	2000			1333			1000	
90	55	2000			1333			1000	
90	60	2000			1333			1000	
90	65	2000			1333			1000	
90	70	2000			1333			1000	
90	75	2000			1333			1000	
90	80	2000			1333			1000	
90	85	2000			1333			1000	
90	90	2000			1333			1000	
90	95	2000			1333			1000	
90	100	2000			1333			1000	
90	105	2000			1333			1000	

Question 3.6 - Building Renovations/Expansion

Ref: Exhibit 2/Tab 3/Schedule 1/Attachment 1

Exhibit 2/Tab 3/Schedule 6, pp. 67-70

In Exhibit 2/Tab 3/Schedule 1/Attachment 1, Bluewater states that it expects to incur expenditures of $863,315 in 2009 on Project 05 "Building Renovations/Expansion". This is a considerably higher expenditure than the 2008 level of $185,000 and the 2007 level of $28,154.

In Exhibit 2/Tab 3/Schedule 6, pp. 67-70, Bluewater identifies a number of reasons for this increased level of expenditures. These reasons often appear to be related to factors that go back a number of years, for instance it is stated on page 68 that "Since 1990 staff has increased significantly and, as a result, staff are doubled up in offices, sitting in hallways, or utilizing spaces not designated to safely and effectively accommodate personnel". Other factors are cited that appear to go back to the 2000 merger. For example, for equipment bay space, on page 68, it is stated that "similar to the personnel impact of the merger Bluewater assumed responsibility for all equipment bay storage requirements for the trucks and other equipment absorbed as part of the merger."

Question 3.6 (a)

For each of the years from the 2000 merger to 2011, during which Phase V of the Multi-Year Program will commence, please provide the overall level of expenditures on building renovations/expansions, broken down by major line items. For each phase of the multi-year program, please specify the amounts that have been, or are anticipated to be spent in each year and what they will be spent on.

3.6 (a) Response:

Please see the attachment below which provides the overall level of expenditures on building renovations/expansions, broken down by major line items.

Attachment: "Board Staff 3.6 a – Bldg Renos & Expansion"

OEB Question 3.6 a : Building Renovations/Expansion

2000:	
Pre-Merger - data not readily available	NIL
2001:	
Miscellaneous	29,548
2002:	
No capital additions	NIL
2003:	
Substation building improvements	44,087
2004:	
Repaving yard and walkways	50,668
Engineering office renovations	87,304
Miscellaneous	16,347
	154,319
2005:	
Electrical related upgrades	17,298
Various office renovations	9,595
Security system	10,476
Bunks for pole storage	15,084
Miscellaneous	6,693
	59,146
2006:	
Substation building improvements	46,288
Office carpet installation	31,697
Roof upgrade	60,392
Installation of back gate and security system	30,992
Miscellaneous	7,237
	176,606
2007:	
Substation building improvements	63,844
Roof upgrade	62,283
Office furniture replacement	14,095
Heating & cooling system	11,181
Main building improvements (windows, etc)	29,645
Miscellaneous	8,665
	189,713
2008 Estimated Actuals:	
Substation building improvements	35,000
Roof upgrade	94,925
Main building renovations (offices, lobby)	245,925
Rooftop air conditioner unit	19,400
Miscellaneous	2,077
	397,327

OEB Question 3.6 a : Building Renovations/Expansion

2009 Test Year:	
Substation building improvements	106,970
Roof upgrade	53,485
Building expansion (vehicle bays, equip storage)	863,315
	1,023,770
2010:	
Substation building improvements	100,000
Service center improvements	50,000
Parking lot expansion	150,000
Basement renovation (meeting room, storage area)	250,000
	550,000
2011:	
Substation building improvements	100,000
Service center improvements	50,000
Building addition ($2.5M to $4.0M)	4,000,000
	4,150,000

Question 3.6 (b)

Please provide any cost/benefit analyses that may have been undertaken to justify the Multi-Year Program and the other expenditures.

3.6 (b) Response:

Bluewater Power believes a multi-year program is the most prudent approach in order to complete the total project without an undue drain on internal resources, both financial and human. Although a new building addition is inevitable, we believe it is best to start with the smaller “no-choice-left” expenditures before tackling the total building addition.

Question 3.7 - SAP Upgrade

Ref: Exhibit 2/Tab 3/Schedule 6, pp.54-66

Exhibit 2/Tab 3/Schedule 6, Attachment 1

Exhibit 2/Tab 3/Schedule 1, Attachment 1

In Exhibit 2/Tab 3/Schedule 1/Attachment 1, Bluewater states that it expects to incur expenditures of $1,445,145 in 2009 on Project IT18 "SAP Upgrade". No expenditures are stated as having been incurred on this project in either 2007 or 2008.

In its evidence, Bluewater discusses the reasons for undertaking the SAP upgrade, including alternatives considered such as the outlined "Alternative #1: SAP Upgrade," on page 59 of Exhibit 2/Tab3/Schedule 6 and "Alternative #2: Custom Development", on page 64 of the same exhibit." In support of these expenditures, Bluewater also provides an independent technology assessment by SJH Consulting.

Question 3.7 (a)

Please file with the Board all supporting documents including prior studies and cost/benefit analyses that Bluewater conducted to assess alternative ERP systems and to justify the selection, development and implementation of the SAP system. Please include an explanation as to why Bluewater could not deploy more cost effective systems to meet its ERP needs.

3.7 (a) Response:

Bluewater Power implemented its ERP as part of its transition to market opening. The prudence of this expenditure was addressed as part of Bluewater Power's Regulatory Assets Review (RP-2005-0020/EB-2005-0527), and approved by the Board in a final decision. Although Bluewater Power could re-file its evidence from that proceeding, it would be inappropriate to re-open the prudence of an expenditure that was approved as part of a final Board decision.

Question 3.7 (b)

Please provide a complete overview of the factors leading to Bluewater's decision to undertake this upgrade expenditure including an explanation of why this expenditure was determined to be necessary.

3.7 (b) Response:

Bluewater Power addressed its decision to undertake this upgrade expenditure (including an explanation of why this expenditure was determined to be necessary) at Exhibit 2, Tab 3, Schedule 6, pages 54 through 66. It also provided an independent assessment of this proposed expenditure at Exhibit 2, Tab 3, Schedule 6, Attachment 1, pages 1 through 9.

Nevertheless, to summarize, Bluewater Power last upgraded its SAP system almost five years ago, but in reality is working on end user development that dates back to 1999. The vendor has since released a series of upgrades with significant product maturity and industry improvements and is recommending an upgrade to its latest product. Bluewater Power reviewed the current SAP implementation and assessed it against this latest version of SAP. A number of business process limitations were identified in the current system and it was determined that these would be resolved in an upgraded system. To further assess the apparent value of upgrading the system, an independent consultant having expertise with SAP and in the utilities industry, was engaged to develop a report assessing the existing implementation of SAP at Bluewater Power. This report (included in the rate application and noted above) concurred with the Bluewater Power assessment. Because of these investigations, it became clear that Bluewater Power needs to engage in an upgrade to its SAP installation. Given the inevitability of software upgrades, further consideration was given to the timing of such a project. With the introduction of Smart Metering in 2010 and the significance of that undertaking, it was determined that an SAP upgrade would need to be performed in 2009. This approach will result in the overall lowest costs and will provide the best benefit to Bluewater Power and its customers.

Question 3.7 (c)

Please provide the total annual ongoing costs to maintain this system including the breakdown cost such as licence fees, maintenance fees, etc.

3.7 (c) Response:

Ongoing costs to maintain SAP include the following…

- Annual SAP Software Maintenance ----------$130,000
- Annual Datacentre Costs ------------------------$ 23,000
- Annual Deloitte AMO Costs --------------------$128,500
- Total Annual Costs -------------------------------$281,500

For the most part, these are the required costs to maintain SAP. Through the Deloitte AMO most of the regular minor upgrades and system maintenance can be managed. The Deloitte AMO is typically utilized fully –utilized in these pursuits. However, in addition to those costs, there can be costs incurred above that for legislated changes such as two tier billing, or Global 686. These fluctuate but each year Bluewater Power is able to do more 'in-house' because of knowledge gained.

Finally, as with any system, there are upgrades required every 4 to 7 years. With this upgrade, future upgrade should be have costs of a lesser magnitude for two reasons: (i) Bluewater Power's existing platform includes custom features dating back to 1999 that will be eliminated and, therefore, will not require accommodation in future upgrades, and (ii) SAP's current software platform is designed to accommodate the needs of mid-sized more efficiently. Therefore, it is our belief and understanding that future upgrades will be at a lesser costs.

Question 3.7 (d)

Please state whether Exhibit 2/Tab 3/Schedule 6/Attachment 1 "Bluewater Power SAP ERP 6.0 Upgrade Plan – Independent Assessment" represents the full report by SJH Consulting, or a summary of it. If it is not the full report, please provide a copy of this report. Please also state whether SJH Consulting undertook any quantitative assessments in support of its recommendations and, if so, please provide them.

3.7 (d) Response:

The report provided was the full report. SJH Consulting did not undertake a specific quantitative assessment to document the anticipated cost savings as they would apply to Bluewater Power for the report. Rather, the report includes high level quantitative assessments as derived from other upgrades and industry statistics.

The focus of the report is to identify the limitations of the current system, and assess whether upgrade is justified at this time. How these quantitative assessments will specifically impact BWP was not explored in detail, as this upgrade was driven by more practical factors with a primary focus on timing and resources.

Question 3.8 - Trans Station Meter Upgrade - Modeland

Ref: Exhibit 2/Tab 3/Schedule 6, p .46

Exhibit 2/Tab 3/Schedule 1/Attachment 1

In Exhibit 2/Tab 3/Schedule 1/Attachment 1, Bluewater states that it expects to incur expenditures of $525,074 in 2009 on Project M7 Trans Station Meter Upgrade - Modeland. No expenditures are stated to have been incurred on this project in either 2007 or 2008.

Question 3.8

Please provide a more detailed explanation as to how the costing on meter upgrade projects of this kind is determined including alternatives assessed and whether or not any competitive bidding is involved.

3.8 Response:

The budget for this project was based on the costs incurred for a similar project completed in 2007 at the St Andrews transmission station. Details of this project are shown in Exhibit 2, Tab 3, Schedule 6, page 45. The St Andrews project entailed individually metering six feeders. The total cost for that project was approximately $314,000. The proposed Modeland project is similar in all aspects except there are nine feeders that need to be individually metered instead of six. The table below details the actual costs for the St Andrews project which were used as a proxy to estimate the projected costs for Modeland.

	Costing for St. Andrews Project	Budget for Modeland Project
Labour Costs	$ 45,121	$ 70,389
Vehicle Costs	$ 5,113	$ 7,669
Metering units	$ 235,089	$ 352,633
Other Direct materials	$ 28,490	$ 42,735
Inflation costs and Contingency		$ 51,647
Total	$ 313,813	$ 525,074

There are no alternatives to individually metering these feeders. The instrument transformers currently in use at Modeland are owned by Hydro One and are non-compliant with Measurement Canada regulations.

Given that we cannot use the same metering set-up as is currently in place, we evaluated installing the meters on the feeders exiting the station or on the feeders entering the station. It was determined that installing meters on the low voltage feeders exiting will cost less than installing meters on the high voltage incoming feeders because of the increased cost of 230 KV rated instrument transformers and additionally this option would entail leasing land from Hydro One.

Bluewater Power is planning on using our existing meter service provider to provide registration, material procurement, installation and maintenance for this project, therefore will not be going through a competitive bidding process.

Question 3.9 - 27.6 kV Neutral Program

Ref: Exhibit 2/Tab 3/Schedule 1/Attachment 1

Exhibit 2/Tab 3/Schedule 6, pp. 20-22

In Exhibit 2/Tab 3/Schedule 1/Attachment 1, Bluewater states that it expects to incur expenditures of $146,820 in 2009 on Project UT5 "27.6 kV Neutral Program." This proposed expenditure follows expenditures in this area of $40,000 in 2008 and $24,512 in 2007.

On Page 21 of Exhibit 2/Tab 3/Schedule 6, Bluewater provides a justification for this expenditure stating that:

> *"Commencing in 2009, Bluewater Power plans to commence a multi-year program to replace its remaining neutral conductors to improve reliability and power quality. Bluewater Power estimates that the entire program will take approximately 5 to 7 years to complete at a costs of $150,000 per year."*

Question 3.9

Please provide any quantitative analyses including engineering studies that were undertaken that support the multi-year program expenditures referenced above.

3.9 Response:

Electrical distribution utilities utilize neutral conductors (parallel path for fault current) to provide a low-impedance path for clearing line-to-case faults. A properly sized neutral plays a key role in a Y connected electrical distribution system. If a ground fault occurs (arcing) then severe over voltages can occur on a poorly grounded system. The intermittent fault can cause the system voltage to ground to rise to six or eight times the phase-to-phase voltage. Over voltages caused by intermittent faults can be controlled by grounding the distribution system to an appropriately sized neutral. The connection of the neutral points of transformers and electrical apparatus to the earth ground network provides a reference point of zero volts. This protective measure offers many advantages.

- Reduced magnitude of transient over-voltages
- Simplified ground fault location
- Improved system and equipment fault protection
- Reduced maintenance time and expense
- Greater safety for personnel

- Improved lightning protection
- Reduction in frequency of faults.

A 1999 report prepared by Elecsar Engineering Limited (see attachment Board Staff IR #3.12(d)) stated that Sarnia Hydro had a serious problem regarding undersized system neutrals. The report identified that Sarnia Hydro began to convert from a 3 wire 27.6kV system to 27.6/16.2 kV system beginning in early 1980; the reason for this was to relieve overloaded circuits on the 4kV system. The problem with this type of conversion (because it was gradual and over a long period of time) is that the neutral conductors were not upgraded; the newly converted system relied on small, undersized system neutrals that are not capable of handling available fault currents. Conversion from 4kV to 27.6 kV is still taking place annually.

It is imperative that upgrades to the existing neutral system take place on all 15 of Bluewater Power's 27.6KV circuits feeding Sarnia customers. There are also neutral upgrades required in the outlier shareholders of Oil Springs, Petrolia, Alvinston and Watford.

Upgrades to the neutral conductors help eliminate possible step potential hazards, as well improve fault-clearing times on each feeder thus avoiding extended voltage reductions and lengthy unplanned outages. The neutral program ensures that public and employee safety is maintained.

- The large industrial customers out of St Andrews TS have experienced more power quality issues recently which is in part related to the inadequate/substandard neutral size, which has lead to the need to ramp up the conductor replacement.
- These neutrals would not be up to current standards for new construction, so it is part of our plan to increase the neutral program.

Our goal is to increase spending on neutral upgrades over a 7 year time frame. The increased spending will help improve system reliability, system safety and will better position Bluewater Power to accept new growth opportunities.

Question 3.10 - Animal Protection

Ref: Exhibit 2/Tab 3/Schedule 1/Attachment 1

Exhibit 2/Tab 3/Schedule 6, pp. 28-29

In Exhibit 2/Tab 3/Schedule 1/Attachment 1, Bluewater states that it expects to incur expenditures of $103,940 in 2009 on Project UT29 "Animal Protection." This proposed expenditure follows expenditures in this area of $50,000 in 2008 and $22,421 in 2007.

On Page 28 of Exhibit 2/Tab 3/Schedule 6, Bluewater states that these expenditures relate to its implementation of a multi-year capital program from 2006 to 2013 designed to reduce outages and facility damage caused by animal interference.

Question 3.10 (a)

Please provide a breakdown of total actual and planned expenditures for the 2006 to 2013 period on this program broken down by the categories listed on page 28.

3.10 (a) Response:

Project Name	2006 Actual	2007 Actuals	2008 Budget	2009 Budget	2010 Budget	2011 Budget	2012 Budget
3M Guthrie Guard	23,587	6,421	10,000				
Plastic Rodent Barrier			10,000	10,000	10,000	5,000	5,000
Protective Switch Covers			20,000	65,000	20,000	10,000	10,000
3M Greenline		16,000	10,000	28,000	20,000	10,000	5,000
Total Animal Protection	23,587	22,421	50,000	103,000	50,000	25,000	20,000

Question 3.10 (b)

Please provide any quantitative analyses that were undertaken that support this program.

3.10 (b) Response:

Please see response to Board Staff IR #3.15 for a response on the analysis undertaken to support the capital investment for the Animal Protection program.

Question 3.11 - Geographical Information System (GIS)

Ref: Exhibit 2/Tab 3/Schedule 1/Attachment 1

Exhibit 2/Tab 3/Schedule 6, pp. 40-42

In Exhibit 2/Tab 3/Schedule 1/Attachment 1, Bluewater states that it expects to incur expenditures of $160,189 in 2009 on Project UT45 "Geographical Information System (GIS)." There are no expenditures shown in this area in either 2007 or 2008.

On Page 42 of Exhibit 2/Tab 3/Schedule 6, Bluewater states that:

> *"Bluewater Power considered the alternative of building a custom application, but dismissed this alternative because it would be difficult and expensive to implement, maintain and update. Bluewater Power expects that there will be improved customer service and efficiency savings resulting from the proposed GIS upgrade. The savings will be reflected in improved outage management and thus a reduction in outage time. The proposed system will allow Bluewater Power to better utilize resources through a quicker response time and better time management."*

Question 3.11

Please provide any quantitative analyses that were undertaken that support this expenditure.

3.11 Response:

Bluewater Power has provided both a qualitative and quantitative analysis in response to VECC IR #11(c)

With respect to the option of a custom upgrade, the fact that Bluewater Power does not employ in-house programmers would mean that any custom applications must be contracted out for development and maintenance. Bluewater Power has learned from experience that this can be cost prohibitive and not the best solution. Improving our outage management system by implementing outage management software will move us away from a labour intensive manual system. Automating detection and response to outages will allow faster response time. This in turn, will lead to a reduction in outage times and frequency, which will improve our reliability indices.

Question 3.12 - Asset Management Plan

Ref: Exhibit 2/Tab 3/Schedule 9
Exhibit 2/Tab 3/Schedule 1, p.4

On page 4 of Exhibit 2/Tab 3/Schedule 1, Bluewater states that:

"Therefore, Bluewater Power's distribution system is nearing the end of its life. If Bluewater Power does not increase its sustaining capital investment in operating assets going forward, it will be required to make significant investments between 2020 and 2030. To avoid this last-minute catch-up scenario, commencing in 2010, Bluewater Power intends to work toward increasing its sustaining capital investment in operating assets to approximately $4 million per year."

Exhibit 2/Tab 3/Schedule 9/p. 1, which is Bluewater's asset management plan states that:

"A high-level preliminary analysis would suggest that annual spending of $5 million will be required in coming years to maintain the distribution infrastructure adequately. This projected $5 million expenditure includes $4 million in sustaining capital investments…plus $1 million in non-routine capital investments typically pursued annually."

Question 3.12 (a)

Please indicate whether or not this conclusion arises out of the development of or was derived separately from Bluewater's asset management plan, or was derived separately from the development of the plan. Please state how this conclusion is integrated into the asset management plan.

3.12 (a) Response:

Bluewater Power Asset Management Plan found at Exhibit 2, Tab 3, Schedule 9 represents a summary of the asset management programs that have been in place at Bluewater Power. Those programs have been subject to continuous improvement, as evidence by the undertaking of the 1999 Report. The Asset Management Plan has been put together to document those efforts.

The specific conclusion that annual spending of $5M in capital will be required in Operations was a preliminary conclusion reached following training offered by the Electrical Distributors Association. Further individual study permitted Operations Staff to put together a cursory estimate of the replacement value of our fixed distribution assets. The details of that calculation are provided in answer to Question #3.12 (b).

<u>Question 3.12 (b)</u>

Please provide the high-level preliminary analysis referred to above that led to this conclusion including supporting documents for deriving this estimate.

<u>3.12 (b) Response:</u>

The high-level analysis performed by Bluewater Power is provided below.

The goal of the analysis was to determine the estimated total replacement value of the system. That calculation was based on the quantity of underground lines, overhead lines and substations. The estimated cost per kilometre of line is an "all-in" price based on poles, wires and appurtenances. The estimate cost per substation represents an average substation. Based on this analysis, the total replacement value of our system is $289,300,000.

The analysis assumes that the system requires replacement each year in equal amounts based on its projected lifespan. Therefore, the total replacement value of the system was divided by the estimated lifespan of 50 years (the lifespan is 40-50 years, but the larger value was utilized in order to be conservative).

The resulting figure was $5.7M, which we rounded down to $5M in our preliminary conclusion. Given that this result was intended to be a preliminary, high-level analysis, our objective was to be conservative. Further study is required and that will be undertaken in 2009 in accordance with capital project UT-40, Asset Condition Assessment.

Component of System		*Quantity*	*Cost*	*Total*
Underground	**Primary (km)**	160	$ 250,000	**$ 40,000,000**
	Secondary (km)	476	$ 150,000	**$ 71,400,000**
		636		**$ 111,400,000**
Overhead	**Primary (km)**	600	$ 150,000	**$ 90,000,000**
	Secondary (km)	819	$ 100,000	**$ 81,900,000**
		1,419		**$ 171,900,000**
Substation (# of stations)		20	$ 300,000	**$ 6,000,000**
Total Replacement Value of System				**$ 289,300,000**
Expected lifespan				**50**
Estimate replacement value per annum				**$ 5,786,000**

Question 3.12 (c)

Please state whether this conclusion also arose from any external studies such as the 1999 study referenced in the asset management plan by Elecsar Engineering Ltd. and if so, provide any such studies.

3.12 (c) Response:

This conclusion does not relate to the 1999 Report or any other external studies.

<u>Question 3.12 (d)</u>

Please indicate whether Bluewater has utilized any asset condition study in developing its Asset Management Plan. Please file any such study.

<u>3.12 (d) Response:</u>

The 1999 Report is, in part, an asset condition study. It is filed as an Attachment to this response.

We note that the 2009 capital budget includes UT40, which represents a full-scale Asset Condition Assessment.

Attachment: Board Staff 3.12.d. BWP 1999 Report

Elecsar Engineering Ltd.

SURVEY OF SARNIA HYDRO OWNED STATIONS

PROJECT: ESSH99

Cautionary Notice

This survey contains technical information that is the property of Sarnia Hydro. It is furnished to the recipient strictly for use in connection with the facilities concerned, and is to be held confidential.

Prepared by: **Elecsar Engineering Ltd.**
B. Schwarz, C.E.T.
D. McGarry, C.E.T.

Date: **December 17, 1999**

Revision: **P4 (Preliminary) Issue for Discussion**

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SECTION 1.0 FORWARD

Elecsar Engineering, as part of the Due Diligence Survey, has conducted a preliminary inspection of Sarnia Hydro's substations. This review is NOT intended as a detailed engineering audit of the facilities. In a number of stations, further investigation/ review is indicated.

The criteria used to evaluate the substations is the Industrial Standards as outlined in the "Ontario Electrical Safety Code", (O.E.S.C.) and enforced by the new Electrical Safety Authority (ESA). An incorporated utility will be required to be fully compliant with the code. Non-safety related issues may be "Grandfathered" (not changed). However, where the Code deals with public safety, retrofits will likely be required at the discretion of ESA.

In particular, the following sections of the OESC are relevant to our review.

Fencing	26-300
Grounding	10-000 to 10-1108, 36-302
Warning Notices, Single line diagrams	36-006
Batteries	26-540
Wharves and Harbours	Section 78

Please note: Items that are bolded and italicized REQUIRE IMMEDIATE ATTENTION

SECTION 2.0 GENERAL OBSERVATIONS

2.1 Polychlorinated Biphenyls (PCB's)

There are two stations that list on the bank PCB's greater than 50 ppm . These stations require immediate clay berms or other containment methods installed that would contain an oil spill inside the station. These stations are Sub 10 and Sub 21.

No site has a spill containment facility. Some of the sites are in the middle of residential areas and care must be taken that oil is not spilled, nor does it enter the drainage systems or adjacent properties.

2.2 Two stations have capacitors present that are of the askarel type. They are out of service and it would be prudent to have the capacitors removed and disposed of. These stations are Sub 1 and Sub 2. The sites do not have spill containment or any signage on the entrance that would notify emergency crews of the hazard present in case of fire. In addition, the installations are not grounded.

There is also a requirement that records are available for all devices containing oil. We do not believe that these records are available.

2.3 Site Security

Sarnia Hydro is required to provide protection to the public at all sites.

Due diligence dictates all reasonable effort must be taken to prevent entry and, secondly, if the public comes within the vicinity of any facility, they should not be harmed.

Two things provide security when a site is constructed as a Distribution Station. Firstly, Ground Resistance studies are done to ensure the ground counterpoise is constructed in such a manner as to prevent Step and Touch Potentials from appearing that would put people at risk. This includes an area outside the fence of approx. three feet which would be a typical reach of a person coming up to the fence. Secondly, all areas should be fenced in accordance with the OESC Code, Section 26-300.

2.4 Nomenclature (Personnel Protection)

In order to safely operate a utility, such as Sarnia Hydro, all devices must be identified with a singular name that is not repeated and is clearly visible to all personnel who are called upon to operate the devices. All devices should be noted on an operating diagram. This diagram should be available to all personnel so they can visualize the operations they are to perform.

Written procedures in the form of orders to operate refer to these devices which they can then follow.

One common nomenclature system should be adopted.

The Sarnia Hydro Nomenclature System will need to be reviewed or revised.

All stations need current Single Line Diagrams posted to reflect what is in service, what is open, and what is closed. Every station needs a current AC and DC elementary, so that proper isolation can be achieved for personnel doing work on equipment. This would not only protect people, but also would prevent the unnecessary interruption to customers and damage to equipment. A complete and current set of prints should be available for all stations showing the wiring diagrams. See Section 36-006 of OESC Code.

Where two jurisdictions come together, there should be nomenclature to inform all parties this is where care must be taken. One such location is in Point Edward where Sarnia Hydro and Point Edward share the same distribution system on the same poles. Typically, there are open points that should remain open to ensure the metering is always correct and, when faults occur, the equipment is cleared properly, as expected, so that people are not put at risk.

There are several points where Ontario Hydro and Sarnia Hydro share the same facilities and an indication should be present to inform both parties.

There are transformer stations, for example - Tashmoo, where a mid span opener has 4 kV from St. Andrews on one side and 4 kV from Lambton T.S. via a 16 kV to 4 kV transformer on the other, with no nomenclature.

There are other locations where a pole shares 4 kV and 27.6 kV with no indication that more than one voltage is present in the same location.

There are distribution stations that were taken over from Ontario Hydro. The rest of the city is 4 kV except for these stations which are 8 kV. Identification is important to prevent personnel from thinking they are working on 4 kV equipment instead of 8 kV equipment or vice versa and prevent the installation of equipment that is the wrong class. The size of the insulators and arrestors cannot be used as a guide to identify voltage levels because many have been upgraded to 16 kV as a result of a previous failure.

2.5 Safety Equipment

All stations have switch sticks to operate equipment in the station, and hang protection tags etc. This equipment must be tested for compliance and date stamped for re-test.

The use of untested switchsticks violates the letter and intent of EUSA Rule 113. These devices should not be used, nor should they remain available to use. See EUSA Rule 113.

2.6 The overhead cranes in Sub 1 do not appear to meet Ministry requirements because there are no certificates of inspection. The cranes should be labelled, ***"Lock-Out of Service" - "Do Not Operate",*** until the certificate of inspection is posted.

2.7 Conversion of the Distribution System from 3 Wire to 4 Wire

2.7.1 Distribution System

Over the years, the system has grown and some things have not kept pace with the changes. The 27.6 kV system was a 3 wire, 27.6 kV delta system, with distribution stations throughout the city to step down the voltage and distribute to customers. The distribution systems from all these stations, at this time, had a limited ground fault capability (450 Amps). These systems were made up of 4160 Wye connected feeders going out to the streets to be stepped down by transformers for distribution to houses. A small neutral was strung along the streets and care was taken to balance the load between the phases to ensure very small current unbalance would flow in the neutral.

These Distribution Stations were becoming overloaded. A choice was made to change to a Wye connected 27.6/16 kV system and supply distribution transformers directly from the primary feeder, rather than increase the size or number of these feeders. Feeders from the main transformer stations were placed into service. However, instead of installing a neutral for all feeders, the existing 4 kV neutral was utilized. If the system were balanced again, the neutral would carry very little current.

Along with this, every time a 16 kV single phase transformer was installed, the neutral would be grounded at this point and there would be a shared path for ground currents.

Over time, a new neutral should have been pulled back to the station. This has happened very slowly or not at all. Now there are feeders out there with very small neutrals and very large unbalanced loads.

Large imbalances present a serious problem. At least 10,000 Amps of ground current can be delivered out on these feeders in a fault condition and with the small conductor, it is not possible to deliver this magnitude of current. This situation could result in high ground fault currents that could cause step potential to the public. In addition, there could be slow clearing faults that could cause voltage reductions for a longer time until relays would time out and trip breakers to clear them. This could cause undesirable outages to customers.

2.7.2 A neutral refurbishing program must be undertaken to upgrade the 27.6 kV and 4.16 kV systems. In the meantime, the distribution stations should have the currents balanced and, approximately every 6 to 10 pole spans, a ground must be dropped down the pole to ground rods. If a transformer is located at these intervals, the transformer ground connection will suffice.

According to the maximum demands on feeders and transformers, there appears to be a number of overloaded breakers. They should be tabulated and loads re-arranged to reduce overloading.

2.7.3 Lightning Surge Protection

Lightning outages are a major problem because of power interruptions and equipment damage. It would be more cost efficient to install the bundled arrestors at the same spacing as the ground rods. This could be done when a 16 kV transformer is installed. The three arrestors would be installed at this same location, if the spacing warrants. Sarnia Hydro has feeders that are very long, for instance, the one going out towards Bright's Grove and other areas. One line section in the city, consisting of 22 poles, between London Road and Michigan, has no protection at all. This affects two feeders, M31 and M29.

When the feeders were converted to 27.6/16 kV, all 34 kV arrestors protecting cables, stations etc. should have been changed to 21 kV. The 34 kV arrestors overstress new equipment because the new equipment is designed for a lower voltage class.

2.8 4160 V Relay Protection

2.8.1 The old system, with lower ground currents and a balanced system survived on a protection system that looked at only two phases of current and no ground. A method was devised to protect the white phase by creating an artificial summing of red, white, and blue current phase relay. The cost of installing a neutral relay of the same vintage would be more than installing the newer Electronic Microprocessor based relays. A Schweitzer 251 relay would give three phases of current and a neutral protection as well as a reclosure. It would also give fault information, metering, and distance to fault information. The cost is about $1600 for the relay. With the reclosure, it would be possible to return customers to service more quickly.

2.8.2 Trip Circuit Monitors
A shortcoming at all stations is the inability to distinguish if a trip coil is intact on a breaker. A very large number of green lights are burned out at the stations, and yet the breaker is closed and current is flowing. If the feeder were required to trip and the trip coil were open circuited, the breaker would not operate and the entire station or feeder could be totally interrupted. Green light monitor relays should be added for every breaker. This is something a microprocessor based relay (i.e. Schweitzer 251 relay) could do as well. This information should be made available via SCADA to operators.

2.8.3 SCADA System
At the stations, it is impossible to determine if the breakers or reclosures are being controlled from the master station via the supervisory board. The SCADA system needs to be refined to show firstly, that the station is being controlled remotely and secondly, what part is being controlled. There must also be a means of isolating the control of devices from the SCADA. A local remote control toggle switch at the station would provide the local RTU. There should be an indication back on the master that the switch has been moved.

Individual blocking switches should be present for each device for two reasons, Firstly, If someone takes a protection on a feeder, there must be a way to ensure no one can operate the device. Secondly , if an operator cannot close a breaker it could be because the SCADA system is applying a permanent trip to the device.. A blocking switch would allow this to be blocked and possibly restore customers more quickly. This entire SCADA system should be included on prints. All alarms should be reported back as well.

If SCADA is not at a station that has breakers, it should be added to maintain customer satisfaction. If reclosure is not available at a station, it should be added for the same reason.

2.8.4 Cables

There are two basic styles of cable. The first style is one that has a concentric neutral, which has the same current carrying capability as the centre conductor, and as such, can be grounded at both ends. Circulating current and load current can flow through this cable to fulfill the requirements of the customers.

The second style is one that has a shield around the cable. The purpose of the shield is to drain off any stray voltages that might appear so they will not interfere with the primary current delivered. As such, we cannot ground both ends of the cable but only one end and allow the other end to float. To prevent high voltages from being introduced, a surge arrestor to limit these voltages can be installed on the ungrounded end to maintain a level that will not damage the insulation of the cable.

2.8.5 Metering Processes

A process, within the billing software system, should alarm to show when a demand is greater than 1000 divisions on a particular meter. Engineering would then be notified to check that the current transformers or self contained meters are not overloaded. Currently, accuracy suffers and equipment is stressed to the point of failure. Some co-relation between kVA available and load should also be alarmed.

2.8.6 Protection Issues

Protections are handled differently from station to station. Tags are left over, partially filled out, and some systems, like reclosure, need to be reviewed, to explain the intent of a reclosure block and the reason it needs to be put back when "hold off" is no longer required. This whole process needs to be reviewed and standardized.

Work protection courses are an ongoing requirement and must be reviewed and recorded annually for all employees who use the code. Supervisors should not allow employees, who are not trained in the latest code, to hold work protections.

SECTION 3.0 SUB 1 - HENRY ROSS (Front Street)

3.1 Transformer 1T1 7500/10000 kVA Ferranti Packard ONAN/ONAF Fans available. Impedance 5.4%z @ 27.6/4.16 kV Delta/ Wye.

3.2 Transformer 1T2 7500/10000 kVA Ferranti Packard ONAN/ONAF Fans available.
Impedance 5.3%z @ 7500 kVA 27.6/4.16 kV Delta/ Wye.

3.3 Fuse at Transformer SM-5S 150E TCC 153-4.

3.4 Cables to the Sub are not fused and are protected by 34.5 kV lightning arrestors. The system is 27.6/16 kV and therefore should have 21 kV arrestors to limit the phase to ground potential.

3.5 Security:

- The trees all around the fence are growing over it. This will allow easy access.
- There does not appear to be any fence grounding around the entire property. This can cause a step and touch hazard for close in ground faults.
- Uncovered guy wires come down to ground within three feet of fence, allowing for a touch voltage hazard.

Action 1: ***Remove trees near exposed equipment ASAP.***
2: Separate security fence from T.S. building with non-conducting section.

3.6 A Bell Telephone pedestal, within one foot of the fence allows for a touch potential hazard on the outside of the fence.

3.7 1T2-A closed
1T1-A closed
T1-T2 closed
Transformers are paralleled on the 28 kV primary of the bank. The nameplate also indicates that the windings are aluminum.

3.8 The transformer installation does NOT appear to meet Section 26-012 of the Electrical Code for Indoor Liquid-Filled Transformers.

Transformers have spill containment but no fire protection or monitoring for indoor transformers. Transformers are labelled no PCB hazard. Spill containment is open between the two banks, which would allow a fire to spread easily between them. The 4160 Wye cables from one transformer pass through the oil containment of the other transformer.

3.9 Gravel should be around the perimeter of the outdoor switchgear including the ground mat area, to minimize the step and touch potential. There should be a ground mat at each switch.

3.10 The fenced area around battery is not grounded. Since these are lead acid batteries, there should be fans that come on when the batteries are placed on equalize to remove hydrogen gas, See Electrical Code, OESC 26-540.

3.11 Quindar system is not grounded nor is other equipment in the control room area.

3.12 Every breaker has a bypass switch. Only the 1FY is labelled and locked. All the others need nomenclature and must be locked.

