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December 18, 2008

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 Board Staff Interrogatories

Please find enclosed the response to the interrogatories of Ontario Energy Board Staff in the above-noted proceeding.

Respectfully submitted,

Margaret Maw
CFO
Lakeland Holding Ltd.

Board Staff Interrogatories
2009 Electricity Distribution Rates
Lakeland Power Distribution Ltd. ("Lakeland")
EB-2008-0234
Responses to Board Staff Interrogatories
By Lakeland Power Distribution Ltd.
December 18, 2008

Economic Assumptions

1. Ref: n/a

a) Given the general economic situation in Ontario, has Lakeland 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?

Lakeland has assessed the given economic situation working with both the Town of Bracebridge as well as the District of Muskoka. Although we feel there is likely an impact, at this time the order of magnitude is too uncertain to measure.

b) If so, please indicate if Lakeland will be updating its current application, in whole or in part, to address any material impacts. If yes, please provide an estimate of the timing of the update.

Lakeland does not anticipate updating its current application

2. Ref: Exh2/Tab3/Sch2

a) Please provide a list of criteria and the rationale that Lakeland has used in the prioritization and selection of 2009 maintenance and capital projects in its application.

Lakeland uses a number of different criteria for determining which projects will be undertaken within a year.

1. **Line crews/Engineering technicans identify areas of high volume trouble calls and where repeated maintenance has been performed (aging assets). Also through documented visual inspection and GIS system updates (colouring system – red areas), Lakeland is able to determine the specific areas of concern.**
2. **For vehicles, truck hours and increasing maintenance costs will determine the timing of change out**
3. **For customer demand items, it is specifically initiated by developers**
4. **In general terms, an overall look at the areas of highest vulnerability to the system (ie greatest number of customers that would lose power if a device fails) is made along with financial constraints to determine the prioritization of projects.**

The list identified in the rate application is only a subset of the identified areas that require capital. Time and resources preclude doing more than those listed in the application in any one year.

b) Please identify, individually, maintenance and capital programs, if any, that Lakeland may consider as a candidate for a deferral, cut, or partial adjustment, given the current economic situation. Please identify these programs, if any, in a ranking order that Lakeland would consider, using a ranking of "1" as the first suitable candidate, ranking of "2" as the second suitable candidate, ranking of "3" as the third suitable candidate, etc.

Lakeland has been under a period of general growth for the past few years that has resulted in expansion to our system through capital contributions. Due to our small number of line staff, they have been unable to attend to many of the capital projects that are required to keep the distribution system up to date. We are now approaching a critical time in many areas and need to start investing back into the system. The cutting of any capital investment in aging asset replacement, will only result in higher maintenance costs. Lakeland has not been investing at the rate of depreciation and needs to start reinvesting in the system.

The original list indicated a replacement bucket truck for a 2002 of $165 K, this will actually now be replaced next week (Dec 2008). The timing of the replacement needed to be moved up due to engine and boom failure.

Lakeland will not be revising the rate application to account for the increase in amortization for 2009 as it does not believe it to be a material item.

Priority List

1. Pickup truck replacement – can be deferred to 2010 $45 K

c) Please identify the rationale for the selection of these maintenance and capital programs and projects.

The replacement was of a 2004 pickup which can likely be deferred another year.

d) Please describe the expected impacts on Lakeland's revenue requirement, operations and service quality and reliability to customers if the identified programs are reduced, deferred or cut during the economic downturn.

Lakeland does not feel this deferred item would have a material impact on the business.

Operating Costs

3. Ref: Exh5/Tab1/Sch2/p1; Exh4/Tab2/Sch2/p1

For 2007, Lakeland reports:

1. $551,855 debit in USoA (consisting of $54,823 principal and $497,032 of interest) account 1590 in Exh5/Tab1/Sch2
2. $238,350 debit in USoA account 5130 in Exh4/Tab2/Sch2.

For each of the accounts above please provide the following:

a) State the amount reported to the Board in Lakeland's 2007 annual filing pursuant to RRR 2.1.7 for each USoA account.

RRR Filing

Account 1590	**$685,595.59**	
Principal		**$189,374.71**
Interest		**$496,220.88**
Account 5130	**$ 27,613.05**	

b) Identify the components of any difference between the amounts in a) and the amount reported in exhibits 5 and 4.

Account 1590 – see revised table below

Account 5130 - $27,613.05 plus $210,737 for a total $238,350

$210,737 relates to the Storm costs incurred in 2006 (Account 5130) but reversed out in 2007 to Account 1572 as per OEB decision. The amounts were corrected into the proper years for the purposes of the rate application in order to remove the timing difference.

c) Explain each component of any difference identified in b). Please include an explanation of which other accounts now contain any such difference by component.

Account 1572 contains the amount of $210,727 and is being recovered over a one year period

d) State which amount (the amount in a) above or the amount in exhibits 5 and 4 has been reflected in Lakeland's 2007 audited financial statements and identify the line item in the audited financial statements.

Account 1590 balance of $685,595.59 is reflected in the line item Regulatory assets on page 3 (Balance sheet)

Account 5130 amount of $27,613.05 is reflected on the line item Distribution on page 4 (Statement of Operations). In Schedule 1 it is reflected as $(217,468) in Storm damage costs and $245,081 in Maintenance. The difference between $217,468 and $210,737 is the amount disallowed in the OEB decision and thus remained in Account 5130 once the entry was made in 2007.

e) State which value should be relied upon in this proceeding, and, if different from the value reported in the 2007 audited financial statements, explain why the Board should rely on such different value.

The values regarding Account 5130 are the same in all filings, application and audited financial statements, just presented from different perspectives.

For Account 1590, LPDL inadvertently used the current 2008 balances as the Dec 07 closing balances. A revised schedule is below. The RRR filing and the audited statements utilize the same amount and this account has no impact in the rate application as LPDL is not requesting disposition of any Regulatory Asset accounts at this time.

Regulatory Assets - Continuity Schedule

Regulatory Assets - Continuity Schedule		2006 EDR		2006 EDR Storm Costs		2006 EDR		2006 EDR	
Account Description	**Account Number**	**Opening Principal Amounts as of Jan-1-05**	**Transactions during period excluding interest and adjustments**	**Adjustments during period - instructed by Board**	**Closing Principal Balance as of Dec-31-07**	**Opening Interest Amounts as of Jan-1-05**	**Interest Jan-1-05 to Dec31-07**	**Adjustments during period - instructed by Board**	**Closing Interest Amounts as of Dec-31-07**
RSVA - Wholesale Market Service Charge	1580	$ 182,054	$ (174,371)	$ (187,056)	$ (179,373)	$ 29,598	$ 13,925	$ (48,216)	$ (4,694)
RSVA - One-time Wholesale Market Service	1582	$ 33,260	$ 10,297	$ (43,555)	$ 2	$ 4,759	$ 922	$ (5,680)	$ 0
RSVA - Retail Transmission Network Charge	1584	$ (201,735)	$ (618,986)	$ 321,340	$ (499,381)	$ (9,634)	$ (55,826)	$ 33,241	$ (32,219)
RSVA - Retail Transmission Connection Charge	1586	$ 24,350	$ 1,512,708	$ (2,080,523)	$ (543,465)	$ 18,155	$ 41,030	$ (94,431)	$ (35,247)
RSVA - Power	1588	$ 97,694	$ 1,189,529	$ (97,694)	$ 1,189,529	$ (7,831)	$ 126,450	$ (1,613)	$ 117,006
RSVA - Power - Sub account Global Adjustment(incl above)	1588	$ -	$ 280,260		$ 280,260		$ 5,249		$ 5,249
	Sub-Totals	$ 135,623	$ 2,199,437	$ (2,087,488)	$ 247,572	$ 35,046	$ 131,749	$ (116,699)	$ 50,096
Other Regulatory Assets - Sub - Other	1508	$ 13,567	$ 62,950	$ (76,517)	$ -	$ 1,901	$ 1,311	$ (3,212)	$ -
Other Regulatory Assets - Sub - OEB Cost Assessments	1508	$ 17,267	$ 33,894	$ (17,267)	$ 33,894	$ 207	$ 4,700	$ (1,531)	$ 3,376
Other Regulatory Assets - Sub - Pension Contributions	1508		$ 91,943		$ 91,943		$ 9,457		$ 9,457
Retail Cost Variance Account - Retail	1518	$ (30,304)	$ (45,108)	$ 30,304	$ (45,108)	$ (2,638)	$ (5,941)	$ 5,567	$ (3,012)
Retail Cost Variance Account - STR	1548	$ 81,338	$ 69,638	$ (81,338)	$ 69,638	$ 7,524	$ 12,600	$ (15,387)	$ 4,737
Misc. Deferred Debits	1525	$ 659	$ 32,646	$ (33,305)	$ -	$ -	$ 2,616	$ (2,616)	$ -
LV Variance Account	1550		$ (28,766)		$ (28,766)	$ -	$ (698)		$ (698)
Smart Meter - Sub-Account - Capital	1555		$ 41,990		$ 41,990		$ -		$ -
Smart Meter - Sub-Account - Recoveries	1555		$ (42,881)		$ (42,881)		$ (877)		$ (877)
Smart Meter - Sub-Account - Stranded Meter Costs	1555		$ -		$ -		$ -		$ -
Smart Meter OM&A Variance	1556		$ -		$ -		$ -		$ -
Deferred Payments in Lieu of Taxes	1562	$ (135,475)	$ (262,898)		$ (398,373)	$ 13,793	$ (60,204)		$ (46,411)
Deferred Payments in Lieu of Taxes - Contra	1563	$ 135,475	$ 262,898		$ 398,373	$ (13,793)	$ 60,204		$ 46,411
CDM Expenditures and Recoveries	1565		$ (16,359)		$ (16,359)		$ -		$ -
CDM Contra	1566		$ 16,359		$ 16,359		$ -		$ -
Qualifying Transition Costs	1570	$ 409,694	$ (40,865)	$ (368,829)	$ -		$ 104,473	$ (104,473)	$ -
Pre-Market Opening Energy Variances Total	1571	$ 841,109	n/a	$ (841,109)	$ -		$ -	$ (238,203)	$ -
Extra-Ordinary Event Costs - Storm Costs/Recovery	1572	$ -	$ (50,209)	$ 210,737	$ 160,528		$ -		$ -
PILs & Taxes Variance	1592		$ -		$ -		$ -		$ -
Regulatory Asset Recovery	1590	$ (320,427)	$ (2,965,748)	$ 3,475,549	$ 189,375	$ (6,760)	$ 26,427	$ 476,554	$ 496,221
	Sub-Totals	$ 1,012,903	$ (2,840,516)	$ 2,298,225	$ 470,612	$ 234	$ 154,067	$ 116,699	$ 509,203
	Totals	**$ 1,148,526**	**$ (641,079)**	**$ 210,737**	**$ 718,184**	**$ 35,280**	**$ 285,816**	**$ -**	**$ 559,299**

Trend Analysis of the Composition of Account 1590 – the interest related to the accounts to be disposed of (2006 EDR), were posted separately but as the recovery was collected, it was posted to the base account. The amounts of $(1,012,095) in 2006 and $(1,343,501) in 2007 could have been posted as a split number between principal and interest recovery. In any event, the balance would still be the same.

		2005						2006							2007					
Account Description	Account Number	Opening Principal Amounts as of Jan-1-05	Transactions (additions) during 2005, excluding interest and adjustments	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	Transfer of Board-approved amounts to 1590 as per 2006 EDR	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	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	Total Balance
Reg. Asset Recovery to March 2005	1590	$(320,427)	$ (202,012)	$(522,439)	$ (6,760)	$(34,899)	$(41,659)	$(522,439)			$ (522,439)	$(41,659)	$(28,220)		$ (69,879)	$ (522,439)		$ (522,439)	$ (69,879)	$ (24,698)	$ (94,578)	$ (617,016)
to April 2005 to April 2006	1590	$ -	$ (408,085)	$(408,085)	$ -	$ (8,561)	$ (8,561)	$(408,085)	$ (249,367)		$ (657,452)	$ (8,561)	$(31,430)		$ (39,991)	$ (657,452)		$ (657,452)	$ (39,991)	$ (31,081)	$ (71,072)	$ (728,524)
to May 2006 to December 2007	1590	$ -		$ -	$ -		$ -	$ -	$ (762,728)		$ (762,728)	$ -	$ (9,403)		$ (9,403)	$ (762,728)	$(1,343,501)	$(2,106,229)	$ (9,403)	$ (67,689)	$ (77,091)	$(2,183,320)
Balances as per 2006 EDR (May 2006)	1590	$ -		$ -	$ -		$ -	$ -		$3,475,494	$3,475,494	$ -	$ 98,049	$476,609	$574,658	$3,475,494		$ 3,475,494	$574,658	$164,304	$738,962	$ 4,214,456
Grand Total	**1590**	**$(320,427)**	**$ (610,097)**	**$(930,524)**	**$ (6,760)**	**$(43,460)**	**$(50,220)**	**$(930,524)**	**$(1,012,095)**	**$3,475,494**	**$1,532,876**	**$(50,220)**	**$ 28,997**	**$476,609**	**$455,385**	**$1,532,876**	**$(1,343,501)**	**$ 189,375**	**$455,385**	**$ 40,836**	**$496,221**	**$ 685,596**

4. Ref: Exh4/Tab1/Sch1

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

Table 1

		Col. 1	*Col. 2*	*Col. 3*
		2003	**2004**	**2005**
1	**Operation**	77,558	94,206	172,643
2	**Maintenance**	650,311	621,624	687,495
3	**Billing and Collection**	525,057	600,723	568,262
4	**Community Relations**	25,401	28,599	43,532
5	**Administrative and General Expenses**	769,255	557,983	475,782
6	**Total OM&A Expenses**	2,047,582	1,903,135	1,947,713

a) Please confirm Lakeland's agreement with the numbers for Total OM&A Expenses that are summarized in Table 1.

As explained in the rate application, LPDL's auditors required a write off of Regulatory asset balances in 2001/2002 as the likelihood of recovery was unknown at the time, $900 K. In 2004 to 2006, this was written back on as it was now known that recovery was imminent in the 2006 EDR. Lakeland would like to submit the following revised table.

Table 1 Revised

		Col. 1	*Col. 2*	*Col. 3*
		2003	**2004**	**2005**
1	**Operation**	77,558	94,206	172,643
2	**Maintenance**	650,311	621,624	687,495
3	**Billing and Collection**	525,057	600,723	568,262
4	**Community Relations**	25,401	28,599	43,532
5	**Administrative and General Expenses**	769,255	557,983	475,782
6	**Total OM&A Expenses**	2,047,582	1,903,135	1,947,713
7	**Addback of prior W/O Incl in Acct 5665**	0	266,000	266,000
8	**Acct 5660 not included??**	13,836	13,278	8,222
9	**True OM&A Expenses**	2,061,418	2,182,413	2,221,935

Board staff prepared Table 2 below to review Lakeland's OM&A expenses. Note rounding differences may occur, but are immaterial to the questions below.

