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January 29, 2009

VIA MAIL and E-MAIL

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

Dear Ms. Walli:

RE: Lakeland Power Distribution Ltd.
EB-2008-0234
2009 Electricity Distribution Rate Application
Responses to VECC Supplemental Interrogatories

Please find enclosed the response to the supplemental interrogatories of the Vulnerable Energy Consumers Coalition (VECC) in the above-noted proceeding.

Respectfully submitted,

Margaret Maw

Margaret Maw
CFO
Lakeland Holding Ltd.

Lakeland Power Distribution Ltd. (LPD)

2009 Electricity Rate Application

Board File No. EB-2008-0234

VECC's Interrogatories – Round #2

Responses to VECC Supplemental Interrogatories
By Lakeland Power Distribution Ltd.
January 29, 2009

Question #1

Reference: VECC #4 a)

a) Please provide the actual results (i.e., the estimated equation and R2 values) for the revised regression analysis.

The estimating equation is as follows

Lakeland Monthly Predicted kWh Purchases
= Heating Degree Days * 9,301
+ Cooling Degree Days *25,232
+ Ontario Real GDP Monthly Index * (92,598)
+ Number of Peak Hours * (3,595)
+ Number of Days in Month *645,917
+ Residential and GS<50 Customers * 4,576
+ GS>50-999 Customers * 8,104
+ GS>1000-4999 Customers * 0
+ Spring Fall Flag * (1,151,818)
+ Blackout Flag * (1,228,589)
+ Constant of (31,086,571)

The R square value is 91.0% and the Adjusted R Square is 88.5%

Question #2

Reference: VECC #4 b)

a) The response suggests that OEB #22 provided a revised load forecast using an updated economic outlook. However, OEB #22 makes no reference to using a different economic outlook – it only references the use of different definitions of "weather normal". Also, the response to VECC #4 b) makes reference to a "following table" which has not been provided. Please address these discrepancies and provide a response to the original IR.

The referenced table was inadvertently not included in the original response. The table has been provided below. This table is the forecast referenced in the Preamble under the title of Load Forecasting in the responses to OEB staff interrogatories but revised to assume a real Ontario GDP of 0.1 % for 2008 and 0.7% for 2008 based on the Ontario Ministry of Finance 2008 Ontario Economic Outlook and Fiscal Review dated October 22, 2008.

	2008 Weather Normal	2009 Weather Normal
Actual kWh Purchases		
Predicted kWh Purchases	234,300,864	237,301,466
% Difference		
Billed kWh	228,115,651	231,037,042
By Class		
Residential		
Customers	7,498	7,562
kWh	85,755,986	89,739,657
General Service < 50 kW		
Customers	1,538	1,549
kWh	49,049,078	50,745,067
General Service > 50 to 999 kW		
Customers	91	91
kWh	54,078,166	51,526,070
kW	140,372	133,747
General Service > 1000 to 4999 kW		
Customers	6	6
kWh	36,948,556	36,727,786
kW	78,019	77,552
Streetlights		
Connections	7	7
kWh	1,986,637	2,007,912
kW	5,280	5,336
Sentinel Lights		
Connections	43	42
kWh	41,641	41,511
kW	116	115
Unmetered Loads		
Connections	48	45
kWh	255,587	249,040
Total		
Customer/Connections	9,231	9,303
kWh	228,115,651	231,037,042
kW from applicable classes	223,786	216,751

<u>Question #3</u>

Reference: VECC #4 g)

a) Please explain how the data provided supports the contention that 100% of Residential and GS<50 loads are weather sensitive.

The data shows that GS > 50 customers have a certain percentage of load that is weather sensitive and non-weather sensitive. The data also shows that for Street Lighting and Sentinel lighting the total actual weather amounts and the total normalized amounts are the same which suggest they are not weather sensitive. The data shows the classes that are partially weather sensitive and those that are 100% non-weather sensitive but the Residential and GS<50 loads did not fall into these two categories. As a result, Lakeland concluded that Residential and GS<50 loads are 100% weather sensitive. If these classes were partially weather sensitive then Hydro One would have provided similar information as was provided for the GS > 50 customers.