3.13 The Feeders have only R and B over current relaying - no ground protection and no reclosure.

3.14
- 1YY has no indicating lights and does not show Amps
- 1F1 has Green Light; currents are 120/100/120
- 1F2 has Green Light; currents are 100/100/100
- 1T1MA has Green Light; currents are 80/150/160
- 1F3 has Green Light; currents are 120/120/120
- 1T1MB currents are 100/80/60. There is no explanation on the Emergency Trip button on the panel telling what it is or why you might want to push it.
- 1F4 Shows no Lights no Amps and has a Red Tag "Do Not Operate" attached that is not filled out.
- 1F9 No Lights and No Current.
- Meters on 1M5 panel should be removed.
- 1F5 Shows no Lights no Amps and has a Red Tag "Do Not Operate" attached that is not filled out.
- 1F6 Shows no lights and no Amps. It has a Red Tag "Do Not Operate" attached but it is not completely filled out.
- 1T2MA has Green Light. Amps are 60/90/100. All the Transformer Breakers have two extra relays labelled 27.6 kV out of service .
- 1F7 has Green Light; currents are 90/90/90.
- 1T2MB currents are 100/80/60.
- 1F8 has Green Light; currents are 120/120/120.
- 1F10 spare no lights and no current.

The B1-B2 could not be found. It is probably the 1FY
Reviewing the current balance, between the four secondary cables, requires some more investigation. It does not appear to be sharing the load equally between windings of the paralleled transformers.

3.15 Capacitors are present in the line-up of breakers. There are no lights describing the status of the capacitors and no indication on the line-up about the PCB content but one must assume because of age that it is present. A stand-alone capacitor bank at the back is labelled PCB Hazard. There is no spill containment. The capacitor cage is not grounded and says 150 KVAR. The breaker is open with a red Tag not filled out. There are 39 Cans, each about one foot by one foot by 3 inches wide.

The cost to remove and dispose of these capacitors is $ 10,000. See 22.2 #1, Rondar Estimate.

3.16 There are two overhead cranes, which should have inspection stickers from the Ministry of Labour on them. A record could not be found.

3.17 This is a four-wire station with no neutral protection and no reclosure for the feeders. There is an RTU system but no indication as to what it operates or alarms. The single line diagram is not marked up to date. There should be AC and DC single line diagrams in the station. A set of field marked prints should be at the station. It appears that the transformers are parallel on the secondary side as well as on the primary side and the currents are not being shared equally which will lead to over-heating. More investigation is required to determine the problem.

3.18 The station fire extinguishers are stamped up to date.

3.19 All Breakers should have Trip Coil Monitoring or Green Light relays that are alarmed on SCADA.

3.20 Recommendations:

3.20.1 An infrared/ultraviolet fire monitoring system should be installed in the basement, around the 10 MVA transformers.

3.20.2 This station has two transformers that should be fed from different 27.6 kV feeders. This would provide added security to customers. If the Low Voltage Busses were run separately, a fault would only affect half the feeders. If the feeders are to be paralleled on the 4160 V side, directional over-current relays should be installed to discriminate faults.

3.20.3 A civil engineering review of the indoor transformers should be conducted concerning the fire and building codes. A water or foam deluge system should be considered.

3.20.4 The 4160 cables should be re-routed such that they DO NOT enter the oil containment of the other transformers.

3.20.5 The area north of the station has coal-tar contamination. An engineering review was conducted in 1997 and is on file with Sarnia Hydro.

3.21 See Section 22 of this report for future alternatives.

SECTION 4.0 SUB 2 - ST. ANDREWS (St. Andrews at Vidal Street)

4.1 Transformer 2T1 Molony Electric ONAN/ONAF 6000/8000 kVA 27.6/4.16 kV Delta/ Wye no fans available. 5.27% z @6 MVA

4.2 **Observations**

4.2.1 On the 2T1 breaker, the cables are pulled back and hanging free going to the outdoors; outdoor cables are cut off at the conduit.

4.2.2 Hazard to Personnel:

- 2T1 and 2T2 switch blades are open, without tags indicating the position or why they are open.

- **Control panels** associated with 2T1 and 2T2 are as follows:
  - 2T1 is open, white light is on and there are no relays in the case. The DC is closed and a red tag is on the control switch but it is not filled out.
  - 2T2 has no lights, the breaker is open and the DC is pulled with relays in the case.
  - 2T4 is closed, with no lights on the control panel. 200 Amps is showing on the ammeters, with a maximum indication of 400 Amp. Cables from the transformer protrude into the walkway. Blades to B DS bus are closed.

- **Feeders**
  - F1 is closed, blades are closed, and approximately 25 Amps shows with a green light on.
  - F3 is open, the breaker is open, and the green tag on control handle says "junk". This may be so but the tag should say "feeder unavailable for service". The blades are open and are tagged with a blue WP tag 120 which is not filled in.
  - F4 breaker and disconnects are closed, there is a green light and 150 Amps is shown on the ammeters.
  - F6 is closed, the blades are closed, and there are no lights on the control panel but approx. 50 Amps is showing.
  - F7 is closed, the blades are closed, and about 225 Amps is showing.
  - F8 the breaker is closed and the blades are closed, and about 100 Amps is showing.
  - BY is open; it has no lights and the blades are closed.

4.3 **Capacitors**

4.3.1 The capacitor blades are open with a "Do Not Operate" tag, not filled out, on the blade. The capacitors are tagged with PCB hazard on the breaker cubicle. The cage and structure does not appear to be grounded. None of the cans appears to be leaking but there is no containment for spillage.

4.3.2 The bank is made up of 48 cans. The approximate size - one-foot by one-foot by 4 inches in width.

4.3.3 The cost to remove and dispose of these capacitors is approximately $10,000. See Section 22.2 #1, Rondar estimate.

4.4 The building needs better lighting. This is a real hazard for switching and trouble shooting.

4.5 A lot of equipment is in service that does not have to be and as such will unnecessarily burden and place exposure on the DC system.

4.6 ***The 4 kV potential transformers are leaking compound and should be replaced immediately because they could fail explosively.*** There is no nomenclature on potential transformers or fuses. This could result in a backfeed hazard to personnel.

4.7 The station service area in the basement should be fenced and signs placed noting 4 kV present. All the transformer cases should be grounded.

4.8 There should be Trip Coil Monitor Relays reported back on SCADA

4.9 There should be ground relays installed on the 4 kV system with reclosure on the breakers.

4.10 There should be AC and DC single line prints at the stations as well as a current single line of the station. A set of field marked prints should be at the station.

4.11 The transformer should be protected with 21 kV arrestors. All the old equipment should be removed.

4.12 The 4 kV entrance cables have their sheath grounded in a variety of ways. They should be consistent with the heavier braid as on F8 and F3. Crimp connectors to join ground wires should not be used.

F7	#14 yellow
F4	#14 red
F6	#14 green
F1	#14 wt

4.13 Control wiring downstairs needs a lot of work. It is hanging out of the cable pans, wires are exposed and moisture has gotten into the system as evidenced by rust on the trays and wires. The cable pans do not appear to be grounded. The cable trays for the DC batteries should be grounded and spare trays removed.

4.14 The control panels upstairs should be grounded individually. There appears to be only one ground going upstairs and bolts provide the ground from panel to panel. The ground for the current transformers and metering equipment probably comes from these panels. It is doubtful if the ground is providing any protection to personnel.

There does not appear to be a set of prints at the station to enable troubleshooting. When a problem occurs, this could lead to a prolonged outage to customers.

4.15 There are no spare high voltage fuse links available at the station. Therefore, it is not known for sure what link has been installed. If a fuse blows it could lead to a lengthy outage to customers.

4.16 The SCADA cabinet is not grounded.

4.17 The switch sticks in the building have no stamp to indicate they were ever tested for safety.

They should be removed immediately.

4.18 There is no single line diagram in the station that is up to date and pinned regarding the status of the equipment out of service and in service.

4.19 The instruction book, about operating the station, is completely out of date. M1 and M7 at St. Andrews no longer feeds the transformer. It is now fed from M11 with the fuse cubicle outside and a single cable going to indoors to feed through the 2T4 breaker. There is no trip going back into St. Andrews from the transformer protection to trip the St. Andrews breakers. All equipment still appears to be in service in the sub and this only serves to expose more equipment to error.

4.20 All four kV feeders are protected with a set of over current relays. The relays monitor only the red and blue phases of current; the white phase is covered off by how the relay sees the difference current. Ground protection, to protect against low infeed ground faults, must be added. Also, there is no reclosure available on the feeders. They trip and stay open and require an operator to close the feeder back in. There is no indication that a Trip Coil is intact. A Green Light Relay or Trip Coil Monitor Relay should be added. The SCADA system should be expanded to allow operation of the breakers from a remote location and include all status and alarms.

4.21 Current Readings Transformer 3 leads:

	R	14.2	Ground leads
	W	16.0	transformer to
	B	13.0	neutral bus.
Total		43.2	Amps
Ground		21.3	Amps
		17	Amps
Neutral		43.7	Amps

The station needs more investigation to rationalize the current readings.

4.22 **Recommendations**

4.22.1 This station requires immediate attention. The station should be repaired or eliminated ASAP.

4.22.2 All of the indoor switches, including relaying, new 4160 cables etc., could be replaced at an installed cost of $527,000. (Class IV Estimate)
See attached estimates.

The entrance into St. Andrews was locked with Ontario Hydro locks only. This could lead to a delay in responding to a trouble call. Operations at Ontario Hydro were contacted and a Sarnia Hydro lock was attached to the Main Gate.

SECTION 5.0 SUB 3 (Between East Street and Indian Road)

5.1 The cable into the station should be fused. The arrestors look like the 21 kV style.

5.2 The switch sticks have no test date and as such must not be used.

5.3 The transformer is Brown Boveri 5000/6667 at 5.6% Z.
Oil is dripping from the transformer, although it is disconnected.

5.4 The feeder current transformers do not look healthy and should not go back into service without thorough testing.

5.5 Underground cables, grounded at both ends, cause circulating currents to flow, resulting in overheating and de-rating of the cable.

5.6 There is no single line drawing.

5.7 The station service transformers are leaking.

5.8 There is no way to measure transformer and neutral currents.

5.9 Fuses appear to be 150E TCC153-4.

5.10 The panel in the building is made of plywood and links which are arranged vertically. There is no way to short and open links to work on metering equipment.

5.11 Nothing is grounded in the building.

5.12 The new transformer brought in 6/8 MVA 5.47% Z 27.6/4.160 kV.

SECTION 6.0 SUB 5 - MICHIGAN AVENUE (Michigan Ave. at Colborne Road)

The tap into the station has no fuse and has 34 kV arrestors that should be changed to 21 kV arrestors.

6.1 The fence is not secure. Anyone could climb over the fence the way it is constructed. A children's park is thirty feet to the east of the fence. The fence is over-grown with bushes and trees.

Remove trees immediately.

The main gate lock did not prevent the gate from opening. It must be locked correctly.

6.2 **Observations**

- The house on the west side is within three feet and has aluminum siding. A gas meter is also about a foot away from the fence. A non-conducting fence should be erected. Ungrounded light standards inside the fenced area are all broken and are situated within one foot of the fence. This is a step and touch hazard.
- The yard should have more gravel.
- The transformer is labelled 3T1 instead of 5T1.
- The bank is a GE 2000/3600 kVA, Impedance of 5.97% on 3600 kVA.
- 26400/2300/4000 Y

6.3 All the gauges on the bank are broken.

Repair Immediately.

6.4 **Observations**

- The telephone pole and supporting cables in the southwest corner should be relocated.
- The transformer was tested and was stamped "No PCB".
- No oil spill containment for bank.
- The transformers wet around the top.
- The transformer needs painting.
- The conservator tank shows below normal.
- The ground link should be labelled "Do Not Open".
- Equipment mounted on the side of the switchgear is not grounded.
- A single line is present but not fastened. The print says the fuses are 80E.
- Prints should be present. The spare fuseholder indicates SM-5.

Please note: Items that are bolded and italicized REQUIRE IMMEDIATE ATTENTION

- The F1 ammeter nomenclature has been crossed out and, penciled in it says "F2" which indicates 50/50/50 with a maximum demand 120/150/120.
- The F2 ammeter nomenclature has been crossed out and, penciled in it says "F1" which indicates 0/0/0 with a maximum demand of 0/0/20.
- F3 ammeters indicate 10/10/10 with a maximum demand 120//175/75.

6.5 ***Wooden Switch sticks in the cubicle are not test dated and should be removed immediately.***

Trees and shrubs should be removed and gravel added to the entire area.

6.6 Readings:

Readings:	Transformer	35 Amps
	Neutral	23 Amps
	Ground	16 Amps

6.7 **Fencing Recommendations**

The fence should be replaced immediately.

Move the fence in by 1 metre on all sides.

The conducting fences shall be separated from the playground and backyard fences by a 10-foot non-conducting section.

6.7.1 The southeast corner of the substation fence is electrically connected to the backyard fence of the adjacent house. See 6.7.3 below.

6.7.2 The southwest corner of the substation has a telephone pole with climbing stirrups and a telephone cable termination box attached (for ready access to the station).

6.7.3 The east fence, adjacent to the playground, is six feet high with the barbed wire turned in.

The north and east substation fence should be replaced with an eight- (8) foot fence with barbed wire TURNED OUT. The North Park fence should be separated from the station fence with a ten- (10) foot non-conducting section.

The west fence, going north/south, is within 3 feet of the adjacent house. (The gas meter is within 1 foot)

The west and south fence should be replaced with a non-conducting fence per OESC Code 26-300 to eliminate the step and touch and ground potential transfer problems.

The installed cost of this fence and grounding work would be approximately $30,000. See Section 22.3 for details.

6.8 There are numerous split bolt connectors on the 27.6 kV/ 4160V common neutral conductor on the street north of the station.

The neutral should be replaced with 336 aluminum Ampact or Crimp type connectors in this area.

6.9 The pole-top 27.6 kV air break switch, east of this station, has the "Cap & Pin" insulators that historically are breaking and falling due to the cement type bonding glue used.

The insulators on this switch or the entire switch should be replaced.

SECTION 7.0 SUB 7 - INDIAN ROAD AT CATHCART BOULEVARD

7.1 7T1-L is really an Air Break Switch. This switch is interlocked with the transformer main switch. However, the spare key is in the airbreak switch at the street, defeating the interlock.

7.2 **Observations**

7.2.1 The arrestors are 34 kV and should be 21 kV. The underground cable should be fused.

7.2.2 None of the equipment in building is grounded or bonded to the water system, SCADA system or the battery charger.

7.2.3 There is no indication what SCADA controls or how to stop it.

7.2.4 Meters should be removed and links and fuses should be labelled.

7.2.5 A single line is present and indicates primary fuses 125E.

7.2.6 The bank is a GE 3000/4000 ONS/ONP 27.6 kV/44.16/2.4 kV.

7.2.7 The impedance is 5.4% Z at 3000 and 7.2 %Z at 4000. Fans available.

7.2.8 The main transformer breaker is protected by R and B Phase only, no neutral or reclosure.

7.2.9 There are no lights, the breaker is closed, and the currents are 150/150/170 with a maximum rating of 540/580/600+.

7.2.10 Feeder F1 has R and B Phase protection but no ground nor reclosure. The Green Light Breaker is closed. It has a current of 80/50/80 with maximum 280/250/300.

7.2.11 Feeder F2 has no green light breaker It is closed and is protected by R and B Phase over current, with no ground or reclosure.

7.2.12 Feeder F3 has a green light breaker which is closed and is protected by R and B Phase with no neutral and no reclosure. Current is 20/20/20 with a maximum of 180/150/150.

7.2.13 The readings are:

Transformer	75.1 Amps
Neutral	28 Amps
Ground	47 to 63 Amps

There is a problem here and more investigation is needed.

7.2.14 Ground link should be labelled "Do Not Open".

7.2.15 The transformer is labelled "No PCB".

7.2.16 There is no spill containment.

7.2.17 There should be prints at the station as well as AC and DC single line diagrams.

7.2.18 There should be trip coil monitoring added.

7.2.19 The ground is broken off on the little fence and all the outdoor lighting is broken.

SECTION 8.0 SUB 8 - EAST STREET (Between Exmouth and London Rd)

8.1 The tap into the station should be fused. The old meters, Sangamo SC, should be removed.

8.2 All equipment in the station should be grounded, and SCADA etc. added.

8.3 T1B breaker is protected by R and B relays. There is no neutral and no reclosure. The current is 320/250/250 with a maximum demand of 560/500/500. The green light is on with the breaker closed.

8.4 The 8F1 breaker is closed with the green light on. It is protected with R and B phase over current with no neutral and reclosure. The reclosure blocking switch should be painted Orange. The current is 100/100/100, with a maximum of 160/180/140.

8.5 The 8F2 breaker is closed with the green light on. It is protected by R and B only with no neutral or reclosure. The reclosure blocking switch should be painted orange. The current is 200/120/140, with a maximum of 360/350/360.

8.6 The second bank indicates a current of 200/300/300, with a maximum of 320/400/420. Meters should be removed.

8.7 The 8F4-B breaker is closed. There is no green light. It is protected by R and B phase with reclosure and no neutral. The current is 100/100/100, with a maximum of 220/220/210.

8.8 The 8F5-B breaker is closed with a green light and is protected by R and B phase with reclosure. It has no neutral. The current is 100/180/200 with a maximum of 140/220/280.

8.9 T1 is a 3000/4000 kVA bank 27.6 kV /4160V with Z of 5.5% at 3000 and 7.3 % @ 4000. Fans are available The currents seen are:

Transformer	93	Amps
Neutral	34.7	Amps
Ground	63	Amps

This needs more investigation.

8.10 T2 is a 3000/4000 kVA Bank ONS/ONP 227.6/4.16 kV with fans available.

Transformer	119 Amps
Neutral	53 Amps
Ground	54 AMPS

The Link should be labelled "Do Not Open".
The percentage Z on the bank cannot be read.
This needs more investigation.

8.11 There is a single line diagram, which indicates fuses are 125 E.

8.12 There is no AC or DC single line diagram or prints at the station.

8.13 There is no indication regarding the function of SCADA.

SECTION 9.0 SUB 9 - (Between Indian and Murphy, north of Confederation)

9.1 The underground cable into station should be fused. The lightning arrestors should be changed from 34 kV to 21 kV.

9.2 The fire extinguishers in the station are all date stamped up to date as is consistent with all the distribution stations.

9.3 Old metering equipment in the station should be removed.

9.4 The SCADA equipment and all other equipment in the station should be grounded.

9.5 The transformer breaker 9T1B is protected by R and B phase, without a neutral or reclosure and the green lights on the breaker are closed. The current is 200/210/190 to a maximum of 390/350/320 with a sign saying all readings should be multiplied by 2.

9.6 The 9F1-B is protected by R and B phase, with no neutral or reclosure. The breaker is closed with a green light. The current is 100/100/100 with a maximum of 280/240/240.

9.7 The 9F2-B is protected by R and B phase, with no neutral or reclosure. The breaker is closed with a green light. The current is 100/100/100 with a maximum of 240/240/180 Amps.

9.8 The 9F3-B is protected by R and B phase, with no neutral or reclosure. The breaker is closed without a green light. The current is 180/220/170, with a maximum of 280/320/300.

9.9 The 9F4-B is protected by R and B phase, with no neutral or reclosure. The breaker is closed with no green light. The current is 0/0/0 with a maximum of 160/140/160.

9.10 The 9F5-B is out of service. The breaker is racked out.

9.11 The single line in the station, although not posted, shows all the feeders to be different from the nomenclature on the breaker. The single line says 9F1, 9F2 etc. instead of 9F1-B, 9F2-B etc.

9.12 The single line says the fuses are 125 E.

9.13 The transformer tested no PCB.

9.14 There is no spill containment.

9.15 The transformer is Ferranti Packard 6000 kVA 27.6 kV/4160/2400 kV with impedance of 6.1 %Z. It is equipped with fans.

9.16 The outside AC lighting cable is lying across the yard causing a possible tripping hazard. The outdoor lights are all broken.

9.17 The currents seen are:

Transformer	78.3 Amps
Neutral	43.2 +36.8 Amps
Ground	5.7 Amps

This needs more investigation.

9.18 The neutral link should be labelled "Do Not Open".

9.19 The yard needs more gravel.

9.20 There are no grounds on any equipment indoors.

9.21 The building overhang and eve troughs should be grounded within 3 feet of the station.

SECTION 10.0 WELLINGTON STREET (near Sarnia General Hospital)

10.1 There is a single line taped to the panel which shows a 150E Fuse. There is no AC or DC single line drawing.

10.2 The equipment is not bonded to ground in the Sub including the SCADA.

10.3 The transformer is labelled PCB Hazard. There is no spill containment and it is right in between the houses. The transformer is 5000/5600 kVA 27.6 kV/4.16 kV. At 5000 %Z, it is 5.4 and at 5600 %Z it is 6.1. Fans are available

10.4 All old meters should be removed.

10.5 10T1 is protected by R and B but there is no neutral and no reclosure. The breaker is closed with a green light. The current is 500/590/600 with a maximum of 680/800+/780.

10.6 10F1 is protected by R and B without a neutral or reclosure. The breaker is closed but there are no lights. The currents are 120/150/120 with a maximum of 230/340/240. The reclosure blocking switch should be painted Orange.

10.7 10F2 is protected by R and B without any neutral or reclosure. The breaker is closed with a green light. The currents are 80/80/100 with a maximum of 180/210/210.

10.8 10F3 is protected with R and B without any neutral or reclosure. The breaker is closed with no lights. The currents are 120/160/150, with a maximum of 190/240/230.

10.9 10F4 is protected with R and B with no neutral but with reclosure. The breaker is closed with no lights. The currents are 250/240/250 with a maximum of 260/260/320.

10.10 Transformer Current 87 Amps
Neutral 67 Amps
Ground 2 Amps

10.11 The neutral link should be labelled "Do Not Open".
This needs more investigation

SECTION 11.0 SUB 11 - INDIAN ROAD (between Michigan and Exmouth)

11.1 The underground feed should be fused into the station.

11.2 Inside the equipment is not bonded to ground or to the water system.

11.3 SCADA gives no hint as to what it operates and how it can be blocked.

11.4 The transformer breaker has no green light and it is closed. It is protected by R and B Phase relays without any neutral or reclosure. The current is 300/280/240, with a maximum current of 800+/800+/700. The breakers appear to be 800 Amp breakers.

11.5 F1 is closed and has a green light. It is protected by R and B phase relays with reclosure and no neutral protection.. The reclosure blocking switch should be painted Orange. Currents are 100/100/100, with a maximum of 260/240/190.

11.6 F2 is closed with a green light. It is protected by R and B phase with reclosure but without any neutral protection. The currents are 110/110/110, with a maximum of 150/320/320.

11.7 F3 is closed with no green light. It is protected by R and B phase with reclosure but without any neutral protection. The currents are 100/100/100, with a maximum of 320/300/220.

11.8 There should be Trip Coil Monitor Alarms.

11.9 The single line shows 150 E Fuse Link.

11.10 The bank is a GE 5000/5600 kVA with an Impedance of 5.5% at 5000 and 6.2 %Z at 5600. Fans are available. 27 .6 kV/4.16-2.44 kV.

11.11 The transformer tested - no PCB.

11.11 There is no spill containment.

11.12 The tapchanger is not locked.

11.13 The ground link should be labelled "Do Not Open".

11.14 Transformer Current 67.4 Amps
Neutral Current 62.6 Amps
Ground Current 1.0 Amps
This needs more investigation. It almost seems that the ground connection is open.

11.15 All outdoor lightning is broken.

11.16 All old metering should be removed.

11.17 The single lines drawings should be mounted.

11.18 The prints are on site but are not up to date. All SCADA equipment is added and does not show up on the prints.

11.19 There should be AC and DC single line drawings present.

SECTION 12.0 SUB 12 -- INDIAN ROAD (between London and Exmouth)

12.1 The cable entrance is not fused.

12.2 The arrestors appear to be 21 kV.

12.3 None of the equipment is bonded to ground in the Sub.

12.5 Remove all the old meters that are not in service.

12.6 12T1 - The equipment is protected by R and B but has no ground. It has no reclosure and the green light is on. The current is 300/360/300, with a maximum of 680/780/740.

12.7 F1 - The breaker is closed and the green light is on, protected by R and B with no neutral. The reclosure is available and the reclosure-blocking switch should be painted Orange. The currents are 50/80/100, with a maximum of 220/250/250.

12.8 F2 is protected by R and B with no neutral. The breaker is closed with a green light. The current is 100/120/60, with a maximum of 240/320/120. Reclosure is also available.

12.9 F3 is protected by R and B and neutral. There is no green light but the breaker is closed. There is reclosure. Currents are 100/100/100, with a maximum of 220/220/300.

12.10 F4 is protected by R and B and neutral with reclosure. There is no green light but the breaker is closed. Currents are 100/80/60, with maximum of 200/160/150 Amps.

12.11 The Fire extinguishers are up to date.

12.12 The transformer tests - no PCB. There is no spill containment.

12.13 The ground link should be labelled "Do Not Open".

12.14 Transformer 48 Amps
Ground 7.5 Amps
Neutral A clip-on ammeter cannot be placed around the neutral.

Please note: Items that are bolded and italicized REQUIRE IMMEDIATE ATTENTION

12.15 The tapchanger is not locked.

12.16 The GE Transformer looks as though it is 5000/5600 kVA with % Z 5.4 and 6.1. Fans are available.

12.17 All outdoor lights are broken.

12.18 The conservator tank shows low oil.

12.19 The breakers should have a Trip Coil Monitor.

12.20 There is no indication of the purpose of the SCADA.

12.21 The single line drawings, AC and DC single line diagrams, and prints in the station must be updated to show correct information. SCADA has been but is not shown on the prints.

SECTION 13.0 SUB 13 - COLBORNE ROAD (at Cathcart Blvd.)

13.1 The entrance cable needs fuses.

13.2 Observations

13.2.1 The transformer breaker is protected with R and B but without any ground protection. The current is 240/260/210, with a maximum demand of 780/640/640.

13.2.2 It has a green light with the breaker closed. The breaker indicates 800 Amps on the nameplate.

13.2.3 F1 has a green light with the breaker closed. It is protected with R and B but there is no neutral or reclosure.

13.2.4 The current is 80/100/100, with a maximum demand of 220/240/260.

13.2.5 F2 has no light and the breaker is closed. It is protected with R and B, but without a neutral or reclosure. The current is 100/100/80, with a maximum demand of 250/230/200.

13.2.6 F3 has a green light with the breaker closed. It is protected with R and B, without a neutral, but with a reclosure. The current is 130/100/100, with a maximum demand of 320/200/230.

13.2.7 The breaker nameplate indicates 400 Amps.

13.2.8 The SCADA cabinet, battery charger and all equipment is not bonded to ground. There does not appear to be any connection to the city water system. Meters should be removed. Links and fuses are not labelled. There is no indication that SCADA controls the equipment and in what way.

13.2.9 The ground link should be labelled "Do Not Open".

13.2.10 The transformer reads 44 Amps.

13.2.11 The neutral reads 32.67 Amps.

13.2.12 The ground reading is 13.9 Amps.

13.2.13 There is a second link neutral of 10.2 Amps, with a ground of 10.6 Amps. More investigation is required to understand the results.

13.2.14 The transformer nameplate is taped over with black but it looks like 5000/5600 kVA 27.6 kV/4160V. Fans are available.

13.2.15 The transformer is labelled "No PCB Hazard". There should be records to indicate this.

13.2.16 There is no spill containment.

13.2.17 The reclosure blocking switch should be painted orange.

13.2.18 There are no single line diagrams, no AC and DC elementary drawings and also no prints for the station.

13.2.19 The offload tapchanger is not locked.

13.2.20 There should be a trip coil monitor.

SECTION 14.0 SUB 14 (Behind Sarnia Hydro Office)

14.1 There are no fuses on the cable into the station.

14.2 There are 34 kV arrestors instead of 21 kV.

14.3 There is no place to measure and monitor the transformer ground and neutral current.

14.4 The main switch has no nomenclature.

14.5 The transformer tapchanger is not locked.

14.6 The transformer is a 3000/4000 kVA 27.6/4.160/2.400 kV.
It is an ONAN/ONAF 5.7% Z - 7.59 % Z.

14.7 The transformer is labelled "No PCB Hazard".

14.8 The transformer has no spill containment.

14.9 The labelling on the feeder cubicles is very small: 14F1, 14F2, and 14F3. They should be redone, and the labels placed in the vicinity of the switch handles. The station itself also needs to be labelled.

14.10 The fence is not grounded. The transformer is grounded and the feeder cubicles do not appear to be grounded but could be internally.

14.11 The SCADA cabinet is not grounded.

14.12 The 4 kV, where it appears up the pole, is not protected by 4 kV arrestors and it should be.

SECTION 15.0 SUB 20 - CONFEDERATION DS (Confed at Modeland)

15.1 All nomenclature in the station refers to the old Ontario Hydro name 1847A-L. It should be called 20A-L etc.

15.2 The yard is covered in weeds and has very little gravel. This presents a hazard to personnel for step and touch voltages.

15.3 The ground cables, attached to the station ground and laying over the yard, should be removed. It is probably the result of temporary grounding transformers.

15.4 The feeder switches at the road are called 47F1-F2 and 47F2-F3, instead of 20F1-F2. From a safety point of view, when the feeder starts down the roadway, the circuits should be arranged, so that one feeder supplies one side of the pole and the other feeder supplies the other side. They share phases on either side of the pole now.

15.5 Brush and trees have overgrown the fence and provide an easy access to obtain entry to the grounds. It also provides a hazard for people from step and touch potentials. The area for three feet around the fence should be cleared and gravelled, as well as the area inside the fence, to protect for step and touch potential.
Trim back trees immediately.

15.6 The fence ground connections are broken around the perimeter. ***This should be repaired***. There is standing water around the property that would be covered with more gravel.

15.7 There is only one feeder in service. It should have 8 kV lightning arrestors added, as should the 8 kV Bus in the station. There are 34 kV arrestors on the bank that should be changed to 21 kV.

15.8 The spare holder in the station is fused with an S&C 150 E. TCC119-1, which is also what the list inside the station says it should be. All the spare fuses in the station are 150E TCC153-1.

15.9 There is no single line in the station.

15.10	Transformer Current	8.69 Amps
	Neutral Current	7.54 Amps
	Ground Current	1.37 Amps

15.11 There is no spill containment for transformer. It is labelled "No PCB hazard".

SECTION 16.0 SUB 21 - MICHIGAN DS (Michigan at Modeland)

16.1 The nomenclature in the station refers to the old Ontario Hydro 1852T1L-X, instead of 21T1L-X. It all should be changed to refer to Sarnia Sub 21.

16.2 ***Trim back the trees*** from the fence as it creates an easy access to the station, and also to step, and touch potential hazard.

16.3 The ***metal clad building should be removed*** from the site because it provides "limits of approach hazard" to the 4 kV bus.

The barbed wire on top of the fence is rusted through and missing in several places. ***Replace immediately***.

16.4 There should be 4 kV bus lightning arrestors added.

16.5 There are no fuses on the secondary of the transformer. ***The "cut-outs" south of the station should be replaced with fused "cut-outs".***

16.6 The neutral from the transformer to the road should be buried, rather than lying on top of the ground. This is a tripping hazard and could be accidentally cut.

16.7 The yard needs more gravel to prevent step and touch potential hazard.

16.8 There is no spill containment. The transformer has a warning "PCB Hazard greater than 50".

Install clay berm immediately.

16.9 The bank is 7500 kVA 5.4% Z ONAN
27.6 kV/4160 /2400 - 8320 /4800 Delta /Wye
The spare fuse is SMD -2C 300E TCC 153-1

16.10 There are no single line diagrams for the station

16.11 It is difficult to tell if the current transformers from the transformer are connected or not. The kWh meter shows a demand of 380 X 6400 or 2432 kW but it might have been from some time ago because it appears that it is all out of service. A meter box could be added to measure the station load when the building is removed.

Please note: Items that are bolded and italicized REQUIRE IMMEDIATE ATTENTION

16.12 Neutral and Ground readings are:

Transformer	19.2 Amps
Feeder neutral	16.6 Amps
Ground	2.2 Amps

16.13 The arrestors should be changed to 21 kV rating.

SECTION 17.0 SUB 22 - PERCH DS SUB (Waterworks at Lakeshore)

All nomenclature in the station, referenced to the old Ontario Hydro 1848T1-L, should be changed to reflect the Sarnia Hydro Sub 22. (22T1-L) etc.

17.1 All three banks are leaking oil onto the ground and the Red Phase has a major leak which appears to be coming from the head gasket.

17.2 The banks need painting.

17.3 There is no spill containment around the banks.
The transformer is labelled with "No PCB Hazard".

17.4 There needs to be more gravel in the yard to protect personnel from step and touch potential.

17.5 Trees and brush are overgrowing the station. They should all be trimmed back to allow at least a three foot clear area around the property. The fence grounding typically protects people from step and touch voltages for up to three feet.

17.6 ***The guys, from the poles in the yard, come within one foot of the inside fence and hence a person could touch the fence and guy at the same time, which could result in touch voltage potential.***

17.7 ***The ground for the temporary work trailer should come from the ground grid - not the top rail. The ground for the temporary work trailer should be buried. It physically becomes a hazard to people walking as well as for touch potential.***

17.8 **The *spill response building should be moved away from the perimeter of the fence. It is not grounded and sits within one foot of the fence and provides easy access to the station.***

17.9 The station does not have 8 kV bus lightning arrestors in the station. These should be added. Three of the existing arrestors are defective. (The top has blown away.)

17.10 Boxes of HV fuse links indicate the primary fuse is SMU 20 140K TCC 165-1. The notice on the inside the building wall indicates the fuse link to be 125E TCC139-3.

Please note: Items that are bolded and italicized REQUIRE IMMEDIATE ATTENTION

17.11 Two low voltage feeders are protected by reclosures.

F1 B13 200 Amps
F2 B13 280 Amps

F1 has a belted "Hold off" on reclosure. The tag is not filled out but reclosure is blocked. It seems to have been here a long time.

17.12 The transformer is made up of three Ferranti Electric 1200 kVA, 5.8 % Z. The maximum kVA demand is 400 X 4800 or 1920 kVA.

17.13 The measured current on the neutral and ground is as follows:

Transformer	14 Amps
Line Neutral	20 Amps
Ground	5 Amps

This needs further investigation to rationalize the currents.
An A/C single line is needed at station.

17.14 There is no station diagram in the building that could be pinned to show the status and arrangement of the station.

17.15 The primary arrestors should be changed to 21 kV.

SECTION 18.0 AIN-KE-JIG DS ON RESERVE (Delta/ Wye) (LaSalle Road)

18.1 This distribution station is hanging on the end of the 18-M11 feeder out of St. Andrews. There is no neutral along this road and hence ground type faults will be slow in clearing and will tend to affect all other customers.

During ground faults, full neutral shift may occur with high current appearing at the sewage pumping station.

18.2 The nomenclature is unreadable

18.3 All the fence drop ground leads have been cut off.

Install aluminum drop leads ASAP.

18.4 The yard and grounds are overrun with weeds going right up to the transformer bushings. There is a real hazard for step and touch potentials.

Action: Clean up the yard, ASAP.

18.5 There is no spill containment protection. The PCB content of the bank is not labelled.

18.6 The conservator tank oil level indicates one half full. The explosion vent diaphragm is broken. The transformer is showing signs of leaking and likely has water contamination.

This transformer should be repaired or removed from service ASAP.

18.7 There is only one feeder leaving the property and going to Sarnia Sewage Pump around the corner about 1000 ft away. It would seem to make sense to install Sarnia Hydro Transformers and feed the customer directly.