Table 2

		Col. 1 2006 Bd Appr.	Col. 2 2006 Actual	Col. 3 2007	Col. 4 2008 Bridge	Col. 5 2009
1	**Operation**	$94,205	$262,589	$197,461	$223,773	$223,674
2	**Maintenance**	$621,624	$529,040	$593,016	$835,279	$927,043
3	**Billing and Collection**	$610,994	$652,753	$606,167	$647,111	$655,137
4	**Community Relations**	$15,320	$27,365	$17,610	$8,467	$11,255
5	**Administrative and General Expenses**	$1,268,289	$1,021,904	$898,023	$988,152	$1,036,938
6	**Total**	2,610,432	2,493,651	2,312,277	2,702,782	2,854,047

Board Staff Table 3 below was created to review Lakeland's OM&A forecast expenses from the evidence provided in Exhibit 4. Note rounding differences may occur, but are immaterial to the following questions.

Table 3

Lakeland Power Distribution Ltd.

		Col. 1 2006 Board Approved	Col. 2 Variance 2006/2006	Col. 3 2006 Actual	Col. 4 Variance 2007/2006	Col. 5 2007 Actual	Col. 6 Variance 2008/2007	Col. 7 2008 Bridge	Col. 8 Variance 2009/2008	Col. 9 2009 Test	Col. 11 Variance 2009/2006
1	**Operation**	94,205	168,384	262,589	-65,128	197,461	26,312	223,773	-99	223,674	-38,915
2			*178.7%*		*-24.8%*		*13.3%*		*0.0%*		***-14.8%***
3	**Maintenance**	621,624	-92,584	529,040	63,976	593,016	242,263	835,279	91,764	927,043	398,003
4			*-14.9%*		*12.1%*		*40.9%*		*11.0%*		***75.2%***
5	**Billing & Collections**	610,994	41,759	652,753	-46,586	606,167	40,944	647,111	8,026	655,137	2,384
6			*6.8%*		*-7.1%*		*6.8%*		*1.2%*		***0.4%***
7	**Community Relations**	15,320	12,045	27,365	-9,755	17,610	-9,143	8,467	2,788	11,255	-16,110
8			*78.6%*		*-35.6%*		*-51.9%*		*32.9%*		***-58.9%***
9	**Administrative and General Expenses**	1,268,289	-246,385	1,021,904	-123,881	898,023	90,129	988,152	48,786	1,036,938	15,034
10			*-19.4%*		*-12.1%*		*10.0%*		*4.9%*		***1.5%***
11	**Total OM&A Expenses**	**2,610,432**	**-116,781**	**2,493,651**	**-181,374**	**2,312,277**	**390,505**	**2,702,782**	**151,265**	**2,854,047**	**360,396**
			-4.5%		-7.3%		16.9%		5.6%		***14.5%***
	Combined O&M (lines 1 & 3)	715,829	75,800	791,629	-1,152	790,477	268,575	1,059,052	91,665	1,150,717	359,088
			10.6%		*-0.1%*		*34.0%*		*8.7%*		***45.4%***

b) Please confirm that Lakeland agrees with the two tables prepared by Board Staff presented above. If Lakeland does not agree with any table please advise why not. If Lakeland determines that the tables require amending, please provide amended tables with full explanation of changes made.

	Table 2 Revised	*Col. 1* **2006 Bd Appr.**	*Col. 2* **2006 Actual**	*Col. 3* **2007**	*Col. 4* **2008 Bridge**	*Col. 5* **2009**
1	**Operation**	$94,205	$262,589	$197,461	$223,773	$223,674
2	**Maintenance**	$621,624	$529,040	$593,016	$835,279	$927,043
3	**Billing and Collection**	$610,994	$652,753	$606,167	$647,111	$655,137
4	**Community Relations**	$15,320	$27,365	$17,610	$8,467	$11,255
5	**Administrative and General Expenses**	$878,903	$1,021,904	$898,023	$988,152	$1,036,938
	Total OM&A	**2,221,046**	**2,493,651**	**2,312,277**	**2,702,782**	**2,854,047**
5a	**Addback of prior yr w/o in Acct 5665**	(266,000)	Already removed	0	0	0
5b	**LV Charges that should be in Cost of Power – Acct 5665**	655,386	0	0	0	0
6	**Total**	2,610,432	2,493,651	2,312,277	2,702,782	2,854,047

Table 3 - Revised

Description	2006 Board Approved	Variance 2006/2006	2006 Actual	Variance 2007/2006	2007 Actual	Variance 2008/2008	2008 Bridge	Variance 2009/2008	2009 Test
OM&A expenses									
Operation	94,205	168,384	262,589	(65,128)	197,461	26,312	223,773	(99)	223,674
Maintenance	621,624	(92,584)	529,040	64,741	593,781	241,498	835,279	91,764	927,043
Billing and Collections	610,994	41,759	652,753	(46,586)	606,167	40,944	647,111	8,026	655,137
Community Relations	15,320	12,045	27,365	(9,755)	17,610	(9,143)	8,467	2,788	11,255
Administrative and General Expenses	878,903	143,001	1,021,904	(123,880)	898,023	90,129	988,152	48,786	1,036,938
Total OM&A Costs	**2,221,046**	**272,604**	**2,493,650**	**(180,609)**	**2,313,041**	**389,741**	**2,702,782**	**151,264**	**2,854,046**
% Change - OM&A		12%		-7%		17%		6%	
Write on of previous provision	(266,000)	(102,000)	(368,000)	368,000	0	0	0	0	0
Administrative and General Expenses	655,386	(655,386)	0	0	0	0	0	0	0
Total Costs as per accounts(RRR filing)	**2,610,432**	**(484,782)**	**2,125,650**	**187,391**	**2,313,041**	**389,741**	**2,702,782**	**151,264**	**2,854,046**
% Change - Total		-19%		9%		17%		6%	
Total O&M Costs	**715,829**	**75,800**	**791,629**	**(387)**	**791,242**	**267,810**	**1,059,052**	**91,665**	**1,150,717**
% Change - O&M		11%		0%		34%		9%	

5. Ref: Exh4/Tab2/Sch3

The table on page 1 of this schedule lists the major drivers of the $360k increase between 2006 and 2009 for OM&A costs. Two of the most significant drivers are new hires and tree trimming.

a) Please provide more detail concerning the description of the $175k which is described as "Supervision – ½ Operations Mgr, Line Supervisor". For example, if only ½ of an Operations Manager is charged to Operations, where is the other ½ charged?

See below

b) When were these positions vacated, and when were they filled?

The two positions were vacated early in 2006 (3 months) as the incumbents did not meet the requirements needed. Operations Manager was filled in the beginning of 2007 then resigned the first half of 2008 and replaced the last quarter of 2008. Lines Supervisor was filled from July 2007 to August 2008 then vacated and a more suitable candidate hired in October 2008. Expense in 2006 was $32 K, the expense in 2009 will be $205K for different competency level employees.

6. Ref: Exh4/Tab2/Sch2

Beginning on page 1 Lakeland itemizes the account balances for OM&A expenses.

a) For the 2009 Forecast Test Year, please identify and describe any one-time costs other than those explained for regulatory and legal costs above.

Lakeland did not forecast any one time costs in the 2009 Test Year

b) Are there any one time costs that were inadvertently carried forward from previous years?

Lakeland believes that it removed all one time costs from prior years as identified on Exhibit 4/2/3 page 1

c) Are there any expenses for charitable donations in the 2009 forecast? If there are please identify them.

Lakeland does not make specific charitable donations other than the Share The Warmth program at $3 K per year.

d) Are there any costs in the forecast for conversion due to the adoption of International Financial Reporting Standards? If there are please itemize the costs and the rational of the drivers of the costs.

No costs are in the forecast for conversion to IFRS however LPDL is attending OEB conferences as well as training for finance staff in 2008 and 2009. LPDL is in the process of putting together a conversion plan with a consultant. At this point in time, initial cost estimates are one time $120 K. Lakeland would like to reflect this in the final decision as a cost taken over the four year rates period.

e) Please identify any programmes in the 2009 forecast that are specifically aimed at productivity and efficiency improvements.

Lakeland has been running an operation with too few resources to date and is now at the point of burn out of senior staff. The increasing regulatory burden is creating concerns for retaining competent staff and succession planning is becoming a greater issue. Aside from this issue, the tree trimming program is expected to reduce trouble call costs in future years.

f) What inflation rate is used for 2009 and what is the source document for the inflation assumptions?

No specific inflation rate was used as zero based budgeting was the starting point

g) Please explain the analysis and conclusion for the establishment of the forecast level of bad debt, Account 5335.

This is the criteria that Lakeland uses to determine the allowance for bad debt and adjusts the allowance on a quarterly basis.

10% of Finalled Accounts - 0-3 mths
25% of Finalled Accounts - 4-6 mths
75% of Finalled Accounts - 6-12 mths
100% of Finalled Accounts - > 12 mths
100% of Bankrupt Accounts
10% of Accounts 2-3 mths old
25% of Accounts 4-6 mths old
75% of Accounts 6-12 mths old
100% of Accounts > 12 mths old

For the actual charges to bad debt account, in addition to the allowance changes from above, there were two specific bankruptcies that account for most of the fluctuation in the account amounts.

2006 – w/o of Dura bankruptcy $48 K

- setting up of allowance per calc $ 31 K

- other accts write offs-bad debt $ 5 K small accounts under $1 K

2007 – recovery from court – Dura $(15) K

- setting up of allowance per calc $ 29 K

2008 – setting up of allowance per calc $35 K due to economic pressures ($12 K in the first 6 months actual-expect higher amounts in last quarter of 2008)

2009 – setting up of allowance per calc $35 K due to economic pressures

The larger customers (Commerical/Industrial) have not been included in the estimate for 2008/2009 as Lakeland has procured Credit Risk Insurance ($15 K) for these customers. In 2008 alone, Lakeland has claimed over $40 K in bad debts from this class of customer.

7. Ref: Exhibit 4/Tab 2/Schedule 3

On page 2 of this schedule, Lakeland shows the actual and forecast annual balances for Account 5655, Regulatory Expenses.

a) Please provide the breakdown for actual and forecast, where applicable, for the 2006 Board approved, 2006 Actual, 2007 Actual, 2008 Bridge Year, and 2009 Forecast Test Year regarding the following regulatory costs and present it in the table format shown below.

See below

b) Under "Ongoing or One-time Cost", please identify and state if any of the regulatory costs are "One-time Cost" and not expected to be incurred by the applicant during the impending period when the applicant is subject to the 3rd Generation IRM process or it is "Ongoing Cost" and will continue throughout the 3rd Generation of IRM process.

The costs related to this rate application have been allocated over the years of 3rd Generation IRM. Although they are a one time cost for this application process, they have been treated as an ongoing cost in order to apply them equitably over the intervening years between cost of service applications.

Regulatory Account - 5655

Description of Charge		2006 Approved	2006 Actual	2007 Actual	% Change 2007 vs 2006	2008 to Dec/08	% Change 2008 vs 2007	2009 Test	% Change 2008 vs 2007	2010 Estimate	2011 Estimate
OEB Assessment	ongoing	$ 34,648.00	$ 33,586.00	$ 29,395.00	-12%	$ 26,234.00	-11%	$ 26,233.95	0%	$ 26,233.95	$ 26,233.95
Licence fee	ongoing	$ 800.00	$ 800.00	$ 800.00	0%	$ 800.00	0%	$ 800.00	0%	$ 800.00	$ 800.00
Amount to 1508 (deferral) to May 2006	one time		-$ 14,054.29		-100%	$ -		$ -			
OEB Hearing Assessments	one time			$ 1,890.40			-100%				
Section 30 Cost awards	on going		$ 2,352.03	$ 5,068.07	115%	$ 526.07	-90%	$ 1,500.00	185%	$ 1,500.00	$ 1,500.00
Legal costs for regulatory matters								$ 40,000.00			
Consultant costs for regulatory matters						$ 22,573.54		$ 25,000.00			
Incremental labour for rate application						$ 14,496.62		$ 9,000.00			
Operating expenses associated /w staff resources						$ 6,755.18		$ 6,000.00			
Intervenor costs - 5 intervenors (base Lakefront $)								$ 43,000.00			
Total actual spending in year		$ 35,448.00	$ 22,683.74	$ 37,153.47	64%	$ 71,385.41	92%	$ 151,533.95	112%	$ 28,533.95	$ 28,533.95
Reallocate rate application costs						-$ 2,119.00		-$ 81,293.67		$ 41,706.33	$ 41,706.33
Total indicated in rate application		**$ 35,448.00**	**$ 22,683.74**	**$ 37,153.47**	64%	**$ 69,266.40**	86%	**$ 70,240.28**	1%	**$ 70,240.28**	**$ 70,240.28**

8. Ref: Exh4/Tab2/Sch6

This exhibit itemizes Lakeland's purchased services.

a) With the exclusion of purchased power costs, what is the percentage of Total OM&A that is purchased?

With the exclusion of purchased power cost, the percentage of Total OM&A that is purchased is between 60 and 65 %

b) Please provide a similar table showing the purchases by source from 2006 actual to 2009 forecast. (If needed, the 2006 actuals may be adjusted for the re-alignment identified in Table 2 on Exhibit 4/Tab2/Schedule3).