<u>Question #4</u>

Reference: VECC #4 h)

a) Please reconcile the 11,508 kWh value for residential with the following values taken from Sheet I6 of Lakeland's Cost Allocation Run:
   - Residential Weather Normalized Load – 88,474,021 kWh
   - Residential Customers - 7300
   - Loss Factor – 1.0428
   - ➔ Average Retail Use of 11,622 kWh

In preparing the response to this interrogatory it has come to Lakeland attention that incorrect data was provided in the original response. The correct Retail NAC (i.e. kWh/annual) by customer class calculated based on the Hydro One weather normalized 2004 data for those classes that are weather sensitive is as follows.

Residential	General Service < 50 kW	General Service > 50 to 999 kW
11,782	33,412	1,012,142

During the preparation of the cost allocation study, Lakeland provided rate class information to Hydro One at the wholesale level in order for Hydro One to prepare wholesale 2004 weather normalized data needed in the cost

allocation study. The wholesale level rate class data was determined by applying an adjustment factor to the actual 2004 billed retail rate class data. Hydro One also required that the total of wholesale level rate class information was to be made equal to total energy purchased by Lakeland in 2004. In the case of Lakeland, the adjustment factor reflected losses and other adjustments to ensure the rate class wholesale amounts totaled the wholesale purchases. For the Residential class this adjustment factor was 2.86%. As a result,

- **Residential Weather Normalized Load – 88,474,021 kWh**
- **Residential Customers - 7300**
- **Adjustment Factor – 1.0286**

➔ **Average Retail Use of 11,782 kWh**

Question #5

Reference: VECC #4 i)

a) Please confirm if the values set out in Table 6 (Exhibit 3/Tab 2/Schedule 2) are year end customer counts.

Confirmed, this is correct.

b) The October 2008 customer counts for Residential, GS<50 and GS>50 reported in this response are all more than the 2008 forecast values in the Application and some are even more than the forecast 2009 values. Does Lakeland propose to revise its customer count forecast for 2009? If not, why not?

As per response to OEB 25 a) Lakeland believes the lost factor used in the load forecasting model should have been 6.14%. If a loss factor of 6.14% was used in the load forecast the 2009 total billed kWh load forecast would decline from 225,921,346 kWh to 218,623,574 kWh.. If a revised customer count forecast was used the 218,623,574 kWh would slightly increase but not higher than 225,921,346 kWh. However, as a rate mitigation strategy, Lakeland is proposing to maintain the load forecast of 225,921,346 kWh and the 2009 customer count forecast in the Application.

Question #6

Reference: VECC #7 c)

a) As per the original question, please provide Sheet O6 of the revised Cost Allocation run. Also, please confirm that the total revenue requirement in the revised run is $4,134,339 (per VECC #6 c)) and, if not, reconcile.

2006 COST ALLOCATION INFORMATION FILING

Lakeland Power Distribution Ltd.