There is NO 4160 neutral going to the pumping station. The 4160 transformer appears to be of the open delta connection type.

Action: A neutral should be strung along the road to this location and would be ready to service new customers, if they come, with 16 kV. It would also, improve clearance times.

SECTION 19.0 POINT EDWARD DS NW 1860 SARNIA HYDRO 60 (Front Street at Highway # 402)

19.1 This station is being reviewed although it is owned by Ontario Hydro but it is serviced via the Modeland city feeder M25.

19.2 The station has three feeders although it appears only two are in service with load. All breakers are available. Green lights indicate F3 and F2 are closed and a white light indicates F1 is open.

19.3 F3 is protected by R and B with no neutral but with reclosure. Currents are 60/132/60 with a maximum of 132/168/ 105.

19.4 F2 is protected by R and B with no neutral but with reclosure. Currents are 120/114/0 with a maximum of 120/144/0.
This needs further investigation.

19.5 The total station metering indicates 240/280/120 with a maximum of 528/540/252. The kVA meter indicates 1920 kVA with a maximum of 3648 kVA.

19.6 The indoor cable transformer potheads are leaking.

19.7 Primary fuses on the bank are SMU_20 140K TCC165-1. The station also has two spares and, in addition, two holders fused and ready for service.

19.8 The transformer has no spill containment and is leaking quite badly around the head gaskets. The transformer is brush 3000 kVA ON 27.6/4.16 kV % Z 5.46 and the fans are disconnected.

19.9 The Sub has 34 kV arrestors instead of 21 kV ones. The guy wires come down to the ground within two feet of the fence, creating a touch potential hazard. The guy should be bonded to the fence.

19.10 There are no LV arrestors at the transformer secondary 4.16 kV side.

19.11

Transformer Current	95 Amps
Neutral Amps	93 Amps
Ground	5 Amps

This needs further investigation.

19.12 4.16 kV SYSTEM

While looking over the 16 kV distribution system around Sub 1, it was noted that the 4 kV system may have some problems, in particular, around the Government docks. One location, called "Government Dock Central", has three transformers connected wye / delta with the centre wye point floating and not tied to the 4 kV neutral or ground. This appears to be a feed to boats and the output to the customer would be less than desirable. The primary connection is allowed to float and shift along the wye and, depending on whether the load is balanced or not, could produce some strange secondary voltages. With this system, the secondary voltage could appear very distorted if a primary fuse blows or if for any reason, a phase is missing.

At this same location, a 4 kV cable goes off to another site, Government Dock West. A pad mounted transformer is located here. If the Y primary were connected, it would be tied to ground because the neutral does not appear to go here. From this location, a single phase pad mount is fed from an underground cable with no neutral connection, only a phase. The primary of the bank must get its neutral from a driven ground rod.

Sandrin Bros. Ltd. #1 has three 200 kVA transformers connected primary wye and secondary delta. The primary wye connection is floating, not connected to ground or neutral and, for the same reasons as above, the voltage will be unstable to the customer. The meter tank feeding this customer looks, from the ground, as though it had been subjected to a fault and it is in bad shape. The meter shows no demand.

At Shelley Machine and Marine the banks are hooked up delta primary and wye grounded secondary. This is okay, except that the wye point at the transformer is joined together with a very small conductor compared to the phase connection it goes to. The 4 kV neutral at this point is attached to ground with a small bare conductor. The load is then fed down the stack three phases of at least 1000 MCM cable and the ground for this location comes from ground rods and there is no connection to the neutral.

A new bank has been added to feed boat docks. It is fed through three mid span fused disconnects, with no nomenclature . The bank is hooked up wye/wye, which is good, and the customer is metered with meter PT.P102. The banks are labelled 37 kVA. The meter is locked but the other part is not very secure.

A detailed engineering code review is required at the Federal Docks. The primary neutral of the 4160 wye banks should be connected to the 4160 neutral and grounded at the banks. See Section 78 of the Code Book.

The Federal Docks should be visited by E.S.A. to outline what the code requires for this type of service. The review should be conducted before the ships dock in December 1999.

19.13 Sandy Lane

There is a tap that goes along this road to feed three apartments and Canatara Park. The print shows none of this but there are three underground cables:

29M077
29M001
29M073

The single-phase tap to the park has no nomenclature. The neutral runs along the main feeder and when it taps off to this road it taps with a little piece of copper.

SECTION 20.0 FEEDER SURVEYS

20.1 Switch 225L

20.1.1 The pole has three separate nomenclatures on it.

225L
CON-2
96M28

20.1.2 The feeder is actually M27.

20.1.3 The load switch has a bypass associated with it. This is not labelled nor indicated on the single line diagram. Looking at this switch, from ground, it appears to look too short to provide a bypass.

20.1.4 A method of identifying could be 225L for the load switch and 225L-S for the bypass.

20.2 Procor - Pro-L

The three phase switch is in series with a fuse and an underground cable. The cable has the shield pulled back and is grounded. The other end of the cable is done the some way . These shielded cables should be grounded at one end only. If there is a concern that high voltage might build up, a 600 Volt arrestor can be attached between the sheath and ground at the ungrounded end. The sheath is not built to carry current.

The guy wire on this switch should be bonded to the ground mat. A switchman could be in contact with both the guy and switch and experience touch potential.

20.3 216F

The three-phase tap on Brigden Side Road is fused. It then reduces to a single-phase lateral with a transformer to reduce the voltage from 16 kV to 8 kV. There is no indication that this has happened. The first pole has two nomenclatures 16M28-01 and 179-1, and the next pole has 16M28-R2 and 179-2.

20.4 216L

There are two signs on the pole, 216L and PE2.

20.5 227S

The pole has three signs on it: 227S, 557, and M28-S9.

20.6 255-F

The sign cannot be read. It should be replaced.

20.7 562-JX

The sign should be replaced; it cannot be read.

20.8 Bright's Grove

A lot of work has been going on out here and prints do not reflect what has been happening.

20.8.1 Going out Lakeshore towards Mandaumin, the switches and taps have no nomenclature on the load break switches. There are more three phase and single phase taps taken off with no names. There does not appear to be any identification to distinguish between single and three phase laterals.

20.9 160A

This is probably the switch behind Bingoland East. There is no name on the switch and it is completely overrun with vines. The customer's fence is within one foot of the switch handle and would present a touch potential hazard if you could operate it. The handle should be moved to the opposite side of the pole.

20.10 229S

At SW 229S there are two single phase taps. One is fused with no identification and the other has no fuse in tap.

20.11 241L

The name should be at the switch handle.

20.12 758JX

The nomenclature is labelled on the pole but is not on the single line.

20.13 1805T1L-X

This switch was probably a leftover from the old Ontario Hydro feeders. It may be for the Ramada Hotel or the Canterbury Fitness Centre. It is not on the print.

20.14 E-1805-LC-1410JX

The ground is loose on the switch handle.

20.15 D-1805-LC-1419-JX

The ground is broken on the switch handles.

20.16

From the road, before it comes into these feeds to the Mall and Wal Mart, there is a switch consisting of three single phase blades with no name.

20.17 Dow Research Laboratory

The tap, into the facility, is actually three phase, cable fused, with three arrestors. One arrestor is 21 kV and the other two are 34 kV.

20.18 138A

This has two names, 1816-M16 and 138A.
These two switches provide the feed to Enbridge. A meter tank measures the load supplied and it is customary to place lightning arrestors on both sides of the meter tank. There are none here nor are there any arrestors on the taps to the individual feeds to the transformers within Enbridge. All units within the site are 34 kV.

20.19 142A

It has two nomenclatures: 1816-M4 and 142A.

20.20 143A

It has two nomenclatures: 143A and 1876M4-66.

20.21 157S

On the pole, it says, 96M29 and 96M24 and it is really 96M31.

20.22 <u>157S and 167S</u>

These are two switches which are typical of others on the system. They appear to be short so when the switch is open it cannot be used as a switch for work protection. There was an old study by municipalities, a few years ago, which said (if I remember it correctly) a distance of 18 inches is required to prevent restrike. These switches look like the old 15 inch variety.

20.23 <u>159L</u>

The switch has two names on same pole: CON-1 and 159-L.

20.24 <u>230L</u>

The pole has on it M29-M24 and 11F2 -11F3 and 230L.

20.25 <u>301S</u>

This is a point of separation between two jurisdictions, Point Edward and Sarnia. There should be some type of identification to indicate the separation of authority. This would be an indication to each authority's work force when these switches are closed. Load transfers and work protections must be made out to indicate all changes.

20.26 <u>M29 and M31</u>

These two feeders share the same pole line from London Road to Michigan. There are a total of 22 poles along this stretch without a set of lightning arrestors. There should be a cluster about every 6 to 10 poles at least. M29, where it goes under 402, has 34 kV arrestors and the newer M31 has 21 kV arrestors. The cables, when they go up the pole, should have one more length of cover up. It appears the children play here and we need to protect them from themselves.

These cables do not appear to be the ones with concentric neutral. They are only shielded cables and as such both ends of the cable should not be grounded. The standards on cables should be reviewed.

20.27 <u>Feeder End M31</u>

At the Lakeshore Road end, both 8 kV and 27.6 kV, appear on the pole. The label on the pole should show this.

20.28 Tashmoo

There are two jurisdictions down this road. There is a 4 kV out of St. Andrews Sub 2 and a 16 kV to 4 kV transformer fed from Lambton M5. These two sources share the same mid span opener in front of 1124 Tashmoo and there are no identifying labels here. Prints do not show this.

20.29 22F1-9

This switch has two labels on the pole: 503 and 22F1-9.

20.30 164A

It should be 162L. It also has unidentified bypass on its structure. On the same pole, there are two more labels, 588-J and 588-JS.

20.31 332F

This switch appears to be incorrectly labelled 323F.

20.32 Hiawatha

20.32.1 HWT1-L

The ground mat offers no protection. The mat is completely covered with grass. The meters looking at the track are indicating 1000 divisions plus, indicating the CT's are overloaded.

20.33 133A

There are two labels on the pole: S1-M26 and 133A.

20.34 Cargill Grain

The tap into the station has a mid span set of openers called 20A7 which are not on the print. From this point on, no neutral is run to the station. The station has 34 kV arrestors.

20.35 121A

The switch, 121A, is really 121L. Just after the switch, a cable takes off into an apartment. The cable has fuses but they are not labelled at this location. A 4 kV stand off at the transformer is also floating.

20.36 267A

It is really 267L.

20.37 288L

At this switch location, the building that just sold on the corner of Vidal, has a tall old antenna next to the 27.6 kV line. A line truck should volunteer to cut and remove this in the interest of public safety.

20.38 721JX

The switch on this pole is not identified.

20.39

The pole next to the St. Clair Corporate Centre is not fused. Shields are grounded at both ends of the cable, using split bolt connectors. There is no nomenclature on the switch going across the road.

20.40 Lakeshore at Blackwell Side Road

A fused single-phase tap takes off. The fuse has no nomenclature.

21.0 SUMMARY NOTES

2.1.1 PCB's

Wherever PCB's exist at more than 50 ppm, care must be taken to prevent a spill that would contaminate adjacent property.

Sub 10 and 20 fall into this category and clay berms should be erected immediately to contain a spill.

Sub 1 and 2 contain capacitors that have PCB's and since they are not required, they should be removed immediately.

In the meantime, a notice has to be put up warning emergency personnel of the hazard within.

2.1.2 Security

Properties must be secured against public entry. The condition of many sites is such that, with very little effort, a person could be where they should not be. The outside perimeters could be easily breached. In addition to this, there are situations that would allow a person to be subjected to step and touch potentials when they come in the vicinity of the stations.

2.1.3 Ontario Electrical Safety Code and E.S.A.

The Electrical Safety Authority (E.S.A.) will present a classroom course, including 1998 Safety Code Books (to keep) for approximately $100 per person. All electrical staff at Sarnia Hydro should take this course.

SECTION 22.0 FUTURE ALTERNATIVES AND COST ESTIMATES

22.1 Henry Ross Sub Station

The cost to have the indoor oil-filled transformers meet the Electrical, Fire and Building Code will likely be more than moving the transformers outdoors and installing outdoor metal-enclosed 4160 breakers.

The Ross Substation building will incur tax liability for a "Local Distribution Company" (LDC) in the future. Outdoor transformers and gear would avoid this cost.

22.2 Sub 1 - St. Andrews Rehabilitation

The Class IV Cost Estimate to replace the old 4160 breakers and to bring the station up to code requirements is as follows:

1.	Dispose of capacitors (See Rondar estimate - half to Sub 1 and half to Sub 2)	approx.$10,000
2.	New gear - 1 main/6 feeders (See Cutler-Hammer)	$250,000
3.	Install gear and cables Ground equipment Clean-up station (See Tee-Jay Instrumentation)	$120,000
4.	Engineering / Procurement Construction Management (≈10%)	$50 000
5.	Contingency @ 20%	$86,000
	TOTAL ESTIMATE (TNIP)	$516,000

The monthly cost to finance this capital expenditure over 10 years (120 payments) at an interest rate of 7.25% is $6,187.04/ month. See Royal Bank Memo.

22.3 Sub 5 - Michigan / Colborne Avenue

Class IV estimate to repair/replace fencing and bring the grounding to code requirements.

Replace 180 feet of chain link fence		$5,000
Replace west & south fence with vinyl fence (See St. Clair Estimate)		$8,700
Repair/replace ground rods & counter poise, Remove old lights	Labour	$8,000
	Material	$3,300
Contingency @ 20%		$5,000
TOTAL ESTIMATE (TNIP)		$30,000

Question 3.13 - Capital Programs and Projects

Ref: http://www.oeb.gov.on.ca/documents/minfilingrequirements_report_141106.pdf
Ref: Exhibit 2/Tab 3/Schedule 1
Ref: Exhibit 2/Tab 3/Schedule 6

Asset management consists of processes and systems that help evaluate, prioritize, and select the distributor's maintenance and capital plans to maximize the benefits to its customers and shareholder.

For the purpose of providing the information regarding its maintenance and capital plans, Bluewater should use its identified materiality threshold items.

In regards to Bluewater's 2009 capital plans:

Question 3.13 (a)

Please provide a list of criteria and rationale that Bluewater has utilized in the prioritization and selection of its 2009 capital projects.

3.13 (a) Response:

Bluewater Power has five capital projects that meet the materiality threshold of $350,000 which are listed on the schedule in 3.13 part b.

Bluewater Power considers the following criteria in the evaluation of capital projects (not in any implied order of importance)

1. *Safety*
2. *System Integrity/Planning*
3. *New Customer Additions*
4. *Regulatory/Government Compliance*
5. *Maintenance of an effective billing system*
6. *Asset condition/protection*
7. *Environmental Compliance*
8. *Employee health and welfare*
9. *Life cycle cost reduction*
10. *Customer Service*

11. Provision of efficient administrative services

Question 3.13 (b)

Please complete the following Table 8 and provide a ranking and description of the capital projects using the threshold test that is outlined above. Please note that a rating of "1" is the highest priority, rating "2" is the second highest priority, rating "3" is the third highest priority etc. Please use additional rows, if necessary.

3.13 (b) Response:

Attachment: Board Staff 3.13.b Capital Plan Ranking

Table 8 - Capital Projects

Priority Ranking	Project ID	Project Name	Description of Project	Type of Program (replacement, rehabilitation, upgrade of asset or new additon of asset)	Capital Investment	Discretionary or non-discretionary	Start date of project	Date in service	Rationale for Priority Selection
2	UT12	Vehicle Replacement	Purchase 5 vehicles: 1. Single bucket truck $286K, 2. Minivan $27.5K, 3. Minivan $27.5K, 4. Minivan $22K, 5. Boom/Dump Box $165K	Replacement for #1-4, Addition for #5	$ 528,000	Non-discretionary	Q1-Q2	Q2	To ensure acceptable Customer Srevice
1	UT13	New Connections	To connect new residential and commercial customers in order to meet demand for new services.	New Addition	$ 978,799	Non-discretionary	Q1-Q4	Q1-Q4	New customers require service, no choice
1	M7	Transmission Station Meter Upgrade - Modeland	This is a mandatory installation of 2 meters outside the Modeland transmission station in order to comply with the IESO Market Rules.	Upgrade	$ 525,074	Non-discretionary	Q1	Q3-Q4	This is a compliance driven project and is mandatory.
2	IT18	SAP Upgrade	To upgade the now outdated version 4.7 of Bluewaters's SAP ERP system.	Upgrade	$ 1,445,145	Non-discretionary	Q1	Q3	Necessary for effective utility administration and customer billing
2	O5	Building Renovation	Phase 2 of a 5 year program to update and expand Bluewater Power Service Centre. This phase entails new vehicle bays and equipment storage space.	Upgrade	$ 863,315	Non-discretionary	Q1	Q3-Q4	Necessary to ensure proper care of high value assets
Total $ for Prioritized Programs					**$ 4,340,333**				
Total $ Prioritized Programs as a % of Overall Total 2009 CAPEX					52%				
Discretionary Programs as % of Total Prioritized Programs					0%				
Non-discretionary Programs as % ot Total Prioritized Programs					100%				
Replacement Programs as % of Total Prioritized Programs					8%				
Rehabilitation Programs as % of Total Prioritized Programs					0%				
Upgrade Programs as % of Total Prioritized Programs					65%				
New Additions as % of Total Prioritized Programs					26%				

2009 Proposed Capital Expenditures					**8,285,818**				

Materiality Threshold defined as 1% of Net Fixed Assets. For 2009 Bluewater's is $39,545,075, therefore the material projects are those greater than $395,000

Notes:

1. Type of program can be replacement, rehabilitation, or upgrade of an existing asset, or an addition of a new asset.
2. Non-discretionary – a “must do” project or related directly to the core infrastructure (e.g. stations, feeders, etc.), or the need for which is determined beyond the control of the Applicant, e.g. regulatory or Government initiatives.
3. Discretionary – the need is determined at the discretion of the Applicant and the program can be deferred.
4. Some programs may have the same priority ranking.

Question 3.13 (c)

Please explain and file with the Board necessary evidence, if any, with respect to how the priorities of these projects are determined using the criteria identified in part "a", e.g. asset condition study, system planning, regulatory compliance, etc.

3.13 (c) Response:

The projects described in table (b) have all reached the point where they have become a non-discretionary expenditures. Several years ago, certain projects were more of a discretionary nature however; these have been deferred to the point of becoming a mandatory expenditure.

Question 3.14 - Cost of Power Assumptions

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

In this attachment, Bluewater provides a breakdown of its working capital calculation, but does not provide its cost of power assumptions for 2008 and 2009.

Question 3.14

Please state which rates Bluewater is assuming for its working capital calculation and how they were determined as well as any other key assumptions that may have been made.

3.14 Response:

Working capital is comprised of the components displayed in Table 3.14.1 below:

Table 3.14.1 – Working Capital Allowance

		2009
Eligible Distribution Expenses:		
3500-Distribution Expenses - Operation		3,535,352
3550-Distribution Expenses - Maintenance		157,640
3650-Billing and Collecting		1,497,443
3700-Community Relations		216,871
3800-Administrative and General Expenses		5,951,113
3950-Taxes Other Than Income Taxes		297,750
Total Eligible Distribution Expenses		11,656,169
3350-Power Supply Expenses		79,099,884
Total Expenses for Working Capital		90,756,053
Working Capital Allowance	**15.0%**	**13,613,408**

The details on the Power Supply Expenses of $79,099,884 including the rates can be found at Exhibit 1/Tab 3/Schedule 4/Attachment 1. The Power Supply Expenses are made up of ‘Pass Through Charges’ namely: Electricity Commodity, Transmission Network Charge, Transmission Connection Charge, Wholesale Market Service Charge, Rural Rate Protection and Low Voltage charges.

Bluewater Power assumed a cost of power price of $.0545/kWh which was based on the OEB Regulated Price Plan report dated April 11, 2008. However, on October 15, 2008 the OEB released an updated RPP price of $.0603/kWh. This change would increase the working capital allowance by $996,825 as detailed in Table 3.14.2.

Table 3.14.2 – Impact of Updating RPP Price on Working Capital

		Original Electricity Commodity as Filed ($/kWh)	Updated Electricity Commodity based on Oct 15/08 RPP price ($/kWh)		Increase to Working Capital (at 15%)
Customer	**2009**	**$0.05450**	**$0.06030**		
Class Name	**Volume**	**Amount**	**Amount**	**Variance**	
Residential	275,919,502	15,037,613	16,637,946	1,600,333	240,050
General Service <50 kW	124,835,762	6,803,549	7,527,596	724,047	108,607
General Service 50 to 999 kW	223,932,369	12,204,314	13,503,122	1,298,808	194,821
General Service 1,000 to 4,999 kW	185,691,188	10,120,170	11,197,179	1,077,009	161,551
Large	323,391,044	17,624,812	19,500,480	1,875,668	281,350
Unmetered Scattered Load	2,266,760	123,538	136,686	13,147	1,972
Sentinel Lighting	708,493	38,613	42,722	4,109	616
Street Lighting	9,030,349	492,154	544,530	52,376	7,856
TOTAL	**1,145,775,469**	**62,444,763**	**69,090,261**	**6,645,498**	**996,825**

The second assumption impacting the Pass-through charges relates to the Retail Transmission Service Rates ("RTSR") which will change as of January 1, 2009. The response to Board Staff Interrogatory 10.1 fully addresses the impact of the RTSR rate change, and the associated impact of the RPP change on the revenue requirement and rates.

Bluewater Power requests the ability to fully update the revenue requirement and associated rates as a result of the change to the RPP rate, and the change to the RTSR.

Question 3.15 - Service Quality and Reliability

Ref: Exhibit 2/Tab 1/Schedule 1, p.2

Please provide the following information on service reliability indicators recorded and used by Bluewater:

Question 3.15 (a)

A list of the Service Reliability Indicators maintained and used, and their actual values for the years 2002 through 2007;

Response:

Table 3.15.1 details the Service Reliability Indicators maintained and used for the years 2002 through 2007.

Table 3.15.1

	All Causes of Interruptions			**Excluding Loss of Supply**		
Year	**SAIDI**	**SAIFI**	**CAIDI**	**SAIDI**	**SAIFI**	**CAIDI**
2002	2.94	2.34	1.26			
2003	3.85	4.09	0.94			
2004	2.31	3.41	0.68			
2005	3.25	4.41	0.74			
2006	2.31	2.57	0.90			
2007	2.76	2.66	1.04	2.67	2.49	1.07
Estimate 2008	2.61	2.55	1.03	2.35	2.28	1.03
3 Year Average (2005-2007)	**2.77**	**3.21**	**0.89**			

<u>Question 3.15 (b)</u>

Bluewater's 2008 and 2009 reliability improvement targets, if any, for the SAIDI, SAIFI and CAIDI indicators.

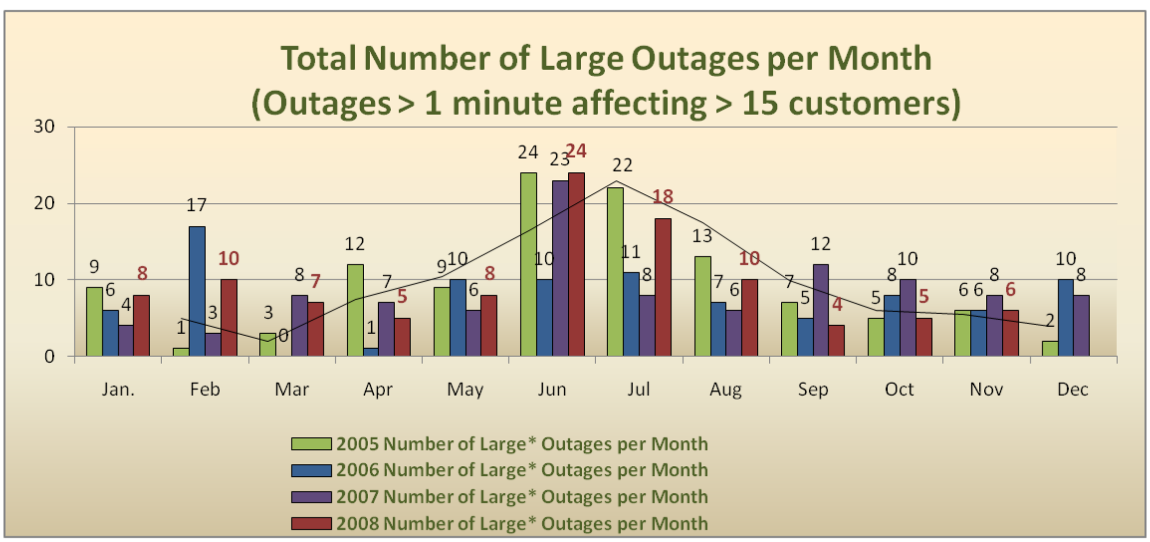
<u>3.15 (b) Response:</u>

The estimate for 2008 is indicated in Table 3.15.1 above, and is based on the year-to-date October 2008 actual results along with an estimate of November and December 2008.

Given the slight increase in the CAIDI values over the past four years, Bluewater Power will attempt to reduce the number of outages by 10% in 2009. This will equate to reducing the number of outages by 39.

The table below indicates the tracking of the 'large outages' those being outages that last for longer than 1 minute, and affect more than 15 customers. The table shows that most of the outages occur in the summer during extreme weather conditions.

<u>Table 3.15.2 – Large Outages per Month</u>



In order to reduce the outages for 2009, Bluewater Power has targeted three areas that are deemed to be somewhat controllable, thereby giving us the ability to reduce the number of outages:

1. Animal Interference (controllable)
2. Tree Contacts (controllable)
3. Broken poles related to adverse weather (somewhat controllable through pole testing)

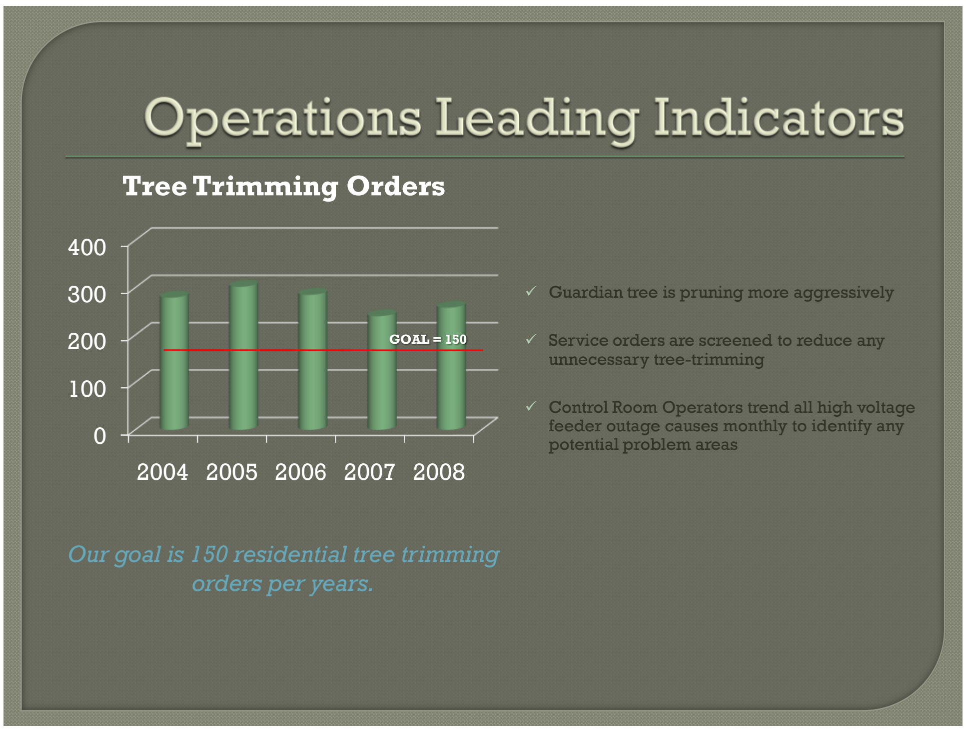
Installing animal protection is becoming a major priority in Bluewater Power's effort to improve customer reliability and power quality. It is one element of service reliability that can be reduced and almost eliminated with the installation of protective devices.

Bluewater Power set up a proactive outage management system in 2005 that helped us pinpoint cause and affect regarding power outages. That is when we started to understand the magnitude of what was happening when animals contacted high voltage circuits. For example animal contacts on circuits radiating from Hydro One's St. Andrews T.S. in the south of Sarnia have had devastating affects for industrial customers for some time. That is because the station is 110KV (not 230KV) and because the station is of such a design that the bus tie must remained closed. That means all customer's fed from the station feel voltage dips associated with faults that occur on electrical feeders that are not directly attached to their supply.

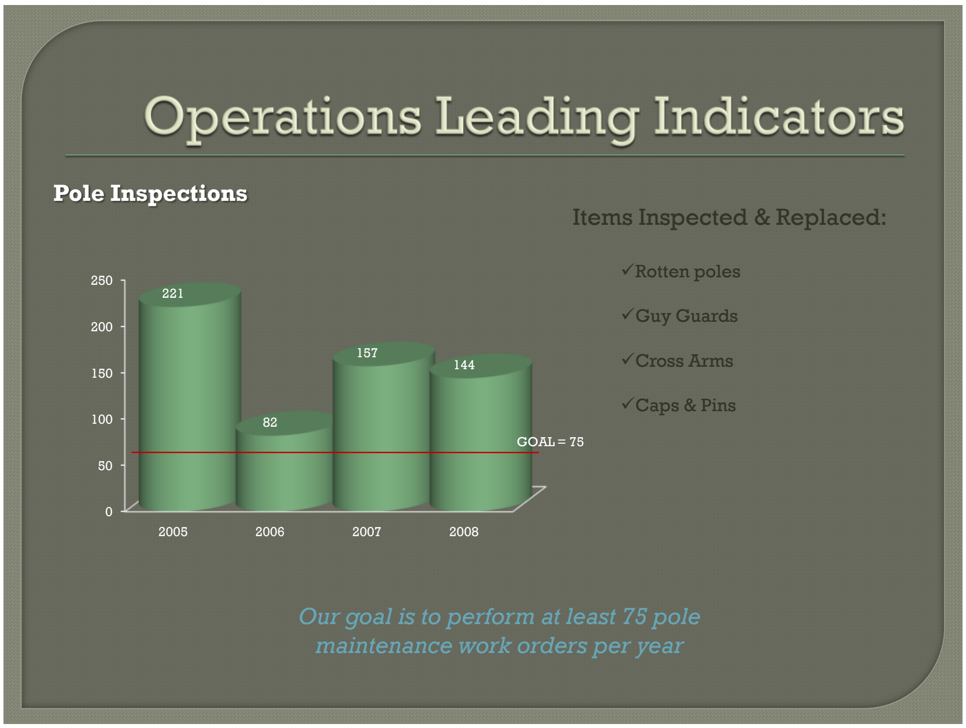
Also the extent of damage to electrical equipment following animal contact with a high voltage circuit is often severe.

Currently, approximately 64% of Bluewater Power's facilities are protected from animal interference, thus approximately 36% is still at risk. Bluewater Power plans to aggressively install more protection in 2009, with a goal to have 100% protection by 2013.

The second target for reducing outages in 2009 is related to tree trimming. The annual tree trimming budget includes both planned trimming (entire service area trimmed on a 4 year cycle), and demand trimming. Bluewater Power has had an excellent tree trimming program in place for 10 years. One way to evaluate our continued progress in meeting our planned tree trimming responsibilities is to see a reduction in the number of demand related trimming service orders. Our 5 year goal is to reach 150 demand driven orders. This reduction over the historic levels will indicate that the overall tree trimming plan is effective.



The third target for reducing outages relates to pole inspections. Bluewater Power has witnessed a decrease in the number of broken poles during storms since implementing our pole testing and inspection program in 2004. Our goal is to have a decline in the number of poles changed as a result of the testing program; to reach the point where we change out on average 5 poles per year (we have approximately 15,000 poles). We believe that goal will take approximately 10 years.



Finally, additional effort will be placed on managing power quality and outage management through the use of a contracted Power Quality Specialist.

The increased use of sensitive electronic equipment in industrial, commercial and residential applications has introduced a new element to electrical distribution systems, “Power Quality”. The Bluewater Power Operations Group will no longer discuss power reliability without reference to power quality.

> *“Today’s electronic loads are susceptible to transients, sags, swells, harmonics, momentary interruptions, and other disturbances that historically were not cause for concern. For sensitive loads, the quality of electric service has become as important as its reliability. Power quality is a new phenomenon. Events such as voltage sags, impulses, harmonics, and phase imbalance are now power quality concerns. Power quality problems have a huge economic impact. As a result, any discussion of power system reliability must also include power quality.”*[1]

1. Measurement Practices for Reliability and Power Quality, U.S. Department of Energy.

The Bluewater Power Operations group began annual forums with large industrial customers in 2005. It became apparent through the meetings that the industry was experiencing problems with power quality that was affecting their system operations. This resulted in loss of production and failure of equipment. It was following the first meetings in 2005 that Bluewater Power and large industrial customers opened up communication channels to share electrical system information. It was then we realized that industrial customers were feeling disturbances from a host of events that were not always directly related to their supply; such as voltage dips on transmission circuits, capacitor banks being switched out at the transmission station, or faults on adjacent feeders. Bluewater Power embarked on several programs like increased lightning arrester coverage on high voltage circuits, neutral upgrade programs, new relaying in substations and animal protection. Bluewater Power also engaged Hydro One to enact similar improvements to their transmission and distribution systems. In 2008 the Bluewater Power Operations Group hired the Power Quality Specialist on contract. The explicit role of the Power Specialist is to;

- Be a direct link to large industrial and commercial customers regarding power reliability and power quality.
- Model all Bluewater power high voltage circuits on SYME software.
- To review and provide new settings for station relays.
- To work with Control Room to reconfigure feeders.
- To provide fault current analysis.
- To provide technical assistance to Engineering staff.
- To liaison between Bluewater Power and Hydro One.

Having a dedicated Power Quality Specialist has been a great benefit to the Operations Group, more importantly to the Bluewater Power large customers.

Question 3.15 (c)

If Bluewater has established such targets, a copy of the plan that identifies programs or projects that Bluewater will undertake to achieve these targets.

3.15 (c) Response:

See response to 3.15 (a)

SMART METERS

<u>Question 4.1 - Smart Meters</u>

Ref: Exhibit 5/Tab 1/Schedule 4

Ref: Ontario Energy Board – Guideline, Smart Meter Funding and Cost Recovery, G-2008-002, p. 10 – 11, http://www.oeb.gov.on.ca/OEB/_Documents/Regulatory/OEB_Guideline_SmartMeters.pdf/

On page 2 of its discussion of smart meters, Bluewater states that:

"In order to mitigate future rate shock, Bluewater Power requests that the rate adder be increased to $1 per meter commencing May 1, 2009."

With reference to the Board guideline on smart meter funding and cost recovery (pages 10-11), please provide the following information:

<u>Question 4.1 (a)</u>

The estimated number of meters to be installed in the rate test year.

<u>4.1 (a) Response:</u>

Bluewater Power is planning a phased in approach to installing smart meters. In 2009, Bluewater Power expects to install approximately 350 meters in the Village of Oil Springs with the remainder to be installed in 2010.

<u>Question 4.1 (b)</u>

The actual or estimated costs per installed meter and in total.

<u>4.1 (b) Response:</u>

The estimated cost per installed meter is $172. The total estimated cost of installing all smart meters is approximately $6.0 million.

Question 4.1 (c)

A statement as to whether the distributor has purchased, or expects to purchase, smart meters or advanced metering infrastructure ("AMI") whose functionality exceeds the minimum functionality adopted in Ontario Regulation 425/06 and an estimate of those costs.