Purchases by Source

Vendor Name	Activity	2006 Amount actual	2007 Amount actual	2008 Amount estimate	2009 Amount estimate	
AEGISYS	IT Support	$ 21,509.99	$ 22,347.96	$ 25,068.84	$ 25,000.00	
ARMSTRONG TRAILERS	Trailer building	$ -	$ 29,457.60	$ -		
BADGER DAYLIGHTING	Electrical components	$ 13,066.08	$ 23,939.23	$ 8,235.83	$ 7,500.00	
BARKLEY TECHNOLOGIES	Lineman crews	$ 125,024.63	$ 2,989.20	$ -		
BDO DUNWOODY	Audit fees	$ 23,540.00	$ 37,630.00	$ 37,630.00	$ 38,000.00	
BELL CANADA	telephone	$ 19,490.20	$ 12,895.75	$ 10,000.00	$ 10,000.00	
BLACK & MCDONALD LTD	Capital work	$ -	$ 40,083.90	$ 339,675.38	$ 358,650.00	specific capital project
BORDEN, LADNER, GERVAIS	legal/consultant			$ 22,573.00	$ 65,000.00	rate application & oral componen
BOWMAN FUELS LTD.	Truck fuel	$ 66,048.86	$ 75,205.48	$ 77,811.84	$ 78,000.00	
BRIAN BERNIE	Contact labour	$ 11,301.77	$ 18,704.03	$ 32,446.08	$ 20,000.00	
BUSINESS COMPUTER	Computers	$ 3,713.40	$ 4,143.90	$ 9,176.73	$ 6,000.00	
CANADA POST CORPORATION	Postage	$ 54,315.00	$ 60,050.00	$ 69,404.44	$ 72,100.00	postage increase to $.54
CANADA POWER PRODUCTS	Switchgear	$ -	$ 40,869.00	$ -		
CANADIAN ELECTRICAL SERVICES	Transformers	$ 83,359.35	$ 13,742.70	$ -		
CAVALCADE FORD	Pick up Truck	$ 6,833.86	$ 4,120.23	$ 47,080.13	$ -	
COLOMBO MOTORS LP	Pick up Truck	$ -	$ 36,762.42	$ -		
COMCO PETROLEUM	Contamination cleanup	$ 73,836.00	$ 26,242.30	$ 36,918.00	$ 30,000.00	continued cleanup with microbes
COMMUNITY TELECOM	Telephone system	$ 855.12	$ 17,361.81	$ -		
CORNERSTONE HYDRO ELECTRIC	Association	$ 13,275.00	$ 10,931.29	$ 10,242.55	$ 10,500.00	
DAVEY TREE EXPERT	Tree trimming		$ 11,567.25	$ 95,918.05	$ 110,000.00	tree trimming plan
DAVID S PROCTOR, CGA	Consultant	$ 34,307.03	$ -	$ -		
DELL COMPUTERS	Computers	$ 2,034.90	$ 19,555.44	$ 1,334.74		
DOCU-LINK INTERNATIONAL	Bill print and stuff	$ 16,201.94	$ 31,891.04	$ 24,036.95	$ 25,000.00	
ELECTRIC SAFETY AUTHORITY	Annual fee	$ 5,195.37	$ 6,774.99	$ 5,108.55	$ 5,200.00	
ELECTRICITY DISTRIBUTORS ASSOC	Association	$ 12,974.40	$ 13,621.00	$ 13,807.50	$ 13,800.00	
ELSTER ELECTRICITY	Meters	$ 9,300.54	$ 14,466.60	$ -		
ENERSOURCE HYDRO	Electrical Standards	$ 34,500.00	$ -	$ -		
ERIC BAIRD CLEANING	Cleaning	$ 10,372.50	$ 9,532.50	$ 9,112.09	$ 9,500.00	
EULER HERMES	Insurance	$ -	$ 17,413.80	$ 15,750.00	$ 15,750.00	
FESTING TOYOTA	Pick up Trucks	$ 86,093.89	$ 386.71	$ -		
FIFE EQUIPMENT	Bucket Truck	$ -	$ -	$ 165,000.00	$ -	
GRAFTON UTILITY SUPPLY	Electrical components	$ 117,961.09	$ 51,599.20	$ -		
GRAND & TOY	Office supplies	$ 13,515.35	$ 8,574.08	$ 12,229.05	$ 10,000.00	
GREEN PORT ENVIRONMENTAL	PCB testing	$ -	$ -	$ 19,246.16	$ 20,000.00	
GREYSTONE PROJECT	Office renovations	$ -	$ 21,072.80	$ -		
GUELPH UTILITY	Mapping/GIS	$ 3,587.58	$ 7,509.18			
H D SUPPLY UTILITIES	Electrical components	$ -	$ 185,867.03	$ 108,526.94	$ 100,000.00	
HARRIS COMPUTER SYSTEMS	Customer information system	$ 68,340.22	$ 68,162.61	$ 70,926.54	$ 71,000.00	
HUNTSVILLE HONDA	Pick up Truck	$ 39,138.28	$ -	$ -		
IDEAL SUPPLY	Electrical components	$ 40,671.47	$ -	$ -		
KAB CONSULTANCY & TRAINING	Training	$ 720.80	$ 21,621.45	$ -		
KABAR INDUSTRIES	Electrical components	$ -	$ 6,754.31	$ 26,170.80		
K-LINE MAINTENANCE	New Substation transformer	$ 258,672.50	$ 7,266.01	$ -		
LAKEPORT POWER LTD	Transformers	$ 42,349.28	$ 33,430.50	$ 78,015.61	$ 60,000.00	
MCNAMARA POWERLINE	Lineman crews	$ 103,319.84	$ 4,770.00	$ 57,616.36	$ 50,000.00	
MEARIE MANAGEMENT INC	Insurance	$ 49,590.65	$ 47,869.28	$ 50,000.00	$ 50,000.00	
MOLONEY ELECTRIC	Transformers	$ 20,224.74	$ 418,920.36	$ 16,000.80	$ 20,000.00	
NEDCO	Electrical components	$ 39,323.11	$ -	$ 783.71		
OLAMETER INC	Meter reading	$ 114,822.13	$ 103,175.15	$ 100,871.60	$ 100,000.00	
ONTARIO ENERGY BOARD	Regulator	$ 37,380.03	$ 31,831.75	$ 14,353.99	$ 70,000.00	includes intervenor cost
P.MEDLEY & SONS	Snowplowing/aggregate/digging	$ 17,389.95	$ 12,879.90	$ 9,933.89	$ 10,000.00	
POSI-PLUS TECHNOLOGIES	Bucket Truck	$ 595,155.34	$ -	$ 1,864.50		
S & C ELECTRIC CANADA	Padmount gear	$ -	$ 1,261.40	$ 28,333.80		
SHIER'S INSURANCE	Insurance	$ 27,255.96	$ 27,981.72	$ 28,541.35	$ 29,000.00	
SUBARU OF MUSKOKA	Vehicle	$ -	$ -	$ 36,742.51	$ 40,000.00	
TD VISA	Miscellaneous expenses	$ 48,407.88	$ 37,335.02	$ 24,797.73	$ 25,000.00	
TERRY EXELL	Lineman crews	$ -	$ 108,714.93	$ 120,991.55	$ 100,000.00	
THE TREEMAN	Tree trimming	$ 40,110.90	$ -	$ -		
TILTRAN	New Substation transformer	$ -	$ -	$ 160,324.62	$ 183,000.00	capital - substation
TRANS CANADA UTILITY POLE	Poles	$ 31,293.18	$ 50,048.28	$ 14,643.17	$ 15,000.00	
TRIMEN ELECTRICAL	Contract labour	$ -	$ -	$ 17,569.44		
UTILISMART CORPORATION	Interval meter management	$ 82,097.60	$ 79,171.40	$ 78,057.00	$ 80,000.00	
Total Purchases by Source		**$ 2,518,477.71**	**$ 1,938,502.49**	**$ 2,132,871.83**	**$ 1,933,000.00**	

c) Please explain any material variances in this table.

9. Ref: Exh4/Tab2/Sch4

On this schedule, Lakeland identifies the types of shared services along with their allocators. A better understanding of some of the allocators is requested.

a) Some allocators are identified as percentage of time allocated.

i Does Lakeland Distribution have a time tracking system?

All LPDL staff complete a daily timesheet.

ii If there is a time tracking system, how are the actuals used in setting the forecast?

The forecast is based on the past history then a true up is done at the end of the year to the actual time

iii If there is no time tracking system, what quantifiable means are used to test the reasonableness of the forecast?

See above

b) Human Resources is allocated based on the percentage of time allocated. Why is that a better allocation than per employee, or a hybrid of time and employee?

The Human Resources cost is an actual person and their timesheet is used for the allocation.

c) Telephone/internet services and IT support are allocated based on the number of employees. Considering that field personal may not have this equipment directly assigned to them, please explain the rationale for the use of this allocator for these two services.

Field personnel numbers do have access to all those items as well as radio communication, GIS/GPS, service order update. Many carry laptops with them to input field data.

d) Office supplies/Photocopying/Postage/Courier services are allocated based on percentage of time. Please explain the rationale for this allocator.

The assumption is that supplies are utilized in the same ratio as time spent working on each companies information

Compensation

10. Ref: Exh4/Tab2/Sch7

This schedule contains the compensation and benefits statistics. Although the changes in the levels of compensation and benefits are forecasted to be 3% or less for 2009, there are large historical increases that have resulted in large component changes from 2006 to 2009.

a) The following Table summarizes the data found on this referenced schedule for Base Wages and Benefits. The indicated percent changes are from one year to the next. The percentage change found in Column 6 is based on comparing 2009 to Actual

2006. Please explain the drivers of the large percentage changes observed in Column 6, referencing the year over year changes for both Base Wage and Benefits by employee type that contribute to these increases.

Due to a clerical error in allocation of the costs to the different expense types and that the part time positions were not inputted as FTE, the table has been recalculated. Please find the corrected allocation below. Total compensation does not change.

The part time staff are not included in the Number of Employees (FTEs) section and should be added together with the Full time employees:

Total FTE – All	2006	2007	2008	2009
	15.1	15.25	16.4	17.6

Management base wages changes by 20% as the new complement of staff is of a higher competence level that previous staff. Of the three positions, two are new in 2008.

Non-unionized staff base wage increase is approximately 3% per year.

Union staff wages are under a collective agreement of 3.5% for 2007 and 4% for 2008. A new contract will be negotiated in 2009.

Table 3
Employee Complement And Compensation

Number of Employees (FTEs)	2006	2007	2008	2009
Executive	0	0	0	0
Management	2	3	3	3
Non-Union	3	3	3	3
Union	8.3	8	8.4	10
Total	13.3	14	14.4	16

Number of Part Time Employees (FTE)	2006	2007	2008	2009
Executive	0	0	0	0
Management	0	0	0	0
Non-Union	1.8	1.25	2.00	1.60
Union	0	0	0	0
Total	1.8	1.25	2	1.6

Total Compensation	2006	2007	2008	2009
Executive				
Management	160,667	238,540	279,726	292,529
Non-Union	217,577	200,803	251,865	244,063
Union	647,712	599,427	679,319	852,609
Total	1,025,956	1,038,769	1,210,910	1,389,201

Compensation - Average Yearly Base Wages	2006	2007	2008	2009
Executive				
Management	67,182	67,024	80,728	81,667
Non-Union	39,294	40,229	41,623	42,917
Union	54,649	56,990	59,504	61,301

Compensation - Average Yearly Overtime	2006	2007	2008	2009
Executive				
Management	3,152	774	-	-
Non-Union	825	529	600	652
Union	14,283	7,225	8,571	8,944

Compensation - Average Yearly Incentive	2006	2007	2008	2009
Executive				
Management	-	-	-	-
Non-Union	-	-	-	-
Union	-	-	-	-

Compensation - Average Yearly Benefits	2006	2007	2008	2009
Executive				
Management	9,999	11,715	12,514	15,843
Non-Union	5,210	6,490	8,150	9,488
Union	9,106	10,714	12,796	15,016

	2006	2007	2008	2009
Total Salary, Wages & Benefits Charged to OM&A	874,634	795,646	959,831	1,089,478

b) Executives and Management do not appear to receive incentive pay. What is Lakeland's rationale for not including incentive pay for Executives and Management?

LPDL's Executives and Management do NOT receive any incentive pay.

Table 4 - Compensation

Compensation - Average Yearly Base Wages	2006	2007	2008	2009
1.1 Executive	-	-	-	-
1.2 Management	67,182	67,024	80,728	81,667
1.3 Non-Union	39,294	40,229	41,623	42,917
1.4 Union	54,649	56,990	59,504	61,301
1.5 Total	161,125	164,243	181,855	185,885

Percentage change	2006	2007	2008	2009	2009/06
2.1 Executive		0%	0%	0%	0%
2.2 Management		0%	20%	1%	22%
2.3 Non-Union		2%	3%	3%	9%
2.4 Union		4%	4%	3%	12%
2.5 Total		2%	11%	2%	15%

Compensation - Average Yearly Benefits	2006	2007	2008	2009
3.1 Executive	-	-	-	-
3.2 Management	9,999	11,715	12,514	15,843
3.3 Non-Union	5,210	6,490	8,150	9,488
3.4 Union	9,106	10,714	12,796	15,016
3.5 Total	24,314	28,919	33,460	40,346

Percentage change	2006	2007	2008	2009	2009/06
4.1 Executive		0%	0%	0%	0%
4.2 Management		17%	7%	27%	58%
4.3 Non-Union		25%	26%	16%	82%
4.4 Union		18%	19%	17%	65%
4.5 Total		19%	16%	21%	66%

c) Please complete the following table.

		Col. 1 **2006Act.**	*Col. 2* **2007**	*Col. 3* **2008**	*Col. 4* **2009**
1	Total Compensation	1,025,956	1,038,769	1,210,910	1,389,201
2	Less Capitalized Amount	151,322	243,123	251,079	299,723
3	Less Billable	0	0	0	0
4	Less Other	0	0	0	0
5	Compensation charged to OMA&G	874,634	795,646	959,831	1,089,478

Rate Base

11. Ref: Exh2/Tab1/Sch1

For each of the years 2003 to 2009 please provide a table listing the following information (actual dollars where available, or expected, planned or projected dollars or % where indicated):

a) Average Fixed Assets in Service

b) Average Depreciation Rate as a % of Average Fixed Assets in Service;

c) Working Capital as a % of Average Fixed Assets in Service;

Table 1 - Question 11 - Rate Base

Description	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual Year	2008 Bridge Year	2009 Test Year
Gross Fixed Assets	15,815,079	16,674,932	17,113,589	17,934,442	18,778,725	19,753,513	21,438,673
(a) Average Fixed Assets in Service	15,256,783	16,245,006	16,894,261	17,524,016	18,356,584	19,266,119	20,596,093
Depreciation	879,460	907,265	962,956	923,842	1,003,551	1,045,062	1,110,213
(b) Average Depreciation Rate	5.7%	5.5%	5.5%	5.4%	5.2%	5.3%	5.2%
Working Capital	16,637,902	16,331,660	18,863,386	18,046,552	18,528,905	19,138,925	19,712,202
(c) Working Capital % of Avg Fixed	109.1%	100.5%	111.7%	103.0%	100.9%	99.3%	95.7%

d) Number of Customer Connections in Each Customer Category

i) New Connections

ii) Service Upgrade Connections

iii) Population (actual or estimated) of Service Area.

Billing Determinants - 2009 Load Forecast								
Class	Description	2003 Actual Data	2004 Actual Data	2005 Actual Data	2006 Actual Data	2007 Actual Data	2008 Bridge Year Normalized	2009 Test Year Normalized
Residential	# of Customers	7,403	7,403	7,403	7,403	7,434	7,498	7,562
	New Connections	114	67	72	57	85	64	64
	Service Upgrade Connection	n/a	n/a	n/a	n/a	n/a	n/a	n/a
GS <50 kW	# of Customers	1,488	1,488	1,488	1,488	1,527	1,538	1,549
	New Connections	24	38	23	22	30	11	11
	Service Upgrade Connection	n/a	n/a	n/a	n/a	n/a	n/a	n/a
GS>=50 kW	# of Customers	93	93	93	93	97	97	97
	New Connections	1	2	1	5	4		
	Service Upgrade Connection	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Street Light	# of Connections	2,058	2,058	2,058	2,058	2,058	2,058	2,058
	New Connections							
	Service Upgrade Connection	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Sentinel	# of Connections	45	45	45	45	44	43	42
	New Connections							
	Service Upgrade Connection	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Unmetered Scattered Lo	# of Customers	66	66	66	66	51	48	45
	New Connections							
	Service Upgrade Connection	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Population of Service Area		21,007	21,007	21,007	21,007	21,007	21,007	21,007

12. Exh1/Tab3/Sch4/p1 and Exh2/Tab1/Sch1/p2/l6

a) Please clarify whether the existing rate base contains capitalized overhead and whether capitalized overhead is included in the proposed 2009 rate base.