EB-2005-0388 EB-2006-0247

January 15, 2007

Sheet O1 Revenue to Cost Summary Worksheet - Second Run

Class Revenue, Cost Analysis, and Return on Rate Base

Adjusted Transformer Allowance

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
crev	Distribution Revenue (sale)	$3,865,824	$2,097,742	$852,652	$865,500	$33,395	$1,133	$15,402
mi	Miscellaneous Revenue (mi)	$325,141	$185,463	$79,559	$48,454	$7,826	$204	$3,635
	Total Revenue	$4,190,965	$2,283,205	$932,211	$913,954	$41,221	$1,337	$19,037
	Expenses							
di	Distribution Costs (di)	$660,050	$350,428	$147,354	$88,151	$70,259	$1,502	$2,356
cu	Customer Related Costs (cu)	$666,773	$435,992	$168,085	$48,300	$283	$178	$13,936
ad	General and Administration (ad)	$637,624	$375,789	$151,314	$68,024	$34,149	$809	$7,538
dep	Depreciation and Amortization (dep)	$778,314	$405,114	$177,759	$143,606	$49,095	$1,050	$1,689
INPUT	PILs (INPUT)	$346,148	$178,947	$78,983	$66,001	$21,048	$450	$718
INT	Interest	$342,436	$177,028	$78,136	$65,294	$20,822	$446	$710
	Total Expenses	$3,431,345	$1,923,297	$801,631	$479,377	$195,657	$4,435	$26,947
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$702,994	$363,425	$160,407	$134,043	$42,747	$915	$1,458
	Revenue Requirement (includes NI)	$4,134,339	$2,286,722	$962,038	$613,420	$238,404	$5,350	$28,405
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$15,885,617	$8,246,497	$3,624,665	$2,966,407	$993,090	$21,245	$33,714
gp	General Plant - Gross	$1,480,882	$768,153	$337,896	$277,344	$92,368	$1,976	$3,145
accum dep	Accumulated Depreciation	($3,313,079)	($1,724,957)	($755,960)	($611,785)	($208,897)	($4,467)	($7,012)
co	Capital Contribution	($1,070,494)	($576,226)	($244,203)	($159,806)	($85,561)	($1,829)	($2,869)
	Total Net Plant	$12,982,927	$6,713,466	$2,962,398	$2,472,161	$790,999	$16,925	$26,978
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$14,974,633	$5,617,500	$3,288,498	$5,920,060	$125,777	$2,743	$20,055
	OM&A Expenses	$1,964,447	$1,162,209	$466,753	$204,475	$104,691	$2,489	$23,830
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$16,939,080*	*$6,779,709*	*$3,755,251*	*$6,124,536*	*$230,468*	*$5,231*	*$43,886*
	Working Capital	$2,540,862	$1,016,956	$563,288	$918,680	$34,570	$785	$6,583
	Total Rate Base	$15,523,789	$7,730,422	$3,525,686	$3,390,841	$825,569	$17,710	$33,560
		Rate Base Input equals Output						
	Equity Component of Rate Base	$7,761,894	$3,865,211	$1,762,843	$1,695,421	$412,785	$8,855	$16,780
	Net Income on Allocated Assets	$759,620	$359,908	$130,579	$434,577	($154,436)	($3,098)	($7,910)
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
	Net Income	$759,620	$359,908	$130,579	$434,577	($154,436)	($3,098)	($7,910)
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES %	101.37%	99.85%	96.90%	148.99%	17.29%	24.99%	67.02%
	EXISTING REVENUE MINUS ALLOCATED COSTS	$56,626	($3,517)	($29,827)	$300,535	($197,183)	($4,013)	($9,368)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.79%	9.31%	7.41%	25.63%	-37.41%	-34.99%	-47.14%

Question #7

Reference: VECC # 9 a)

a) The intent of the original question was to obtain the derivation of the current fixed/variable split percentages set out in the Table. i.e., how was it determined that 60.1% was the fixed portion of residential revenues based on current rates? Please provide.

Using 2009 Forecasted data and 2008 Rates, a determination of Distribution revenue was made into the fixed and variable components. For example, residential

Annual number of monthly charges	**7,562*12 = 90,744**
2008 Monthly Distribution charge	**$14.61 ($14.86 - $.25 SM)**
Total fixed distribution revenue	**$1,325,770**
Annual consumption	**87,027,546**
2008 Variable Distribution charge	**$.0101 ($.0131 - .0030 LV)**
Total variable distribution charge	**$ 878,978**

Fixed Percentage $1,325,770/($1,325,770+$878,978) = 60.1%

Question #8

Reference: OEB Staff #25 a)

a) What is the basis for the 1.048 adjustment factor used to derive the revised actual billed loads for each year?

1.0428 is the loss factor Lakeland has used to bill its customers with since market opening.

b) Please reconcile the values for both total retail billed loads and purchases as reported in Appendix A of Exhibit 3/Tab 2/Schedule 2 with those reported in Exhibit 4/Tab 2/Schedule 9, page 1.

The actual purchases in Exhibit 4/Tab 2/Schedule 9, page 1 exclude Supply Facilities Losses and the purchases in Appendix A of Exhibit 3/Tab 2/Schedule 2 include Supply Facilities Losses. The actual purchases in Exhibit 4/Tab 2/Schedule 9, page 2 are equal to the purchases in Appendix A of Exhibit 3/Tab 2/Schedule 2.