4.1 (c) Response:

Bluewater Power does not expect to purchase smart meters or advanced metering infrastructure with functionality exceeding the minimum standards.

<u>Question 4.1 (d)</u>

A statement as to whether the distributor has incurred, or expects to incur, costs associated with functions for which the SME has the exclusive authority to carry out pursuant to Ontario Regulation 393/07 and an estimate of those costs.

<u>4.1 (d) Response:</u>

Bluewater Power is proceeding on the assumption that the SME will be available to handle its intended functions. Should the authorized SME not be available when Bluewater Power is ready, then alternative vendors may have to be investigated. We do not have an estimation of what those costs would be.

PILS

Question 5.1 - Additions to Taxable Income

Ref: Exhibit 4/Tab 3/Schedule 1/Attachment 1
Exhibit 1/Tab 3/Schedule 3/Attachments 1 and 2
Exhibit 1/Tab 3/Schedule 2

Bluewater's taxable income calculation, as shown on page 2 of Exhibit 4/ Tab 3/Schedule 1/Attachment 1 includes additions related to "Net employee future benefits (accrual less amounts paid)" in amounts of $847,994 for 2008 and $694,415 for 2009.

In Exhibit 1/Tab 3/Schedule 2/Attachment 1, which is Bluewater's 2007 Financial Statements, the Balance Sheet shows a 2007 year ending "Employee future benefits" amount of $5,508,399.

In Exhibit 1/Tab 3/Schedule 3/Attachment 1 Page 2 of 5, the 2008 Pro-Forma Trial Balance shows a 2008 year ending "Employee Future Benefits" amount of $6,202,814. In Exhibit 1/Tab 3/Schedule 3/Attachment 2, page 3 of 5, the 2009 Pro-Forma Trial Balance shows a 2009 year ending "Employee Future Benefits" amount of $6,742,660.

When the differences between the previous three numbers are calculated, they produce a 2008/2007 differential of $694,415, as compared to the amount of $847,994 referenced in the first paragraph above and a 2009/2008 differential of $539,846, as compared to the amount of $694,415 referenced in the first paragraph above.

Question 5.1

Please provide an explanation of, and reconciliation between, these two sets of numbers.

5.1 Response:

Please refer to the PDF electronic file attachment labelled “SEC 8 a. AVR Report”. This AVR report was completed in June 2008.

2008/2007 Differential in Forecasted “Employee Future Benefits” Liability Amounts:

The liability forecast figure for 2008 is incorrect. Upon investigation, the $694,415 O&M amount for 2009 was inadvertently added to the December 31, 2007 $5,508,399 liability by mistake. The 2008 $847,994 O&M amount (as per the AVR) should have been added, which would result in the 2008 liability forecast being $6,356,393 (also per the AVR). Therefore, the $847,994 amount included as an ‘addback’ on the 2008 T2S1 (Exh 4, Tab 3, Sch 1, Attachment 1) is correct as this amount is also correctly included in the 2008 O&M, and hence, net income calculation – which is the starting point for the T2S1.

2008/2007 Differential between a) Difference in Liability Amounts and b) T2S1 Amount:

As per the above explanation, there is no difference.

2009/2008 Differential in Forecasted “Employee Future Benefits” Liability Amounts:

The differential of $539,846 is correct. However, the 2009 liability forecast is incorrect due to the 2008 liability forecast being incorrect as explained above. The correct 2008 liability forecast is $6,356,393. The correct 2009 liability forecast is $6,896,239. The difference is $539,846. All three figures agree to the AVR.

2009/2008 Differential between a) Difference in Liability Amounts and b) T2S1 Amount:

As stated in the question, and explained above, the difference between the liability amounts is $539,846. It is true that this amount differs from the $694,415 amount included in the 2009 O&M. Because the $694,415 is part of the 2009 net income calculation – which is the starting point for the T2S1 – it is correctly presented as an ‘addback’ on the T2S1 (Exh 4, Tab 3, Sch 1, Attachment 1).

The reason and explanation for using the $694,415 as the 2009 O&M amount versus the $539,846 is found on Exh 4, Tab 2, Sch 3, Page 9 of 21. The $694,415 is calculated as follows:

$505,711 – actual expense in 2006 (confirmed in audited financials)
$523,092 – actual expense in 2007 (confirmed in audited financials)
<u>$847,994</u> – actual expense in 2008 (will be confirmed in audited financials as from AVR)
$1,876,797
<u>Divide by 3</u>
$625,599 – average of these three years (as explained in evidence)
<u>$ 68,816</u> – additional amount to reflect growth in employees (as explained in evidence)
<u>$694,415</u>

Question 5.2 - Additions to Taxable Income

Ref: Exhibit 4/Tab 3/Schedule 1, p. 2

> *This page enumerates additions to taxable income incorporated by Bluewater in calculating its taxable income. Included in these additions is an item "Carrying charges accrued (expensed not paid)" in the amount of $243,636 for 2009.*

Question 5.2 (a)

Please describe what the "Carrying charges accrued (expensed not paid)" are. In addition, please state whether this item includes amounts related to regulatory assets and if so what the amounts are and the accounts to which they are attributable.

5.2 (a) Response:

In 2009, Bluewater Power is forecasted to have $243,636 in net carrying charges on the net regulatory balances owing to customers. As these amounts will not be settled with customers during 2009, and will be deducted as an accrued expense in the 2009 income statement, they need to be added back on the T2S1. This will ensure consistency with the tax treatment of carrying charges in prior years. Bluewater Power's tax preparer, KPMG, have always made an adjustment on the T2S1 to reverse any amounts accrued in accounting income, whether the accrual is an expense or revenue. Carrying charges have always been brought into taxable income when collected or paid through rates.

2009 Forecasted Carrying Charges:

Account	Description	2009
1508	OEB Assessment	3,244
1508	OMERS	16,557
1525	Rebate Credits	15
1550	Low Voltage Charges - ongoing	(3,125)
1555	Smart Meter - Capital & Billings	(11,881)
1556	Smart Meter - O&M	2,860
1562	PILS	(7,692)
1580	RSVA - IESO	(91,748)
1584	RSVA - Network	(11,107)
1586	RSVA - Connection	(19,620)
1588	RSVA - Cost of Power	(162,962)
1588	RSVA - Global Adjustment	52,515
1550	Low Voltage Charges - Hydro One RAR'05	1,335
1590	1590 - Recoveries	(12,027)
		(243,636)

Note: Assumed carrying charge rate of 3.35% for all of 2009. This was latest approved rate per the OEB at the time of preparing the 2009 rate application.

Question 5.2 (b)

Please provide Bluewater's basis for believing that the inclusion of these amounts in the calculation of its taxable income for regulatory purposes is appropriate.

5.2 (b) Response:

The 2009 T2S1 starts with "Income/(Loss) before PILs/Taxes (Accounting)" of $1,974,129 which is Bluewater Power's deemed return on equity for the 2009 test year. Per previous OEB communication (Halton Hills second round interrogatories #8), "The equity return on rate base occurs after the deduction of interest". Bluewater Power agrees with this statement, and as such has no add back on the T2S1 for actual interest expense and no deduction for deemed interest expense.

Bluewater Power distinguishes interest income from carrying charges income, and interest expense from carrying charges expense. They are different because carrying charges has no single identifiable person or entity for settlement, whereas interest income/expense does. As well, it is unknown when the accrued carrying charges will be settled in the future. Furthermore, it is unknown how much will be settled as this is due to a future OEB ruling. Hence, these are the reasons for its tax treatment as explained above, and for why carrying charges expense cannot be considered to be interest expense, or even included as part of deemed interest.

Therefore, to ensure consistency with past tax preparation practices, it is appropriate to add back the accrued carrying charges expense on the T2S1 that was deducted in accounting income.

LOAD FORECAST

Question 6.1 - General – Economic Assumptions

Question 6.1 (a)

Since the filing of Bluewater's application, given the economic situation, has Bluewater assessed the situation and identified any specific issues that may have a material impact on its load and revenue forecasts and bad debt expense forecast?

6.1 (a) Response:

Bluewater Power filed the rate application on September 9, 2008, and prior to that completed a detailed load forecast in March and April 2008. In October 2008, Ontario's economy began to feel the impacts of the U.S recession. Forecasts for Ontario's employment outlook are available from the Canadian Chartered Banks and are indicated below. The table shows that in the spring of 2008, there was expected to be positive employment growth, whereas the latest updates from the majority of the Banks indicate negative employment growth.

Table 6.1.1

Year	BMO	RBC	Scotia	TD	Average
2008	0.7	0.9	1.1	1.0	0.9
2009 (spring 2008)	0.7	1.0	0.7	0.4	0.7
2009 (fall 2008)	-0.3	1.2	-1.5	-0.4	-0.7

Bluewater has assessed the commercial customers to determine the type of business they are in, to determine how they may be impacted by the economic downturn. The biggest risk to Bluewater Power would be a downturn in the chemical and petroleum based industries, which there are signs of. There have been layoffs in industries in the Sarnia-Lambton area, however many of the businesses are not Bluewater Power customers directly.

The four Large customers of Bluewater Power represent approximately 30% of the total load, so the loss of any of these customers would present a significant hardship.

Table 6.1.2
Percent of Customers by Sector

	GS 50 - 999 kW	GS 1000 - 4999 kW	Large
Commercial/Office/Hotels	28%		
Apartments	19%		
Food and beverage distributor/retailer	15%		
Retail	12%	7%	
Chemical/petroleum (manufacturer, distributor, retailer etc)	8%	33%	75%
Other Manufacturing		13%	
Construction Company	5%		
Other	5%	13%	
Automotive related (manufacturer, retailer, repair etc)	4%	7%	25%
Transportation	3%		
Utilities/Municipal operations	1%	27%	
	100%	100%	100%

Bluewater Power has two known impacts of the economic downturn that would affect the 2009 load forecast.

1. On December 8, 2008 public notice was given that a customer currently in the GS 1000-4999 kW rate class will be closing permanently in 2009. The press release is attached. This decline of this specific customer was discussed in Bluewater Power's evidence Exhibit 3, Tab 2, Schedule 2, page 2. Through 2007 the customer decreased their load such that they were reallocated from the Large Use rate class to the GS 1000-4999 kW rate class in March, 2008. The load forecast presented in evidence assumed they would continue to operate in the GS 1000-4999 kW rate class but at 50% of their 2007 volumes. Given the information that the customer will be closing operations in 2009, Bluewater Power now has a known issue with the forecast. There are two financial implications related to this closure:
    a. The impacts on the forecast are presented below. Base revenue requirement would be decreased by $15,617 given the reduction in working capital allowance related to lower throughput volumes.

    b. The amount of distribution revenue expected from this customer at proposed rates was $87,731. Therefore Bluewater Power will see a shortfall in its margin for 2009.

Table 6.1.3
Impact on kWh and kW components of 2009 Forecast

	2009 Amount embedded in Forecast for customer	2009 Forecast for GS 1000-4999 Class	Customer % of GS 1000-4999 Forecast	Total 2009 Forecast	Customer % of Total Forecast
Total 2009 kWh Fcst	15,562,898	181,109,127	9%	1,117,857,569	1%
Total 2009 kW Fcst	26,306	398,767	7%	1,510,992	2%

Table 6.1.4
Impact on Working Capital, Rate Base and Revenue Requirement

	Original Filing	Without customer	Variance	Original Reference
Total Pass-through Charges	$ 79,099,884	$ 78,033,708	$ (1,066,176)	E1, T3, S4, A1
Working Capital Allowance	$ 13,613,408	$ 13,453,482	$ (159,926)	E2, T1, S3
Total Rate Base	$ 53,158,483	$ 52,998,557	$ (159,926)	E2, T1, S2
Revenue Requirement				
OM&A Expenses	$ 11,656,169	$ 11,656,169	$ -	
3850-Amortization Expense	$ 4,358,109	$ 4,358,109	$ -	
Total Distribution Expenses	$ 16,014,278	$ 16,014,278	$ -	
Regulated Return On Capital	$ 4,098,944	$ 4,086,613	$ (12,332)	
PILs (with gross-up)	$ 1,322,854	$ 1,319,569	$ (3,285)	
Service Revenue Requirement	$ 21,436,076	$ 21,420,460	$ (15,617)	
Less: Revenue Offsets	$ 728,598	$ 728,598	$ -	
Base Revenue Requirement	$ 20,707,479	$ 20,691,862	$ (15,617)	E3, T1, S2

Table 6.1.5 – Distribution Revenue Loss

Distribution Revenue Impact of Intermediate Customer	Proposed Fixed Rate	Proposed Variable Rate	Distribution Revenue
	$ 3,508.63	**1.7345**	**$ 87,731.32**

2. The second impact on the 2009 load forecast relates to an overall change to the economic climate. A revised load forecast for the weather sensitive rate classes (residential, GS<50 and GS>50) is presented in response to VECC IR #17 (b), and is reproduced below under the column 'Updated December 2008'. In all cases, the 2009 projected load is lower than what Bluewater Power had originally filed.

Table 6.1.6

	ORIGINAL FILING		UPDATED DECEMBER 2008		VARIANCE	
Year	Weather Normal	%chg	Weather Normal	%chg	Weather Normal	%chg
RESIDENTIAL						
2007	262,311,194	-3.20%	262,311,194	-3.20%	0	0.00%
2008F	264,548,206	0.90%	263,729,281	0.50%	-818,925	-0.40%
2009F	266,434,436	0.70%	261,847,739	-0.70%	-4,586,697	-1.40%
GS<50						
Year			Weather Normal	%chg		
2007	119,643,998	-1.00%	119,643,998	-1.00%	0	0.00%
2008F	119,801,538	0.10%	119,759,801	0.10%	-41,737	0.00%
2009F	120,544,382	0.60%	120,287,121	0.40%	-257,261	-0.20%
GS>50 kWh						
Year			Weather Normal	%chg		
2007	214,903,890	-1.40%	214,903,890	-1.40%	0	0.00%
2008F	215,661,960	0.40%	215,311,922	0.20%	-350,038	-0.20%
2009F	216,234,424	0.30%	214,354,332	-0.40%	-1,880,092	-0.70%
GS>50 kW						
Year			Weather Normal	%chg		
2007	589,074	-0.80%	589,074	-0.80%	0	0.00%
2008F	590,129	0.20%	589,328	0.00%	-801	-0.20%
2009F	593,516	0.60%	588,341	-0.20%	-5,175	-0.80%

In addition, if we were to assume the same level of new customers additions as we have seen in 2008 continue into 2009, we would project a smaller rate of growth as presented in the table below.

Table 6.1.7 – Number of Connections

	Residential	**GS<50**	**GS>50**
2007 Actual	31,436	3,826	362
2008 Forecast (in rate application)	31,720	3,875	379
2009 Forecast (in rate application)	32,006	3,924	396
Projected growth in original Forecast	0.9%	1.3%	4.6%
2008 YTD September (actual results)	31,498	3,858	393
Revised projected growth	**0.2%**	**0.8%**	**1.5%**
Revised 2009 Forecast	31,560	3,890	399
Variance in # connections	-446	-34	3

The combination of the lower expectations on throughput volume and the lower expectation of number of new connections, would impact distribution revenue as follows:

Proposed Rates

	Proposed Fixed Rate (without smart meters)	Proposed Variable Rate	Per
Residential	$ 17.50	0.0150	kWh
GS<50	$ 31.52	0.0160	kWh
GS>50	$ 433.49	2.1298	kW

Variance of Load Forecast

	# Connections	Volume	Per
Residential	-446	(4,586,697)	kWh
GS<50	-34	(257,261)	kWh
GS>50	3	(5,175)	kW

Financial Impact

	Fixed Charge Revenue	Variable Charge Revenue	Total Revenue
Residential	$ (93,660.00)	$ (68,800.46)	$ (162,460.46)
GS<50	$ (12,860.16)	$ (4,116.18)	$ (16,976.34)
GS>50	$ 15,605.64	$ (11,021.72)	$ 4,583.93
Total	$ (90,914.52)	$ (83,938.35)	$ (174,852.87)

In summary, the combination of the loss of an Intermediate customer, and the revised economic outlook means a potential loss of distribution revenue of approximately $262,000 in 2009. Although Bluewater Power is not requesting to fully update the load forecast at this time related to these issues, we want to inform the OEB that there is a real risk associated with the forecast.

ATTACHMENT – Board Staff 6.1 – Georgia Gulf – Royal Polymers

close

Georgia Gulf

<< Back

Georgia Gulf Announces Closure of Sarnia PVC Resin Plant

ATLANTA--(BUSINESS WIRE)--Dec. 8, 2008--Georgia Gulf Corporation (NYSE: GGC) announced today it is permanently closing its Sarnia, Ontario (Canada) PVC resin plant. The plant had operated only periodically in 2008 due to decreased demand in the housing and construction markets. In response to continued weakening in the markets, Georgia Gulf has made the decision to permanently close the facility, which had the capacity to produce 450 million pounds of PVC resin annually.

"We operated the Sarnia facility as a swing plant with the intention of re-starting production as soon as the markets recovered and demand improved. In light of prevailing market conditions, we have made the difficult decision to permanently close this facility in an effort to better match our supply with the realities of the marketplace," stated Paul Carrico, President and CEO of Georgia Gulf Corporation.

As a result of the Sarnia PVC resin plant closure, the Company expects to record a non-cash charge of about $50 million in the 4th quarter of 2008. The Company expects the cash costs related to the Sarnia plant closure and other cash restructuring costs incurred in the third and fourth quarters of 2008 to be approximately $12 million. Under the terms of the last credit facility amendment, these charges can be excluded from EBITDA for purposes of Georgia Gulf's covenant calculations.

About Georgia Gulf

Georgia Gulf Corporation is a leading, integrated North American manufacturer of two chemical lines, chlorovinyls and aromatics, and manufactures vinyl-based building and home improvement products. The Company's vinyl-based building and home improvement products, marketed under Royal Group brands, include window and door profiles, mouldings, siding, pipe and pipe fittings, and deck, fence and rail products. Georgia Gulf, headquartered in Atlanta, Georgia, has manufacturing facilities located throughout North America to provide industry-leading service to customers.

Safe Harbor

This news release contains forward-looking statements subject to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. These forward-looking statements are based on management's assumptions regarding business conditions, and actual results may be materially different. Risks and uncertainties inherent in these assumptions include, but are not limited to continued compliance with covenants in our credit facility and availability of funds thereunder, future global economic conditions, economic conditions in the industries to which our products are sold, uncertainties regarding competitive conditions, industry production capacity, raw materials and energy costs, uncertainties relating to Royal Group's business and other factors discussed in the Securities and Exchange Commission filings of Georgia Gulf Corporation, including our annual report on Form 10-K for the year ended December 31, 2007.

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or
Investor Relations
Martin Jarosick, 770-395-4524

Source: Georgia Gulf Corporation

Question 6.1 (b)

If so, can Bluewater provide the necessary evidence and an estimate of the timing of any update including necessary calculations?

6.1 (b) Response:

Not applicable.

Question 6.2 - Weather Normalization

Ref: Exhibit 3/Tab 2/Schedule 1/Attachment 1/Page 7/ 2nd paragraph

On page 7, Bluewater states: "For Bluewater, the 10 year average from 1998 to 2007 has been adopted as the appropriate definition of weather normal."

Question 6.2

Instead of using the average monthly heating degree days (HDD) and cooling degree days (CDD) from 1998 to 2007, please develop the weather normalized load forecast for 2009 by using a ***trend*** *of monthly HDD and CDD from 1988 to 2007. Please calculate the variance and percent variance for 20-year trend forecast as compared to the Bluewater's10-year average forecast and comment on the results.*

6.2 Response:

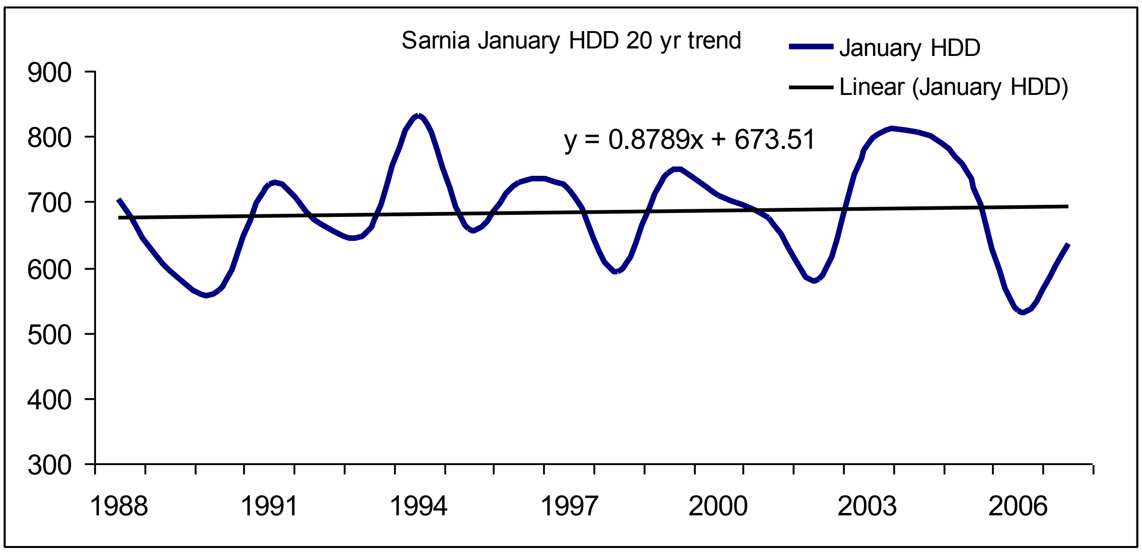
Our understanding is that Board Staff are requesting a linear trend forecast of monthly heating and cooling degree days for each month for 2009 based on 20-years of historical data from 1988 to 2007 at Sarnia Airport. The following table presents the linear trend forecast values:

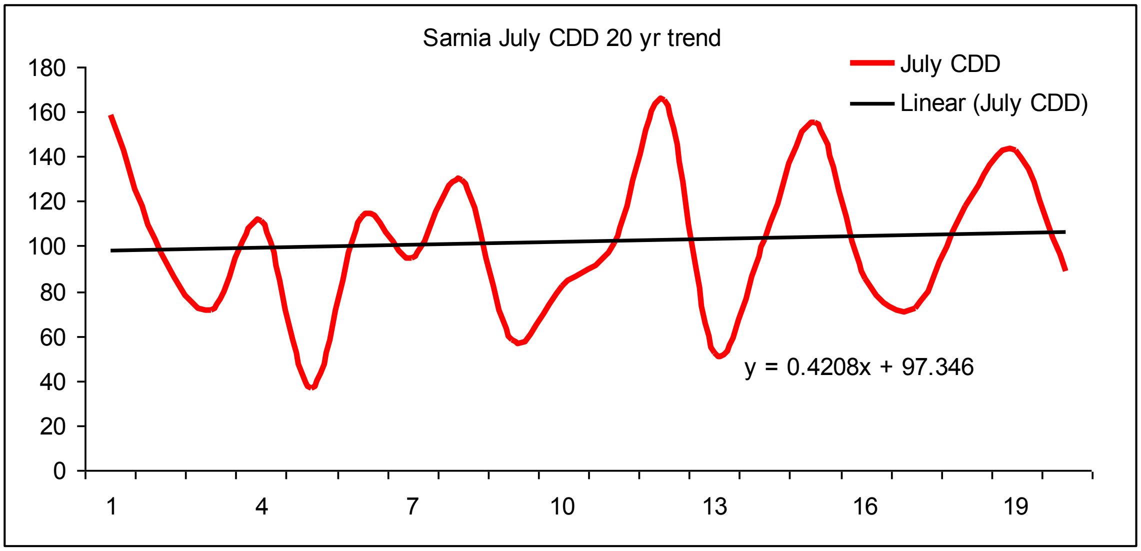
20-yr linear trend HDD & CDD (1988-2007)			
Sarnia Airport 2009			
	HDD	CDD	
Jan	692.8	0.0	
Feb	608.8	0.0	
Mar	529.3	0.1	
Apr	328.9	0.1	
May	172.8	12.0	
Jun	38.3	71.0	
Jul	7.3	106.6	
Aug	9.6	82.5	
Sep	42.2	42.2	
Oct	210.5	10.8	
Nov	380.3	0.0	
Dec	579.7	0.0	

Using the above forecast degree days for 2009, the following kWh forecast for Residential, GS<50 and GS>50 classes and associated variances is presented below:

Year 2009	10-yr weather norm	20-yr trend	Variance	Variance %
Residential	266,434,436	266,217,026	-217,410	-0.08%
GS<50	120,544,382	120,449,457	-94,926	-0.08%
GS>50	216,234,424	216,114,212	-120,212	-0.06%

In commenting on the above results, we note that a trend forecast is not a weather normal in the sense of a climatologically long term average. Rather, it is a projection of actual degree days using a simple linear trend based on the degree days for each month over the 20 year period 1998-2007. A graphical representation of these trends is displayed in the following charts for January and July.





Given the very small slope of the trend lines displayed, the resulting value is almost equivalent to the average.

It should be noted that ERA has developed weather-normal load forecasts for several LDCs including Bluewater and has consistently adopted the most recent 10 years (1998 to 2007) as the definition of weather normal. ERA adopted this definition of "weather normal" as the Board has accepted this definition in other cases involving electricity distribution; namely, Toronto Hydro Electric System Limited ("THESL"). For example, in their forward test year filing in the 2006 EDR process (EB-2005-0421), THESL proposed to use the most recent 10 years (1995 to 2004) as the definition of "weather normal." In its Decision with Reasons, dated April 12, 2006, the Board accepted the load forecast as proposed by the Applicant.

THESL again proposed the most recent 10 years (1996 to 2005) in their multi-year rate filing for 2008 – 2010 rates (EB-2007-0680). In their Application, THESL explained that the 10 year average was chosen over the 30 year average due to a pronounced trend in HDD and CDD, as illustrated in Figure 2 at Exhibit K1, Tab 1, Schedule 1, Page 7 of their Application. Again, the Board in their Decision with Reasons issued May 15, 2008, accepted this definition of weather normal.

Bluewater and ERA have developed a model to weather normalize Bluewater's throughput based on best efforts and relying upon a definition that was previously filed and approved by the Board with the least amount of complexity necessary and that is consistent across LDCs (to the extent that data allows). Bluewater and ERA were careful to design the model and definition of weather normal based on what appeared to be reasonable and based on past practice of other LDCs that have had approval by the Board. In developing the model, it was paramount that the model specification and weather normal definition be as consistent as possible across LDCs and that model specification and weather normal definition not be driven by a desired result (i.e., choosing a specification and weather normal definition in order to get a particular result).

We note that while there are many definitions of weather normal, the US NOAA/ESRL also uses the 10 year period 1998-2007 (among others) as a long term climatologically base period comparator.

Question 6.3 - Economic and Growth Projections

Ref: Exhibit 3/Tab 2/Schedule 1/Attachment 1/Page 11/ 2nd paragraph

On page 11, Bluewater states: "Table 8 below outlines the average number of active customer connections in each class and a trend forecast for annual customers based on the average customer additions from 2003 and 2007 period."

Question 6.3

Please file with the Board the supporting material related to the customer/connection forecast that Bluewater states that it is a reasonable reflection of economic expectations in its service area.

6.3 Response:

We have based our forecast for customers in classes other than Intermediate and Large Use on the average annual growth rate over the 2003 to 2007 period. No changes in the number of customers are expected for the Intermediate and Large Use classes. We are unaware of any forecast related to economic conditions that is specific to Sarnia and area. However, appended to the ERA Load Forecast Report at Exhibit 3/Tab 2/Schedule 1/Attachment 1/Page 16 was a page summarizing population and dwelling counts for Sarnia, Ontario from the 2006 Census of Canada. This indicated that the population growth in Sarnia over the 5 years 2001 to 2006 was 0.8%, compared to 6.6% for the Province of Ontario. Therefore, the annual population growth in Sarnia over that period is less than 0.2% per year. The 2001 Census of Canada indicated that there were 30,859 private dwellings in Sarnia. This increased to 31,610 in 2006, and increase of about 2.4% or just under 0.5% per year.

Also, as indicated in response to VECC IR #17 (b), year-to-date growth in full-time employment in the Windsor-Sarnia Economic Region (which includes November 2008) is 0.9% over the same period last year.

Question 6.4 - kWh Load

Ref: Exhibit 3/Tab 2/Schedule 1/Attachment 1/Page 10, 1st paragraph and Table 6

On page 10, Bluewater states: "For classes that do not have weather sensitivity (intermediate and large users, street and sentinel lighting, unmetered scattered load), class consumption is forecast based on the annual consumption trend over the past 4 years."

Referencing to Table 6 of the above evidence, Board staff notes that the 2008 and 2009 consumption forecasts are calculated using average of growth rate percentages for the period from 2003 to 2007.

Question 6.4 (a)

Please explain the methodology that Bluewater has used to forecast the consumptions for non-weather sensitive classes.

6.4 (a)Response:

These classes are forecast based on the average rate of growth for the period from 2003 to 2007.

Question 6.4 (b)

If Bluewater has used an arithmetic average to calculate percentages for the period from 2003 to 2007, please update and file with the Board revised Table 6 using a trending methodology and calculate the variance from the proposed forecast consumption for 2008 and 2009.

6.4 (b) Response:

Table 6 from the ERA load report has been updated below, based on a linear trend line forecast. Please note that Bluewater Power made changes to the ERA Table 6 forecast as described in Exhibit 3, Tab 2, Schedule 1, pages 2-3. The interrogatory response to VECC 17 (c) details the original Table 6 and the updated Table 6. However the response to this question deals with the original ERA Table 6 as referenced.

Intermediate and Large Users Historic and Trend Forecast Consumption

	Intermediate				*Large User*			
Year	kWh	%	kW	%	kWh	%	kW	%
2003	215,734,696		424,741		312,370,603		491,030	
2004	223,698,552	3.7%	435,039	2.4%	319,916,639	2.4%	491,745	0.1%
2005	225,996,193	1.0%	430,146	-1.1%	295,104,220	-7.8%	479,410	-2.5%
2006	209,342,236	-7.4%	415,068	-3.5%	304,292,895	3.1%	494,407	3.1%
2007	202,583,345	-3.2%	428,081	3.1%	318,201,517	4.6%	492,550	-0.4%
Linear trend forecast								
2008F	203,273,299	0.3%	422,628	-1.3%	308,788,600	-3.0%	491,539	-0.2%
2009F	199,207,397	-2.0%	421,299	-0.3%	308,392,408	-0.1%	492,109	0.1%

Lighting Customers Historic and Trend Forecast Consumption

	Street lighting				*Sentinel Lighting*			
Year	kWh	%	kW	%	kWh	%	kW	%
2003	8,219,864		24,138		691,348		1,655	
2004	8,969,846	9.1%	24,180	0.2%	721,397	4.3%	1,655	0.0%
2005	8,585,892	-4.3%	24,423	1.0%	699,473	-3.0%	1,850	11.8%
2006	8,581,095	-0.1%	24,059	-1.5%	669,378	-4.3%	1,608	-13.1%
2007	8,536,684	-0.5%	23,751	-1.3%	685,929	2.5%	1,634	1.6%
Linear trend forecast								
2008F	8,652,143	1.4%	23,842	0.4%	674,648	-1.6%	1,654	1.2%
2009F	8,676,632	0.3%	23,752	-0.4%	668,362	-0.9%	1,645	-0.5%

Unmetered Scattered Load (USL)

Year	kWh	%
2003	2,938,924	
2004	3,006,781	2.3%
2005	2,997,759	-0.3%
2006	2,992,773	-0.2%
2007	2,978,570	-0.5%
Linear trend forecast		
2008F	3,002,547	0.8%
2009F	3,009,075	0.2%

Variance of the linear trend line forecast from the ERA Report forecast is summarized in the table below:

Variance from Proposed Forecast

	Street lighting		Sentinel Lighting		USL
Year	kWh	kW	kWh	kW	kWh
2008F	24,327	185	-10,385	18	13,791
2009F	-43,288	190	-15,776	8	10,098

Intermediate and Large User Historic Consumption

	Intermediate		Large Use	
Year	kWh	kW	kWh	kW
2008F	3,667,496	-6,448	-11,277,846	-1,491
2009F	2,535,373	-8,775	-13,549,896	-1,401

Question 6.5 - kWh Load and Revenue

Ref: Exhibit 3/Tab.2/Schedule 5/Page 1/Table 3.2.5.1

Using information in Table 3.2.5.1 from the above reference, staff calculated the 2009 normalized average consumption for Unmetered Scattered Load ("USL") reduced by 26.5% as compared to 2007 normalized average consumption for USL class. Staff also calculated the 2009 normalized average consumption for General Service 1,000 to 4,999 kW ("GS 1000-4999 kW") class reduced by 10.6% as compared to 2007 normalized average consumption for GS 1000-4999 kW class.

Question 6.5 (a)

Please explain the reasons of the reduction in normalized average consumption for USL and GS 1000-4999 kW classes.

6.5 (a) Response:

1. The reduction in the USL consumption is attributable to a traffic light conversion program through 2007 for one of Bluewater Power's municipalities. The conversion program entailed converting the pedestrian signs and traffic lights at over 80 intersections. Table 6.5.1 below indicates the decrease in the average usage per customer for the USL rate category.

Table 6.5.1

	2007 Actual	2009 Normalized	Variance
kWh	2,978,570	2,188,838	(789,732)
number of connections	266	266	-
Average kWh per connection	11,198	8,229	
% reduction		-26.5%	

The LED conversion program reduced the load of the specific customer by 86% over the 2004 level as shown in Table 6.5.2. The one specific customer accounts for approximately 30% of the total USL load, thus the reduced consumption has a major impact on the total for the rate category.

Table 6.5.2
Consumption for the Customer with the LED conversion program

Year	Annual kWh	Average kWh/month	% reduction from 2004
2004	914,330	76,194	
2005	951,511	79,293	
2006	824,952	68,746	
2007	631,248	52,604	
10 months 2008	109,039	9,087	
2008 Expected	127,212		-86%
Annual kWh reduced (over 2004)	787,118		

2. The decrease in the average use per customer in the Intermediate rate category is also mainly attributable to the reduction in consumption for one customer. As indicated in Exhibit 3, Tab 2, Schedule 2, Page 2-3 starting at line 22, one of Bluewater Power's former large customers had reduced its load significantly, and now resides in the Intermediate rate category. The customers load in 2007 is significantly higher than the projection for 2009, thus accounts for most of the 10.6% reduction in the class.

Table 6.5.3 – GS 1000-4999 kW, 2007 Actual vs. 2009 Forecast

	2007 Actual	2009 Normalized	Variance	% reduction
kWh	202,583,345	181,109,127	(21,474,218)	-10.6%
kW	423,081	398,767	(24,314)	-5.7%
number of connections	16	16	-	

The table below indicates the actual and forecast consumption and demand of one customer who is part of the Intermediate rate category. The projected decrease in 2009 contributes the majority of the projected 10.6% decrease of the rate category.

Table 6.5.4 – Impact of One Customer's reduced Forecast

	2007 Actual	2009 Forecast	Variance	% contribution to Class Variance
kWh	32,061,336	16,030,668	(16,030,668)	75%
kW	52,367	26,184	(26,184)	108%

Question 6.5 (b)

Please provide evidence and assumption to justify the reduction in normalized average consumption for USL and GS 1000-4999 kW classes.

6.5 (b) Response:

Please see response to part (a) for explanation of decreases in the USL and GS 1000-4999 kWh rate categories.