LPDL does not capitalize any overheads other than employee benefits which are directly attributable to the labour working on the project. Supervision is not capitalized, only the employees that are directly working on the capital project.

b) Please clarify whether the existing rate base contains AFUDC (also known as "Interest During Construction").

LPDL does not include AFUDC in the rate base

c) As stated in the Exhibit 1 reference above, "The capital costs of any constructed assets will not include an appropriate allowance for use of funds during construction". Please elaborate on what projects or project types will have AFUDC omitted from their total capital costs.

The only project that would be possibly a candidate for this treatment is the building of the two distribution stations due to the leadtime on purchasing the components, installation and energization date.

d) If AFUDC is not to be included in 2009 and subsequent capital additions, how will this capital or expense item be recovered and dealt with in determining cost of service?

To date this has not been as issue nor is it expected to be in the next three years.

13. Ref: Exh2/Tab2/Sch1

Please confirm that the continuity statement has included interest during construction and all overheads for the years until 2008 and not for 2009 and elaborate on any changes regarding Interest During Construction.

The continuity statement does NOT have AFUDC nor overheads in any year. LPDL's accounting policy is NOT to allocate overheads nor AFUDC to capital projects unless the costs can be specifically identified as belonging to that project.

Capital Expenditures

14. Ref: Exh2/Tab1/Sch1

a) Please provide a record of reliability indices for the years 2003 through 2009 (estimated) and indicate the desired values.

Table 1 - Question 14 - Reliability Indices

Description	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual Year	2008 Bridge Year	2009 Test Year
SAIDI	23.01	0.05	4.61	3.44	11.75	8.00	6.00
CAIDI	13.78	2.21	4.66	5.01	2.72	2.00	1.50
SAIFI	1.67	0.02	0.99	0.69	4.32	2.00	1.00

b) Indicate if and how the reliability indices relate to the capital expenditures for each of the projects that have been undertaken for reasons of reliability in years 2008 and projected 2009.

Lakeland identified $70 K in reliability projects. Through an audit of the system, 70 poles were identified as being cracked, hollow, or damaged and in need of replacement. If these are not replaced and fail, they can cause power outages (lowering an indice), or cause public danger. These projects are to avoid potential issues as opposed to improving indices. Most of the impact on service quality/reliability indices will come through the tree trimming plan. Downed lines due to trees is the single largest issue in power outages, then locating them in densely treed areas is difficult.

15. Ref: Exh2/Tab1/Sch1

a) Please provide Lakeland's Code of Business Conduct.

Attached at end of document – labelled Code of Ethics (Appendix A)

b) For the years 2003 to 2009 inclusive, please provide a table listing the following information (actual dollars where available, or expected, planned or projected dollars or % where indicated):

i Net income;

ii Actual Return on Equity (%);

iii Allowed Return on Equity (%);

iv Retained Earnings;

v Dividends to Shareholders;

vi Sustainment Capital Expenditures excluding smart meters;

vii Development Capital Expenditures excluding smart meters;

viii Operations Capital Expenditures;

ix Smart meter Capital Expenditures;

x Other Capital Expenditures (identify);

xi Total Capital Expenditures including and excluding smart meters;

xii Depreciation.

Table 1 - Question 15 - Statistics

Description	2003 Actual	2004 Actual	2005 Actual	2006 Actual *	2007 Actual *	2008 Bridge Year	2009 Test Year status quo	2009 Test Year new rates
Net Income	1,051,389	1,024,403	1,050,891	510,540	697,190	345,886	168,006	574,963
Actual Return on Equity %	9.87%	8.77%	8.33%	4.78%	6.38%	3.20%	1.53%	5.06%
Allowed Return on Equity %	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%	8.57%	8.57%
Retained Earnings	1,430,955	2,455,358	3,393,749	1,454,289	1,701,479	1,572,368	1,740,374	2,147,331
Dividends to Shareholders	-	-	112,500	2,450,000	450,000	-	-	-
Capital Expenditures								
Sustainment	874,768	727,716	363,255	341,845	620,654	709,906	887,160	887,160
Development	78,384	358,136	359,703	903,073	774,247	0	1,500,000	1,500,000
Contributed Capital	(78,384)	(358,136)	(359,703)	(903,073)	(774,247)	0	(1,000,000)	(1,000,000)
Operations	242,091	132,137	75,402	479,007	223,630	264,882	298,000	298,000
Smart meter	0	0	0	0	0	0	0	0
Other								
Total Capital	1,116,859	859,853	438,657	820,852	844,284	974,788	1,685,160	1,685,160
Depreciation	879,460	907,265	962,956	923,842	1,003,551	1,045,062	1,110,213	1,110,213

* not adjusted for Storm Costs so data ties to audited statements

16. Ref: Exh2/Tab3/Sch1/p2

2009 Capital Addition: Distribution Stations addition: Line 1

Capital cost of $500,000 for this project is purported to have been spent in 2008 but the facilities will be brought into service in 2009. Please provide the project start date, the end date, and the date that these facilities are to be brought into service in 2009.

Currently, 50% of the funds have been spent(at Sept/08) and it is expected that the balance will be paid upon receipt of the transformer. Civil work has been undertaken and it is expected to be energized in April 2009. The full cost of the project is $1.5 M of which a capital contribution will be received of $1.0 M. The final evaluation will be done when all costs are known.

17. Ref: Exh2/Tab3/Sch1/p6

Security Project, Kirk Line-to-Taylor Road 1000 m connecting line.

Please list other engineering solutions that were investigated in order to reduce the outage time that is to be reduced by the proposed $250,000 solution. Please list the reasons these other solutions were rejected.

Option1 – build a new circuit on existing subtransmission Hydro One pole line. This was rejected as a majority of the poles would be required to be replaced with taller poles, it was on a main street (3 circuits on poles-esthetic issue) and the cost was considerably higher

Option 2 – redo a link through a subdivision. The switch gear and site restoration combined with the cost of the underground made this the most expensive option.

Option 3 – Kirk Line to Taylor Road – this was the most cost effective method to achieve the ability to do proper maintenance without shutting down power to customers for 16 hours at a time.

18. Ref: Exh2/Tab3/Sch1/p10

Vehicles and Related Equipment

Tree trimming is listed as a major maintenance cost. Will any of the capital equipment expected to be purchased as capital items in 2009 ($205,000) be used in the tree trimming maintenance planned. If so, please provide a description of the use of such vehicles in tree trimming activities.

The majority of tree trimming is completed by contract labour and their own equipment as LPDL does not have the staff to complete this program.

19. Ref: Exh2/Tab3/Sch2/p2

Regulatory Project, Replacement of PCB-contaminated transformers.

Please quote the regulation that mandates replacement of transformers testing PCBs greater than 50 ppm

PCB Regulations

SOR/2008-273

Registration September 5, 2008

CANADIAN ENVIRONMENTAL PROTECTION ACT, 1999

PCB Regulations

P.C. 2008-1659 September 5, 2008

END-OF-USE DATES AND EXTENSION

Equipment referred to in subparagraphs 14(1)(*d*)(i) to (iii)

16. (1) A person may use the equipment referred to in subparagraphs 14(1)(*d*)(i) to (iii) until the following dates if the equipment is in use on the day on which these Regulations come into force:

(*a*) in the case of equipment containing PCBs in a concentration of 500 mg/kg or more, December 31, 2009; and

(*b*) in the case of equipment containing PCBs in a concentration of at least 50 mg/kg but less than 500 mg/kg,

(i) December 31, 2009, if the equipment is located at a drinking water treatment plant or food or feed processing plant, in a child care facility, preschool, primary school, secondary school, hospital or senior citizens' care facility or on the property on which the plant or facility is located and within 100 m of it, and

(ii) December 31, 2025, if the equipment is located at any other place.

Light ballasts and pole-top electrical transformers

(2) A person may use the following equipment containing PCBs in a concentration of 50 mg/kg or more until December 31, 2025, if the equipment is in use on the day on which these Regulations come into force:

(*a*) light ballasts; and

(*b*) pole-top electrical transformers and their pole-top auxiliary electrical equipment.

Liquid — concentration of 2 mg/kg or more

(3) A person may use a liquid containing 2 mg/kg or more of PCBs that is in equipment until the day on which the liquid is removed from the equipment.

Extension of end-of-use date

17. (1) Despite subsection 15(2), paragraph *16*(1)(*a*) and subparagraph *16*(1)(*b*)(i), a person may use the equipment and the liquids used for servicing that equipment, referred to in those provisions, until the date set out in an extension granted by the Minister under subsection (2) for that equipment and those liquids.

Smart Meters

20. Ref. Exh1/Tab1/Sch5/p1 and Exh1/Tab3/Sch5/AppendixA/p21

Lakeland states that it seeks approval to charge for $0.25 per customer per month to cover the costs of Smart Metering. Lakeland is pursuing the implementation of smart meters totalling $3.0 million but it appears that it has not included any capital or expense items relating to this initiative in the application:

a) Please provide the amount of capital expended on the smart metering installation in 2006, 2007, 2008 and projected 2009.

To date, Lakeland's investment in Smart Meters has been limited to consulting costs to get the project plan in place and assist with the documents and filing with the London RFP process. Lakeland is currently in negotiation with its second vendor as the first one has opted out of the Ontario market. It is expected that Lakeland will be procuring meters early in 2009 with installation in the summer of 2009. The communication devices will be in place before mass meter rollout. The back end systems, including the Operational data storage and the integration with the customer viewing website will be completed after this process. This is all in preparation to meet the Ontario mandate of the end of 2010 and billing TOU through the MDMR.

b) Based on the capital expenditures for smart meters in 2007, 2008 and projected 2009, please provide justification for the $0.25 per customer per month or any other figure for smart metering.

Lakeland is requesting the $.25 per customer per month as a placeholder until a separate application can be filed using the OEB G-2008-0002 Guideline for Smart Meter Funding and Cost Recovery

c) How does Lakeland intend receiving the desired return from the investment in smart meters if any?

For the purpose of this rate application, LPDL has taken all spending related to Smart Meters out in order to not cloud the application. Lakeland will be filing a separate Smart Meter Cost Recovery application in order to receive the desired return from the investment.

Payments in Lieu of Taxes

21. Exh4/Tab3/Sch1/p1

Lakeland has calculated their 2009 regulatory Net income before tax at $965,096. Board staff cannot reconcile this figure using the same rate base of $15,521,320, a

deemed equity at 43.3% and cost of equity at 8.57%, where use of these figures yields $886,213.

a) Please calculate, and show the calculations of the before-tax regulatory income, when calculated on those assumptions.

The rate base number on Exh.4/Tab3/Sch1/pg1 and Exh.7/Tab1/Sch1 is $15,499,710. All analysis is based on this number. The only reference to $15,521,320 is in Table 1 Exh2/Tab1/Sch1 and Exh6/Tab1/Sch2 in error and it was not used for any calculations. Lakeland was unable to replicate the figures used by Board staff so it has explained the amounts actually used in the rate application.

Capital Structure for 2009

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	8,168,347	52.70%	5.16%	421,214.44
Unfunded Short Term Debt	619,988	4.00%	4.47%	27,713.48
Total Debt	8,788,336	56.70%		448,927.92
Common Share Equity	6,711,375	43.30%	8.57%	574,963.45
Total equity	6,711,375	43.30%		574,963.45
Total Rate Base	15,499,710	100%	6.61%	1,023,891.38

	$1,023,891	**(from table above)**
Less deemed interest	**(448,928)**	
Less Income Loss at existing	**89,602**	**(see table below)**
Revenue deficiency after tax	**$ 664,566**	
Revenue deficiency before tax	**$ 991,889**	

Add revenue deficiency back to original net income calculation

$(26,793)	**loss as per below 2009 Test at Existing rates**
$ 991,889	
Total $ 965,096	

Revenue Deficiency Determination

Description	2009 Test Existing Rates	2009 Test - Required Revenue
Revenue		
Revenue Deficiency		**$991,889.00**
Distribution Revenue	3,966,075.53	3,966,075.53
Other Operating Revenue (Net)	407,336.27	407,336.27
Total Revenue	**4,373,411.79**	**5,365,300.79**
Costs and Expenses		
Operation & Maintenance & Administration	2,854,045.56	2,854,045.56
Depreciation & Amortization	1,086,259.19	1,086,259.19
Property Taxes	10,972.40	10,972.40
Capital Taxes	10,498.84	10,498.84
Deemed Interest	448,927.92	448,927.92
Total Costs and Expenses	**4,410,703.92**	**4,410,703.92**
Less OCT Included Above	-10,498.84	-10,498.84
Total Costs and Expenses Net of OCT	**4,400,205.08**	**4,400,205.08**
Utility Income Before Income Taxes	**-26,793.29**	**965,095.71**
Income Taxes:		
Capital Tax	10,498.84	10,498.84
Corporate Income Taxes	52,310.05	379,633.42
Total Income Taxes	**62,808.89**	**390,132.26**
Utility Net Income	**-89,602.17**	**574,963.45**
Capital Tax Expense Calculation:		
Total Rate Base	15,499,710.19	15,499,710.19
Exemption	10,833,559.20	10,833,559.20
Deemed Taxable Capital	**4,666,150.99**	**4,666,150.99**
Ontario Capital Tax	10,498.84	10,498.84
Income Tax Expense Calculation:		
Accounting Income	-26,793.29	965,095.71
Tax Adjustments to Accounting Income	185,308.58	185,308.58
Taxable Income	**158,515.29**	**1,150,404.29**
Income Tax Expense	52,310.05	379,633.42
	33.00%	33.00%
Actual Return on Rate Base:		
Interest Expense	448,927.92	448,927.92
Net Income	-89,602.17	574,963.45
Total Actual Return on Rate Base	**359,325.75**	**1,023,891.38**
Actual Return on Rate Base	2.32%	6.61%
Return Rates:		
Return on Debt (Weighted)	5.11%	5.11%
Return on Equity	8.57%	8.57%
Deemed Interest Expense	448,927.92	448,927.92
Return On Equity	574,963.45	574,963.45
Total Return	**1,023,891.38**	**1,023,891.38**
Expected Return on Rate Base	6.61%	6.61%
Revenue Deficiency After Tax	**664,565.63**	**0.00**
Revenue Deficiency Before Tax	**991,889.00**	**0.00**

Above is Net income of $965,096, Tax rate of 33%, and Proportions as per the Capital Structure table above