The actual retail billed amount in Exhibit 4/Tab 2/Schedule 9, page 1 excludes the 1.0428 losses referenced in response to OEB #25 a) and the actual retail billed amount in Appendix A of Exhibit 3/Tab 2/Schedule 2 includes these losses.

c) Are the actual historical billed and purchased kWhs different from what are set out in Appendix A of Exhibit 3/Tab 2/Schedule 2?

- If the purchased values are different, do the equations used in load forecast need to be re-estimated?
- Does this mean that the historical average use values for each customer class as set out in Table 9 and used to project average use for 2008 and 2009 need to be revised?

The purchases values used in the regression model to determine the prediction equation reflects the values that the IESO charges Lakeland for commodity which means they are the correct values. With regards to the historical average use values, as per response to VECC #5 above Lakeland understands that they are not correct but if these values were corrected other elements of the forecast would also need to be corrected which would produce a lower forecast. As a rate mitigation strategy, Lakeland is proposing to maintain the load forecast outlined in the Application.

<u>Question #9</u>

Reference: OEB Staff #33

a) The revised 2008 Rate Schedule still does not reconcile with the 2008 rates used for the impact calculations in Exhibit 9/Tab 2/Schedule 9, Attachment A. Please confirm that the impact calculations did not have included either the 2008 or 2009 the smart meter rate adders.

The Bill impact calculation split the monthly Service charge into distribution and smart meter rider. For example;

2008 Tariff Sheet	**Residential Service Charge**	**$14.86 per month**
Bill Impact schedule		
	Monthly Service Charge	**$14.61**
	Smart Meter Rider (separate line item)	**$ .25**
	Total	**$14.86**

Question #10

Reference: OEB #36

a) Is Lakeland now proposing any adjustments to its current Retail Transmission Service Rates?
- If yes, what are the new rates and how were they determined?
- If not, why not?

After completing OEB #36, Lakeland is proposing an adjustment to its current RTSR. In order to determine the new rates, two years of historical data (2006 and 2007) of amounts billed to customers by month was used to determine the % split by class of the charges. The actual charges from Hydro One were recalculated using their new rates (2.01 for Network and 1.88 for Connection). The total revised dollars where then prorated to the classes based on the historical data. These allocated amounts were then divided by the number of billing units (kWh or kW depending on class) adjusted by 1.0614/1.0428 (proposed new loss factor), to determine the rate.

	Per unit	At 2.01/ kW Network Rate	At 1.88 /kW Connection Rate
Residential	**kWh**	**.0041**	**.0038**
GS <50 kW	**kWh**	**.0038**	**.0034**
GS >50 kW	**kW**	**1.6259**	**1.4489**
Streetlight	**kW**	**1.1842**	**1.0576**
Sentinel	**kWh**	**.0033**	**.0030**
USL	**kWh**	**.0038**	**.0034**

b) Please comment on whether the following interpretation of the response to OEB #36 part (d) is correct:
- Does 35.13% represent estimated amount by which customers would over pay Network charges in 2009 assuming no change in either Hydro One's or Lakeland's current retail transmission rates?

The 35.13% represents the estimated amount by which customers would over pay Network charges if only Hydro One's rate were changed to the current lower rates of $2.01, for the entire two years.

- Assuming HON's retail transmission network rates increase by the 11.3% approved for January 1, 2009, then a reduction of roughly 17.6% (i.e., 1.113/1.3513) would balance Lakeland's transmission network charges and revenues.

See proposed rates in part a) based on the interim rates (now approved).

<u>Question #11</u>

Reference: VECC #12 c)

Preamble: The original IR asked for "the impact on the revenue requirement of pursuing a 5-year tree trimming program rather than the 7-year program chosen by LPDL."

Lakeland's response was "The shorter the program becomes, the lower the costs per kilometer will be as the size of the trees will be smaller and more manageable. It would also help the trouble call costs to be reduced sooner. The differential in cost in the first five years of the program would be an increase of approximately $50K."

a) Please provide details with respect to how the increase of approximately $50K in the first five years was estimated.