Question 6.6 - Other Distribution Revenue

Ref: Exhibit 3/Tab 3/Schedule 2/Page 7/1st and 2nd paragraph
Exhibit 1/ Tab 3/ Schedule 7/ page 1

In the first paragraph on page 7 of the above reference, Bluewater states: "The 2008 bridge year is comprised of anticipated interest income of $100,320 related to positive cash balances and an additional credit of ($223,924) related to carrying charges on the regulatory accounts expected in 2008." In the second paragraph on page 7 of the above reference, Bluewater states: "The projected ($243,636) is related to carrying charges on the deferral accounts for 2009."

Question 6.6 (a)

Please explain why the carrying charges are recorded in Interest & Dividend income (USoA 4405) instead of Other Interest expense (USoA 6035).

6.6 (a) Response:

Please see response to Board Staff Interrogatory 7.3.

Question 6.6 (b)

Bluewater states in Exhibit 1/ Tab 3/ Schedule 7/ page 1/1st paragraph of the above reference that, "The only departure from APH relates to the accounting treatment of carrying charges. That departure is necessary to create consistency between the treatment of carrying charges in the 2006 EDR (EB-2005-0340) application and this application." If this is Bluewater's response to part (a) of this interrogatory, please explain why consistency with the 2006 EDR application seems to be more important than the consistency with the Board's Accounting Procedures Handbook.

6.6 (b) Response:

Please see the answer to OEB Staff IR #7.3

Question 6.7 - Customer Count, kWh load, kW load and Revenue

Ref: Exhibit 3/Tabs 1 and 2

Some of Bluewater's evidence may be required to be adjusted in light of responses to the preceding customer count, load and revenue forecasting interrogatories.

Question 6.7

Please re-file any tables in Exhibit 3 that are required to be updated as a result of any changes in Bluewater's evidence.

6.7 Response:

Although load forecasts are impacted by current economic conditions as addressed elsewhere in our response to OEB Interrogatories, Bluewater Power is not proposing to update any evidence.

The updated evidence highlights the load risk that Bluewater Power faces as a mid-sized utility with a concentrated industry (petrochemical). However, no one forecast change is material enough to require an update to the evidence.

DEFERRAL AND VARIANCE ACCOUNTS

Question 7.1 - Disposition of Deferral and Variance Accounts

Ref: Exhibit 5/Tab 1/Schedule1/Page 1

Question 7.1

Please provide a schedule identifying the rate riders associated with the disposition of the deferral and variance accounts over a one, two and three year periods. Please show all relevant calculations.

7.1 Response:

A summary of the proposed rate riders and annual amount of disposition for a one, two and three year period is shown in table 7.1.1 below.

A detailed calculation of the rate riders is shown in Attachment 7.1.

Table 7.1.1 – Summary of Rate Riders

Rate Classification	3 Year Disposition	2 Year Disposition	1 Year Disposition	Per kWh or kW
Residential	(0.0009)	(0.0013)	(0.0026)	kWh
General Service <50 kW	(0.0011)	(0.0016)	(0.0033)	kWh
General Service 50 to 999 kW	(0.4555)	(0.6832)	(1.3665)	kW
General Service 1,000 to 4,999 kW	(0.6174)	(0.9262)	(1.8523)	kW
Large	(0.8909)	(1.3363)	(2.6726)	kW
Unmetered Scattered Load	(0.0008)	(0.0012)	(0.0025)	kWh
Sentinel Lighting	(0.3737)	(0.5606)	(1.1212)	kW
Street Lighting	(0.3256)	(0.4884)	(0.9769)	kW
Annual Disposition Amount	(1,324,781)	(1,987,172)	(3,974,344)	

ATTACHMENT 7.1 - RATE RIDER CALCULATION

Rate Rider Calculation

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Residential	General Service <50 kW	General Service 50 to 999 kW	General Service 1,000 to 4,999 kW	Large	Unmetered Scattered Load	Sentinel Lighting	Street Lighting
1505-LRAM and SSM (holding account only)	130,666	$ for LRAM	111,248	9,070	10,348	0	0	0	0	0
1508-Other Regulatory Assets	681,832	Distribution Revenue (proposed rates)	351,144	111,821	105,309	36,769	57,441	3,979	1,089	14,280
1525-Miscellaneous Deferred Debits	517	kWh's	123	56	100	84	149	1	0	4
1550-LV Variance Account	(34,719)	Transmission Connection Revenue	(9,719)	(3,958)	(7,458)	(5,493)	(7,774)	(72)	(16)	(229)
1580-RSVAWMS	(1,830,435)	kWh's	(436,273)	(197,385)	(354,073)	(296,557)	(527,164)	(3,584)	(1,120)	(14,278)
1584-RSVANW	116,991	kWh's	27,884	12,616	22,630	18,954	33,693	229	72	913
1586-RSVACN	(396,669)	kWh's	(94,544)	(42,775)	(76,730)	(64,266)	(114,241)	(777)	(243)	(3,094)
1588-RSVAPOWER	(2,854,674)	kWh's	(680,394)	(307,834)	(552,198)	(462,498)	(822,144)	(5,590)	(1,747)	(22,268)
2425-Sub account of 1588 Global Adjustment (holding account only)	212,147	kWh's	50,564	22,877	41,037	34,371	61,098	415	130	1,655
Sub-Total for recovery	**(3,974,344)**		**(679,966)**	**(395,513)**	**(811,035)**	**(738,637)**	**(1,318,941)**	**(5,398)**	**(1,835)**	**(23,018)**
Total Recoveries Required	**(3,974,344)**		**(679,966)**	**(395,513)**	**(811,035)**	**(738,637)**	**(1,318,941)**	**(5,398)**	**(1,835)**	**(23,018)**
	Annual Amount	**# YEARS RECOVERY**								
Recovery Amounts	(1,324,781)	3	(226,655)	(131,838)	(270,345)	(246,212)	(439,647)	(1,799)	(612)	(7,673)
	(1,987,172)	2	(339,983)	(197,757)	(405,517)	(369,318)	(659,471)	(2,699)	(918)	(11,509)
	(3,974,344)	1	(679,966)	(395,513)	(811,035)	(738,637)	(1,318,941)	(5,398)	(1,835)	(23,018)
Annual Volume (kWh or kW)			266,434,436	120,544,382	593,516	398,767	493,510	2,188,838	1,637	23,562
Proposed Rate Rider		**3 year recovery**	**($0.0009)**	**($0.0011)**	**($0.4555)**	**($0.6174)**	**($0.8909)**	**($0.0008)**	**($0.3737)**	**($0.3256)**
		2 year recover	**($0.0013)**	**($0.0016)**	**($0.6832)**	**($0.9262)**	**($1.3363)**	**($0.0012)**	**($0.5606)**	**($0.4884)**
		1 year recovery	**($0.0026)**	**($0.0033)**	**($1.3665)**	**($1.8523)**	**($2.6726)**	**($0.0025)**	**($1.1212)**	**($0.9769)**
per			kWh	kWh	kW	kW	kW	kWh	kW	kW

Allocators		2009 Projection Total	Residential	General Service <50 kW	General Service 50 to 999 kW	General Service 1,000 to 4,999 kW	Large	Unmetered Scattered Load	Sentinel Lighting	Street Lighting
Customers / Connections		47,147	32,006	3,924	396	16	4	266	526	10,009
kWh's		1,117,857,569	266,434,436	120,544,382	216,234,424	181,109,127	321,942,304	2,188,838	684,138	8,719,920
Distribution Revenue (proposed rates)		20,815,558	10,720,012	3,413,752	3,214,963	1,122,521	1,753,622	121,470	33,253	435,965
Transmission Connection Revenue		4,928,296	1,379,598	561,761	1,058,654	779,749	1,103,538	10,200	2,304	32,492
$ for LRAM		130,666	111,248	9,070	10,348					

Question 7.2 - Continuity Schedule for Regulatory Assets

Ref: Exhibit 5/Tab 1/Schedule 2

For all deferral and variance accounts, please complete the attached continuity schedule for regulatory assets. Furthermore, please prepare a separate schedule using the attached continuity schedule for all deferral and variance accounts that are being requested for disposition. Please note that including forecasted principal transactions beyond 2007 and the accrued interest on these forecasted balances in the attached continuity schedule is optional.

7.2 Response:

Please refer to the electronic spreadsheet named “Board Staff 7.2 – Reg Assets Continuity – All Accounts” which summarizes all deferral and variance accounts. This spreadsheet was provided by the OEB. Please note that Account 1505 has been added which is used to hold Bluewater Power’s balances pertaining to LRAM and SSM.

Please refer to the electronic spreadsheet names “Board Staff 7.2 – Reg Assets Continuity – Disposition Accounts” which summarizes all deferral and variance accounts being requested for disposition. Please note that Account 1505, as explained above, has been added to this spreadsheet. Please also note that Account 1588, which includes Global Adjustment, has been included with the accounts proposed for disposition. The total of all accounts requested for disposition is a credit of $3,974,344 (owing to rate payers) which agrees to Exh 5, Tab 1, Sch 2, Attachment 2 of Bluewater Power’s evidence.

ATTACHMENTS :

Board Staff 7.2 Reg Assets Continuity – All accounts.xls

Board Staff 7.2 Reg Assets Continuity – Disposition Accounts.xls

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Bluewater Power Distribution Corporation	**LICENCE NUMBER**	ED-2002-0517
NAME OF CONTACT	Leslie Dugas	**DOCID NUMBER**	EB-2008-0221
E-mail Address	ldugas@bluewaterpower.com		
VERSION NUMBER	v3.0	**PHONE NUMBER**	519-337-8201 Ext 255
Date	22-Dec-08	**(extension)**	

Enter appropriate data in cells which are highlighted in yellow only.
Enter the total applied for Regulatory Asset amounts for each account in the appropriate cells below:
Debits should be recorded as positive numbers and credits should be recorded as negative numbers.
Repeat cells going across as necessary for each year in application

		2005									2006					
Account Description	**Account Number**	**Opening Principal Amounts as of Jan-1-05** [1]	**Transactions (additions) during 2005, excluding interest and adjustments** [6]	**Transactions (reductions) during 2005, excluding interest and adjustments** [6]	**Adjustments during 2005 - instructed by Board** [2]	**Adjustments during 2005 - other** [3]	**Closing Principal Balance as of Dec-31-05**	**Opening Interest Amounts as of Jan-1-05**	**Interest Jan-1 to Dec31-05**	**Closing Interest Amounts as of Dec-31-05**	**Opening Principal Amounts as of Jan-1-06**	**Transactions (additions) during 2006, excluding interest and adjustments** [6]	**Transactions (reductions) during 2006, excluding interest and adjustments** [6]	**Adjustments during 2006 - instructed by Board** [2]	**Adjustments during 2006 - other** [3]	**Transfer of Board-approved amounts to 1590 as per 2006 EDR**
RSVA - Wholesale Market Service Charge	1580	$ 1,468,949	$ 700,237				$ 2,169,186	$ 213,687	$ 117,035	$ 330,722	$ 2,169,186	$ (1,208,707)		$ -	$ -	$ (1,468,949)
RSVA - One-time Wholesale Market Service	1582	$ 61,014					$ 61,014	$ 9,913	$ 4,417	$ 14,330	$ 61,014					$ (61,014)
RSVA - Retail Transmission Network Charge	1584	$ 402,819	$ (56,334)				$ 346,485	$ 58,495	$ 27,233	$ 85,728	$ 346,485	$ 82,203		$ -	$ -	$ (402,819)
RSVA - Retail Transmission Connection Charge	1586	$ 68,982	$ (277,189)				$ (208,207)	$ 5,432	$ (10,483)	$ (5,051)	$ (208,207)	$ (118,351)		$ -	$ -	$ (68,982)
Sub-Totals		$ 2,001,764	$ 366,714		$ -	$ -	$ 2,368,478	$ 287,527	$ 138,202	$ 425,729	$ 2,368,478	$ (1,244,855)		$ -	$ -	$ (2,001,764)
LRAM and SSM (holding account only)	1505						$ -			$ -	$ -					
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 33,625	$ 87,733	$ -	$ -	$ -	$ 121,358	$ -	$ 4,441	$ 4,441	$ 121,358	$ 9,091	$ -	$ -	$ -	$ (33,625)
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -	$ 358,572	$ -	$ -	$ -	$ 358,572	$ -	$ 6,290	$ 6,290	$ 358,572	$ 135,662	$ -	$ -	$ -	$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508						$ -			$ -	$ -					
Other Regulatory Assets - Sub-Account - Other [7]	1508						$ -			$ -	$ -					
Other Regulatory Assets - Sub-Account - Other [7]	1508						$ -			$ -	$ -					
Retail Cost Variance Account - Retail	1518						$ -			$ -	$ -					
Retail Cost Variance Account - STR	1548						$ -			$ -	$ -					
Misc. Deferred Debits	1525	$ 45,022	$ 447	$ -	$ -	$ -	$ 45,469	$ 5,897	$ 3,264	$ 9,161	$ 45,469	$ -	$ -	$ -	$ -	$ (45,022)
LV Variance Account	1550						$ -			$ -	$ -	$ 16,336	$ -	$ -	$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555						$ -			$ -	$ -	$ 13,078	$ -	$ -	$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555						$ -			$ -	$ -	$ (68,594)				
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555						$ -			$ -	$ -					
Smart Meter OM&A Variance	1556						$ -			$ -	$ -	$ 11,155	$ -	$ -	$ -	$ -
Conservation and Demand Management Expenditures and Recoveries	1565						$ -			$ -	$ -					
CDM Contra	1566						$ -			$ -	$ -					
Qualifying Transition Costs [5]	1570	$ 3,295,468	n/a	n/a	$ -	$ -	$ 3,295,468	$ 721,521	$ 238,921	$ 960,442	$ 3,295,468	n/a	n/a	$ -	$ -	$ (3,295,468)
Pre-Market Opening Energy Variances Total [5]	1571	$ 2,581,692	n/a	n/a	$ -	$ -	$ 2,581,692	$ 528,488	$ 187,173	$ 715,661	$ 2,581,692	n/a	n/a	$ -	$ -	$ (2,581,692)
Extra-Ordinary Event Costs	1572						$ -			$ -	$ -					
Deferred Rate Impact Amounts	1574						$ -			$ -	$ -					
Other Deferred Credits	2425						$ -			$ -	$ -					
Sub-Totals		$ 5,955,807	$ 446,752	$ -	$ -	$ -	$ 6,402,559	$ 1,255,906	$ 440,089	$ 1,695,995	$ 6,402,559	$ 116,728	$ -	$ -	$ -	$ (5,955,807)
Deferred Payments in Lieu of Taxes	1562					see PILs reconciliation requested										see PILs reconciliation reque
2006 PILs & Taxes Variance	1592					see PILs reconciliation requested										see PILs reconciliation reque
Sub-Totals						see PILs reconciliation requested										see PILs reconciliation reque
Total		$ 7,957,571	$ 813,466	$ -	$ -	$ -	$ 8,771,037	$ 1,543,433	$ 578,291	$ 2,121,724	$ 8,771,037	$ (1,128,127)	$ -	$ -	$ -	$ (7,957,571)
The following is not included in the total claim but is included on a memo basis:																
Deferred PILs Contra Account [8]	1563					see PILs reconciliation requested										see PILs reconciliation reque
RSVA - Power (including Global Adjustment)	1588	$ 76,728	$ (919,404)				$ (842,676)	$ 116,999	$ (53,129)	$ 63,870	$ (842,676)	$ 12,753		$ -	$ -	$ (76,728)
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ -	$ (499,490)				$ (499,490)	$ -	$ (39,199)	$ (39,199)	$ (499,490)	$ 1,112,994		$ -	$ -	$ -
Recovery of Regulatory Asset Balances	1590						$ -			$ -	$ -					

Q:\2009 REBASING\2. Interrogatories\Board Staff\Filing Schedules\[Board Staff 7.2 - Reg Assets Continuity - All Accounts.xls]Continuity Schedule

[1] As per general ledger, if does not agree to Dec-31-04 balance filed in 2006 EDR then provide supplementary analysis
[2] Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-off, and etc.
[3] Provide supporting statement indicating nature of this adjustments and periods they relate to
[4] Not included in sub-total
[5] Closed April 30, 2002
[6] For RSVA accounts only, report the net additions to the account during the year. For all other accounts, record the additions and reductions separately.
[7] Please describe "other" components of 1508 and add more component lines if necessary.
[8] 1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obligation to the ratepayer.
[9] Interest projected on December 31, 2007 closing principal balance.

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Bluewater Power Distribution Corporation
NAME OF CONTACT	Leslie Dugas
E-mail Address	ldugas@bluewaterpower.com
VERSION NUMBER	v3.0
Date	22-Dec-08

Account Description	**Account Number**	**Closing Principal Balance as of Dec-31-06**	**Opening Interest Amounts as of Jan-1-06**	**Interest Jan-1 to Dec31-06**	**Transfer of Board-approved amounts to 1590 as per 2006 EDR**	**Closing Interest Amounts as of Dec-31-06**	**2007** **Opening Principal Amounts as of Jan-1-07**	**Transactions (additions) during 2007, excluding interest and adjustments [6]**	**Transactions (reductions) during 2007, excluding interest and adjustments [6]**	**Adjustments during 2007 - instructed by Board [2]**	**Adjustments during 2007 - other [3]**	**Closing Principal Balance as of Dec-31-07**	**Opening Interest Amounts as of Jan-1-07**	**Interest Jan-1 to Dec31-07**	**Closing Interest Amounts as of Dec-31-07**
RSVA - Wholesale Market Service Charge	1580	$ (508,470)	$ 330,722	$ 48,020	$ (355,686)	$ 23,056	$ (508,470)	$ (1,209,477)		$ -	$ -	$ (1,717,947)	$ 23,056	$ (50,076)	$ (27,020)
RSVA - One-time Wholesale Market Service	1582	$ -	$ 14,330	$ 1,472	$ (15,802)	$ -	$ -					$ -	$ -		$ -
RSVA - Retail Transmission Network Charge	1584	$ 25,869	$ 85,728	$ 6,079	$ (97,434)	$ (5,627)	$ 25,869	$ 85,823		$ -	$ -	$ 111,692	$ (5,627)	$ 5,369	$ (258)
RSVA - Retail Transmission Connection Charge	1586	$ (395,540)	$ (5,051)	$ (17,339)	$ (12,100)	$ (34,490)	$ (395,540)	$ 67,632		$ -	$ -	$ (327,908)	$ (34,490)	$ (17,958)	$ (52,448)
Sub-Totals		$ (878,141)	$ 425,729	$ 38,232	$ (481,022)	$ (17,061)	$ (878,141)	$ (1,056,022)		$ -	$ -	$ (1,934,163)	$ (17,061)	$ (62,665)	$ (79,726)
LRAM and SSM (holding account only)	1505	$ -	$ -			$ -	$ -				$ 130,666	$ 130,666	$ -		$ -
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 96,824	$ 4,441	$ 5,259	$ (2,577)	$ 7,123	$ 96,824	$ -	$ -	$ -	$ -	$ 96,824	$ 7,123	$ 4,577	$ 11,700
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 494,234	$ 6,290	$ 20,014	$ -	$ 26,304	$ 494,234	$ -	$ -	$ -	$ -	$ 494,234	$ 26,304	$ 23,365	$ 49,669
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -	$ -			$ -	$ -					$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -	$ -			$ -	$ -					$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -	$ -			$ -	$ -					$ -	$ -		$ -
Retail Cost Variance Account - Retail	1518	$ -	$ -			$ -	$ -					$ -	$ -		$ -
Retail Cost Variance Account - STR	1548	$ -	$ -			$ -	$ -					$ -	$ -		$ -
Misc. Deferred Debits	1525	$ 447	$ 9,161	$ 1,115	$ (10,249)	$ 27	$ 447	$ -	$ -	$ -	$ -	$ 447	$ 27	$ 21	$ 48
LV Variance Account	1550	$ 16,336	$ -	$ 83	$ -	$ 83	$ 16,336	$ (49,477)	$ -	$ -	$ -	$ (33,141)	$ 83	$ (12)	$ 71
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ 13,078	$ -	$ 58	$ -	$ 58	$ 13,078	$ -	$ -	$ -	$ -	$ 13,078	$ 58	$ 619	$ 677
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ (68,594)	$ -	$ (870)		$ (870)	$ (68,594)	$ (116,678)				$ (185,272)	$ (870)	$ (5,879)	$ (6,749)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555	$ -	$ -			$ -	$ -					$ -	$ -		$ -
Smart Meter OM&A Variance	1556	$ 11,155	$ -	$ 106	$ -	$ 106	$ 11,155	$ 27,071	$ -	$ -	$ -	$ 38,226	$ 106	$ 880	$ 986
Conservation and Demand Management Expenditures and Recoveries	1565	$ -	$ -			$ -	$ -					$ -	$ -		$ -
CDM Contra	1566	$ -	$ -			$ -	$ -					$ -	$ -		$ -
Qualifying Transition Costs [5]	1570	$ -	$ 960,442	$ 79,640	$ (1,040,082)	$ -	$ -	n/a	n/a			$ -	$ -		$ -
Pre-Market Opening Energy Variances Total [5]	1571	$ -	$ 715,661	$ 62,391	$ (778,052)	$ -	$ -	n/a	n/a			$ -	$ -		$ -
Extra-Ordinary Event Costs	1572	$ -	$ -			$ -	$ -					$ -	$ -		$ -
Deferred Rate Impact Amounts	1574	$ -	$ -			$ -	$ -					$ -	$ -		$ -
Other Deferred Credits	2425	$ -	$ -			$ -	$ -					$ -	$ -		$ -
Sub-Totals		$ 563,480	$ 1,695,995	$ 167,796	$ (1,830,960)	$ 32,831	$ 563,480	$ (139,084)	$ -	$ -	$ 130,666	$ 555,062	$ 32,831	$ 23,571	$ 56,402
Deferred Payments in Lieu of Taxes	1562	sted								see PILs reconciliation requested					
2006 PILs & Taxes Variance	1592	sted								see PILs reconciliation requested					
Sub-Totals		sted								see PILs reconciliation requested					
Total		$ (314,661)	$ 2,121,724	$ 206,028	$ (2,311,982)	$ 15,770	$ (314,661)	$ (1,195,106)	$ -	$ -	$ 130,666	$ (1,379,101)	$ 15,770	$ (39,094)	$ (23,324)
The following is not included in the total claim but is included on a memo basis:															
Deferred PILs Contra Account [8]	1563	sted								see PILs reconciliation requested					
RSVA - Power (including Global Adjustment)	1588	$ (906,651)	$ 63,870	$ (50,948)	$ (124,416)	$ (111,494)	$ (906,651)	$ (1,420,297)		$ -	$ -	$ (2,326,948)	$ (111,494)	$ (88,319)	$ (199,813)
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ 613,504	$ (39,199)	$ 20,664	$ -	$ (18,535)	$ 613,504	$ (413,909)		$ -	$ -	$ 199,595	$ (18,535)	$ 21,157	$ 2,622
Recovery of Regulatory Asset Balances	1590	$ -	$ -			$ -	$ -					$ -	$ -		$ -

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Bluewater Power Distribution Corporation
NAME OF CONTACT	Leslie Dugas
E-mail Address	ldugas@bluewaterpower.com
VERSION NUMBER	v3.0
Date	22-Dec-08

Account Description	Account Number	Projected Interest on Dec 31 -07 balance from Jan 1, 2008 to Dec 31, 2008 [9]	Projected Interest on Dec 31 -07 balance from Jan 1, 2009 to April 30, 2009 [9]	Claim before Forecasted Transactions	Forecasted Transactions, Excluding Interest from Jan 1, 2008 to Dec 31, 2008	Forecasted Transactions, Excluding Interest from Jan 1, 2009 to April 30, 2009	Projected Interest from Jan 1, 2008 to April 30, 2009 on Forecasted Transx (Excl Interest) from Jan 1, 2008 to December 31, 2008	Projected Interest from Jan 1, 2009 to April 30, 2009 on Forecasted Transx (Excl Interest) from Jan 1, 2009 to April 30, 2009	Total Claim
RSVA - Wholesale Market Service Charge	1580	$ (66,284)	$ (19,184)	$ (1,830,435)					$ (1,830,435)
RSVA - One-time Wholesale Market Service	1582			$ -					$ -
RSVA - Retail Transmission Network Charge	1584	$ 4,309	$ 1,247	$ 116,990					$ 116,990
RSVA - Retail Transmission Connection Charge	1586	$ (12,652)	$ (3,662)	$ (396,670)					$ (396,670)
Sub-Totals		$ (74,627)	$ (21,599)	$ (2,110,115)	$ -	$ -	$ -	$ -	$ (2,110,115)
LRAM and SSM (holding account only)	1505			$ 130,666					$ 130,666
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 3,736	$ 1,081	$ 113,341					$ 113,341
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 19,069	$ 5,519	$ 568,491					$ 568,491
Other Regulatory Assets - Sub-Account - Other [7]	1508			$ -					$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508			$ -					$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508			$ -					$ -
Retail Cost Variance Account - Retail	1518			$ -					$ -
Retail Cost Variance Account - STR	1548			$ -					$ -
Misc. Deferred Debits	1525	$ 18	$ 5	$ 518					$ 518
LV Variance Account	1550	$ (1,279)	$ (370)	$ (34,719)					$ (34,719)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ 505	$ 146	$ 14,406					$ 14,406
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ (7,149)	$ (2,069)	$ (201,239)					$ (201,239)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555			$ -					$ -
Smart Meter OM&A Variance	1556	$ 1,475	$ 427	$ 41,114					$ 41,114
Conservation and Demand Management Expenditures and Recoveries	1565			$ -					$ -
CDM Contra	1566			$ -					$ -
Qualifying Transition Costs [5]	1570			$ -					$ -
Pre-Market Opening Energy Variances Total [5]	1571			$ -					$ -
Extra-Ordinary Event Costs	1572			$ -					$ -
Deferred Rate Impact Amounts	1574			$ -					$ -
Other Deferred Credits	2425			$ -					$ -
Sub-Totals		$ 16,375	$ 4,739	$ 632,578	$ -	$ -	$ -	$ -	$ 632,578
Deferred Payments in Lieu of Taxes	1562			$ (275,274)					
2006 PILs & Taxes Variance	1592								
Sub-Totals				$ -					$ -
Total		$ (58,252)	$ (16,860)	$ (1,477,537)	$ -	$ -	$ -	$ -	$ (1,477,537)
The following is not included in the total claim but is included on a memo basis:									
Deferred PILs Contra Account [8]	1563								
RSVA - Power (including Global Adjustment)	1588	$ (89,781)	$ (25,984)	$ (2,642,526)					$ (2,642,526)
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ 7,701	$ 2,229	$ 212,147					$ 212,147
Recovery of Regulatory Asset Balances	1590			$ -					$ -

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Bluewater Power Distribution Corporation	**LICENCE NUMBER**	ED -2002-0517
NAME OF CONTACT	Leslie Dugas	**DOCID NUMBER**	EB-2008-0221
E-mail Address	ldugas@bluewaterpower.com		
VERSION NUMBER	v3.0	**PHONE NUMBER**	519-337-8201 Ext 255
Date	22-Dec-08	**(extension)**	

Enter appropriate data in cells which are highlighted in yellow only.

Enter the total applied for Regulatory Asset amounts for each account in the appropriate cells below:
Debits should be recorded as positive numbers and credits should be recorded as negative numbers.
Repeat cells going across as necessary for each year in application

ACCOUNTS FOR DISPOSITION

		2005									2006					
Account Description	**Account Number**	**Opening Principal Amounts as of Jan-1-05** [1]	**Transactions (additions) during 2005, excluding interest and adjustments** [6]	**Transactions (reductions) during 2005, excluding interest and adjustments** [6]	**Adjustments during 2005 - instructed by Board** [2]	**Adjustments during 2005 - other** [3]	**Closing Principal Balance as of Dec-31-05**	**Opening Interest Amounts as of Jan-1-05**	**Interest Jan-1 to Dec31-05**	**Closing Interest Amounts as of Dec-31-05**	**Opening Principal Amounts as of Jan-1-06**	**Transactions (additions) during 2006, excluding interest and adjustments** [6]	**Transactions (reductions) during 2006, excluding interest and adjustments** [6]	**Adjustments during 2006 - instructed by Board** [2]	**Adjustments during 2006 - other** [3]	**Transfer of Board-approved amounts to 1590 as per 2006 EDR**
RSVA - Wholesale Market Service Charge	1580	$ 1,468,949	$ 700,237				$ 2,169,186	$ 213,687	$ 117,035	$ 330,722	$ 2,169,186	$ (1,208,707)		$ -	$ -	$ (1,468,949)
RSVA - One-time Wholesale Market Service	1582	$ 61,014					$ 61,014	$ 9,913	$ 4,417	$ 14,330	$ 61,014					$ (61,014)
RSVA - Retail Transmission Network Charge	1584	$ 402,819	$ (56,334)				$ 346,485	$ 58,495	$ 27,233	$ 85,728	$ 346,485	$ 82,203		$ -	$ -	$ (402,819)
RSVA - Retail Transmission Connection Charge	1586	$ 68,982	$ (277,189)				$ (208,207)	$ 5,432	$ (10,483)	$ (5,051)	$ (208,207)	$ (118,351)		$ -	$ -	$ (68,982)
Sub-Totals		$ 2,001,764	$ 366,714		$ -	$ -	$ 2,368,478	$ 287,527	$ 138,202	$ 425,729	$ 2,368,478	$ (1,244,855)		$ -	$ -	$ (2,001,764)
LRAM and SSM (holding account only)	1505						$ -			$ -	$ -					
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 33,625	$ 87,733	$ -	$ -	$ -	$ 121,358	$ -	$ 4,441	$ 4,441	$ 121,358	$ 9,091	$ -	$ -	$ -	$ (33,625)
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -	$ 358,572	$ -	$ -	$ -	$ 358,572	$ -	$ 6,290	$ 6,290	$ 358,572	$ 135,662	$ -	$ -	$ -	$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508						$ -			$ -	$ -					
Other Regulatory Assets - Sub-Account - Other [7]	1508						$ -			$ -	$ -					
Other Regulatory Assets - Sub-Account - Other [7]	1508						$ -			$ -	$ -					
Retail Cost Variance Account - Retail	1518						$ -			$ -	$ -					
Retail Cost Variance Account - STR	1548						$ -			$ -	$ -					
Misc. Deferred Debits	1525	$ 45,022	$ 447	$ -	$ -	$ -	$ 45,469	$ 5,897	$ 3,264	$ 9,161	$ 45,469	$ -	$ -	$ -	$ -	$ (45,022)
LV Variance Account	1550						$ -			$ -	$ -	$ 16,336	$ -	$ -	$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555						$ -			$ -	$ -					
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555						$ -			$ -	$ -					
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555						$ -			$ -	$ -					
Smart Meter OM&A Variance	1556						$ -			$ -	$ -					
Conservation and Demand Management Expenditures and Recoveries	1565						$ -			$ -	$ -					
CDM Contra	1566						$ -			$ -	$ -					
Qualifying Transition Costs [5]	1570	$ 3,295,468	n/a	n/a	$ -	$ -	$ 3,295,468	$ 721,521	$ 238,921	$ 960,442	$ 3,295,468	n/a	n/a	$ -	$ -	$ (3,295,468)
Pre-Market Opening Energy Variances Total [5]	1571	$ 2,581,692	n/a	n/a	$ -	$ -	$ 2,581,692	$ 528,488	$ 187,173	$ 715,661	$ 2,581,692	n/a	n/a	$ -	$ -	$ (2,581,692)
Extra-Ordinary Event Costs	1572						$ -			$ -	$ -					
Deferred Rate Impact Amounts	1574						$ -			$ -	$ -					
Other Deferred Credits	2425						$ -			$ -	$ -					
Sub-Totals		$ 5,955,807	$ 446,752	$ -	$ -	$ -	$ 6,402,559	$ 1,255,906	$ 440,089	$ 1,695,995	$ 6,402,559	$ 161,089	$ -	$ -	$ -	$ (5,955,807)
Deferred Payments in Lieu of Taxes	1562					see PILs reconciliation requested										see PILs reconciliation reque
2006 PILs & Taxes Variance	1592					see PILs reconciliation requested										see PILs reconciliation reque
Sub-Totals						see PILs reconciliation requested										see PILs reconciliation reque
Total		$ 7,957,571	$ 813,466	$ -	$ -	$ -	$ 8,771,037	$ 1,543,433	$ 578,291	$ 2,121,724	$ 8,771,037	$ (1,083,766)	$ -	$ -	$ -	$ (7,957,571)
The following is not included in the total claim but is included on a memo basis:																
Deferred PILs Contra Account [8]	1563					see PILs reconciliation requested										see PILs reconciliation reque
RSVA - Power (including Global Adjustment)	1588	$ 76,728	$ (919,404)				$ (842,676)	$ 116,999	$ (53,129)	$ 63,870	$ (842,676)	$ 12,753		$ -	$ -	$ (76,728)
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ -					$ -	$ -		$ -	$ -			$ -	$ -	$ -
Recovery of Regulatory Asset Balances	1590						$ -			$ -	$ -					

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[1] As per general ledger, if does not agree to Dec-31-04 balance filed in 2006 EDR then provide supplementary analysis
[2] Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-off, and etc.
[3] Provide supporting statement indicating nature of this adjustments and periods they relate to
[4] Not included in sub-total
[5] Closed April 30, 2002
[6] For RSVA accounts only, report the net additions to the account during the year. For all other accounts, record the additions and reductions separately.
[7] Please describe "other" components of 1508 and add more component lines if necessary.
[8] 1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obligation to the ratepayer.
[9] Interest projected on December 31, 2007 closing principal balance.