Revenue Deficiency Determination

Description	2009 Test Existing Rates	2009 Test - Required Revenue
Revenue		
Revenue Deficiency		**$924,028.07**
Distribution Revenue	3,966,075.53	3,966,075.53
Other Operating Revenue (Net)	407,336.27	407,336.27
Total Revenue	**4,373,411.79**	**5,297,439.86**
Costs and Expenses		
Operation & Maintenance & Administration	2,854,045.56	2,854,045.56
Depreciation & Amortization	1,086,259.19	1,086,259.19
Property Taxes	10,972.40	10,972.40
Capital Taxes	10,498.84	10,498.84
Deemed Interest	448,927.92	448,927.92
Total Costs and Expenses	**4,410,703.92**	**4,410,703.92**
Less OCT Included Above	-10,498.84	-10,498.84
Total Costs and Expenses Net of OCT	**4,400,205.08**	**4,400,205.08**
Utility Income Before Income Taxes	**-26,793.29**	**897,234.78**
Income Taxes:		
Capital Tax	10,498.84	10,498.84
Corporate Income Taxes	45,652.40	311,772.49
Total Income Taxes	**56,151.24**	**322,271.33**
Utility Net Income	**-82,944.53**	**574,963.45**
Capital Tax Expense Calculation:		
Total Rate Base	15,499,710.19	15,499,710.19
Exemption	10,833,559.20	10,833,559.20
Deemed Taxable Capital	**4,666,150.99**	**4,666,150.99**
Ontario Capital Tax	10,498.84	10,498.84
Income Tax Expense Calculation:		
Accounting Income	-26,793.29	897,234.78
Tax Adjustments to Accounting Income	185,308.58	185,308.58
Taxable Income	**158,515.29**	**1,082,543.36**
Income Tax Expense	45,652.40	311,772.49
	28.80%	28.80%
Actual Return on Rate Base:		
Interest Expense	448,927.92	448,927.92
Net Income	-82,944.53	574,963.45
Total Actual Return on Rate Base	**365,983.39**	**1,023,891.38**
Actual Return on Rate Base	2.36%	6.61%
Return Rates:		
Return on Debt (Weighted)	5.11%	5.11%
Return on Equity	8.57%	8.57%
Deemed Interest Expense	448,927.92	448,927.92
Return On Equity	574,963.45	574,963.45
Total Return	**1,023,891.38**	**1,023,891.38**
Expected Return on Rate Base	6.61%	6.61%
Revenue Deficiency After Tax	**657,907.99**	**0.00**
Revenue Deficiency Before Tax	**924,028.07**	**0.00**

Above is Net income of $965,096, Tax rate of 28.8%, and Proportions as per the Capital Structure table above

b) Please calculate and show the calculations of income tax using the following assumptions:

i) Net income before taxes of $965,096 and $886,213

ii) Proportions: Short term debt 4.0%; Long term debt 52.7% and Equity 43.3% at costs of 4.77%, 5.16% and 8.57% respectively

iii) Total income tax rate at 28.88% and 33%.

Change is Short Term Debt Rate

Capital Structure for 2009

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	8,168,347	52.70%	5.16%	421,214.44
Unfunded Short Term Debt	619,988	4.00%	4.77%	29,573.45
Total Debt	8,788,336	56.70%		450,787.89
Common Share Equity	6,711,375	43.30%	8.57%	574,963.45
Total equity	6,711,375	43.30%		574,963.45
Total Rate Base	15,499,710	100%	6.62%	1,025,751.34

Revenue Deficiency Determination

Description	2009 Test Existing Rates	2009 Test - Required Revenue
Revenue		
Revenue Deficiency		**$993,748.96**
Distribution Revenue	3,966,075.53	3,966,075.53
Other Operating Revenue (Net)	407,336.27	407,336.27
Total Revenue	**4,373,411.79**	**5,367,160.76**
Costs and Expenses		
Operation & Maintenance & Administration	2,854,045.56	2,854,045.56
Depreciation & Amortization	1,086,259.19	1,086,259.19
Property Taxes	10,972.40	10,972.40
Capital Taxes	10,498.84	10,498.84
Deemed Interest	450,787.89	450,787.89
Total Costs and Expenses	**4,412,563.89**	**4,412,563.89**
Less OCT Included Above	-10,498.84	-10,498.84
Total Costs and Expenses Net of OCT	**4,402,065.05**	**4,402,065.05**
Utility Income Before Income Taxes	**-28,653.25**	**965,095.71**
Income Taxes:		
Capital Tax	10,498.84	10,498.84
Corporate Income Taxes	51,696.26	379,633.42
Total Income Taxes	**62,195.10**	**390,132.26**
Utility Net Income	**-90,848.35**	**574,963.45**
Capital Tax Expense Calculation:		
Total Rate Base	15,499,710.19	15,499,710.19
Exemption	10,833,559.20	10,833,559.20
Deemed Taxable Capital	**4,666,150.99**	**4,666,150.99**
Ontario Capital Tax	10,498.84	10,498.84
Income Tax Expense Calculation:		
Accounting Income	-28,653.25	965,095.71
Tax Adjustments to Accounting Income	185,308.58	185,308.58
Taxable Income	**156,655.32**	**1,150,404.29**
Income Tax Expense	51,696.26	379,633.42
	33.00%	33.00%
Actual Return on Rate Base:		
Interest Expense	450,787.89	450,787.89
Net Income	-90,848.35	574,963.45
Total Actual Return on Rate Base	**359,939.54**	**1,025,751.34**
Actual Return on Rate Base	2.32%	6.62%
Return Rates:		
Return on Debt (Weighted)	5.13%	5.13%
Return on Equity	8.57%	8.57%
Deemed Interest Expense	450,787.89	450,787.89
Return On Equity	574,963.45	574,963.45
Total Return	**1,025,751.34**	**1,025,751.34**
Expected Return on Rate Base	6.62%	6.62%
Revenue Deficiency After Tax	**665,811.81**	**0.00**
Revenue Deficiency Before Tax	**993,748.96**	**0.00**

Above is Net income of $965,096, Tax rate of 33%, and Proportions as per the Capital Structure table above (changed for Short term debt rate)

Tax Exhibit	2009
Deemed Utility Income	574,963
Tax Adjustments to Accounting Income	185,308.58
Taxable Income prior to adjusting revenue to PILs	**760,272**
Tax Rate	33.00%
Total PILs before gross up	**250,890**
Grossed up PILs	**374,462**

Revenue Deficiency Determination

Description	2009 Test Existing Rates	2009 Test - Required Revenue
Revenue		
Revenue Deficiency		**$925,888.04**
Distribution Revenue	3,966,075.53	3,966,075.53
Other Operating Revenue (Net)	407,336.27	407,336.27
Total Revenue	**4,373,411.79**	**5,299,299.83**
Costs and Expenses		
Operation & Maintenance & Administration	2,854,045.56	2,854,045.56
Depreciation & Amortization	1,086,259.19	1,086,259.19
Property Taxes	10,972.40	10,972.40
Capital Taxes	10,498.84	10,498.84
Deemed Interest	450,787.89	450,787.89
Total Costs and Expenses	**4,412,563.89**	**4,412,563.89**
Less OCT Included Above	-10,498.84	-10,498.84
Total Costs and Expenses Net of OCT	**4,402,065.05**	**4,402,065.05**
Utility Income Before Income Taxes	**-28,653.25**	**897,234.78**
Income Taxes:		
Capital Tax	10,498.84	10,498.84
Corporate Income Taxes	45,116.73	311,772.49
Total Income Taxes	**55,615.57**	**322,271.33**
Utility Net Income	**-84,268.83**	**574,963.45**
Capital Tax Expense Calculation:		
Total Rate Base	15,499,710.19	15,499,710.19
Exemption	10,833,559.20	10,833,559.20
Deemed Taxable Capital	**4,666,150.99**	**4,666,150.99**
Ontario Capital Tax	10,498.84	10,498.84
Income Tax Expense Calculation:		
Accounting Income	-28,653.25	897,234.78
Tax Adjustments to Accounting Income	185,308.58	185,308.58
Taxable Income	**156,655.32**	**1,082,543.36**
Income Tax Expense	45,116.73	311,772.49
	28.80%	28.80%
Actual Return on Rate Base:		
Interest Expense	450,787.89	450,787.89
Net Income	-84,268.83	574,963.45
Total Actual Return on Rate Base	**366,519.06**	**1,025,751.34**
Actual Return on Rate Base	2.36%	6.62%
Return Rates:		
Return on Debt (Weighted)	5.13%	5.13%
Return on Equity	8.57%	8.57%
Deemed Interest Expense	450,787.89	450,787.89
Return On Equity	574,963.45	574,963.45
Total Return	**1,025,751.34**	**1,025,751.34**
Expected Return on Rate Base	6.62%	6.62%
Revenue Deficiency After Tax	**659,232.28**	**0.00**
Revenue Deficiency Before Tax	**925,888.04**	**0.00**

Above is Net income of $965,096, Tax rate of 28.8%, and Proportions as per the Capital Structure table above (changed for Short term debt rate)

Tax Exhibit	2009
Deemed Utility Income	574,963
Tax Adjustments to Accounting Income	185,308.58
Taxable Income prior to adjusting revenue to PILs	**760,272**
Tax Rate	28.80%
Total PILs before gross up	**218,958**
Grossed up PILs	**307,526**

c) Please calculate and show the calculations for the taxes as calculated in b) above, **grossed up** for rate purposes.

See above

Load Forecast

Preamble

In preparing the responses to the interrogatories related to Load Forecast is has come to Lakeland's attention that the information filed in Exhibit 3/Tab 2/Schedule 1 and 2 was not consistent with Exhibit 3/Tab 2/Schedule 2 Appendix A and Exhibit 3/Tab 2/Schedule 3. The information in Exhibit 3/Tab 2/Schedule 3 is the correct information and has been used in the determination of proposed rates. Lakeland has provided revised Exhibit 3/Tab 2/Schedule 1 and 2 and Exhibit 3/Tab 2/Schedule 2 Appendix A to be consistent with Exhibit 3/Tab 2/Schedule 3. (the revised Exhibit 3, Tab 2, Schedule 1 can be found at the end of the responses, Appendix B)

22. Ref: Exh3/Tab2/Sch2
Weather Normalization and Modelling
On pages 4-5, Lakeland states: "In order to incorporate weather normal conditions, the average monthly heating degree days and cooling degree days which has occurred from 2001 to 2007 is applied in the prediction formula." Please:

a) Provide any information that supports using a 6-year period as the definition of normal weather and the rationale for using this specific period instead of a longer period, and

Lakeland used 7 years of monthly data (i.e. 2001 to 2007 inclusive) to determine the average weather normal conditions used in the forecast. This period of time

was used to define normal weather since it matched the period of time that Lakeland had monthly purchased energy data available for use in the regression model. The seven year average was also justified based on the recent global activity surrounding climate change which suggest weather conditions that have occurred in more recent years could be a better indication of average weather conditions going forward.

b) Recalculate the resulting 2009 total (system-level) billed kWh load forecast successively using
   i. the 10-year average and
   ii. the 20-year trend to define normal weather.

The resulting 2009 total (system-level) billed kWh load forecast successively using
i. the 10-year average is 225,312,727
ii. the 20-year trend to define normal weather is 227,471,922

23. Ref:Exh3/Tab2/Sch2
Expected Future Change
On page 3, the formula is presented that describes Lakeland's Monthly Predicted kWh Purchases.

a) Considering that CDM has probably only recently had (or is yet to have) an influence on Lakeland's consumption, explain how, and to what extent, the anticipated effect of Lakeland's CDM activities is represented by the formula on page 3 that is used to forecast future consumption.

Since CDM has only recently had an influence on Lakeland's consumption, the impact of Lakeland historical CDM activities on the formula on page 3 will be minimal.

b) Please reconcile the anticipated effect of Lakeland's CDM activities in a) with Lakeland's latest CDM Annual Report to the Board.

The anticipated effect of Lakeland's CDM activities outlined in Lakeland's latest CDM Annual Report to the Board has not been reflected in the forecast.

24. Ref:Exh3/Tab2/Sch2
On page 3 when describing the sources of data for the multi-factor regression model, Lakeland states: "The 2008, 2009 and 2010 rate application (EB-2007-0680) for Toronto Hydro Electric System Ltd. [THESL] provided the Ontario real GDP monthly index." Please:

a) Clarify if the THESL-provided Ontario real GDP was
   i. utilized in both establishing the *historical* weightings for the independent variables and used as the economic *forecast* in determining the 2009 load forecast, or

ii. replaced with a different economic forecast to project into the future and, if so, identify the economic forecast used.

The THESL-provided Ontario real GDP was utilized in both establishing the *historical* weightings for the independent variables and used as the economic *forecast* in determining the 2009 load forecast.

b) If a) i above was answered in the affirmative, please explain why a more up-to-date economic forecast was not used considering that the Ontario real GDP used by THESL had been developed some time before by THESL "based on forecasts of 2007 GDP from the six Canadian chartered banks for 2007" (THESL Exhibit K1, Tab 1, Schedule 1, Filed 2007 Aug 2, page 7 of 11) and that THESL's updated filing used the Toronto GDP (THESL Exhibit K1, Tab 1, Schedule 1, Filed 2007 Aug 2, Updated 2007 Nov 12, page 1 of 4).

A more up-to-date economic forecast was not used since the Ontario Real GDP variable was not a significant contributor to the regression formula. In some people's view the Ontario Real GDP should have been eliminated from the formula since it's T-stat was less than 2.0. However, including this variable provided a slightly better R Square value.

25. Ref:Exh3/Tab2/Sch2/p5
kWh and Revenue Forecast
In Table 5, Lakeland shows the value of the actual Loss Factor for each of the years 2001 to 2007, and the calculated average value which is subsequently used to convert the purchased kWh to billed kWh. Because the 2001 value is much higher than the values in subsequent years, the calculated average value used for 2009 is higher than any value since 2003 and is inconsistent with the downward trend - thus resulting in higher rates. Please:
a) restate the Loss Factor taking account of the trend in Loss Factors and the planned engineering investments designed to reduce losses, and

The following table provides the calculation of the loss factor used in the load forecast. The 7 year average number shown in column C was the loss factor used in the load forecast. The 5 year average loss factor shown in column C excludes the impact of 2001 and 2002. In the process of preparing this response, Lakeland has discovered that an incorrect loss factor was used in the load forecast. It is Lakeland's view that a loss factor of 6.14% as shown in column E as the 5 year average revised loss factor should have been used in the load forecast. This loss factor is also consistent with the proposed total loss factor shown in Exhibit, Tab 2, Schedule 9, Page 2. 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. However, as a rate mitigation strategy, Lakeland is proposing to maintain the load forecast of 225,921,346 kWh

(GWh)	Actual Purchases (A)	Actual Billed (B)	Loss Factor (C) = (A)/(B) - 1	Actual Billed Revised (D) = (B) / 1.0428	Revised Loss Factor (E) = (A)/D) - 1
2001	225.5	210.2	7.31%	201.5	11.90%
2002	230.5	224.4	2.76%	215.2	7.16%
2003	233.6	226.9	2.95%	217.6	7.35%
2004	231.6	229.7	0.84%	220.2	5.16%
2005	236.0	231.4	1.98%	221.9	6.35%
2006	229.4	225.2	1.86%	216.0	6.22%
2007	230.1	227.2	1.28%	217.9	5.61%
7 year average	1,617	1,575	2.66%	1,510	7.05%
5 year average	1,161	1,140	1.78%	1,094	6.14%

b) recalculate the resulting 2009 total (system-level) billed kWh load forecast.