LLP has approximately 246km of overhead conductor. This distribution network was broken into seven zones originally, where the number of km trimmed each year varied between ~30km and 42km. The average value to trim a km of line is approximately $3300, this varies whether the circuit lies along a roadway, goes through dense bush and requires off road machinery or manual labour, or is on an island surrounded by water where machinery or equipment needs to be barged in. To give the rough number of $50k, we took the total of 246km and divided by 5 = 49.2km/year then multiplied by $3300 = $162,360. Again these are average rates and do not reflect changing in fuel prices or labour rates.

b) Please provide the revenue requirement impact in the test year of moving to a five-year cycle rather than the seven-year cycle proposed.

LPDL cannot move to a 5 year cycle irrespective of the costs due to the lack of resources both internally as well as externally to manage the program.

c) Please clarify whether the $50K increase in cost over the first five years of moving to a five-year tree trimming program is an annual cost or the cumulative cost over five years.

This would be an annual increase for the first 5 years.

d) Please clarify whether the $50K increase in cost refer simply to the incremental trimming costs of moving to the shorter cycle or whether they also reflect the benefits in savings that would be realized due to "lower costs per kilometer … as the size of the trees will be smaller and more manageable. It would also help the trouble call costs to be reduced sooner."

The benefits would not be seen in the next five years. It is likely that it will reduce trouble call costs, however this would have to be determined during the implementation of the plan. The statement "lower cost per kilometer… " is more of a logical derivative and has not been analyzed any further than that.

e) Has Lakeland done a present value calculation of the net benefits in moving to a five-year cycle? If so, please provide the calculation and include all of the assumptions. If not, please indicate why not.

Moving to a five year cycle could potentially benefit the consumers by reduced outages over time. However the actual cost of implementation may actually exceed the $50 K.   As with any tree trimming project, the staff time to manage the project and respond to customers questions will also increase by approximately 30%. These values have not been calculated at this time. The seven year cycle is a manageable target.

Question #12

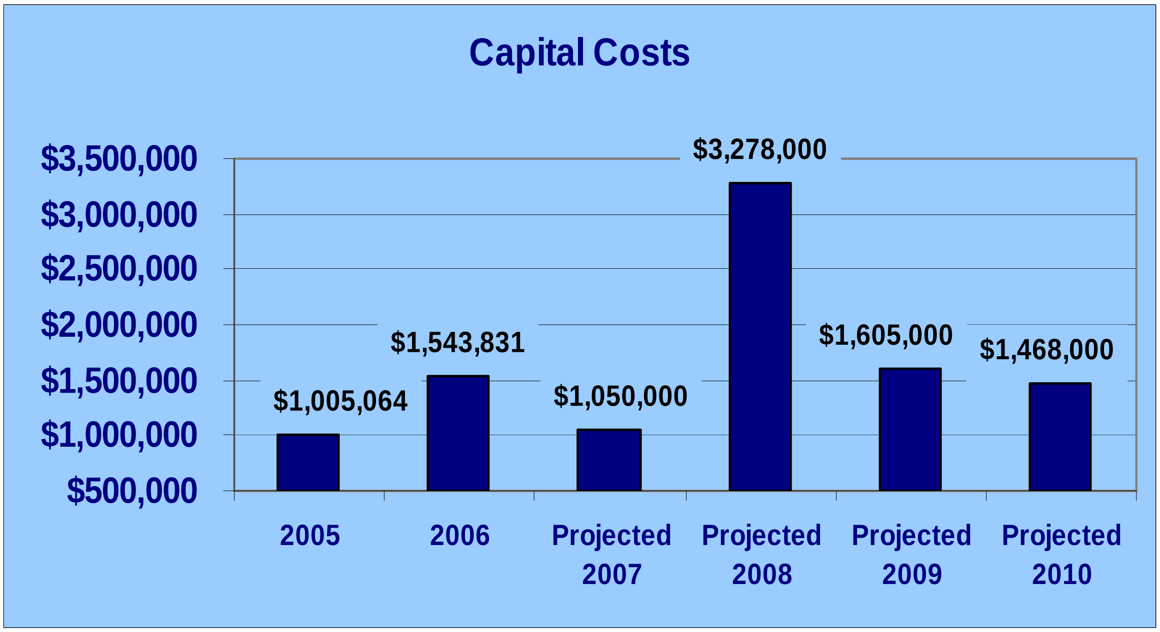
Reference: VECC #13 a)