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Bluewater Power Distribution Corporation
NAME OF CONTACT	Leslie Dugas
E-mail Address	ldugas@bluewaterpower.com
VERSION NUMBER	v3.0
Date	22-Dec-08

							2007								
Account Description	**Account Number**	**Closing Principal Balance as of Dec-31-06**	**Opening Interest Amounts as of Jan-1-06**	**Interest Jan-1 to Dec31-06**	**Transfer of Board-approved amounts to 1590 as per 2006 EDR**	**Closing Interest Amounts as of Dec-31-06**	**Opening Principal Amounts as of Jan-1-07**	**Transactions (additions) during 2007, excluding interest and adjustments [6]**	**Transactions (reductions) during 2007, excluding interest and adjustments [6]**	**Adjustments during 2007 - instructed by Board [2]**	**Adjustments during 2007 - other [3]**	**Closing Principal Balance as of Dec-31-07**	**Opening Interest Amounts as of Jan-1-07**	**Interest Jan-1 to Dec31-07**	**Closing Interest Amounts as of Dec-31-07**
RSVA - Wholesale Market Service Charge	1580	$ (508,470)	$ 330,722	$ 48,020	$ (355,686)	$ 23,056	$ (508,470)	$ (1,209,477)		$ -	$ -	$ (1,717,947)	$ 23,056	$ (50,076)	$ (27,020)
RSVA - One-time Wholesale Market Service	1582	$ -	$ 14,330	$ 1,472	$ (15,802)	$ -	$ -					$ -	$ -		$ -
RSVA - Retail Transmission Network Charge	1584	$ 25,869	$ 85,728	$ 6,079	$ (97,434)	$ (5,627)	$ 25,869	$ 85,823		$ -	$ -	$ 111,692	$ (5,627)	$ 5,369	$ (258)
RSVA - Retail Transmission Connection Charge	1586	$ (395,540)	$ (5,051)	$ (17,339)	$ (12,100)	$ (34,490)	$ (395,540)	$ 67,632		$ -	$ -	$ (327,908)	$ (34,490)	$ (17,958)	$ (52,448)
Sub-Totals		$ (878,141)	$ 425,729	$ 38,232	$ (481,022)	$ (17,061)	$ (878,141)	$ (1,056,022)		$ -	$ -	$ (1,934,163)	$ (17,061)	$ (62,665)	$ (79,726)
LRAM and SSM (holding account only)	1505	$ -	$ -			$ -	$ -				$ 130,666	$ 130,666	$ -		$ -
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 96,824	$ 4,441	$ 5,259	$ (2,577)	$ 7,123	$ 96,824	$ -	$ -	$ -	$ -	$ 96,824	$ 7,123	$ 4,577	$ 11,700
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 494,234	$ 6,290	$ 20,014	$ -	$ 26,304	$ 494,234	$ -	$ -	$ -	$ -	$ 494,234	$ 26,304	$ 23,365	$ 49,669
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -	$ -			$ -	$ -					$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -	$ -			$ -	$ -					$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -	$ -			$ -	$ -					$ -	$ -		$ -
Retail Cost Variance Account - Retail	1518	$ -	$ -			$ -	$ -					$ -	$ -		$ -
Retail Cost Variance Account - STR	1548	$ -	$ -			$ -	$ -					$ -	$ -		$ -
Misc. Deferred Debits	1525	$ 447	$ 9,161	$ 1,115	$ (10,249)	$ 27	$ 447	$ -	$ -	$ -	$ -	$ 447	$ 27	$ 21	$ 48
LV Variance Account	1550	$ 16,336	$ -	$ 83	$ -	$ 83	$ 16,336	$ (49,477)	$ -	$ -	$ -	$ (33,141)	$ 83	$ (12)	$ 71
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ -	$ -			$ -	$ -					$ -	$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ -	$ -			$ -	$ -					$ -	$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555	$ -	$ -			$ -	$ -					$ -	$ -		$ -
Smart Meter OM&A Variance	1556	$ -	$ -			$ -	$ -					$ -	$ -		$ -
Conservation and Demand Management Expenditures and Recoveries	1565	$ -	$ -			$ -	$ -					$ -	$ -		$ -
CDM Contra	1566	$ -	$ -			$ -	$ -					$ -	$ -		$ -
Qualifying Transition Costs [5]	1570	$ -	$ 960,442	$ 79,640	$ (1,040,082)	$ -	$ -	n/a	n/a			$ -	$ -		$ -
Pre-Market Opening Energy Variances Total [5]	1571	$ -	$ 715,661	$ 62,391	$ (778,052)	$ -	$ -	n/a	n/a			$ -	$ -		$ -
Extra-Ordinary Event Costs	1572	$ -	$ -			$ -	$ -					$ -	$ -		$ -
Deferred Rate Impact Amounts	1574	$ -	$ -			$ -	$ -					$ -	$ -		$ -
Other Deferred Credits	2425	$ -	$ -			$ -	$ -					$ -	$ -		$ -
Sub-Totals		$ 607,841	$ 1,695,995	$ 168,502	$ (1,830,960)	$ 33,537	$ 607,841	$ (49,477)	$ -	$ -	$ 130,666	$ 689,030	$ 33,537	$ 27,951	$ 61,488
Deferred Payments in Lieu of Taxes	1562	sted								see PILs reconciliation requested					
2006 PILs & Taxes Variance	1592	sted								see PILs reconciliation requested					
Sub-Totals		sted								see PILs reconciliation requested					
Total		$ (270,300)	$ 2,121,724	$ 206,734	$ (2,311,982)	$ 16,476	$ (270,300)	$ (1,105,499)	$ -	$ -	$ 130,666	$ (1,245,133)	$ 16,476	$ (34,714)	$ (18,238)
The following is not included in the total claim but is included on a memo basis:															
Deferred PILs Contra Account [8]	1563	sted								see PILs reconciliation requested					
RSVA - Power (including Global Adjustment)	1588	$ (906,651)	$ 63,870	$ (50,948)	$ (124,416)	$ (111,494)	$ (906,651)	$ (1,420,297)		$ -	$ -	$ (2,326,948)	$ (111,494)	$ (88,319)	$ (199,813)
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ -	$ -		$ -	$ -	$ -			$ -	$ -	$ -	$ -		$ -
Recovery of Regulatory Asset Balances	1590	$ -	$ -			$ -	$ -					$ -	$ -		$ -

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Bluewater Power Distribution Corporation
NAME OF CONTACT	Leslie Dugas
E-mail Address	ldugas@bluewaterpower.com
VERSION NUMBER	v3.0
Date	22-Dec-08

Account Description	**Account Number**	**Projected Interest on Dec 31 -07 balance from Jan 1, 2008 to Dec 31, 2008 [9]**	**Projected Interest on Dec 31 -07 balance from Jan 1, 2009 to April 30, 2009 [9]**	**Claim before Forecasted Transactions**	**Forecasted Transactions, Excluding Interest from Jan 1, 2008 to Dec 31, 2008**	**Forecasted Transactions, Excluding Interest from Jan 1, 2009 to April 30, 2009**	**Projected Interest from Jan 1, 2008 to April 30, 2009 on Forecasted Transx (Excl Interest) from Jan 1, 2008 to December 31, 2008**	**Projected Interest from Jan 1, 2009 to April 30, 2009 on Forecasted Transx (Excl Interest) from Jan 1, 2009 to April 30, 2009**	**Total Claim**
RSVA - Wholesale Market Service Charge	1580	$ (66,284)	$ (19,184)	$ (1,830,435)					$ (1,830,435)
RSVA - One-time Wholesale Market Service	1582			$ -					$ -
RSVA - Retail Transmission Network Charge	1584	$ 4,309	$ 1,247	$ 116,990					$ 116,990
RSVA - Retail Transmission Connection Charge	1586	$ (12,652)	$ (3,662)	$ (396,670)					$ (396,670)
Sub-Totals		$ (74,627)	$ (21,599)	$ (2,110,115)	$ -	$ -	$ -	$ -	$ (2,110,115)
LRAM and SSM (holding account only)	1505			$ 130,666					$ 130,666
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 3,736	$ 1,081	$ 113,341					$ 113,341
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 19,069	$ 5,519	$ 568,491					$ 568,491
Other Regulatory Assets - Sub-Account - Other [7]	1508			$ -					$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508			$ -					$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508			$ -					$ -
Retail Cost Variance Account - Retail	1518			$ -					$ -
Retail Cost Variance Account - STR	1548			$ -					$ -
Misc. Deferred Debits	1525	$ 18	$ 5	$ 518					$ 518
LV Variance Account	1550	$ (1,279)	$ (370)	$ (34,719)					$ (34,719)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555			$ -					$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555			$ -					$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555			$ -					$ -
Smart Meter OM&A Variance	1556			$ -					$ -
Conservation and Demand Management Expenditures and Recoveries	1565			$ -					$ -
CDM Contra	1566			$ -					$ -
Qualifying Transition Costs [5]	1570			$ -					$ -
Pre-Market Opening Energy Variances Total [5]	1571			$ -					$ -
Extra-Ordinary Event Costs	1572			$ -					$ -
Deferred Rate Impact Amounts	1574			$ -					$ -
Other Deferred Credits	2425			$ -					$ -
Sub-Totals		$ 21,544	$ 6,235	$ 778,297	$ -	$ -	$ -	$ -	$ 778,297
Deferred Payments in Lieu of Taxes	1562								
2006 PILs & Taxes Variance	1592								
Sub-Totals				$ -					$ -
Total		$ (53,083)	$ (15,364)	$ (1,331,818)	$ -	$ -	$ -	$ -	$ (1,331,818)
The following is not included in the total claim but is included on a memo basis:									
Deferred PILs Contra Account [8]	1563								
RSVA - Power (including Global Adjustment)	1588	$ (89,781)	$ (25,984)	$ (2,642,526)					$ (2,642,526)
RSVA - Power - Sub-Account - Global Adjustment [4]	1588			$ -					$ -
Recovery of Regulatory Asset Balances	1590			$ -					$ -
				$ (3,974,344)	= total proposed account balance recoveries as summarized on Exh 5, Tab 1, Sch 2, Attachment 2				

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<u>Question 7.3 - Compliance with the Uniform System of Accounts</u>

Ref: Exhibit 1/ Tab 3/ Schedule 7/ page 1

In the first paragraph on page 1 of the above reference, Bluewater states: "The only departure from APH relates to the accounting treatment of carrying charges. That departure is necessary to create consistency between the treatment of carrying charges in the 2006 EDR (EB-2005-0340) application and this application."

<u>Question 7.3</u>

Please explain how Bluewater justifies a departure from the Board's Accounting Procedures Handbook (APH) and being in compliance with APH just to create consistency between the treatment of carrying charges in the 2006 EDR application and this application.

<u>7.3 Response:</u>

Bluewater Power's position is that technical compliance with the Accounting Procedures Handbook would result in unfair rates. As discussed at Exhibit 1, Tab 3, Schedule 7, the APH is not consistent in its treatment of carrying charges: the APH requires that carrying charges collected from ratepayers are required to be charged to Account 4405 where they serve as a revenue offset; the APH requires that carrying charges accrued in favour of ratepayers be charged to Account6035, where they are not recovered through rates.

In fact, we submit that the OEB has already recognized the unfairness of the APH in numerous applications under the 2006EDR. Numerous LDCs sought to exclude carrying charges earned on Regulatory Assets as one-time adjustments. Those adjustments were permitted by the OEB. In 2008, Lakefront sought similar relief and the OEB refused its application, not because the relief would be wrong, but that the relief should have been sought previously or the original decision appealed. The OEB concluded in EB-2007-0761, Decision dated May 9, 2008 at page 26

> *"If the application of the 2006 EDR model resulted in the inappropriate treatment of an account, or part of an account, it was Lakefront's responsibility to identify this and bring it to the Board's attention. The 2006 EDR Handbook included the option for a distributor to make adjustments for this situation, namely the re-classification of amounts between accounts to ensure the proper determination of the revenue requirement. Many distributors applied for*

and received approval to make similar adjustments, and Lakefront undertook certain other account adjustments of a similar nature"

Bluewater Power points out the accounting treatment in the 2006EDR was not "wrong"; the treatment for which Lakefront sought relief was the exactly the treatment required by the APH. It is not the 2006EDR model that was "wrong", it is the APH that is "wrong" to the extent its mechanistic application is unfair. Bluewater Power did not seek relief in the 2006EDR; nor did we seek to appeal the results of our 2006EDR approval; we seek to avoid the unfairness in the APH going forward as many LDCs did in the 2006EDR.

The relief we now seek is different, but it is one-time relief based on the same principle which resulted in LDCs receiving relief from the OEB in the 2006EDR applications. The only difference is the mechanism (one-time adjustment to a historical test-year versus a one-time adjustment to reallocate costs between accounts). In our case, fairness is created by assessing the carrying charges projected for 2009 against Account 4405, instead of Account 6035**.**

COST ALLOCATION

Question 8.1 - Cost Allocation Informational Filing

Ref: Exhibit 8/Tab 1/Schedule 1

Question 8.1

Please file Sheets O1 and O2 from the Cost Allocation Informational Filing EB-2007-0001, along with sheets O1 and O2 from Bluewater's updated 2006 Cost Allocation Model, as part of the record of this application. Please file Run 1 or 2, whichever one is more closely representative of Bluewater's situation. Alternatively, as a means of avoiding the difficulties described in the third paragraph of the reference page, file a modified run that is more closely representative than either of the runs in the Informational Filing.

8.1 Response:

Four Attachments, Sheets O1 and O2 from:

1. Original Cost Allocation Informational Filing submitted on January 12, 2007 (Run 2)
2. Updated Cost Allocation study (Run 2) completed for the rate application.

Ontario

2006 COST ALLOCATION INFORMATION FILING
Bluewater Power Distribution Corporation
EB-2005-0340 EB-2007-0001
Monday, January 15, 2007
Sheet O1 Revenue to Cost Summary Worksheet - Second Run

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS>50-Regular	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
crev	Distribution Revenue (sale)	$15,877,533	$8,121,495	$2,723,492	$2,151,562	$868,098	$1,681,510	$239,699	$14,397	$77,282
mi	Miscellaneous Revenue (mi)	$1,931,374	$1,061,000	$318,802	$279,605	$61,201	$114,022	$67,124	$6,117	$23,504
	Total Revenue	$17,808,908	$9,182,495	$3,042,294	$2,431,166	$929,298	$1,795,532	$306,823	$20,514	$100,786
	Expenses									
di	Distribution Costs (di)	$4,306,128	$2,186,020	$606,651	$717,797	$182,017	$369,123	$210,731	$18,669	$15,119
cu	Customer Related Costs (cu)	$1,973,038	$1,233,884	$419,143	$219,405	$18,609	$9,989	$391	$654	$70,963
ad	General and Administration (ad)	$3,424,946	$1,853,734	$558,202	$514,699	$112,359	$212,240	$118,951	$10,848	$43,912
dep	Depreciation and Amortization (dep)	$3,130,369	$1,550,698	$491,323	$509,671	$143,792	$273,078	$139,588	$12,362	$9,857
INPUT	PILs (INPUT)	$1,121,709	$566,717	$178,178	$180,796	$46,905	$88,330	$52,429	$4,650	$3,705
INT	Interest	$1,646,412	$831,810	$261,524	$265,367	$68,846	$129,648	$76,953	$6,825	$5,439
	Total Expenses	$15,602,602	$8,222,863	$2,515,021	$2,407,736	$572,528	$1,082,408	$599,043	$54,008	$148,996
	Direct Allocation	$162,484	$0	$0	$14,953	$6,866	$140,665	$0	$0	$0
NI	Allocated Net Income (NI)	$2,043,822	$1,032,592	$324,650	$329,421	$85,464	$160,943	$95,528	$8,473	$6,751
	Revenue Requirement (includes NI)	$17,808,908	$9,255,455	$2,839,671	$2,752,110	$664,857	$1,384,016	$694,571	$62,481	$155,747
	$0	**Revenue Requirement Input equals Output**								

Ontario

2006 COST ALLOCATION INFORMATION FILING
Bluewater Power Distribution Corporation
EB-2005-0340 EB-2007-0001
Monday, January 15, 2007
Sheet O1 Revenue to Cost Summary Worksheet - Second Run

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
			1	2	3	5	6	7	8	9
	Rate Base Calculation									
	Net Assets									
dp	Distribution Plant - Gross	$58,696,991	$28,818,022	$9,317,305	$9,603,806	$2,785,370	$5,235,594	$2,530,783	$224,221	$181,890
gp	General Plant - Gross	$13,539,973	$6,829,102	$2,151,365	$2,184,540	$570,504	$1,074,314	$629,805	$55,855	$44,486
accum dep	Accumulated Depreciation	($36,797,227)	($17,772,525)	($5,837,653)	($6,070,496)	($1,862,627)	($3,497,981)	($1,512,127)	($133,879)	($109,938)
co	Capital Contribution	($2,049,843)	($1,010,676)	($326,920)	($335,065)	($94,981)	($178,767)	($89,267)	($7,911)	($6,255)
	Total Net Plant	$33,389,894	$16,863,923	$5,304,098	$5,382,785	$1,398,266	$2,633,159	$1,559,194	$138,286	$110,183
	Directly Allocated Net Fixed Assets	$1,541,171	$0	$0	$0	$0	$1,541,171	$0	$0	$0
COP	Cost of Power (COP)	$68,756,970	$18,020,057	$8,479,826	$14,687,423	$11,444,040	$15,297,130	$587,062	$43,479	$197,951
	OM&A Expenses	$9,704,111	$5,273,638	$1,583,996	$1,451,901	$312,985	$591,352	$330,073	$30,171	$129,995
	Directly Allocated Expenses	$32,733	$0	$0	$14,953	$6,866	$10,914	$0	$0	$0
	Subtotal	*$78,493,814*	*$23,293,695*	*$10,063,823*	*$16,154,277*	*$11,763,891*	*$15,899,396*	*$917,135*	*$73,651*	*$327,946*
	Working Capital	$11,774,072	$3,494,054	$1,509,573	$2,423,142	$1,764,584	$2,384,909	$137,570	$11,048	$49,192
	Total Rate Base	$46,705,137	$20,357,977	$6,813,671	$7,805,927	$3,162,850	$6,559,239	$1,696,764	$149,333	$159,375
	$1		**Rate Base Input equals Output**							
	Equity Component of Rate Base	$23,352,568	$10,178,989	$3,406,836	$3,902,963	$1,581,425	$3,279,620	$848,382	$74,667	$79,687
	Net Income on Allocated Assets	$2,043,822	$959,633	$527,273	$8,478	$349,904	$572,459	($292,220)	($33,495)	($48,209)
	Net Income on Direct Allocation Assets	$55,110	$0	$0	$0	$0	$55,110	$0	$0	$0
	Net Income	$2,098,933	$959,633	$527,273	$8,478	$349,904	$627,569	($292,220)	($33,495)	($48,209)
	RATIOS ANALYSIS									
	REVENUE TO EXPENSES %	100.00%	99.21%	107.14%	88.34%	139.77%	129.73%	44.17%	32.83%	64.71%
	EXISTING REVENUE MINUS ALLOCATED COSTS	$0	($72,959)	$202,623	($320,944)	$264,441	$411,516	($387,748)	($41,967)	($54,961)
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.99%	9.43%	15.48%	0.22%	22.13%	19.14%	-34.44%	-44.86%	-60.50%

2006 COST ALLOCATION INFORMATION FILING
Bluewater Power Distribution Corporation
EB-2005-0340 EB-2007-0001
Monday, January 15, 2007

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Second Run

Ontario

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	5	6	7	8	9
	Residential	**GS <50**	**GS>50-Regular**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Customer Unit Cost per month - Avoided Cost	$3.58	$12.23	$62.49	$250.59	$281.29	$0.00	$0.09	$19.89
Customer Unit Cost per month - Directly Related	$5.46	$18.21	$94.01	$358.73	$408.82	$0.01	$0.14	$31.35
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$12.92	$27.15	$114.61	$375.71	$477.98	$9.70	$8.51	$37.55
Fixed Charge per approved 2006 EDR	$13.92	$25.45	$331.21	$3,088.16	$18,042.49	$1.37	$1.81	$12.60

Information to be Used to Allocate PILs, ROD, ROE and A&G

		1	2	3	5	6	7	8	9
	Total	**Residential**	**GS <50**	**GS>50-Regular**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
General Plant - Gross Assets	$13,539,973	$6,829,102	$2,151,365	$2,184,540	$570,504	$1,074,314	$629,805	$55,855	$44,486
General Plant - Accumulated Depreciation	($7,120,277)	($3,591,226)	($1,131,340)	($1,148,786)	($300,012)	($564,950)	($331,196)	($29,373)	($23,394)
General Plant - Net Fixed Assets	$6,419,696	$3,237,876	$1,020,025	$1,035,754	$270,493	$509,364	$298,609	$26,483	$21,092
General Plant - Depreciation	$862,402	$434,966	$137,027	$139,140	$36,337	$68,426	$40,114	$3,558	$2,833
Total Net Fixed Assets Excluding General Plant	$26,970,198	$13,626,046	$4,284,073	$4,347,031	$1,127,774	$2,123,795	$1,260,585	$111,803	$89,091
Total Administration and General Expense	$3,424,946	$1,853,734	$558,202	$514,699	$112,359	$212,240	$118,951	$10,848	$43,912
Total O&M	$6,279,166	$3,419,905	$1,025,794	$937,202	$200,626	$379,112	$211,122	$19,323	$86,082

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

			1	2	3	5	6	7	8	9
USoA Account #	**Accounts**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
	Distribution Plant									
1860	Meters	$6,626,362	$3,101,094	$2,164,568	$1,085,057	$194,571	$81,071	$0	$0	$0
	Accumulated Amortization									
	Accum. Amortization of Electric Utility Plant - Meters only	($3,905,078)	($1,827,551)	($1,275,633)	($639,451)	($114,665)	($47,777)	$0	$0	$0

Summary

			1	2	3	5	6	7	8	9
			Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
	Meter Net Fixed Assets	**$2,721,284**	**$1,273,543**	**$888,935**	**$445,606**	**$79,905**	**$33,294**	**$0**	**$0**	**$0**
	Misc Revenue									
4082	Retail Services Revenues	($62,619)	($41,849)	($11,086)	($6,048)	($211)	($188)	($18)	($29)	($3,190)
4084	Service Transaction Requests (STR) Revenues	($506)	($338)	($89)	($49)	($2)	($2)	($0)	($0)	($26)
4090	Electric Services Incidental to Energy Sales	($85,392)	($57,068)	($15,117)	($8,248)	($288)	($257)	($24)	($40)	($4,350)
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($129,052)	($90,336)	($25,810)	($12,905)	$0	$0	$0	$0	$0
	Sub-total	*($277,568)*	*($189,591)*	*($52,103)*	*($27,250)*	*($500)*	*($447)*	*($42)*	*($70)*	*($7,566)*
	Operation									
5065	Meter Expense	$387,862	$181,517	$126,699	$63,512	$11,389	$4,745	$0	$0	$0
5070	Customer Premises - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*$387,862*	*$181,517*	*$126,699*	*$63,512*	*$11,389*	*$4,745*	*$0*	*$0*	*$0*
	Maintenance									
5175	Maintenance of Meters	$10,987	$5,142	$3,589	$1,799	$323	$134	$0	$0	$0
	Billing and Collection									
5310	Meter Reading Expense	$93,429	$65,805	$20,915	$3,587	$2,204	$918	$0	$0	$0
5315	Customer Billing	$1,033,078	$690,414	$182,892	$99,782	$3,481	$3,108	$290	$485	$52,626
5320	Collecting	$262,579	$175,484	$46,486	$25,362	$885	$790	$74	$123	$13,376
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$979	$654	$173	$95	$3	$3	$0	$0	$50
	Sub-total	$1,390,065	$932,357	$250,466	$128,826	$6,573	$4,819	$364	$609	$66,052
	Total Operation, Maintenance and Billing	$1,788,914	$1,119,016	$380,754	$194,136	$18,284	$9,699	$364	$609	$66,052
	Amortization Expense - Meters	$230,380	$107,816	$75,256	$37,724	$6,765	$2,819	$0	$0	$0
	Allocated PILs	$91,423	$42,798	$29,861	$14,967	$2,680	$1,117	$0	$0	$0
	Allocated Debt Return	$134,189	$62,817	$43,830	$21,968	$3,934	$1,639	$0	$0	$0
	Allocated Equity Return	$166,579	$77,980	$54,409	$27,271	$4,884	$2,035	$0	$0	$0
	Total	**$2,133,917**	**$1,220,836**	**$532,008**	**$268,817**	**$36,047**	**$16,862**	**$322**	**$539**	**$58,486**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

			1	2	3	5	6	7	8	9
USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
	Distribution Plant									
1860	Meters	$6,626,362	$3,101,094	$2,164,568	$1,085,057	$194,571	$81,071	$0	$0	$0
	Accumulated Amortization									
	Accum. Amortization of Electric Utility Plant - Meters only	($3,905,078)	($1,827,551)	($1,275,633)	($639,451)	($114,665)	($47,777)	$0	$0	$0
	Meter Net Fixed Assets	$2,721,284	$1,273,543	$888,935	$445,606	$79,905	$33,294	$0	$0	$0
	Allocated General Plant Net Fixed Assets	$647,601	$302,624	$211,653	$106,173	$19,165	$7,985	$0	$0	$0

Summary

		Total	1 Residential	2 GS <50	3 GS>50-Regular	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
	Meter Net Fixed Assets Including General Plant	$3,368,884	$1,576,168	$1,100,588	$551,779	$99,071	$41,279	$0	$0	$0
	Misc Revenue									
4082	Retail Services Revenues	($62,619)	($41,849)	($11,086)	($6,048)	($211)	($188)	($18)	($29)	($3,190)
4084	Service Transaction Requests (STR) Revenues	($506)	($338)	($89)	($49)	($2)	($2)	($0)	($0)	($26)
4090	Electric Services Incidental to Energy Sales	($85,392)	($57,068)	($15,117)	($8,248)	($288)	($257)	($24)	($40)	($4,350)
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($129,052)	($90,336)	($25,810)	($12,905)	$0	$0	$0	$0	$0
	Sub-total	*($277,568)*	*($189,591)*	*($52,103)*	*($27,250)*	*($500)*	*($447)*	*($42)*	*($70)*	*($7,566)*
	Operation									
5065	Meter Expense	$387,862	$181,517	$126,699	$63,512	$11,389	$4,745	$0	$0	$0
5070	Customer Premises - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*$387,862*	*$181,517*	*$126,699*	*$63,512*	*$11,389*	*$4,745*	*$0*	*$0*	*$0*
	Maintenance									
5175	Maintenance of Meters	$10,987	$5,142	$3,589	$1,799	$323	$134	$0	$0	$0
	Billing and Collection									
5310	Meter Reading Expense	$93,429	$65,805	$20,915	$3,587	$2,204	$918	$0	$0	$0
5315	Customer Billing	$1,033,078	$690,414	$182,892	$99,782	$3,481	$3,108	$290	$485	$52,626
5320	Collecting	$262,579	$175,484	$46,486	$25,362	$885	$790	$74	$123	$13,376
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$979	$654	$173	$95	$3	$3	$0	$0	$50
	Sub-total	*$1,390,065*	*$932,357*	*$250,466*	*$128,826*	*$6,573*	*$4,819*	*$364*	*$609*	*$66,052*
	Total Operation, Maintenance and Billing	$1,788,914	$1,119,016	$380,754	$194,136	$18,284	$9,699	$364	$609	$66,052
	Amortization Expense - Meters	$230,380	$107,816	$75,256	$37,724	$6,765	$2,819	$0	$0	$0
	Amortization Expense - General Plant assigned to Meters	*$86,997*	*$40,654*	*$28,433*	*$14,263*	*$2,575*	*$1,073*	*$0*	*$0*	*$0*
	Admin and General	$970,276	$606,554	$207,194	$106,617	$10,240	$5,430	$205	$342	$33,694
	Allocated PILs	$113,180	$52,968	$36,971	$18,533	$3,323	$1,385	$0	$0	$0
	Allocated Debt Return	$166,122	$77,744	$54,266	$27,202	$4,878	$2,032	$0	$0	$0
	Allocated Equity Return	$206,221	$96,510	$67,364	$33,768	$6,055	$2,523	$0	$0	$0
	Total	**$3,284,522**	**$1,911,671**	**$798,135**	**$404,995**	**$51,620**	**$24,513**	**$527**	**$880**	**$92,181**

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	1 Residential	2 GS <50	3 GS>50-Regular	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
	Distribution Plant									
1565	Conservation and Demand Management Expenditures and Recoveries	$315,520	$171,846	$51,545	$47,093	$10,081	$19,050	$10,609	$971	$4,326
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0

Summary

			1	2	3	5	6	7	8	9
			Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$2,919,306	$2,157,172	$260,778	$25,339	$845	$352	$420,553	$37,023	$17,244
1830-5	Poles, Towers and Fixtures - Secondary	$823,394	$609,256	$73,593	$6,441	$0	$0	$118,778	$10,456	$4,870
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$3,780,542	$2,793,569	$337,711	$32,814	$1,094	$456	$544,622	$47,945	$22,332
1835-5	Overhead Conductors and Devices - Secondary	$1,066,307	$788,995	$95,303	$8,341	$0	$0	$153,819	$13,541	$6,307
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$747,986	$552,711	$66,817	$6,492	$216	$90	$107,754	$9,486	$4,418
1845-5	Underground Conductors and Devices - Secondary	$2,813,850	$2,082,059	$251,494	$22,011	$0	$0	$405,909	$35,734	$16,644
1850	Line Transformers	$3,029,504	$2,241,466	$270,895	$23,696	$0	$73	$436,986	$38,469	$17,918
1855	Services	$2,621,246	$1,672,342	$404,007	$176,794	$0	$0	$326,032	$28,702	$13,369
1860	Meters	$6,626,362	$3,101,094	$2,164,568	$1,085,057	$194,571	$81,071	$0	$0	$0
	Sub-total	*$24,744,016*	*$16,170,510*	*$3,976,711*	*$1,434,078*	*$206,807*	*$101,092*	*$2,525,062*	*$222,327*	*$107,429*
	Accumulated Amortization									
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	($12,792,587)	($8,273,589)	($2,150,086)	($786,047)	($115,746)	($48,267)	($1,256,691)	($110,631)	($51,530)
	Customer Related Net Fixed Assets	$11,951,429	$7,896,921	$1,826,625	$648,031	$91,061	$52,825	$1,268,371	$111,696	$55,899
	Allocated General Plant Net Fixed Assets	$2,840,471	$1,876,498	$434,914	$154,404	$21,841	$12,669	$300,453	$26,457	$13,234
	Customer Related NFA Including General Plant	$14,791,900	$9,773,419	$2,261,540	$802,435	$112,901	$65,495	$1,568,824	$138,154	$69,133
	Misc Revenue									
4082	Retail Services Revenues	($62,619)	($41,849)	($11,086)	($6,048)	($211)	($188)	($18)	($29)	($3,190)
4084	Service Transaction Requests (STR) Revenues	($506)	($338)	($89)	($49)	($2)	($2)	($0)	($0)	($26)
4090	Electric Services Incidental to Energy Sales	($85,392)	($57,068)	($15,117)	($8,248)	($288)	($257)	($24)	($40)	($4,350)
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($129,052)	($90,336)	($25,810)	($12,905)	$0	$0	$0	$0	$0
4235	Miscellaneous Service Revenues	($219,909)	($146,967)	($38,932)	($21,240)	($741)	($662)	($62)	($103)	($11,202)
	Sub-total	*($497,477)*	*($336,558)*	*($91,035)*	*($48,490)*	*($1,241)*	*($1,108)*	*($103)*	*($173)*	*($18,768)*
	Operating and Maintenance									
5005	Operation Supervision and Engineering	$288,824	$209,175	$28,566	$4,926	$58	$63	$40,774	$3,589	$1,672
5010	Load Dispatching	$178,026	$128,932	$17,608	$3,036	$36	$39	$25,132	$2,212	$1,031
5020	Overhead Distribution Lines and Feeders - Operation Labour	$342,237	$252,965	$30,575	$2,906	$77	$32	$49,317	$4,342	$2,022
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$70,555	$52,151	$6,303	$599	$16	$7	$10,167	$895	$417
5035	Overhead Distribution Transformers- Operation	$565	$418	$51	$4	$0	$0	$82	$7	$3
5040	Underground Distribution Lines and Feeders - Operation Labour	$292,525	$216,387	$26,142	$2,341	$18	$7	$42,186	$3,714	$1,730
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$9,879	$7,308	$883	$79	$1	$0	$1,425	$125	$58

Summary

			1	2	3	5	6	7	8	9
	Summary		**Residential**	**GS <50**	**GS>50-Regular**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
5055	Underground Distribution Transformers - Operation	$31,303	$23,160	$2,799	$245	$0	$1	$4,515	$397	$185
5065	Meter Expense	$387,862	$181,517	$126,699	$63,512	$11,389	$4,745	$0	$0	$0
5070	Customer Premises - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
5085	Miscellaneous Distribution Expense	$13,292	$9,626	$1,315	$227	$3	$3	$1,876	$165	$77
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$1,733	$1,281	$155	$15	$0	$0	$250	$22	$10
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0
5105	Maintenance Supervision and Engineering	$16,493	$11,945	$1,631	$281	$3	$4	$2,328	$205	$95
5120	Maintenance of Poles, Towers and Fixtures	($796)	($588)	($71)	($7)	($0)	($0)	($115)	($10)	($5)
5125	Maintenance of Overhead Conductors and Devices	$29,695	$21,949	$2,653	$252	$7	$3	$4,279	$377	$175
5130	Maintenance of Overhead Services	$0	$0	$0	$0	$0	$0	$0	$0	$0
5135	Overhead Distribution Lines and Feeders - Right of Way	$0	$0	$0	$0	$0	$0	$0	$0	$0
5145	Maintenance of Underground Conduit	$284	$210	$25	$2	$0	$0	$41	$4	$2
5150	Maintenance of Underground Conductors and Devices	$31,869	$23,574	$2,848	$255	$2	$1	$4,596	$405	$188
5155	Maintenance of Underground Services	$7,806	$4,980	$1,203	$526	$0	$0	$971	$85	$40
5160	Maintenance of Line Transformers	$158,753	$117,458	$14,196	$1,242	$0	$4	$22,899	$2,016	$939
5175	Maintenance of Meters	$10,987	$5,142	$3,589	$1,799	$323	$134	$0	$0	$0
	Sub-total	*$1,871,891*	*$1,267,591*	*$267,169*	*$82,240*	*$11,932*	*$5,043*	*$210,724*	*$18,551*	*$8,641*
	Billing and Collection									
5305	Supervision	$96,206	$64,295	$17,032	$9,292	$324	$289	$27	$45	$4,901
5310	Meter Reading Expense	$93,429	$65,805	$20,915	$3,587	$2,204	$918	$0	$0	$0
5315	Customer Billing	$1,033,078	$690,414	$182,892	$99,782	$3,481	$3,108	$290	$485	$52,626
5320	Collecting	$262,579	$175,484	$46,486	$25,362	$885	$790	$74	$123	$13,376
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$979	$654	$173	$95	$3	$3	$0	$0	$50
5335	Bad Debt Expense	$87,712	$50,436	$21,320	$15,956	$0	$0	$0	$0	$0
5340	Miscellaneous Customer Accounts Expenses	$206	$138	$36	$20	$1	$1	$0	$0	$10
	Sub-total	*$1,574,189*	*$1,047,226*	*$288,855*	*$154,094*	*$6,898*	*$5,109*	*$391*	*$654*	*$70,963*
	Sub Total Operating, Maintenance and Biling	*$3,446,080*	*$2,314,817*	*$556,024*	*$236,334*	*$18,829*	*$10,153*	*$211,115*	*$19,204*	*$79,604*
	Amortization Expense - Customer Related	$929,520	$614,731	$144,151	$49,354	$6,850	$2,857	$98,826	$8,700	$4,052
	Amortization Expense - General Plant assigned to Meters	$381,580	$252,083	$58,425	$20,742	$2,934	$1,702	$40,362	$3,554	$1,778
	Admin and General	$1,873,656	$1,254,729	$302,569	$129,792	$10,545	$5,684	$118,947	$10,782	$40,608
	Allocated PILs	$497,068	$328,438	$75,971	$26,952	$3,787	$2,197	$52,752	$4,646	$2,325
	Allocated Debt Return	$729,582	$482,072	$111,507	$39,559	$5,559	$3,225	$77,428	$6,819	$3,412
	Allocated Equity Return	$905,688	$598,435	$138,423	$49,108	$6,901	$4,003	$96,118	$8,464	$4,236
	PLCC Adjustment for Line Transformer	$265,435	$229,471	$27,750	$2,430	$0	$8	$0	$3,956	$1,820
	PLCC Adjustment for Primary Costs	$309,457	$267,368	$32,391	$3,122	$99	$41	$0	$4,317	$2,120
	PLCC Adjustment for Secondary Costs	$402,088	$355,027	$40,356	$3,800	$0	$0	$0	$0	$2,906
	Total	$7,288,718	**$4,656,882**	**$1,195,539**	**$493,999**	**$54,065**	**$28,663**	**$695,445**	**$53,723**	**$110,402**

	1	2	3	5	6	7	8	9
Summary	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load