See response to a)

26. Ref: Exh3/Tab2/Sch/p2/Table2;
Exh3/Tab2/Sch2/pp10-11/Tables 14-17;
Exh3/Tab2/Sch2/Appendix A/p1; and
Exh3/Tab2/Sch3/p2.

Customer Count, kWh load, kW load and Revenue

In Tables 2 and 14, Lakeland shows the 2009 billed energy (GWh) forecast by customer class. In Table 17, Lakeland shows the 2009 kW forecast by customer class for those classes that uses the kW charge determinant. In Appendix A, Lakeland shows the 2009 kWh and kW by customer class. In the second unnumbered table in Schedule 3, page 2, Lakeland shows the 2009 kWh or kW forecast (depending on the charge determinant for the class) by customer class. Some of the values in the second unnumbered table in Schedule 3, page 2, do not match the corresponding values in Tables 2 and 14. In addition, some of the values in Appendix A do not match the values in Table 17.

Please provide a single table summarizing the 2009 forecast showing, for each customer class and for the total of all classes:

a) Number of Customers/Connections;
b) Billed kWh;
c) Billed kW (for those classes that use this charge determinant); and
d) Distribution Revenue.

2009	Number of Customer/ Connections	Billed KWh	Billed kW	Distribution Revenue
Residential	7,562	87,027,546		$2,774,726
General Service < 50 kW	1,549	49,211,450		$1,166,638
General Service > 50 kW	97	87,383,887	209,041	$671,848
Streetlights	2,058	2,007,912	5,336	$305,767
Sentinel Lights	42	41,511	115	$6,815
Unmetered Loads	45	249,040		$32,171
Total	11,353	225,921,346	214,493	$4,957,965

27. Ref: Exh3
Customer Count, kWh load, kW load and Revenue
Issue: Some of Lakeland's evidence may require adjustment in light of responses to the preceding customer count, load and revenue forecasting interrogatories.

Please re-file any Exhibit 3 tables that require to be updated as a result of changes in Lakeland's evidence.

Lakeland will not be updating the information in Exhibit 3 in light of responses to the preceding customer count, load and revenue forecasting interrogatories.

28. Ref: Exh3/Tab3/Sch1/p1
Other Distribution Revenue
In the table on page 1, Lakeland shows data for various accounts including 4375 – Revenue from Non-Utility Operations and 4405 – Interest and Dividend Income. For each of these accounts there is a significant difference between the "2007 Actual" and "2009 Test" values.

Please explain in detail the development of the 2009 Test values for the two identified accounts.

4375 _ Revenue from Non-Utility Operations
The revenue in this account was for on call/trouble call in Bracebridge Generation charged out at market rates. With utilizing other options in Generation, the need for Lakeland Power assistance is no longer required. All of the time charged out was incremental (nights and weekends).

4405 – Interest and Dividend Income
The majority of the amounts in this account came from the carrying charges for Regulatory assets. As those balances are now declining, it seemed evident that this account would not be as large as in prior years. Lakeland's cash balance is due to retained earnings that were not paid out as dividends.

Low Voltage Costs and Revenue

29. Ref: Exh2/Tab4/Sch1/p3; Exh9/Tab1/Sch1/p7

The forecast cost of LV Charges in Account 4750 is $656,843, compared with $613,233 in 2007, and estimated $666,534 in 2008.

a) Please describe the services received, if other than Shared Lines, and please provide the annual kW amounts billed to Lakeland in 2007 noting which ones if any involve a service other than Shared Lines.

Lakeland is currently charged by Hydro One for LV on 10 sites and LVDS on 7 sites. Based on the best documentation available at the time of the application preparation, it was expected that there would be a fixed as well as variable portion on the rates charged by Hydro One.

c) Please describe the assumptions that Lakeland has used for 2008 and 2009 about the LV (or sub-transmission) rates charged by the host distributor, compared to those charged during 2007.

	LV	LVDS	LV	LVDS	LV	LVDS	Data used	Total
	per kW	per kW	per site	per site	# of sites	# of sites	in App.	Dollars
Jan - April/07	$ 0.630	$ 2.110	$ -	$ -	19	7 actual	$ 241,500
May - Nov/07	$ 0.633	$ 2.120	$ -	$ -	19	7 actual	$ 313,114
Dec/07	$ 0.633	$ 2.120	$ -	$ -	10	7 actual	$ 58,619
Jan-July/08	$ 0.633	$ 2.120	$ -	$ -	10	7 actual	$ 386,543
Aug-Dec/08	$ 0.580	$ 1.240	$ 741.00	$ 741.00	10	7 estimate	$ 279,991
Jan-Dec/09	$ 0.580	$ 1.240	$ 741.00	$ 741.00	10	7 estimate	$ 656,843

Cost Allocation

30. Ref: Exh8/Tab1/Sch2

Please provide for the record of this Application an electronic copy of Lakeland's cost allocation study Informational Filing EB-2006-0247 ('rolled-up version of Run 2).

Lakeland will submit electronic copy of Cost Allocation Study Informational Filing – Run 2 as a separate file

31. Ref: Informational Filing, worksheet O2 'Monthly Fixed Charge Min. & Max.', & worksheet O3.5 'USL Metering Credit'

a) The results filed in the Informational Filing show that the calculated customer-related cost for Unmetered Scattered Load (USL) is higher than for the GS<50 class. Is this calculation done for USL on a per-customer or a per-connection basis? If "per-connection", please provide an explanation of how the cost can be higher given the absence of meter-related costs. If "per-customer", please provide information on the average number of connections per customer.

The calculation is done on a 'per-connection' basis. The issue with the higher costs is the billing costs caused by the default weighting factor. In the model, the factor for GS<50 kW was 2.0 while the factor for USL was 5.0. If the value is changed to 2.0 for USL, the resulting values for Minimum System with PLCC Adjustment changes and shows the expected difference due to metering cost.

Minimum System with PLCC Adjustment	GS <50 kW	USL
Weighting factor as filed	24.47	30.10
Weighting factor of 2.0	24.62	18.08

b)Please confirm that the calculated Metering Cost in worksheet O3.5 is $5.16 per customer per month. Please provide any comments that might be helpful in understanding why the difference between the cost per customer in the GS<50 kW class and the cost per connection of USL in worksheet O2 should not be approximately equal to the result in worksheet O3.5.

see part (a)

Revenue to Cost Ratios

32. Ref: Exh8/Tab1/Sch2

Lakeland specifies that the proposed revenue to cost ratios apply to 2009, and suggests that future ratios would depend on the development of a sector-wide study. In the event that the results of further study were not available in 2010 or 2011, does Lakeland intend to phase in ratios in those years that would be within the ranges listed in Table 2 in the referenced Exhibit?

Lakeland has not contemplated a phased in approach during the interim period however if a study is not feasible to be completed, Lakeland would consider a phase in ratio in the intervening years based on prior Board decisions.

Rate Design

33. Ref: Exh9/Tab1/Sch5; Exh9/Tab1/Sch9/Appendix A

The existing distribution rates shown in Schedule 5 are not consistent with the existing rates used in the impact calculations in Schedule 9. The former appear to be erroneous.

As indicated to Board staff assigned to this application on the date it was filed, it was noticed that that Schedule 5 was an old tariff schedule.

If the rates in Schedule 5 are incorrect, please provide a corrected version. If Schedule 5 is correct, please provide consistent impact calculations in the appendix to Schedule 9.

Lakeland Power Distribution Ltd.

Tariff OF RATES AND CHARGES
Effective May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges, and Loss Factors

EB-2007-0551

MONTHLY RATES AND CHARGES

Residential

Service Charge	**$**	14.86
Distribution Volumetric Rate	**$/kWh**	0.0131
Retail Transmission Rate – Network Service Rate	**$/kWh**	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kWh**	0.0048
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 Less Than 50 kW

Service Charge	**$**	30.05
Distribution Volumetric Rate	**$/kWh**	0.0097
Retail Transmission Rate – Network Service Rate	**$/kWh**	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kWh**	0.0043
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 4,999 kW

Service Charge	**$**	499.50
Distribution Volumetric Rate	**$/kW**	2.6507
Retail Transmission Rate – Network Service Rate	**$/kW**	1.7399
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	1.6988
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)	**$**	14.89
Distribution Volumetric Rate	**$/kWh**	0.0097
Retail Transmission Rate – Network Service Rate	**$/kWh**	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kWh**	0.0043
Wholesale Market Service Rate	**$/kWh**	0.0052
Rural Rate Protection Charge	**$/kWh**	0.0010
Standard Supply Service – Administrative Charge (if applicable)	**$**	0.25

Sentinel Lighting

Service Charge (per connection)	$	1.25
Distribution Volumetric Rate	$/kW	5.1354
Retail Transmission Rate – Network Service Rate	$/kW	1.3188
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3407
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)	$	0.84
Distribution Volumetric Rate	$/kW	3.4931
Retail Transmission Rate – Network Service Rate	$/kW	1.3122
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3133
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration

Arrears certificate	$	15.00
Statement of account	$	15.00
Request for other billing information	$	15.00
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 (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00

Non-Payment of Account

Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge - no disconnection	$	30.00
Collection of account charge - no disconnection - after regular hours	$	165.00
Disconnect/Reconnect at meter - during regular hours	$	65.00
Disconnect/Reconnect at meter - after regular hours	$	185.00
Disconnect/Reconnect at pole - during regular hours	$	185.00
Disconnect/Reconnect at pole - after regular hours	$	415.00

Temporary service install & remove - overhead - no transformer	$	500.00
Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
Specific Charge for Access to the Power Poles $/pole/year	$	22.35

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)
	$/kW	0.00
	$/kW	0.00

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0428
Total Loss Factor – Secondary Metered Customer > 5,000 kW	0.0000
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0323
Total Loss Factor – Primary Metered Customer > 5,000 kW	0.0000

34. Ref: Exh9/Tab1/Sch7

Please confirm that the Monthly Service Charges shown in this schedule are net of the Smart Meter adder, and that the Rate Order is expected to be gross of this adder.
Lakeland wishes to confirm that the schedule is net of the Smart Meter adder as it was unclear at the time of filing as to how the Smart Meters would be handled. The Guideline has now been issued and Lakeland will be submitting a separate Smart Meter filing but wishes to have the $.25 per customer per month as a placeholder should the filing not be approved by May 1, 2009.

35. Ref: Exh9/Tab1/Sch1/p3; Exh9/Tab1/Sch9/Appendix A /p18

The rates including rate adders proposed for the GS > 50 kW class do not result in a constant ratio of fixed to variable revenue, because the fixed rate increases by 1.4% and the volumetric rate decreases by 2.1%.

a) Please provide an estimate of the LV adder component in the current volumetric rate for the GS>50 kW class, and after calculating the 2008 and 2009 volumetric rates net of the LV adder.

The split in volumetric charge can be found on Exh9/Tab1/Sch1 p 10 and is reproduced below;

Rate Schedule - 2009 Test Year Rates

FOR 2009 TEST YEAR	2009 Test Year Core Distribution Rates				Low Voltage		2009 Test Year Distribution Rates Before SM Adder				2009 Total Customer Rate	
Customer Class	Connection	Customer	kW	kWh	kW	kWh	Connection	Customer	kW	kWh	Smart Meter Rate Rider ($) per Metered Cust./Mont	Customer Rate including Smart Meter Adder
Residential		$16.3600		$0.0148		$0.0032		**$16.3600**		**$0.0180**	**$0.2500**	**$16.6100**
GS <50 kW		$39.1300		$0.0089		$0.0028		**$39.1300**		**$0.0118**	**$0.2500**	**$39.3800**
GS>=50 kW		$506.3200	$1.4703		$1.1241			**$506.3200**	**$2.5943**		**$0.2500**	**$506.5700**
Street Light	$3.6200		$11.1206		$0.8690		**$3.6200**		**$11.9896**			
Sentinel	$3.8500		$13.3059		$0.8871		**$3.8500**		**$14.1930**			
Unmetered Scattered Load	$38.7800			$0.0174		$0.0028	**$38.7800**			**$0.0203**		
Transformer Discount			($0.6000)						**($0.6000)**			

Specifically for GS>50 kW class, the same split as current rates was used for establishing base rate:

Fixed monthly charge $506.32 70.2%

Variable in base rate $1.4703 per kW 29.8%

When the below adder is included;

LV adder variable $1.1241 per kW

Fixed monthly charge $506.32 54.9%

Variable in final rate $2.5943 per kW 45.1%

Customer Class	Total Net Revenue Requirement for 2009	Fixed Portion in Base Rate	Variable Portion in Base Rate	Proposed Fixed Charge Spilt before LV	Proposed Variable Charge Spilt Before LV	LV Charges	Proposed Fixed Charge Spilt	Proposed Variable Charge Spilt
Residential	$ 2,774,725	$ 1,484,572	$ 1,290,153	53.5%	46.5%	$ 276,404	48.7%	51.3%
GS<50 kW	$ 1,166,609	$ 727,348	$ 439,261	62.3%	37.7%	$ 140,017	55.7%	44.3%
GS>=50 kW(incl. trsf adj)	$ 839,135	$ 589,356	$ 249,779	70.2%	29.8%	$ 234,974	54.9%	45.1%
Street Light	$ 148,739	$ 89,400	$ 59,339	60.1%	39.9%	$ 4,637	58.3%	41.7%
Sentinel	$ 3,471	$ 1,940	$ 1,530	55.9%	44.1%	$ 102	54.3%	45.7%
Unmetered Scattered Load	$ 25,286	$ 20,941	$ 4,344	82.8%	17.2%	$ 709	80.6%	19.4%
TOTALS	$4,957,965	$2,913,558	$2,044,407	58.8%	41.2%	$656,843	51.9%	48.1%

c) Please provide a verification that the fixed:volumetric split is being held constant in the proposed rates for the class as stated in Schedule 1.

Lakeland is maintaining the same fixed/volumetric split in the base rate as found in current rates before LV charges and Smart meter charges.