Preamble: The original IR asked "whether the capital budget forecast is a three-year capital budget that is updated annually resulting in successive three-year overlapping plans (2006-08, 2007-09, etc.) If so, please provide a copy of the latest three-year budget and provide a copy of the previous three year budget."

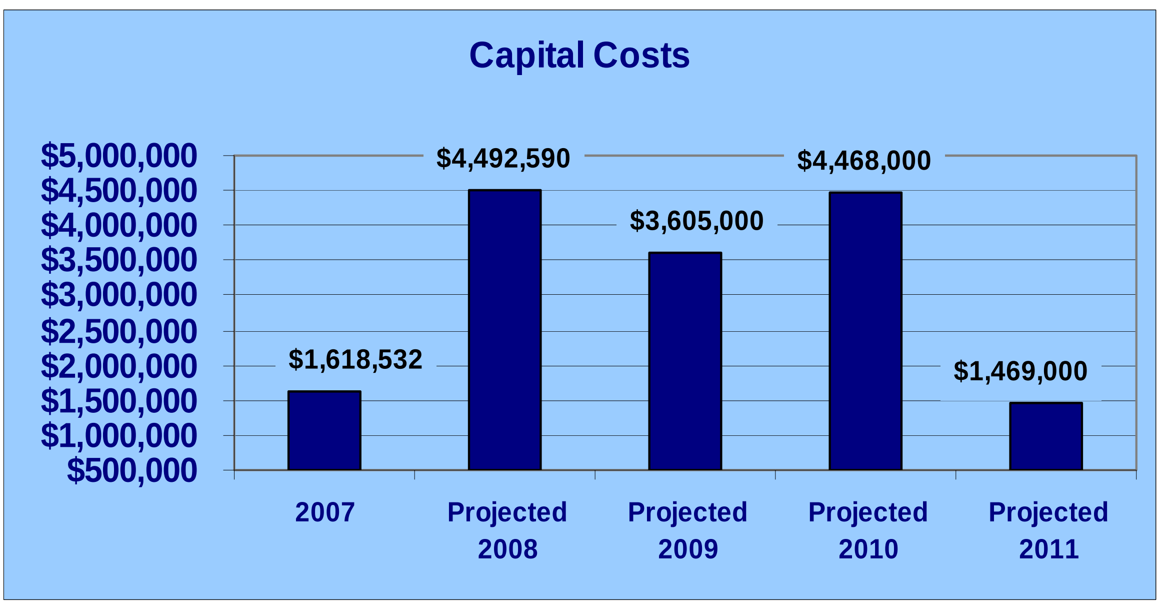
The response provided – in full – was "Lakeland's three year business plan includes a capital component and is included at Exhibit 1/Tab 3/Schedule 5/Appendix A." VECC notes that the referred material is Lakeland's Annual Report.

a) Please provide a complete response to the original IR.

This is the extent of detail to which our three year plan is presented. LPDL does not do a detailed three year budget but rather a forecast using base line spending plus known larger projects such as Smart Meters and stations.



Projected 2008-2010 Capital Costs are increased due to the implementation of Smart Meters as well as distribution system upgrades to make better use of the company's distribution stations.



Lakeland Power's projected 2008 Capital Costs are increased due to the start of Smart Meter implementation $3M, continuing through 2010 as well as two substations $1M, and a transmission station $3M.

Question #13

Reference: VECC #18 a)

a) Please provide an update with respect to the amount spent on the 10 MVA station to date, contributed capital, and when the station is expected to be in-service.

The current estimate on the final cost of the substation and subdivision is $2.3M with a contributed capital of $1.4 M leaving an LDC asset of $879 K versus the $500 K in the original application. Expected energization date is June 2009. Amounts spent to date are $323 K.