Below: Grouping to avoid disclosure

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
Distribution Plant									
CWMC	$ 6,626,362	$ 3,101,094	$ 2,164,568	$ 1,085,057	$ 194,571	$ 81,071	$ -	$ -	$ -
Accumulated Amortization									
Accum. Amortization of Electric Utility Plant - Meters only	$ (3,905,078)	$ (1,827,551)	$ (1,275,633)	$ (639,451)	$ (114,665)	$ (47,777)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 2,721,284	$ 1,273,543	$ 888,935	$ 445,606	$ 79,905	$ 33,294	$ -	$ -	$ -
Misc Revenue									
CWNB	$ (148,516)	$ (99,255)	$ (26,293)	$ (14,345)	$ (500)	$ (447)	$ (42)	$ (70)	$ (7,566)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (129,052)	$ (90,336)	$ (25,810)	$ (12,905)	$ -	$ -	$ -	$ -	$ -
Sub-total	$ (277,568)	$ (189,591)	$ (52,103)	$ (27,250)	$ (500)	$ (447)	$ (42)	$ (70)	$ (7,566)
Operation									
CWMC	$ 387,862	$ 181,517	$ 126,699	$ 63,512	$ 11,389	$ 4,745	$ -	$ -	$ -
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	$ 387,862	$ 181,517	$ 126,699	$ 63,512	$ 11,389	$ 4,745	$ -	$ -	$ -
Maintenance									
1860	$ 10,987	$ 5,142	$ 3,589	$ 1,799	$ 323	$ 134	$ -	$ -	$ -
Billing and Collection									
CWMR	$ 93,429	$ 65,805	$ 20,915	$ 3,587	$ 2,204	$ 918	$ -	$ -	$ -
CWNB	$ 1,296,636	$ 866,552	$ 229,552	$ 125,238	$ 4,369	$ 3,901	$ 364	$ 609	$ 66,052
Sub-total	$ 1,390,065	$ 932,357	$ 250,466	$ 128,826	$ 6,573	$ 4,819	$ 364	$ 609	$ 66,052
Total Operation, Maintenance and Billing	$ 1,788,914	$ 1,119,016	$ 380,754	$ 194,136	$ 18,284	$ 9,699	$ 364	$ 609	$ 66,052
Amortization Expense - Meters	$ 230,380	$ 107,816	$ 75,256	$ 37,724	$ 6,765	$ 2,819	$ -	$ -	$ -
Allocated PILs	$ 91,423	$ 42,798	$ 29,861	$ 14,967	$ 2,680	$ 1,117	$ -	$ -	$ -
Allocated Debt Return	$ 134,189	$ 62,817	$ 43,830	$ 21,968	$ 3,934	$ 1,639	$ -	$ -	$ -
Allocated Equity Return	$ 166,579	$ 77,980	$ 54,409	$ 27,271	$ 4,884	$ 2,035	$ -	$ -	$ -
Total	**$ 2,133,917**	**$ 1,220,836**	**$ 532,008**	**$ 268,817**	**$ 36,047**	**$ 16,862**	**$ 322**	**$ 539**	**$ 58,486**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Summary

		1	2	3	5	6	7	8	9
		Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
Accounts	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Distribution Plant									
CWMC	$ 6,626,362	$ 3,101,094	$ 2,164,568	$ 1,085,057	$ 194,571	$ 81,071	$ -	$ -	$ -
Accumulated Amortization									
Accum. Amortization of Electric Utility Plant - Meters only	$ (3,905,078)	$ (1,827,551)	$ (1,275,633)	$ (639,451)	$ (114,665)	$ (47,777)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 2,721,284	$ 1,273,543	$ 888,935	$ 445,606	$ 79,905	$ 33,294	$ -	$ -	$ -
Allocated General Plant Net Fixed Assets	$ 647,601	$ 302,624	$ 211,653	$ 106,173	$ 19,165	$ 7,985	$ -	$ -	$ -
Meter Net Fixed Assets Including General Plant	$ 3,368,884	$ 1,576,168	$ 1,100,588	$ 551,779	$ 99,071	$ 41,279	$ -	$ -	$ -
Misc Revenue									
CWNB	$ (148,516)	$ (99,255)	$ (26,293)	$ (14,345)	$ (500)	$ (447)	$ (42)	$ (70)	$ (7,566)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (129,052)	$ (90,336)	$ (25,810)	$ (12,905)	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ (277,568)*	*$ (189,591)*	*$ (52,103)*	*$ (27,250)*	*$ (500)*	*$ (447)*	*$ (42)*	*$ (70)*	*$ (7,566)*
Operation									
CWMC	$ 387,862	$ 181,517	$ 126,699	$ 63,512	$ 11,389	$ 4,745	$ -	$ -	$ -
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 387,862*	*$ 181,517*	*$ 126,699*	*$ 63,512*	*$ 11,389*	*$ 4,745*	*$ -*	*$ -*	*$ -*
Maintenance									
1860	$ 10,987	$ 5,142	$ 3,589	$ 1,799	$ 323	$ 134	$ -	$ -	$ -
Billing and Collection									
CWMR	$ 93,429	$ 65,805	$ 20,915	$ 3,587	$ 2,204	$ 918	$ -	$ -	$ -
CWNB	$ 1,296,636	$ 866,552	$ 229,552	$ 125,238	$ 4,369	$ 3,901	$ 364	$ 609	$ 66,052
Sub-total	*$ 1,390,065*	*$ 932,357*	*$ 250,466*	*$ 128,826*	*$ 6,573*	*$ 4,819*	*$ 364*	*$ 609*	*$ 66,052*
Total Operation, Maintenance and Billing	$ 1,788,914	$ 1,119,016	$ 380,754	$ 194,136	$ 18,284	$ 9,699	$ 364	$ 609	$ 66,052
Amortization Expense - Meters	$ 230,380	$ 107,816	$ 75,256	$ 37,724	$ 6,765	$ 2,819	$ -	$ -	$ -
Amortization Expense - General Plant assigned to Meters	$ 86,997	$ 40,654	$ 28,433	$ 14,263	$ 2,575	$ 1,073	$ -	$ -	$ -
Admin and General	$ 970,276	$ 606,554	$ 207,194	$ 106,617	$ 10,240	$ 5,430	$ 205	$ 342	$ 33,694
Allocated PILs	$ 113,180	$ 52,968	$ 36,971	$ 18,533	$ 3,323	$ 1,385	$ -	$ -	$ -
Allocated Debt Return	$ 166,122	$ 77,744	$ 54,266	$ 27,202	$ 4,878	$ 2,032	$ -	$ -	$ -
Allocated Equity Return	$ 206,221	$ 96,510	$ 67,364	$ 33,768	$ 6,055	$ 2,523	$ -	$ -	$ -
Total	**$ 3,284,522**	**$ 1,911,671**	**$ 798,135**	**$ 404,995**	**$ 51,620**	**$ 24,513**	**$ 527**	**$ 880**	**$ 92,181**

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
	Distribution Plant									
	CDMPP	$ 315,520	$ 171,846	$ 51,545	$ 47,093	$ 10,081	$ 19,050	$ 10,609	$ 971	$ 4,326

Summary		1 Residential	2 GS <50	3 GS>50-Regular	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PNCP	$ 7,447,833	$ 5,503,452	$ 665,306	$ 64,645	$ 2,155	$ 898	$ 1,072,929	$ 94,454	$ 43,995
SNCP	$ 4,703,551	$ 3,480,310	$ 420,390	$ 36,793	$ -	$ -	$ 678,506	$ 59,731	$ 27,822
Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LTNCP	$ 3,029,504	$ 2,241,466	$ 270,895	$ 23,696	$ -	$ 73	$ 436,986	$ 38,469	$ 17,918
CWCS	$ 2,621,246	$ 1,672,342	$ 404,007	$ 176,794	$ -	$ -	$ 326,032	$ 28,702	$ 13,369
CWMC	$ 6,626,362	$ 3,101,094	$ 2,164,568	$ 1,085,057	$ 194,571	$ 81,071	$ -	$ -	$ -
Sub-total	*$ 24,744,016*	*$ 16,170,510*	*$ 3,976,711*	*$ 1,434,078*	*$ 206,807*	*$ 101,092*	*$ 2,525,062*	*$ 222,327*	*$ 107,429*
Accumulated Amortization									
Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	$ (12,792,587)	$ (8,273,589)	$ (2,150,086)	$ (786,047)	$ (115,746)	$ (48,267)	$ (1,256,691)	$ (110,631)	$ (51,530)
Customer Related Net Fixed Assets	$ 11,951,429	$ 7,896,921	$ 1,826,625	$ 648,031	$ 91,061	$ 52,825	$ 1,268,371	$ 111,696	$ 55,899
Allocated General Plant Net Fixed Assets	$ 2,840,471	$ 1,876,498	$ 434,914	$ 154,404	$ 21,841	$ 12,669	$ 300,453	$ 26,457	$ 13,234
Customer Related NFA Including General Plant	$ 14,791,900	$ 9,773,419	$ 2,261,540	$ 802,435	$ 112,901	$ 65,495	$ 1,568,824	$ 138,154	$ 69,133
Misc Revenue									
CWNB	$ (368,425)	$ (246,221)	$ (65,225)	$ (35,585)	$ (1,241)	$ (1,108)	$ (103)	$ (173)	$ (18,768)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (129,052)	$ (90,336)	$ (25,810)	$ (12,905)	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ (497,477)*	*$ (336,558)*	*$ (91,035)*	*$ (48,490)*	*$ (1,241)*	*$ (1,108)*	*$ (103)*	*$ (173)*	*$ (18,768)*
Operating and Maintenance									
1815-1855	$ 496,634	$ 359,678	$ 49,119	$ 8,470	$ 100	$ 109	$ 70,111	$ 6,172	$ 2,875
1830 & 1835	$ 414,525	$ 306,397	$ 37,033	$ 3,520	$ 94	$ 39	$ 59,734	$ 5,259	$ 2,449
1850	$ 190,621	$ 141,037	$ 17,045	$ 1,491	$ -	$ 5	$ 27,496	$ 2,421	$ 1,127
1840 & 1845	$ 302,404	$ 223,695	$ 27,025	$ 2,420	$ 18	$ 8	$ 43,611	$ 3,839	$ 1,788
CWMC	$ 387,862	$ 181,517	$ 126,699	$ 63,512	$ 11,389	$ 4,745	$ -	$ -	$ -
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	$ (796)	$ (588)	$ (71)	$ (7)	$ (0)	$ (0)	$ (115)	$ (10)	$ (5)
1835	$ 29,695	$ 21,949	$ 2,653	$ 252	$ 7	$ 3	$ 4,279	$ 377	$ 175
1855	$ 7,806	$ 4,980	$ 1,203	$ 526	$ -	$ -	$ 971	$ 85	$ 40
1840	$ 284	$ 210	$ 25	$ 2	$ -	$ -	$ 41	$ 4	$ 2
1845	$ 31,869	$ 23,574	$ 2,848	$ 255	$ 2	$ 1	$ 4,596	$ 405	$ 188
1860	$ 10,987	$ 5,142	$ 3,589	$ 1,799	$ 323	$ 134	$ -	$ -	$ -
Sub-total	*$ 1,871,891*	*$ 1,267,591*	*$ 267,169*	*$ 82,240*	*$ 11,932*	*$ 5,043*	*$ 210,724*	*$ 18,551*	*$ 8,641*
Billing and Collection									
CWNB	$ 1,393,048	$ 930,985	$ 246,620	$ 134,550	$ 4,694	$ 4,191	$ 391	$ 654	$ 70,963
CWMR	$ 93,429	$ 65,805	$ 20,915	$ 3,587	$ 2,204	$ 918	$ -	$ -	$ -
BDHA	$ 87,712	$ 50,436	$ 21,320	$ 15,956	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 1,574,189*	*$ 1,047,226*	*$ 288,855*	*$ 154,094*	*$ 6,898*	*$ 5,109*	*$ 391*	*$ 654*	*$ 70,963*
Sub Total Operating, Maintenance and Biling	*$ 3,446,080*	*$ 2,314,817*	*$ 556,024*	*$ 236,334*	*$ 18,829*	*$ 10,153*	*$ 211,115*	*$ 19,204*	*$ 79,604*
Amortization Expense - Customer Related	$ 929,520	$ 614,731	$ 144,151	$ 49,354	$ 6,850	$ 2,857	$ 98,826	$ 8,700	$ 4,052
Amortization Expense - General Plant assigned to Meters	$ 381,580	$ 252,083	$ 58,425	$ 20,742	$ 2,934	$ 1,702	$ 40,362	$ 3,554	$ 1,778
Admin and General	$ 1,873,656	$ 1,254,729	$ 302,569	$ 129,792	$ 10,545	$ 5,684	$ 118,947	$ 10,782	$ 40,608
Allocated PILs	$ 497,068	$ 328,438	$ 75,971	$ 26,952	$ 3,787	$ 2,197	$ 52,752	$ 4,646	$ 2,325
Allocated Debt Return	$ 729,582	$ 482,072	$ 111,507	$ 39,559	$ 5,559	$ 3,225	$ 77,428	$ 6,819	$ 3,412
Allocated Equity Return	$ 905,688	$ 598,435	$ 138,423	$ 49,108	$ 6,901	$ 4,003	$ 96,118	$ 8,464	$ 4,236

Summary

		1	2	3	5	6	7	8	9
		Residential	**GS <50**	**GS>50-Regular**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
PLCC Adjustment for Line Transformer	$ 265,435	$ 229,471	$ 27,750	$ 2,430	$ -	$ 8	$ -	$ 3,956	$ 1,820
PLCC Adjustment for Primary Costs	$ 309,457	$ 267,368	$ 32,391	$ 3,122	$ 99	$ 41	$ -	$ 4,317	$ 2,120
PLCC Adjustment for Secondary Costs	$ 402,088	$ 355,027	$ 40,356	$ 3,800	$ -	$ -	$ -	$ -	$ 2,906
Total	**$ 7,288,718**	**$ 4,656,882**	**$ 1,195,539**	**$ 493,999**	**$ 54,065**	**$ 28,663**	**$ 695,445**	**$ 53,723**	**$ 110,402**

Ontario

2006 COST ALLOCATION INFORMATION FILING

Bluewater Power Distribution Corporation

EB-2005-0340 EB-2007-0001

UPDATED FOR 2009 EDR

Sheet O1 Revenue to Cost Summary Worksheet - Second Run

UPDATED COST ALLOCATION FILING

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	5	6	7	8	9
Rate Base Assets		**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
crev	Distribution Revenue (sale)	$15,780,867	$8,121,495	$2,723,492	$2,151,562	$962,376	$1,490,565	$239,699	$14,397	$77,282
mi	Miscellaneous Revenue (mi)	$1,931,374	$1,062,684	$319,493	$280,849	$67,392	$104,202	$67,117	$6,117	$23,519
	Total Revenue	$17,712,241	$9,184,179	$3,042,985	$2,432,411	$1,029,768	$1,594,767	$306,816	$20,514	$100,801
	Expenses									
di	Distribution Costs (di)	$4,306,128	$2,191,243	$608,826	$721,784	$202,305	$337,418	$210,731	$18,670	$15,150
cu	Customer Related Costs (cu)	$1,973,038	$1,234,183	$419,222	$219,448	$19,002	$9,152	$391	$654	$70,986
ad	General and Administration (ad)	$3,424,946	$1,856,816	$559,464	$516,962	$123,924	$194,040	$118,950	$10,849	$43,941
dep	Depreciation and Amortization (dep)	$3,130,369	$1,554,549	$492,924	$512,602	$158,894	$249,562	$139,595	$12,363	$9,880
INPUT	PILs (INPUT)	$1,121,709	$567,972	$178,702	$181,761	$51,667	$80,822	$52,424	$4,650	$3,712
INT	Interest	$1,646,412	$833,653	$262,294	$266,784	$75,835	$118,628	$76,946	$6,825	$5,449
	Total Expenses	$15,602,602	$8,238,416	$2,521,431	$2,419,341	$631,627	$989,621	$599,036	$54,011	$149,118
	Direct Allocation	$162,484	$0	$0	$14,953	$6,866	$140,665	$0	$0	$0
NI	Allocated Net Income (NI)	$2,043,822	$1,034,879	$325,606	$331,180	$94,140	$147,262	$95,519	$8,472	$6,764
	Revenue Requirement (includes NI)	$17,808,908	$9,273,295	$2,847,037	$2,765,474	$732,633	$1,277,548	$694,555	$62,483	$155,882
	$0	**Revenue Requirement Input equals Output**								

Ontario

2006 COST ALLOCATION INFORMATION FILING

Bluewater Power Distribution Corporation

EB-2005-0340 EB-2007-0001

UPDATED FOR 2009 EDR

Sheet O1 Revenue to Cost Summary Worksheet - Second Run

UPDATED COST ALLOCATION FILING

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS>50-Regular	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
	Rate Base Calculation									
	Net Assets									
dp	Distribution Plant - Gross	$58,696,991	$28,892,273	$9,348,186	$9,660,361	$3,075,688	$4,783,035	$2,530,873	$224,240	$182,335
gp	General Plant - Gross	$13,539,973	$6,844,362	$2,157,739	$2,196,266	$628,507	$982,925	$629,749	$55,854	$44,571
accum dep	Accumulated Depreciation	($36,797,227)	($17,822,094)	($5,858,225)	($6,108,086)	($2,059,132)	($3,193,237)	($1,512,308)	($133,900)	($110,245)
co	Capital Contribution	($2,049,843)	($1,013,204)	($327,972)	($336,994)	($104,796)	($163,428)	($89,267)	($7,912)	($6,270)
	Total Net Plant	$33,389,894	$16,901,337	$5,319,729	$5,411,547	$1,540,267	$2,409,295	$1,559,046	$138,282	$110,390
	Directly Allocated Net Fixed Assets	$1,541,171	$0	$0	$0	$0	$1,541,171	$0	$0	$0
COP	Cost of Power (COP)	$68,756,970	$18,379,055	$8,648,763	$14,980,028	$13,038,912	$12,865,214	$598,758	$44,346	$201,895
	OM&A Expenses	$9,704,111	$5,282,243	$1,587,511	$1,458,194	$345,231	$540,610	$330,072	$30,173	$130,077
	Directly Allocated Expenses	$32,733	$0	$0	$14,953	$6,866	$10,914	$0	$0	$0
	Subtotal	*$78,493,814*	*$23,661,298*	*$10,236,274*	*$16,453,175*	*$13,391,009*	*$13,416,738*	*$928,830*	*$74,519*	*$331,972*
	Working Capital	$11,774,072	$3,549,195	$1,535,441	$2,467,976	$2,008,651	$2,012,511	$139,324	$11,178	$49,796
	Total Rate Base	$46,705,137	$20,450,532	$6,855,170	$7,879,523	$3,548,918	$5,962,977	$1,698,371	$149,460	$160,186
	$1	Rate Base Input equals Output								
	Equity Component of Rate Base	$23,352,568	$10,225,266	$3,427,585	$3,939,761	$1,774,459	$2,981,489	$849,185	$74,730	$80,093
	Net Income on Allocated Assets	$1,947,156	$945,763	$521,554	($1,883)	$391,275	$464,481	($292,220)	($33,497)	($48,317)
	Net Income on Direct Allocation Assets	$55,110	$0	$0	$0	$0	$55,110	$0	$0	$0
	Net Income	$2,002,266	$945,763	$521,554	($1,883)	$391,275	$519,591	($292,220)	($33,497)	($48,317)
	RATIOS ANALYSIS									
	REVENUE TO EXPENSES %	99.46%	99.04%	106.88%	87.96%	140.56%	124.83%	44.17%	32.83%	64.66%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($96,666)	($89,116)	$195,948	($333,063)	$297,135	$317,219	($387,739)	($41,970)	($55,081)
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.57%	9.25%	15.22%	-0.05%	22.05%	17.43%	-34.41%	-44.82%	-60.33%
	Adjusted REVENUE TO EXPENSE %	$17,808,908	$950,924	$524,401	($1,893)	$393,410	$522,427	($293,815)	($33,680)	($48,581)
	Adjusted REVENUE TO EXPENSE %	($16)								
	Adjusted Revenue	$17,808,908	$9,234,303	$3,059,593	$2,445,686	$1,035,388	$1,603,471	$308,491	$20,626	$101,351
	Adjusted Revenue to Expense %	100.00%	99.58%	107.47%	88.44%	141.32%	125.51%	44.42%	33.01%	65.02%

2006 COST ALLOCATION INFORMATION FILING

UPDATED COST ALLOCATION FILING

Bluewater Power Distribution Corporation

EB-2005-0340 EB-2007-0001

UPDATED FOR 2009 EDR

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Second Run

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	5	6	7	8	9
	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$3.58	$12.23	$62.49	$233.41	$337.18	$0.00	$0.09	$19.90
Customer Unit Cost per month - Directly Related	$5.46	$18.21	$94.02	$334.54	$487.50	$0.01	$0.14	$31.36
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$12.91	$27.14	$114.63	$351.80	$566.52	$9.70	$8.50	$37.55
Fixed Charge per approved 2006 EDR	$13.92	$25.45	$331.21	$3,088.16	$18,042.49	$1.37	$1.81	$12.60

Information to be Used to Allocate PILs, ROD, ROE and A&G

		1	2	3	5	6	7	8	9
	Total	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
General Plant - Gross Assets	$13,539,973	$6,844,362	$2,157,739	$2,196,266	$628,507	$982,925	$629,749	$55,854	$44,571
General Plant - Accumulated Depreciation	($7,120,277)	($3,599,251)	($1,134,692)	($1,154,952)	($330,513)	($516,892)	($331,166)	($29,372)	($23,439)
General Plant - Net Fixed Assets	$6,419,696	$3,245,112	$1,023,047	$1,041,314	$297,993	$466,033	$298,582	$26,482	$21,132
General Plant - Depreciation	$862,402	$435,938	$137,433	$139,887	$40,031	$62,605	$40,111	$3,558	$2,839
Total Net Fixed Assets Excluding General Plant	$26,970,198	$13,656,226	$4,296,682	$4,370,233	$1,242,274	$1,943,262	$1,260,464	$111,800	$89,258
Total Administration and General Expense	$3,424,946	$1,856,816	$559,464	$516,962	$123,924	$194,040	$118,950	$10,849	$43,941
Total O&M	$6,279,166	$3,425,426	$1,028,047	$941,232	$221,307	$346,570	$211,122	$19,324	$86,136

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

			1	2	3	5	6	7	8	9
USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
	Distribution Plant									
1860	Meters	$6,626,362	$3,101,094	$2,164,568	$1,085,057	$194,571	$81,071	$0	$0	$0
	Accumulated Amortization									

	Summary		Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
	Accum. Amortization of Electric Utility Plant - Meters only	($3,905,078)	($1,827,551)	($1,275,633)	($639,451)	($114,665)	($47,777)	$0	$0	$0
	Meter Net Fixed Assets	**$2,721,284**	**$1,273,543**	**$888,935**	**$445,606**	**$79,905**	**$33,294**	**$0**	**$0**	**$0**
	Misc Revenue									
4082	Retail Services Revenues	($62,619)	($41,862)	($11,089)	($6,050)	($229)	($151)	($18)	($29)	($3,191)
4084	Service Transaction Requests (STR) Revenues	($506)	($338)	($90)	($49)	($2)	($1)	($0)	($0)	($26)
4090	Electric Services Incidental to Energy Sales	($85,392)	($57,086)	($15,122)	($8,250)	($312)	($206)	($24)	($40)	($4,351)
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($129,052)	($90,336)	($25,810)	($12,905)	$0	$0	$0	$0	$0
	Sub-total	*($277,568)*	*($189,623)*	*($52,112)*	*($27,255)*	*($542)*	*($358)*	*($42)*	*($70)*	*($7,568)*
	Operation									
5065	Meter Expense	$387,862	$181,517	$126,699	$63,512	$11,389	$4,745	$0	$0	$0
5070	Customer Premises - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*$387,862*	*$181,517*	*$126,699*	*$63,512*	*$11,389*	*$4,745*	*$0*	*$0*	*$0*
	Maintenance									
5175	Maintenance of Meters	$10,987	$5,142	$3,589	$1,799	$323	$134	$0	$0	$0
	Billing and Collection									
5310	Meter Reading Expense	$93,429	$65,805	$20,915	$3,587	$2,204	$918	$0	$0	$0
5315	Customer Billing	$1,033,078	$690,636	$182,951	$99,814	$3,772	$2,487	$290	$485	$52,643
5320	Collecting	$262,579	$175,540	$46,501	$25,370	$959	$632	$74	$123	$13,380
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$979	$654	$173	$95	$4	$2	$0	$0	$50
	Sub-total	$1,390,065	$932,635	$250,540	$128,866	$6,938	$4,040	$364	$609	$66,073
	Total Operation, Maintenance and Billing	$1,788,914	$1,119,294	$380,828	$194,177	$18,650	$8,920	$364	$609	$66,073
	Amortization Expense - Meters	$230,380	$107,816	$75,256	$37,724	$6,765	$2,819	$0	$0	$0
	Allocated PILs	$91,423	$42,798	$29,861	$14,967	$2,680	$1,117	$0	$0	$0
	Allocated Debt Return	$134,188	$62,817	$43,830	$21,968	$3,934	$1,639	$0	$0	$0
	Allocated Equity Return	$166,578	$77,980	$54,409	$27,271	$4,884	$2,035	$0	$0	$0
	Total	**$2,133,915**	**$1,221,082**	**$532,073**	**$268,852**	**$36,371**	**$16,172**	**$322**	**$539**	**$58,505**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

			1	2	3	5	6	7	8	9
USoA Account #	**Accounts**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
	Distribution Plant									
1860	Meters	$6,626,362	$3,101,094	$2,164,568	$1,085,057	$194,571	$81,071	$0	$0	$0
	Accumulated Amortization									
	Accum. Amortization of Electric Utility Plant - Meters only	($3,905,078)	($1,827,551)	($1,275,633)	($639,451)	($114,665)	($47,777)	$0	$0	$0
	Meter Net Fixed Assets	$2,721,284	$1,273,543	$888,935	$445,606	$79,905	$33,294	$0	$0	$0
	Allocated General Plant Net Fixed Assets	$647,616	$302,630	$211,657	$106,176	$19,168	$7,985	$0	$0	$0

Summary

			Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
	Meter Net Fixed Assets Including General Plant	$3,368,899	$1,576,174	$1,100,592	$551,783	$99,073	$41,278	$0	$0	$0
	Misc Revenue									
4082	Retail Services Revenues	($62,619)	($41,862)	($11,089)	($6,050)	($229)	($151)	($18)	($29)	($3,191)
4084	Service Transaction Requests (STR) Revenues	($506)	($338)	($90)	($49)	($2)	($1)	($0)	($0)	($26)
4090	Electric Services Incidental to Energy Sales	($85,392)	($57,086)	($15,122)	($8,250)	($312)	($206)	($24)	($40)	($4,351)
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($129,052)	($90,336)	($25,810)	($12,905)	$0	$0	$0	$0	$0
	Sub-total	*($277,568)*	*($189,623)*	*($52,112)*	*($27,255)*	*($542)*	*($358)*	*($42)*	*($70)*	*($7,568)*
	Operation									
5065	Meter Expense	$387,862	$181,517	$126,699	$63,512	$11,389	$4,745	$0	$0	$0
5070	Customer Premises - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*$387,862*	*$181,517*	*$126,699*	*$63,512*	*$11,389*	*$4,745*	*$0*	*$0*	*$0*
	Maintenance									
5175	Maintenance of Meters	$10,987	$5,142	$3,589	$1,799	$323	$134	$0	$0	$0
	Billing and Collection									
5310	Meter Reading Expense	$93,429	$65,805	$20,915	$3,587	$2,204	$918	$0	$0	$0
5315	Customer Billing	$1,033,078	$690,636	$182,951	$99,814	$3,772	$2,487	$290	$485	$52,643
5320	Collecting	$262,579	$175,540	$46,501	$25,370	$959	$632	$74	$123	$13,380
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$979	$654	$173	$95	$4	$2	$0	$0	$50
	Sub-total	*$1,390,065*	*$932,635*	*$250,540*	*$128,866*	*$6,938*	*$4,040*	*$364*	*$609*	*$66,073*
	Total Operation, Maintenance and Billing	$1,788,914	$1,119,294	$380,828	$194,177	$18,650	$8,920	$364	$609	$66,073
	Amortization Expense - Meters	$230,380	$107,816	$75,256	$37,724	$6,765	$2,819	$0	$0	$0
	Amortization Expense - General Plant assigned to Meters	*$86,999*	*$40,654*	*$28,433*	*$14,263*	*$2,575*	*$1,073*	*$0*	*$0*	*$0*
	Admin and General	$970,321	$606,734	$207,247	$106,649	$10,443	$4,994	$205	$342	$33,706
	Allocated PILs	$113,180	$52,968	$36,971	$18,533	$3,323	$1,385	$0	$0	$0
	Allocated Debt Return	$166,122	$77,744	$54,266	$27,202	$4,878	$2,032	$0	$0	$0
	Allocated Equity Return	$206,221	$96,510	$67,364	$33,768	$6,055	$2,523	$0	$0	$0
	Total	**$3,284,569**	**$1,912,098**	**$798,254**	**$405,063**	**$52,147**	**$23,388**	**$528**	**$881**	**$92,211**

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

			1	2	3	5	6	7	8	9
USoA Account #	**Accounts**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
	Distribution Plant									
1565	Conservation and Demand Management Expenditures and Recoveries	$315,520	$172,123	$51,658	$47,296	$11,120	$17,415	$10,609	$971	$4,328
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0

Summary

			Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
1830-4	Poles, Towers and Fixtures - Primary	$2,919,306	$2,157,172	$260,778	$25,339	$915	$282	$420,553	$37,023	$17,244
1830-5	Poles, Towers and Fixtures - Secondary	$823,394	$609,256	$73,593	$6,441	$0	$0	$118,778	$10,456	$4,870
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$3,780,542	$2,793,569	$337,711	$32,814	$1,185	$365	$544,622	$47,945	$22,332
1835-5	Overhead Conductors and Devices - Secondary	$1,066,307	$788,995	$95,303	$8,341	$0	$0	$153,819	$13,541	$6,307
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$747,986	$552,711	$66,817	$6,492	$234	$72	$107,754	$9,486	$4,418
1845-5	Underground Conductors and Devices - Secondary	$2,813,850	$2,082,059	$251,494	$22,011	$0	$0	$405,909	$35,734	$16,644
1850	Line Transformers	$3,029,504	$2,241,466	$270,895	$23,696	$0	$73	$436,986	$38,469	$17,918
1855	Services	$2,621,246	$1,672,342	$404,007	$176,794	$0	$0	$326,032	$28,702	$13,369
1860	Meters	$6,626,362	$3,101,094	$2,164,568	$1,085,057	$194,571	$81,071	$0	$0	$0
	Sub-total	*$24,744,016*	*$16,170,787*	*$3,976,824*	*$1,434,280*	*$208,026*	*$99,277*	*$2,525,062*	*$222,327*	*$107,431*
	Accumulated Amortization									
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	($12,792,587)	($8,273,589)	($2,150,086)	($786,047)	($115,836)	($48,177)	($1,256,691)	($110,631)	($51,530)
	Customer Related Net Fixed Assets	$11,951,429	$7,897,198	$1,826,739	$648,233	$92,189	$51,101	$1,268,371	$111,696	$55,902
	Allocated General Plant Net Fixed Assets	$2,840,525	$1,876,601	$434,950	$154,457	$22,114	$12,255	$300,455	$26,458	$13,235
	Customer Related NFA Including General Plant	$14,791,954	$9,773,799	$2,261,688	$802,690	$114,303	$63,356	$1,568,826	$138,154	$69,137
	Misc Revenue									
4082	Retail Services Revenues	($62,619)	($41,862)	($11,089)	($6,050)	($229)	($151)	($18)	($29)	($3,191)
4084	Service Transaction Requests (STR) Revenues	($506)	($338)	($90)	($49)	($2)	($1)	($0)	($0)	($26)
4090	Electric Services Incidental to Energy Sales	($85,392)	($57,086)	($15,122)	($8,250)	($312)	($206)	($24)	($40)	($4,351)
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($129,052)	($90,336)	($25,810)	($12,905)	$0	$0	$0	$0	$0
4235	Miscellaneous Service Revenues	($219,909)	($147,014)	($38,944)	($21,247)	($803)	($529)	($62)	($103)	($11,206)
	Sub-total	*($497,477)*	*($336,637)*	*($91,056)*	*($48,502)*	*($1,345)*	*($887)*	*($103)*	*($173)*	*($18,774)*
	Operating and Maintenance									
5005	Operation Supervision and Engineering	$288,824	$209,176	$28,566	$4,926	$64	$56	$40,774	$3,589	$1,672
5010	Load Dispatching	$178,026	$128,932	$17,608	$3,036	$40	$34	$25,132	$2,212	$1,031
5020	Overhead Distribution Lines and Feeders - Operation Labour	$342,237	$252,965	$30,575	$2,906	$84	$26	$49,317	$4,342	$2,022
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$70,555	$52,151	$6,303	$599	$17	$5	$10,167	$895	$417
5035	Overhead Distribution Transformers- Operation	$565	$418	$51	$4	$0	$0	$82	$7	$3
5040	Underground Distribution Lines and Feeders - Operation Labour	$292,525	$216,387	$26,142	$2,341	$19	$6	$42,186	$3,714	$1,730
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$9,879	$7,308	$883	$79	$1	$0	$1,425	$125	$58
5055	Underground Distribution Transformers - Operation	$31,303	$23,160	$2,799	$245	$0	$1	$4,515	$397	$185
5065	Meter Expense	$387,862	$181,517	$126,699	$63,512	$11,389	$4,745	$0	$0	$0
5070	Customer Premises - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0

	Summary		Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
5085	Miscellaneous Distribution Expense	$13,292	$9,626	$1,315	$227	$3	$3	$1,876	$165	$77
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$1,733	$1,281	$155	$15	$0	$0	$250	$22	$10
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0
5105	Maintenance Supervision and Engineering	$16,493	$11,945	$1,631	$281	$4	$3	$2,328	$205	$95
5120	Maintenance of Poles, Towers and Fixtures	($796)	($588)	($71)	($7)	($0)	($0)	($115)	($10)	($5)
5125	Maintenance of Overhead Conductors and Devices	$29,695	$21,949	$2,653	$252	$7	$2	$4,279	$377	$175
5130	Maintenance of Overhead Services	$0	$0	$0	$0	$0	$0	$0	$0	$0
5135	Overhead Distribution Lines and Feeders - Right of Way	$0	$0	$0	$0	$0	$0	$0	$0	$0
5145	Maintenance of Underground Conduit	$284	$210	$25	$2	$0	$0	$41	$4	$2
5150	Maintenance of Underground Conductors and Devices	$31,869	$23,574	$2,848	$255	$2	$1	$4,596	$405	$188
5155	Maintenance of Underground Services	$7,806	$4,980	$1,203	$526	$0	$0	$971	$85	$40
5160	Maintenance of Line Transformers	$158,753	$117,458	$14,196	$1,242	$0	$4	$22,899	$2,016	$939
5175	Maintenance of Meters	$10,987	$5,142	$3,589	$1,799	$323	$134	$0	$0	$0
	Sub-total	*$1,871,891*	*$1,267,592*	*$267,170*	*$82,241*	*$11,952*	*$5,020*	*$210,724*	*$18,551*	*$8,641*
	Billing and Collection									
5305	Supervision	$96,206	$64,316	$17,037	$9,295	$351	$232	$27	$45	$4,902
5310	Meter Reading Expense	$93,429	$65,805	$20,915	$3,587	$2,204	$918	$0	$0	$0
5315	Customer Billing	$1,033,078	$690,636	$182,951	$99,814	$3,772	$2,487	$290	$485	$52,643
5320	Collecting	$262,579	$175,540	$46,501	$25,370	$959	$632	$74	$123	$13,380
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$979	$654	$173	$95	$4	$2	$0	$0	$50
5335	Bad Debt Expense	$87,712	$50,436	$21,320	$15,956	$0	$0	$0	$0	$0
5340	Miscellaneous Customer Accounts Expenses	$206	$138	$36	$20	$1	$0	$0	$0	$10
	Sub-total	*$1,574,189*	*$1,047,524*	*$288,934*	*$154,137*	*$7,290*	*$4,272*	*$391*	*$654*	*$70,986*
	Sub Total Operating, Maintenance and Biling	*$3,446,080*	*$2,315,117*	*$556,103*	*$236,378*	*$19,243*	*$9,292*	*$211,115*	*$19,205*	*$79,627*
	Amortization Expense - Customer Related	$929,520	$614,731	$144,151	$49,354	$6,857	$2,850	$98,826	$8,700	$4,052
	Amortization Expense - General Plant assigned to Meters	$381,587	$252,097	$58,430	$20,749	$2,971	$1,646	$40,362	$3,554	$1,778
	Admin and General	$1,873,738	$1,254,952	$302,632	$129,828	$10,775	$5,203	$118,946	$10,782	$40,620
	Allocated PILs	$497,068	$328,450	$75,975	$26,960	$3,834	$2,125	$52,752	$4,646	$2,325
	Allocated Debt Return	$729,582	$482,089	$111,514	$39,572	$5,628	$3,119	$77,428	$6,819	$3,413
	Allocated Equity Return	$905,688	$598,456	$138,432	$49,124	$6,986	$3,872	$96,118	$8,464	$4,236
	PLCC Adjustment for Line Transformer	$265,437	$229,472	$27,750	$2,430	$0	$8	$0	$3,956	$1,820
	PLCC Adjustment for Primary Costs	$313,962	$271,258	$32,862	$3,168	$108	$33	$0	$4,382	$2,151
	PLCC Adjustment for Secondary Costs	$401,930	$354,888	$40,339	$3,798	$0	$0	$0	$0	$2,905
	Total	$7,284,459	**$4,653,636**	**$1,195,230**	**$494,068**	**$54,840**	**$27,181**	**$695,445**	**$53,658**	**$110,402**