Bridge Year at Existing Rates - 2008 Approved Rates Applied to 2008 Billing Determinants

Based on Existing Rates For 2008	Load Forecast - Billing Determinants For 2008					Fixed LDC Revenue		Variable LDC Revenue	
Class	kWh	kw	Transformer Discount kw	Annualized Customers (Average)	Annualized Connections (Average)	Fixed Distribution Revenue	Current Fixed Charge Spilt	Variable Distribution Revenue	Current Volumetric Split
Residential	84,753,044			89,976		$1,314,549	60.56%	$856,006	39.44%
GS <50 kW	48,475,435			18,456		$549,989	62.53%	$329,633	37.47%
GS>=50 kW	90,677,864	217,485	99,820	1,164		$581,127	69.40%	$256,244	30.60%
Street Light	1,986,637	5,280			24,696	$20,745	60.37%	$13,619	39.63%
Sentinel	41,641	116			516	$645	56.20%	$503	43.80%
Unmetered Scattered Load	255,587				576	$8,577	83.36%	$1,712	16.64%
Back-up/Standby Power	0	0				$0			
TOTALS	**226,190,208**	**222,881**	**99,820**	**109,596**	**25,788**	**$2,475,631**	**62.94%**	**$1,457,717**	**37.06%**

2009 Test Year at Proposed Rates - 2009 Proposed Rates Applied to 2009 Billing Determinants

2009	Load Forecast - Billing Determinants For 2009					Fixed LDC Revenue		Variable LDC Revenue	
Class	kWh	kw	Transformer Discount kw	Annualized Customers (Average)	Annualized Connections (Average)	Fixed Distribution Revenue	Current Fixed Charge Split	Variable Distribution Revenue	Current Volumetric Split
Residential	87,027,546	0	0	90,744	0	$1,484,572	53.50%	$1,290,153	46.50%
GS <50 kW	49,211,450	0	0	18,588	0	$727,348	62.35%	$439,261	37.65%
GS>=50 kW	87,383,887	209,041	95,945	1,164	0	$589,356	70.23%	$249,779	29.77%
Street Light	2,007,912	5,336	0	0	24,696	$89,400	60.10%	$59,339	39.90%
Sentinel	41,511	115	0	0	504	$1,940	55.91%	$1,530	44.09%
Unmetered Scattered Load	249,040	0	0	0	540	$20,941	82.82%	$4,344	17.18%
Back-up/Standby Power	0	0	0	0	0	$0			
TOTALS	**225,921,346**	**214,492**	**95,945**	**110,496**	**25,740**	**$2,913,558**	**58.77%**	**$2,044,407**	**41.23%**

Retail Transmission Service Rates

36. Ref: "Electricity Distribution Retail Transmission Service Rates", Guideline G-2008-0001, October 22, 2008

Under the above referenced OEB Guideline, Lakeland is expected to file an update to its Cost of Service application with evidence to support a change in its RTSRs. The adjustment in RTSRs is intended to eliminate future growth in the Applicant's variance accounts that are related to the pass-through of transmission costs.

a) Please file a table showing 2 years of Lakeland's wholesale Network and Connection costs charged by the host distributor, and its retail billings for Network and Connection service to its retail customers.

Network Charges	Billed	Charged	Carrying Charges	Balance	Total Loss Factor Change	Adj. if New H1 Rates
2005 Opening Balance				($107,586)		
2006	($1,225,012)	$1,000,503	($10,259)	($342,354)	($130,866)	($140,292)
2007	($1,232,810)	$1,062,907	($19,343)	($531,600)	($131,699)	($104,271)
TOTALS	($2,457,822)	$2,063,410	($29,602)	**($531,600)**	**($262,564)**	**($244,563)**
Connection Charges	**Billed**	**Charged**	**Carrying Charges**	**Balance**	**Total Loss Factor Change**	**Adj. if New H1 Rates**
2005 Opening Balance				($280,299)		
2006	($1,068,038)	$994,315	($11,149)	($365,171)	($114,096)	($148,487)
2007	($1,074,133)	$881,474	($20,882)	($578,712)	($114,747)	($88,569)
TOTALS	($2,142,171)	$1,875,789	($32,032)	**($578,712)**	**($228,844)**	**($237,057)**

b) Please provide an analysis of the variances between costs and the corresponding revenues, and any trends in these amounts.

	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
2006 Network charge	102,161	97,186	77,760	79,805	80,098	77,553	91,893	74,882	74,625	75,041	81,157	88,344	1,000,503
2007 Network charge	104,860	102,345	99,068	81,199	71,845	87,573	87,313	81,993	80,625	72,319	89,553	104,215	1,062,907
2006 Network billed	123,411	103,499	105,331	100,864	96,669	98,603	88,953	95,302	93,321	97,568	113,201	108,290	1,225,012
2007 Network billed	112,613	112,167	115,887	100,007	101,567	93,122	94,896	89,728	97,680	110,469	97,914	106,760	1,232,810

	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
2006 Connection charge	126,754	122,642	106,093	104,131	66,431	64,320	76,160	62,104	61,891	63,312	67,308	73,269	994,415
2007 Connection charge	86,967	84,881	82,100	67,344	59,586	72,630	72,414	68,002	66,867	59,979	74,272	86,432	881,474
2006 Connection billed	107,271	89,963	91,619	87,870	84,610	86,494	78,118	83,352	81,174	84,877	98,543	94,149	1,068,038
2007 Connection billed	97,899	97,618	100,811	87,142	88,642	81,576	83,167	78,531	84,755	95,896	85,074	93,023	1,074,133

	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
Network % difference 2006	20.8%	6.5%	35.5%	26.4%	20.7%	27.1%	-3.2%	27.3%	25.1%	30.0%	39.5%	22.6%	22.4%
Network % difference 2007	7.4%	9.6%	17.0%	23.2%	41.4%	6.3%	8.7%	9.4%	21.2%	52.8%	9.3%	2.4%	16.0%
Connection % difference 2006	-15.4%	-26.6%	-13.6%	-15.6%	27.4%	34.5%	2.6%	34.2%	31.2%	34.1%	46.4%	28.5%	7.4%
Connection % difference 2007	12.6%	15.0%	22.8%	29.4%	48.8%	12.3%	14.8%	15.5%	26.8%	59.9%	14.5%	7.6%	21.9%

c) Please provide an analysis of what the variances would have been if the requested Total Loss Factor of 1.0614 had been in place instead of the current factor of 1.0428.

see chart in part (a)

d) Please file proposed RTSR rates for each customer class that would adjust to the currently approved RTSRs to recover the wholesale cost of transmission service, based on the assumption that the Interim rates charged by Hydro One to embedded distributors effective May 1, 2008 had been in effect during the 2-year period in part a). Please provide the calculations used to derive the adjustment factors for the Network and Connection RTSR rates.

As per the table above, the average Network retail charge is approximately 19% higher than the rates actually charged by Hydro One, and Connection is 14%. If the interim rates are used for the entire period, the retail charge for Network is 35% higher and Connection 31%.

Network Charges	Actual Billed	Actual Charged	% Overbilled	Interim rates Charged	% Overbilled
2006	($1,225,012)	$1,000,503	22.44%	$860,211	42.41%
2007	($1,232,810)	$1,062,907	15.98%	$958,637	28.60%
TOTALS	($2,457,822)	$2,063,410	19.11%	$1,818,847	35.13%
Connection Charges	**Actual Billed**	**Actual Charged**	**% Overbilled**	**Interim rates Charged**	**% Overbilled**
2006	($1,068,038)	$994,415	7.40%	$845,928	26.26%
2007	($1,074,133)	$881,474	21.86%	$792,905	35.47%
TOTALS	($2,142,171)	$1,875,889	14.19%	$1,638,833	30.71%

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			Current	New										
NETWORK CHARGES INTERIM $ with NEW LOSS FACTOR			1.0428	1.0614										New Loss Factor
Class	Jan AVG	Feb AVG	Mar AVG	Apr AVG	May AVG	Jun AVG	Jul AVG	Aug AVG	Sep AVG	Oct AVG	Nov AVG	Dec AVG	TOTAL	Interim Rate
Residential (kWh)	$76,156	$84,058	$80,078	$68,978	$55,653	$43,887	$44,048	$45,543	$42,286	$42,344	$48,850	$59,327	**$691,210**	$ 0.00414
GS <50 kW (kWh)	$34,241	$35,944	$35,080	$32,995	$28,396	$25,666	$30,653	$31,121	$29,544	$27,178	$26,270	$28,872	**$365,960**	$ 0.00378
GS>=50 kW	$60,459	$60,957	$60,673	$61,108	$59,538	$64,878	$65,343	$63,910	$66,035	$64,233	$63,407	$60,352	**$750,892**	$ 1.62587
Street Light	$1,017	$1,017	$1,017	$1,017	$763	$0	$0	$0	$508	$1,017	$1,017	$1,017	**$8,390**	$ 1.18419
Sentinel (kWh)	$24	$24	$24	$24	$23	$23	$23	$23	$23	$23	$23	$23	**$280**	$ 0.00325
Unmetered Scattered Load (kWh)	$182	$182	$182	$182	$181	$181	$179	$179	$168	$167	$167	$166	**$2,115**	$ 0.00378
Back-up/Standby Power	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**	$ -
TOTALS	**$172,078**	**$182,181**	**$177,054**	**$164,304**	**$144,555**	**$134,635**	**$140,246**	**$140,776**	**$138,565**	**$134,962**	**$139,734**	**$149,757**	**$1,818,847**	

			Current	New										
CONNECTION CHARGES INTERIM $ with NEW LOSS FACTOR			1.0428	1.0614										New Loss Factor
Class	Jan AVG	Feb AVG	Mar AVG	Apr AVG	May AVG	Jun AVG	Jul AVG	Aug AVG	Sep AVG	Oct AVG	Nov AVG	Dec AVG	TOTAL	Interim Rate
Residential (kWh)	$69,077	$76,244	$72,634	$62,569	$50,485	$39,814	$39,961	$41,317	$38,364	$38,416	$44,315	$53,798	**$626,994**	$ 0.00376
GS <50 kW (kWh)	$30,635	$32,159	$31,386	$29,521	$25,406	$22,963	$27,424	$27,844	$26,433	$24,317	$23,503	$25,831	**$327,422**	$ 0.00338
GS>=50 kW	$53,994	$54,276	$54,145	$54,546	$53,280	$58,016	$58,727	$57,485	$58,945	$57,383	$56,637	$53,937	**$671,372**	$ 1.44886
Street Light	$908	$908	$908	$908	$908	$908	$908	$908	$908	$908	$908	$908	**$10,899**	$ 1.05758
Sentinel (kWh)	$22	$22	$22	$22	$21	$21	$21	$21	$21	$21	$21	$21	**$255**	$ 0.00295
Unmetered Scattered Load (kWh)	$162	$162	$162	$162	$162	$162	$160	$160	$150	$149	$149	$149	**$1,890**	$ 0.00338
Back-up/Standby Power	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**	$ -
TOTALS	**$154,798**	**$163,771**	**$159,257**	**$147,728**	**$130,264**	**$121,885**	**$127,201**	**$127,735**	**$124,821**	**$121,194**	**$125,534**	**$134,644**	**$1,638,832**	

Deferral and Variance Accounts

**37. Ref: Exh1/Tab3/Sch1/Appendix A/p13;
Exh1/Tab3/Sch2/Appendix A and B**

The note to the audited financial statements (Schedule 1 reference) suggests that the recovery of the regulatory assets would be complete by mid-2008. In the pro forma balance sheets (Schedule 2 reference) Account 1590 'Recovery of Regulatory Assets' is forecast to have a balance of $685,595.59.

Please describe how this balance has happened or is expected to happen during 2008, and confirm that the balance is not expected to change during 2009.

As Lakeland was not asking for disposition of any deferral or variance accounts at the time of the rate application, it was deemed prudent to use the 2007 ending balances for 2008 and 2009 subsequent years. That would ensure there was no working capital or cash balance transactions related to regulatory accounts. From Jan 2008 until April 2008, the Regulatory rate rider was still in place expecting to be sufficient enough to reduce the balance in 1590 to zero as per 2006 EDR Regulatory Asset calculation.

Trend Analysis of the Composition of Account 1590 – the interest related to the accounts to be disposed of (2006 EDR), were posted separately but as the recovery was collected, it was posted to the base account. The amounts of $(1,012,095) in 2006 and $(1,343,501) in 2007 could have been posted as a split number between principal and interest recovery. In any event, the balance would still be the same.

		2005						2006							2007					
Account Description	Account Number	Opening Principal Amounts as of Jan-1-05	Transactions (additions) during 2005, excluding interest and adjustments	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	Transfer of Board-approved amounts to 1590 as per 2006 EDR	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	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	Total Balance
Reg. Asset Recovery to March 2005	1590	$(320,427)	$ (202,012)	$(522,439)	$ (6,760)	$(34,899)	$(41,659)	$(522,439)			$ (522,439)	$(41,659)	$(28,220)		$ (69,879)	$ (522,439)		$ (522,439)	$ (69,879)	$ (24,698)	$ (94,578)	$ (617,016)
to April 2005 to April 2006	1590	$ -	$ (408,085)	$(408,085)	$ -	$ (8,561)	$ (8,561)	$(408,085)	$ (249,367)		$ (657,452)	$ (8,561)	$(31,430)		$ (39,991)	$ (657,452)		$ (657,452)	$ (39,991)	$ (31,081)	$ (71,072)	$ (728,524)
to May 2006 to December 2007	1590	$ -		$ -	$ -		$ -	$ -	$ (762,728)		$ (762,728)	$ -	$ (9,403)		$ (9,403)	$ (762,728)	$(1,343,501)	$(2,106,229)	$ (9,403)	$ (67,689)	$ (77,091)	$(2,183,320)
Balances as per 2006 EDR (May 2006)	1590	$ -		$ -	$ -		$ -	$ -		$3,475,494	$3,475,494	$ -	$ 98,049	$476,609	$574,658	$3,475,494		$ 3,475,494	$574,658	$164,304	$738,962	$ 4,214,456
Grand Total	**1590**	**$(320,427)**	**$ (610,097)**	**$(930,524)**	**$ (6,760)**	**$(43,460)**	**$(50,220)**	**$(930,524)**	**$(1,012,095)**	**$3,475,494**	**$1,532,876**	**$(50,220)**	**$ 28,997**	**$476,609**	**$455,385**	**$1,532,876**	**$(1,343,501)**	**$ 189,375**	**$455,385**	**$ 40,836**	**$496,221**	**$ 685,596**

38. Exh5/Tab1/Sch2; Exh1/Tab3/Sch1/Appendix A/p13

Lakeland has provided information on opening balances at January 1, 2005 and closing balances at December 31, 2007.

a) Please provide a more detailed continuity schedule for Lakeland's deferral and variance accounts using the Excel spreadsheet attached. (Please note that forecasting principal transactions beyond December 31, 2007 and the interest on those transactions in columns AM – AP is optional.)

see attached file

b) Please provide documentation that would assist parties in understanding the balances in Account 1590 'Regulatory Asset Recovery'. In particular, please include:
- the instructions that result in an interest balance of $497,032, and
- a reconciliation of how the balance in the audited financial statement in the Exhibit 1 reference ($991,978) and the sum of the principal and interest accounts in the Exhibit 5 reference ($1,021,798)

see Board question # 3

c) The continuity schedule spreadsheet provides a sub-total for the accounts: 1508, 1518, 1525, 1548, 1570, 1571, 1572, 1574, 1582, 1592, 1595, 2425. Please calculate a set of rate riders that would dispose of the net balance of these accounts, identifying the date of the balance and how many years the rate rider would be in effect. Please also provide details of how the individual balances would be allocated to customer classes, where possible using updated values of the same allocators as were used for the respective accounts in the 2006 model for regulatory asset recovery rate riders.