Below: Grouping to avoid disclosure

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Summary

Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load

Accounts	Total	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
Distribution Plant									
CWMC	$ 6,626,362	$ 3,101,094	$ 2,164,568	$ 1,085,057	$ 194,571	$ 81,071	$ -	$ -	$ -
Accumulated Amortization									
Accum. Amortization of Electric Utility Plant - Meters only	$ (3,905,078)	$ (1,827,551)	$ (1,275,633)	$ (639,451)	$ (114,665)	$ (47,777)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 2,721,284	$ 1,273,543	$ 888,935	$ 445,606	$ 79,905	$ 33,294	$ -	$ -	$ -
Misc Revenue									
CWNB	$ (148,516)	$ (99,286)	$ (26,301)	$ (14,349)	$ (542)	$ (358)	$ (42)	$ (70)	$ (7,568)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (129,052)	$ (90,336)	$ (25,810)	$ (12,905)	$ -	$ -	$ -	$ -	$ -
Sub-total	$ (277,568)	$ (189,623)	$ (52,112)	$ (27,255)	$ (542)	$ (358)	$ (42)	$ (70)	$ (7,568)
Operation									
CWMC	$ 387,862	$ 181,517	$ 126,699	$ 63,512	$ 11,389	$ 4,745	$ -	$ -	$ -
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	$ 387,862	$ 181,517	$ 126,699	$ 63,512	$ 11,389	$ 4,745	$ -	$ -	$ -
Maintenance									
1860	$ 10,987	$ 5,142	$ 3,589	$ 1,799	$ 323	$ 134	$ -	$ -	$ -
Billing and Collection									
CWMR	$ 93,429	$ 65,805	$ 20,915	$ 3,587	$ 2,204	$ 918	$ -	$ -	$ -
CWNB	$ 1,296,636	$ 866,830	$ 229,625	$ 125,279	$ 4,734	$ 3,122	$ 364	$ 609	$ 66,073
Sub-total	$ 1,390,065	$ 932,635	$ 250,540	$ 128,866	$ 6,938	$ 4,040	$ 364	$ 609	$ 66,073
Total Operation, Maintenance and Billing	$ 1,788,914	$ 1,119,294	$ 380,828	$ 194,177	$ 18,650	$ 8,920	$ 364	$ 609	$ 66,073
Amortization Expense - Meters	$ 230,380	$ 107,816	$ 75,256	$ 37,724	$ 6,765	$ 2,819	$ -	$ -	$ -
Allocated PILs	$ 91,423	$ 42,798	$ 29,861	$ 14,967	$ 2,680	$ 1,117	$ -	$ -	$ -
Allocated Debt Return	$ 134,188	$ 62,817	$ 43,830	$ 21,968	$ 3,934	$ 1,639	$ -	$ -	$ -
Allocated Equity Return	$ 166,578	$ 77,980	$ 54,409	$ 27,271	$ 4,884	$ 2,035	$ -	$ -	$ -
Total	**$ 2,133,915**	**$ 1,221,082**	**$ 532,073**	**$ 268,852**	**$ 36,371**	**$ 16,172**	**$ 322**	**$ 539**	**$ 58,505**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
Distribution Plant									
CWMC	$ 6,626,362	$ 3,101,094	$ 2,164,568	$ 1,085,057	$ 194,571	$ 81,071	$ -	$ -	$ -
Accumulated Amortization									

Summary		Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
Accum. Amortization of Electric Utility Plant - Meters only	$ (3,905,078)	$ (1,827,551)	$ (1,275,633)	$ (639,451)	$ (114,665)	$ (47,777)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 2,721,284	$ 1,273,543	$ 888,935	$ 445,606	$ 79,905	$ 33,294	$ -	$ -	$ -
Allocated General Plant Net Fixed Assets	$ 647,616	$ 302,630	$ 211,657	$ 106,176	$ 19,168	$ 7,985	$ -	$ -	$ -
Meter Net Fixed Assets Including General Plant	$ 3,368,899	$ 1,576,174	$ 1,100,592	$ 551,783	$ 99,073	$ 41,278	$ -	$ -	$ -
Misc Revenue									
CWNB	$ (148,516)	$ (99,286)	$ (26,301)	$ (14,349)	$ (542)	$ (358)	$ (42)	$ (70)	$ (7,568)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (129,052)	$ (90,336)	$ (25,810)	$ (12,905)	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ (277,568)*	*$ (189,623)*	*$ (52,112)*	*$ (27,255)*	*$ (542)*	*$ (358)*	*$ (42)*	*$ (70)*	*$ (7,568)*
Operation									
CWMC	$ 387,862	$ 181,517	$ 126,699	$ 63,512	$ 11,389	$ 4,745	$ -	$ -	$ -
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 387,862*	*$ 181,517*	*$ 126,699*	*$ 63,512*	*$ 11,389*	*$ 4,745*	*$ -*	*$ -*	*$ -*
Maintenance									
1860	$ 10,987	$ 5,142	$ 3,589	$ 1,799	$ 323	$ 134	$ -	$ -	$ -
Billing and Collection									
CWMR	$ 93,429	$ 65,805	$ 20,915	$ 3,587	$ 2,204	$ 918	$ -	$ -	$ -
CWNB	$ 1,296,636	$ 866,830	$ 229,625	$ 125,279	$ 4,734	$ 3,122	$ 364	$ 609	$ 66,073
Sub-total	*$ 1,390,065*	*$ 932,635*	*$ 250,540*	*$ 128,866*	*$ 6,938*	*$ 4,040*	*$ 364*	*$ 609*	*$ 66,073*
Total Operation, Maintenance and Billing	$ 1,788,914	$ 1,119,294	$ 380,828	$ 194,177	$ 18,650	$ 8,920	$ 364	$ 609	$ 66,073
Amortization Expense - Meters	$ 230,380	$ 107,816	$ 75,256	$ 37,724	$ 6,765	$ 2,819	$ -	$ -	$ -
Amortization Expense - General Plant assigned to Meters	$ 86,999	$ 40,654	$ 28,433	$ 14,263	$ 2,575	$ 1,073	$ -	$ -	$ -
Admin and General	$ 970,321	$ 606,734	$ 207,247	$ 106,649	$ 10,443	$ 4,994	$ 205	$ 342	$ 33,706
Allocated PILs	$ 113,180	$ 52,968	$ 36,971	$ 18,533	$ 3,323	$ 1,385	$ -	$ -	$ -
Allocated Debt Return	$ 166,122	$ 77,744	$ 54,266	$ 27,202	$ 4,878	$ 2,032	$ -	$ -	$ -
Allocated Equity Return	$ 206,221	$ 96,510	$ 67,364	$ 33,768	$ 6,055	$ 2,523	$ -	$ -	$ -
Total	**$ 3,284,569**	**$ 1,912,098**	**$ 798,254**	**$ 405,063**	**$ 52,147**	**$ 23,388**	**$ 528**	**$ 881**	**$ 92,211**

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
	Distribution Plant									
	CDMPP	$ 315,520	$ 172,123	$ 51,658	$ 47,296	$ 11,120	$ 17,415	$ 10,609	$ 971	$ 4,328
	Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 7,447,833	$ 5,503,452	$ 665,306	$ 64,645	$ 2,334	$ 718	$ 1,072,929	$ 94,454	$ 43,995
	SNCP	$ 4,703,551	$ 3,480,310	$ 420,390	$ 36,793	$ -	$ -	$ 678,506	$ 59,731	$ 27,822
	Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LTNCP	$ 3,029,504	$ 2,241,466	$ 270,895	$ 23,696	$ -	$ 73	$ 436,986	$ 38,469	$ 17,918
	CWCS	$ 2,621,246	$ 1,672,342	$ 404,007	$ 176,794	$ -	$ -	$ 326,032	$ 28,702	$ 13,369
	CWMC	$ 6,626,362	$ 3,101,094	$ 2,164,568	$ 1,085,057	$ 194,571	$ 81,071	$ -	$ -	$ -

Summary		**Residential**	**GS <50**	**GS>50-Regular**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Sub-total	*$ 24,744,016*	*$ 16,170,787*	*$ 3,976,824*	*$ 1,434,280*	*$ 208,026*	*$ 99,277*	*$ 2,525,062*	*$ 222,327*	*$ 107,431*
Accumulated Amortization									
Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	$ (12,792,587)	$ (8,273,589)	$ (2,150,086)	$ (786,047)	$ (115,836)	$ (48,177)	$ (1,256,691)	$ (110,631)	$ (51,530)
Customer Related Net Fixed Assets	$ 11,951,429	$ 7,897,198	$ 1,826,739	$ 648,233	$ 92,189	$ 51,101	$ 1,268,371	$ 111,696	$ 55,902
Allocated General Plant Net Fixed Assets	$ 2,840,525	$ 1,876,601	$ 434,950	$ 154,457	$ 22,114	$ 12,255	$ 300,455	$ 26,458	$ 13,235
Customer Related NFA Including General Plant	$ 14,791,954	$ 9,773,799	$ 2,261,688	$ 802,690	$ 114,303	$ 63,356	$ 1,568,826	$ 138,154	$ 69,137
Misc Revenue									
CWNB	$ (368,425)	$ (246,300)	$ (65,246)	$ (35,597)	$ (1,345)	$ (887)	$ (103)	$ (173)	$ (18,774)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (129,052)	$ (90,336)	$ (25,810)	$ (12,905)	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ (497,477)*	*$ (336,637)*	*$ (91,056)*	*$ (48,502)*	*$ (1,345)*	*$ (887)*	*$ (103)*	*$ (173)*	*$ (18,774)*
Operating and Maintenance									
1815-1855	$ 496,634	$ 359,679	$ 49,120	$ 8,470	$ 110	$ 96	$ 70,111	$ 6,172	$ 2,875
1830 & 1835	$ 414,525	$ 306,397	$ 37,033	$ 3,520	$ 101	$ 31	$ 59,734	$ 5,259	$ 2,449
1850	$ 190,621	$ 141,037	$ 17,045	$ 1,491	$ -	$ 5	$ 27,496	$ 2,421	$ 1,127
1840 & 1845	$ 302,404	$ 223,695	$ 27,025	$ 2,420	$ 20	$ 6	$ 43,611	$ 3,839	$ 1,788
CWMC	$ 387,862	$ 181,517	$ 126,699	$ 63,512	$ 11,389	$ 4,745	$ -	$ -	$ -
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	$ (796)	$ (588)	$ (71)	$ (7)	$ (0)	$ (0)	$ (115)	$ (10)	$ (5)
1835	$ 29,695	$ 21,949	$ 2,653	$ 252	$ 7	$ 2	$ 4,279	$ 377	$ 175
1855	$ 7,806	$ 4,980	$ 1,203	$ 526	$ -	$ -	$ 971	$ 85	$ 40
1840	$ 284	$ 210	$ 25	$ 2	$ -	$ -	$ 41	$ 4	$ 2
1845	$ 31,869	$ 23,574	$ 2,848	$ 255	$ 2	$ 1	$ 4,596	$ 405	$ 188
1860	$ 10,987	$ 5,142	$ 3,589	$ 1,799	$ 323	$ 134	$ -	$ -	$ -
Sub-total	*$ 1,871,891*	*$ 1,267,592*	*$ 267,170*	*$ 82,241*	*$ 11,952*	*$ 5,020*	*$ 210,724*	*$ 18,551*	*$ 8,641*
Billing and Collection									
CWNB	$ 1,393,048	$ 931,284	$ 246,699	$ 134,594	$ 5,086	$ 3,354	$ 391	$ 654	$ 70,986
CWMR	$ 93,429	$ 65,805	$ 20,915	$ 3,587	$ 2,204	$ 918	$ -	$ -	$ -
BDHA	$ 87,712	$ 50,436	$ 21,320	$ 15,956	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 1,574,189*	*$ 1,047,524*	*$ 288,934*	*$ 154,137*	*$ 7,290*	*$ 4,272*	*$ 391*	*$ 654*	*$ 70,986*
Sub Total Operating, Maintenance and Biling	*$ 3,446,080*	*$ 2,315,117*	*$ 556,103*	*$ 236,378*	*$ 19,243*	*$ 9,292*	*$ 211,115*	*$ 19,205*	*$ 79,627*
Amortization Expense - Customer Related	$ 929,520	$ 614,731	$ 144,151	$ 49,354	$ 6,857	$ 2,850	$ 98,826	$ 8,700	$ 4,052
Amortization Expense - General Plant assigned to Meters	$ 381,587	$ 252,097	$ 58,430	$ 20,749	$ 2,971	$ 1,646	$ 40,362	$ 3,554	$ 1,778
Admin and General	$ 1,873,738	$ 1,254,952	$ 302,632	$ 129,828	$ 10,775	$ 5,203	$ 118,946	$ 10,782	$ 40,620
Allocated PILs	$ 497,068	$ 328,450	$ 75,975	$ 26,960	$ 3,834	$ 2,125	$ 52,752	$ 4,646	$ 2,325
Allocated Debt Return	$ 729,582	$ 482,089	$ 111,514	$ 39,572	$ 5,628	$ 3,119	$ 77,428	$ 6,819	$ 3,413
Allocated Equity Return	$ 905,688	$ 598,456	$ 138,432	$ 49,124	$ 6,986	$ 3,872	$ 96,118	$ 8,464	$ 4,236
PLCC Adjustment for Line Transformer	$ 265,437	$ 229,472	$ 27,750	$ 2,430	$ -	$ 8	$ -	$ 3,956	$ 1,820
PLCC Adjustment for Primary Costs	$ 313,962	$ 271,258	$ 32,862	$ 3,168	$ 108	$ 33	$ -	$ 4,382	$ 2,151
PLCC Adjustment for Secondary Costs	$ 401,930	$ 354,888	$ 40,339	$ 3,798	$ -	$ -	$ -	$ -	$ 2,905
Total	**$ 7,284,459**	**$ 4,653,636**	**$ 1,195,230**	**$ 494,068**	**$ 54,840**	**$ 27,181**	**$ 695,445**	**$ 53,658**	**$ 110,402**

LOSS FACTORS

Question 9.1 - Distribution Loss Factor

Ref: Exhibit 4/Tab 2/Schedule 10/Page 1/ Table 4.2.10.1

Question 9.1

Please explain why Bluewater is using a 5 year average to calculate a Total Distribution Loss Factor of 3.10% instead of using the lowest distribution loss factor of 2.26% over all 5 years.

9.1 Response:

Bluewater Power has determined that a 5 year average is appropriate to calculate the Total Distribution Loss Factor ("DLF") in order to smooth out any years with abnormally higher or lower than average results. Using the lowest one year factor such as 2.26% as evidenced in 2005 would only lead to a growth in the balances in the deferral and variance accounts that use an uplifted quantity as the basis for the calculation. It would not be appropriate to choose the single year with the highest factor such as 4.40% in 2003, as that too would lead to a negative growth in the deferral and variance accounts.

Therefore a five year average has the effect of minimizing the years with the highest and lowest factors, thus mitigating the build up of debit or credit balances in the deferral and variance accounts.

RATE DESIGN

Question 10.1 - Retail Transmission Service Rates

Ref: Exhibit 4/Tab 2/Schedule 13/Page 1
Ref: Ontario Energy Board Guideline (G-2208-001) - Electricity Distribution Retail Transmission Service Rates, p. (III-IV), http://www.oeb.gov.on.ca/OEB/_Documents/Regulatory/Board_Guideline_EDRTS.pdf

On August 28, 2008, the Board issued its Decision and Rate Order in proceeding EB-2008-0113, setting new Uniform Transmission Rates (UTR) for Ontario transmitters, effective January 1, 2009. The change in the UTRs affects the retail transmission service rates (RTSR) charged by distributors. Given that Bluewater is fully embedded within Hydro One Distribution, its wholesale cost of transmission service is affected by the approved UTRs change.

On October 22, 2008, the Board issued its guideline on Electricity Distribution Retail Transmission Service Rates, outlining the evidence it expects distributors to file in support of their cost of service applications.

Bluewater is expected to file an update to that application detailing the calculations for adjusting its RTSRs.

Question 10.1 (a)

Please file a variance analysis using 2 years of actual data examining what, if any, trend is apparent in the monthly balances in the RTSR deferral accounts

10.1 (a) Response:

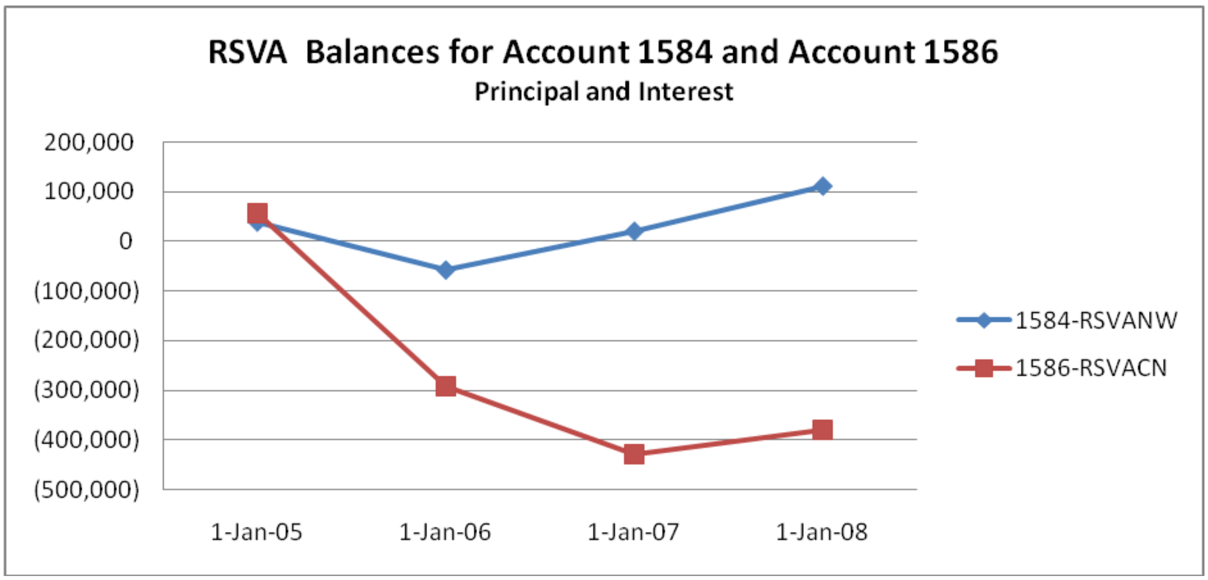
The following information addresses the October 22, 2008 Guideline on updating the RTSR given the new rates effective January 1, 2009. A change to the RTSR affects the working capital calculation. Another item that affects working capital is the price of the electricity commodity assumed in the application. In order to provide the Board with all the relevant information, Bluewater Power has incorporated both the RTSR rate change and an updated electricity commodity price change in the analysis to follow.

As noted above, and indicated in the earlier Board Staff Interrogatory 3.14, Bluewater Power has prepared an analysis which updates the RPP price, given the latest OEB Regulated Price Plan Report dated October 15, 2008. The RPP price assumed in Bluewater Power's original submission was $.0545/kWh, and the October 15, 2008 report updates the RPP price to $.0603/kWh.

Also in its original submission, Bluewater Power has proposed to dispose of the balances in the RSVA accounts given the large credit position. (Exhibit 5, Tab 1, Schedule 1, page 1). We believe it is in the best interest of our customers to return the over-collection which has accumulated over a number of years. Therefore for this analysis we have maintained the same premise, and are proposing to apply the revised RTS rates from May 1, 2009 forward without any adjustments for the current balance in Accounts 1584, and 1586 (RSVANW and RSVACN respectively). The table and graph below indicate the historical trend for the RTSR accounts. The balance in Account 1584 has remained relatively steady, and the balance in Account 1586 dropped in the year 2005, but has remained more constant for the years 2006 and 2007.

Table 10.1 – RTSR Trend (Principal and Interest)

	1-Jan-05	1-Jan-06	1-Jan-07	1-Jan-08
1584-RSVANW	38,816	(58,305)	20,242	111,434
1586-RSVACN	57,271	(292,673)	(430,030)	(380,356)



Question 10.1 (b)

Please file a calculation of the proposed RTSR rates that includes the adjustment of the UTRs effective January 1, 2009 and an adjustment to eliminate ongoing trends in the balances in the RTSR deferral accounts.

10.1 (b) Response:

Bluewater Power proposes to increase the Network Service rate by 11%, and the combined Line Connection and Transformation Connection Service rate by 5%. Table 10.2 provides the calculation.

Table 10.2

Percent Change in the Uniform Transmission Rates

Ontario Uniform Transmission Rates	Network Service Rate$/kW	Line Connection Service Rate $/kW	Transformation Connection Service Rate $/kW	Total Connection Rate $/kW
Rates effective Nov 1/07 to Dec 31/08 (EB-2007-0759)	2.31	0.59	1.61	2.20
Rates Approved for January 1, 2009 (EB-2008-0113)	2.57	0.70	1.62	2.32
$ Variance	0.26	0.11	0.01	0.12
% Variance (rounded to the nearest percent)	11.0%	19.0%	1.0%	5.0%

The percent increase in the retail transmission rates was then applied to the existing Transmission Network Charge rate and Transmission Connection Charge rate to determine the revised rates.

Table 10.3

Revised RTS Rates

	Volumetric Rate Type	Current Retail Transmission Rate $/kWh or $/kW (from 2008 IRM)		Incremental change $/kWh or $/kW (current rate x % increase)		UPDATED RTS RATES $/kWh or $/kW	
		Network	Connection	Network	Connection	Network	Connection
Residential	kWh	0.0047	0.0048	0.0005	0.0002	0.0052	0.0050
General Service Less than 50 kW	kWh	0.0043	0.0043	0.0005	0.0002	0.0048	0.0045
General Service Greater than 50 kW	kW	1.7399	1.6988	0.1914	0.0849	1.9313	1.7837
Intermediate Use(1000 kW to 5000 kW)	kW	1.8479	1.8623	0.2033	0.0931	2.0512	1.9554
Large Use (> 5000 kW)	kW	2.0461	2.1296	0.2251	0.1065	2.2712	2.2361
Unmetered Scattered Load	kWh	0.0043	0.0043	0.0005	0.0002	0.0048	0.0045
Sentinel Lighting	kW	1.3188	1.3407	0.1451	0.0670	1.4639	1.4077
Street Lighting	kW	1.3122	1.3133	0.1443	0.0657	1.4565	1.3790

The second modification to the original application of Bluewater Power entails updating the electricity price to the most recent RPP price available. Section 2.1.1 of the OEB document 'Filing Requirements for Transmission and Distribution Applications' indicates:

- *When filing, the electricity price will be that available from the most recent Board approved RPP, at the time of filing*.

On October 15, 2008, the OEB released an updated Regulated Price Plan report which updated the RPP price from $.0545/kWh to $.0603/kWh. Bluewater Power feels that it would be prudent to update the RPP price in the working capital allowance at the same time as updating the RTSRs in order to provide an accurate impact on customers' bills.

A summary of the impact on the relevant revenue requirement values are provided below.

1. The pass-through charges are impacted, as the electricity commodity, transmission network and transmission connection revenues are increased due to the update to the RTSR rates and the RPP rate.

Table 10.4 – Pass-through Charges

	Original Filing	Updated with RTSR and RPP changes	Variance
Electricity Commodity	$ 62,444,763	$ 69,090,261	$ 6,645,498
Transmission Network Revenue	$ 4,655,750	$ 5,166,656	$ 510,906
Transmission Connection Revenue	$ 4,705,961	$ 4,928,296	$ 222,336
Wholesale Market Service Rate	$ 5,958,032	$ 5,958,032	$ -
Rural Rate Protection	$ 1,145,775	$ 1,145,775	$ -
Low Voltage Charges	$ 189,602	$ 189,602	$ -
Total Pass-through Charges	**$ 79,099,884**	**$ 86,478,623**	**$ 7,378,739**

2. The update to the pass-through charges impacts the total expenses used to calculate the Working Capital Allowance, which impacts the Rate Base amount.

Table 10.5 – Working Capital Allowance and Rate Base

	Original Filing	Updated with RTSR and RPP changes	Variance
Total Eligible Distribution Expenses	$ 11,656,169	$ 11,656,169	$ -
Power Supply Expenses	$ 79,099,884	$ 86,478,623	$ 7,378,739
Total Expenses for Working Capital	$ 90,756,053	$ 98,134,792	$ 7,378,739
Working Capital Allowance (15%)	**$ 13,613,408**	**$ 14,720,219**	**$ 1,106,811**
Rate Base	**$ 53,158,483**	**54,265,294**	**$ 1,106,811**

3. The update to rate base impacts the regulated return on capital and therefore the calculation of the deemed interest expense and the deemed return on equity.

Table 10.6 – Regulated Return on Capital

	Original Filing	Updated with RTSR and RPP changes	Variance
Regulated Return on Capital	$ 4,098,944	$ 4,184,288	$ 85,344
Deemed Interest Expense	$ 2,124,815	$ 2,169,056	$ 44,241
Deemed Return on Equity	$ 1,974,129	$ 2,015,232	$ 41,103

4. The update to the regulated return on capital, and the updated PILs value impacts the revenue requirement.

Table 10.7 – Revenue Requirement

	Original Filing	Updated with RTSR and RPP changes	Variance
OM&A Expenses	$ 11,656,169	$ 11,656,169	$ -
3850-Amortization Expense	$ 4,358,109	$ 4,358,109	$ -
Total Distribution Expenses	$ 16,014,278	$ 16,014,278	$ -
Regulated Return On Capital	$ 4,098,944	$ 4,184,288	$ 85,344
PILs (with gross-up)	$ 1,322,854	$ 1,345,589	$ 22,735
Service Revenue Requirement	$ 21,436,076	$ 21,544,155	$ 108,079
Less: Revenue Offsets	$ 728,598	$ 728,598	$ -
Base Revenue Requirement	$ 20,707,479	$ 20,815,558	$ 108,079

5. The updated revenue requirement impacts the proposed distribution rates.

Table 10.8 – Fixed Rates (before Smart Metering)

	Original Filing	Updated with RTSR and RPP changes	Variance
Residential	$ 17.50	$ 17.59	$ 0.09
General Service <50 kW	$ 31.52	$ 31.69	$ 0.17
General Service 50 to 999 kW	$ 433.49	$ 435.68	$ 2.19
General Service 1,000 to 4,999 kW	$ 3,507.63	$ 3,522.80	$ 15.17
Large	$ 25,755.94	$ 25,872.16	$ 116.22
Unmetered Scattered Load	$ 22.37	$ 22.49	$ 0.12
Sentinel Lighting	$ 3.11	$ 3.12	$ 0.01
Street Lighting	$ 2.36	$ 2.37	$ 0.01

Table 10.9 – Variable Rates

	Original Filing	Updated with RTSR and RPP changes	Variance
Residential	$ 0.0150	$ 0.0151	$ 0.0001
General Service <50 kW	$ 0.0160	$ 0.0161	$ 0.0001
General Service 50 to 999 kW	$ 2.1298	$ 2.1406	$ 0.0108
General Service 1,000 to 4,999 kW	$ 1.7345	$ 1.7420	$ 0.0075
Large	$ 1.6337	$ 1.6411	$ 0.0074
Unmetered Scattered Load	$ 0.0228	$ 0.0229	$ 0.0001
Sentinel Lighting	$ 8.2803	$ 8.3234	$ 0.0431
Street Lighting	$ 6.4356	$ 6.4691	$ 0.0335

Attachment 10.1 details the proposed distribution rates given the update to the RTSR and RPP rates. The tables below provide a summary of the bill impacts.

Table 10.10 – Bill Impacts by Rate Class

Original Submission			Distribution Charges		Total Bill	
Rate Class	**kWh**	**kW**	**$ change**	**% change**	**$ change**	**% change**
Residential	1,000		$7.90	30.9%	$6.35	6.0%
GS<50	2,000		$13.50	26.5%	$9.99	4.7%
GS 50 to 999 kW	52,000	135	$171.94	31.3%	$79.94	1.6%
GS 1000 to 4999 kW	1,700,000	3,532	$1,163.33	13.7%	($1,935.72)	-1.4%
Large	4,446,000	6,900	$11,120.66	42.9%	$4,974.14	1.4%
USL	1,000		$19.79	78.0%	$18.34	17.9%
Sentinel (per connection)	176	0.46	$2.89	71.7%	$2.63	15.6%
Streetlighting (per connection)	99	0.21	$1.56	72.2%	$1.44	15.6%

Updated with RTSR change and RPP price			Distribution Charges		Total Bill	
Rate Class	**kWh**	**kW**	**$ change**	**% change**	**$ change**	**% change**
Residential	1,000		$8.09	31.6%	$7.27	6.9%
GS<50	2,000		$13.87	27.2%	$11.80	5.6%
GS 50 to 999 kW	52,000	135	$175.59	31.9%	$120.89	2.5%
GS 1000 to 4999 kW	1,700,000	3,532	$1,204.99	14.2%	$9,262.28	6.6%
Large	4,446,000	6,900	$11,287.94	43.6%	$33,331.61	9.3%
USL	1,000		$20.01	78.8%	$19.29	18.8%
Sentinel (per connection)	176	0.46	$2.92	72.5%	$2.75	16.4%
Streetlighting (per connection)	99	0.21	$1.57	73.0%	$1.49	16.2%

Variance from Original Submission			Distribution Charges		Total Bill	
Rate Class	**kWh**	kW	**$ change**	**% change**	**$ change**	**% change**
Residential	1,000		$0.19	0.7%	$0.92	0.9%
GS<50	2,000		$0.37	0.7%	$1.81	0.9%
GS 50 to 999 kW	52,000	135	$3.65	0.7%	$40.95	0.8%
GS 1000 to 4999 kW	1,700,000	3,532	$41.66	0.5%	$11,198.00	8.0%
Large	4,446,000	6,900	$167.28	0.6%	$28,357.47	7.9%
USL	1,000		$0.22	0.9%	$0.95	0.9%
Sentinel (per connection)	176	0.46	$0.03	0.7%	$0.12	0.7%
Streetlighting (per connection)	99	0.21	$0.02	0.8%	$0.06	0.6%

Bluewater Power requests the ability to include all the above noted changes to the revenue requirement and rates in the final rate calculation. There may be further updates to RPP prices and other changes that are beyond the control of Bluewater Power and we request the ability to update in the future as required.

Bluewater Power has chosen to provide a summary of the impacts on the original rate application as was filed. We have not updated our original filing. We would be prepared update the application should the OEB require such an update. However, we believe what we have presented is clear and in keeping with our understanding of the OEB's expectations.

ATTACHMENT 10.1 – Board Staff 10.1 PROPOSED RATE SCHEDULE WITH RTSR AND RPP PRICE CHANGE.

With RPP and RTSR updates

Monthly Rates and Charges

		Effective May 1/09
Residential		
Service Charge	$	18.59
Distribution Volumetric Rate	$/kWh	0.0151
Regulatory Asset Recovery	$/kWh	(0.0009)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0052
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0050
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
General Service <50 kW		
Service Charge	$	32.69
Distribution Volumetric Rate	$/kWh	0.0161
Regulatory Asset Recovery	$/kWh	(0.0011)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
General Service 50 to 999 kW		
Service Charge	$	436.68
Distribution Volumetric Rate	$/kW	2.1406
Regulatory Asset Recovery	$/kW	(0.4555)
Retail Transmission Rate – Network Service Rate	$/kW	1.9313
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7837
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
General Service 1,000 to 4,999 kW		
Service Charge	$	3,523.80
Distribution Volumetric Rate	$/kW	1.7420
Regulatory Asset Recovery	$/kW	(0.6174)
Retail Transmission Rate – Network Service Rate	$/kW	2.0512
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.9554
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

With RPP and RTSR updates

Monthly Rates and Charges

		Effective May 1/09
Large		
Service Charge	$	25,873.16
Distribution Volumetric Rate	$/kW	1.6411
Regulatory Asset Recovery	$/kW	(0.8909)
Retail Transmission Rate – Network Service Rate	$/kW	2.2712
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.2361
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
Unmetered Scattered Load		
Service Charge (per connection)	$	22.49
Distribution Volumetric Rate	$/kWh	0.0229
Regulatory Asset Recovery	$/kWh	(0.0008)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

With RPP and RTSR updates

Monthly Rates and Charges

		Effective May 1/09
Sentinel Lighting		
Service Charge (per connection)	$	3.12
Distribution Volumetric Rate	$/kW	8.3234
Regulatory Asset Recovery	$/kW	(0.3737)
Retail Transmission Rate – Network Service Rate	$/kW	1.4639
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4077
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
Street Lighting		
Service Charge (per connection)	$	2.37
Distribution Volumetric Rate	$/kW	6.4691
Regulatory Asset Recovery	$/kW	(0.3256)
Retail Transmission Rate – Network Service Rate	$/kW	1.4565
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3790
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

With RPP and RTSR updates

Monthly Rates and Charges

		Effective May 1/09
Specific Service Charges		
Income tax letter	$	15.00
Returned Cheque charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge / change of occupancy charge	$	10.00
Late Payment - per month	%	1.50
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Retailer Service Agreement -- monthly fixed charge (per retailer)	$	20.00
Retailer Service Agreement -- monthly variable charge (per customer)	$	0.50
Distributor-Consolidated Billing -- monthly charge (per customer)	$	0.30
Retailer-Consolidated Billing -- monthly credit (per customer)	$	(0.30)
Service Transaction Request -- request fee (per request)	$	0.25
Service Transaction Request -- processing fee (per processed request)	$	0.50
Interval Meter Load Management Tool	$	50.00
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)
LOSS FACTORS		
Secondary Metered Customer < 5000 kW		1.0356
Secondary Metered Customer > 5000 kW		1.0145
Primary Metered Customer < 5000 kW		1.0253
Primary Metered Customer > 5000 kW		1.0045