Regulatory Asset Accounts:	Amount	ALLOCATOR	Residential	GS <50 kW	GS>=50 kW	Street Light	Sentinel	Unmetered Scattered Load	Total
WMSC - Account 1580	$ (193,208)	kWh	$ (74,426)	$ (42,086)	$ (74,731)	$ (1,717)	$ (36)	$ (213)	$ (193,208)
One-Time WMSC - Account 1582	$ 2	kWh	$ 1	$ 0	$ 1	$ 0	$ 0	$ 0	$ 2
Network - Account 1584	$ (557,052)	kWh	$ (214,583)	$ (121,340)	$ (215,462)	$ (4,951)	$ (102)	$ (614)	$ (557,052)
Connection - Account 1586	$ (606,411)	kWh	$ (233,596)	$ (132,092)	$ (234,553)	$ (5,390)	$ (111)	$ (668)	$ (606,411)
Power - Account 1588	$ 1,367,162	kWh	$ 526,647	$ 297,803	$ 528,803	$ 12,151	$ 251	$ 1,507	$ 1,367,162
Subtotal - RSVA	$ 10,493		$ 4,042	$ 2,286	$ 4,058	$ 93	$ 2	$ 12	$ 10,493
Other Regulatory Assets - Account 1508	$ 145,083	Dx Revenue	$ 81,196	$ 34,139	$ 19,660	$ 8,948	$ 199	$ 941	$ 145,083
Retail Cost Variance Account - Acct 1518	$ (50,419)	# of Customers	$ (41,386)	$ (8,478)	$ (531)	$ (3)	$ -	$ (21)	$ (50,419)
Retail Cost Variance Account (STR) Acct 1548	$ 77,924	# of Customers	$ 63,965	$ 13,103	$ 820	$ 5	$ -	$ 32	$ 77,924
Rebate Cheques - Acct 1525	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
LV Variance Account - Acct 1550	$ (30,931)	Dx Revenue	$ (17,310)	$ (7,278)	$ (4,191)	$ (1,908)	$ (43)	$ (201)	$ (30,931)
Smart Meter Account - Acct 1555/1556		deferred							$ -
CDM - Acct 1565/1566	$ 0								
Transition Costs - Acct 1570	$ (0)								
Pre-Market Opening - Acct 1571	$ 0								
Extraordinary Event Losses - Acct 1572	$ -								$ -
Deferred Rate Impact Amounts - Acct 1574	$ -								$ -
Other Deferred Credits - Acct 2425	$ -								$ -
Subtotal - Non RSVA	$ 141,658		$ 86,464	$ 31,486	$ 15,758	$ 7,042	$ 157	$ 752	$ 141,658
Total to be Recovered	$ 152,151		$ 90,506	$ 33,771	$ 19,817	$ 7,135	$ 159	$ 763	$ 152,151

Class		Residential	GS <50 kW	GS>=50 kW	Street Light	Sentinel	Unmetered Scattered Load
Regulatory Asset Rate Riders-Non-RSVA	**$ 141,658**	$ 0.0010	$ 0.0006	$ 0.0754	$ 0.0035	$ 1.3644	$ 0.0030
Billing Determinants		kWh	kWh	kW	kWh	kW	kWh

Class		Residential	GS <50 kW	GS>=50 kW	Street Light	Sentinel	Unmetered Scattered Load
Regulatory Asset Rate Riders-ALL	**$ 152,151**	$ 0.0010	$ 0.0007	$ 0.0948	$ 0.0036	$ 1.3812	$ 0.0031
Billing Determinants		kWh	kWh	kW	kWh	kW	kWh

2009	Load Forecast - Billing Determinants For 2009				
Class	kWh	kw	Annualized Customers (Average)	Annualized Connections (Average)	Distribution Revenue
Residential	87,027,546	0	90,744	0	2,774,726
GS <50 kW	49,211,450	0	18,588	0	1,166,638
GS>=50 kW	87,383,887	209,041	1,164	0	671,848
Street Light	2,007,912	5,336	7	24,696	305,767
Sentinel	41,511	115	0	504	6,815
Unmetered Scatter	249,040	0	45	540	32,171
Back-up/Standby P	0	0	0	0	0
TOTALS	**225,921,346**	**214,492**	**110,548**	**25,740**	**4,957,965**

2009	Allocator				
Class	kWh	kw	Customer Number	Connections	Revenue
Residential	38.52%	0.00%	82.09%		55.97%
GS <50 kW	21.78%	0.00%	16.81%		23.53%
GS>=50 kW	38.68%	97.46%	1.05%		13.55%
Street Light	0.89%	2.49%	0.01%		6.17%
Sentinel	0.02%	0.05%	0.00%		0.14%
Unmetered Scatter	0.11%	0.00%	0.04%		0.65%
TOTALS	**100.0%**	**100.0%**	**100.0%**	**0.0%**	**100.0%**

d) Please provide a table and explanatory notes similar to the previous interrogatory, but calculating a rate rider that would dispose of <u>all</u> deferral and variance accounts except Accounts 1562 and 1563.

Results from Model

Regulatory Asset Reco	Non-RSVA only		ALL Accounts (excl. 1555)	
Class	per kWh	per kW	per kWh	per kW
Residential	0.0010		0.0010	
GS <50 kW	0.0006		0.0007	
GS>=50 kW		0.0754		0.0948
Street Light	0.0035		0.0036	
Sentinel		1.3644		1.3812
Unmetered Scatter	0.0030		0.0031	

39. Ref: Exh5/Tab1/Sch2/p1

Please provide an explanation why the interest charges in Account 1590 on December 31, 2007 of $497,032 are significantly greater than the principal in Exh5/Tab1/Sch2/p1.

See Lakeland's response to Board question 3 and 37

Bill Impacts

40. Ref: Exh9/Tab1/Sch9/Appendix A / pp 4 & 10

a) Please provide a version of the detailed impact calculation for a Residential customer consuming 500 kWh per month and a GS< 50 kW customer consuming 2000 kWh per month, changing the 2009 bill such that:

- the 2009 RTSRs are as calculated in part c) of the interrogatory above, and
- the 2009 bill includes a rate rider to recover regulatory assets consistent with the higher of the hypothetical rate riders calculated in the two interrogatories above.

Lakeland Power Distribution Ltd
Monthly Bill Impact Calculations - Revised Network/Connection charges and Reg Asset Rate Rider

RESIDENTIAL Monthly Bill Impact Calculations

500 kWh	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Rate Change	Change %	As a % of 2008
Monthly Service Charge			$14.61			$16.36	$1.75	11.98%	2.95%
Distribution (kWh)	500	$0.0131	$6.55	500	$0.0180	$9.00	$2.45	37.40%	4.13%
Reg Asset Rate Rider (kWh)	500	$0.0000	$0.00	500	$0.0010	$0.50	$0.50	#DIV/0!	#DIV/0!
Smart Meter Rider (per month)			$0.25			$0.25	$0.00	0.00%	0.00%
SSS Administration (per month)			$0.25			$0.25	$0.00	0.00%	0.00%
Distribution Sub-Total			**$21.66**			**$26.36**	**$4.70**	**21.70%**	**7.91%**
Cost of Power Commodity (kWh)	521	$0.0500	$26.05	531	$0.0500	$26.55	$0.50	1.92%	0.84%
Cost of Power Commodity (kWh)	0	0.0590	$0.00	0	0.0590	$0.00	$0.00	#DIV/0!	0.00%
Transmission (kWh)	521	0.0095	$4.95	531	0.0079	$4.19	($0.76)	(15.35%)	(1.28%)
Wholesale Market Service (kWh)	521	0.0062	$3.23	531	0.0062	$3.29	$0.06	1.86%	0.10%
Debt retirement charge (kWh)	500	0.0070	$3.50	500	0.0070	$3.50	$0.00	0.00%	0.00%
Cost of Power Sub-Total			**$37.73**			**$37.53**	**($0.20)**	**(0.53%)**	**(0.34%)**
Total Bill before GST			**$59.39**			**$63.89**	**$4.50**	**7.58%**	**7.58%**

GENERAL SERVICE LESS THAN 50 KW Monthly Bill Impact Calculations

GS <50 kW Consumption	**2008 BILL**			**2009 BILL**			**RATE CHANGE IMPACTS**		
2,000 kWh	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Rate Change	Change %	As a % of 2008
Monthly Service Charge			$29.80			$39.13	$9.33	31.31%	4.42%
Distribution (kWh)	2,000	$0.0097	$19.40	2,000	$0.0118	$23.54	$4.14	21.34%	1.96%
Reg Asset Rate Rider (kWh)	2,000	$0.0000	$0.00	2,000	$0.0007	$1.40	$1.40	#DIV/0!	#DIV/0!
Smart Meter Rider (per month)			$0.25			$0.25	$0.00	0.00%	0.00%
SSS Administration (per month)			$0.25			$0.25	$0.00	0.00%	0.00%
Distribution Sub-Total			**$49.70**			**$64.57**	**$14.87**	**29.92%**	**7.05%**
Cost of Power Commodity (kWh)	750	$0.0500	$37.50	750	$0.0500	$37.50	$0.00	0.00%	0.00%
Cost of Power Commodity (kWh)	1,336	0.0590	$78.82	1,373	0.0590	$81.01	$2.19	2.78%	1.04%
Transmission (kWh)	2,086	0.0086	$17.94	2,123	0.0072	$15.20	($2.74)	(15.27%)	(1.30%)
Wholesale Market Service (kWh)	2,086	0.0062	$12.93	2,123	0.0062	$13.16	$0.23	1.78%	0.11%
Debt retirement charge (kWh)	2,000	0.0070	$14.00	2,000	0.0070	$14.00	$0.00	0.00%	0.00%
Cost of Power Sub-Total			**$161.19**			**$160.87**	**($0.32)**	**(0.20%)**	**(0.15%)**
Total Bill before GST			**$210.89**			**$225.44**	**$14.55**	**6.90%**	**6.90%**

b) In the event that either of the calculated total bill impacts in part a) is greater than 10%, please file a revised version of the whole Appendix A with the revised RTSRs and the hypothetical rate rider.

Loss Factors

41. Ref: Exh4/Tab2/Sch9/Table 1

a) Please clarify whether Lakeland is entirely embedded in the Hydro One distribution system, or alternatively whether it receives part of its requirements directly from transformer stations with bills issued by the IESO.

Lakeland is entirely embedded in the Hydro One distribution system however it receives Power bills from both Hydro One and Bracebridge Generation

b) In light of the Hydro One approved loss factor for embedded distributors of 1.034, and the default Supply Facility Loss Factor of 1.0045 for distributors that are not embedded, please provide an explanation of the requested SFLF at 1.0290.

The power bills received from Hydro One have a loss factor of 1.034 however the bills from Bracebridge Generation have no loss factor as they are metered at the same point as the supply point. Approximately 12% of Lakeland's power requirement comes from Bracebridge Generation, resulting in a blended SFLF of 1.029

c) Please provide a brief explanation of why the requested Total Loss Factor is more than 2% higher than the existing approved factor.

The Total Loss Factor is 2% higher because in the original determination of the TLF, the SFLF was not taken into account and only the Distribution loss adjustment factor was used rather than the two added together.

(see chart below where SFLF value used was 1.0)

42. Ref: Exh9/Tab1/Sch7/p 3

Please confirm that the proposed Total Loss Factor should be 1.0614 rather than 1.0654 as shown.

Lakeland TLF should be as below as were the values used in all calculations.

Loss Factors	2008	2009 Updated
Supply Facilities Loss Factor	1.0000	1.0290
Distribution Loss Factor - Secondary Metered Customer < 5,000 kW	1.0428	1.0315
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	1.0324	1.0212
Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0428	1.0614
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0324	1.0508

Appendix A

Code of Ethics

LAKELAND HOLDING LTD.
Corporate Governance

Code Of Ethics

POLICY

It is the policy of Lakeland Holding Ltd. to conduct its business affairs in compliance with all applicable laws, statutes, rules and regulations and expects Employees acting on its behalf to do likewise. In addition, business dealings among Employees with customers, suppliers, governmental and regulatory authorities, communities and shareholders ("Stakeholders") must be based on principles of honesty, integrity and the ethical standards outlined below.

PROCEDURE

This Code of Ethics and Business Conduct (sometimes referred to heron as the "Code") applies to all directors, officers and employees (collectively "Employees") of Lakeland Holding Ltd. and its subsidiaries ("Lakeland" or the "Company") in all locations where Lakeland does its business. The principles outlined in this document are intended to:

- establish a minimum standard of conduct by which all Employees are expected to abide,
- protect the business interests of Lakeland, its Employees and customers,
- maintain Lakeland's reputation for integrity, and
- ensure that Lakeland, through its Employees, complies with applicable legal and regulatory obligations.

The principles in the Code are the individual and collective responsibility of all Employees.

The principles in the Code are extremely important because they establish a minimum standard of conduct for all Employees at all levels and ensure a consistent and high standard of ethical conduct no matter where a customer, supplier or other person or entity may have contact with Lakeland. Employees must familiarize themselves with and carefully follow these principles in their daily activities. All Employees must act, and must also be seen by Stakeholders to be acting, in accordance with these principles. Employees are also responsible for managing risk effectively and preventing losses.

The Code is not meant to be a complete listing of business conduct and ethics covering every eventuality. Consequently, should an Employee be confronted with a situation where further guidance is required, the matter should be discussed with their immediate supervisor or senior management.

The Code is an addition to and does not detract from any other agreements, manuals, guidelines and policies that may also be applicable to Employees and which may deal with items also dealt with in the Code.

I. REPORTING VIOLATIONS OF THE CODE

Employees have a duty to report situations of non-compliance with respect to this Code of which they become aware including any violation of the laws, rules, regulations or policies that apply to the Company, to their immediate supervisor, the CEO, or to the Chairman of the Audit Committee of the Board of Directors of Lakeland (the "Board") by mail, telephone or e-mail. Aside from instances of non-compliance, Employees may also report concerns relating to business conduct and ethics in the same manner. All reports of known or suspected violations of the law or this Code will be handled sensitively and with discretion. Your supervisor, the CEO and the Company will protect your confidentiality to the extent possible, consistent with the law and the Company's need to investigate your concern. A failure to comply with the Code will result in disciplinary actions up to and including termination. All violations will be reported to the CEO.

II. POLICY AGAINST RETALIATION

Retaliation in any form against an individual who, in good faith, seeks help or reports known or suspected violations of this Code or of the law, even if the report is mistaken, or who assists in the investigation of a reported violation, is itself a serious violation of this Code. Acts of retaliation should be reported immediately and will be disciplined appropriately, including potential termination of employment. Lakeland does not tolerate retaliation on any form against Employees who honestly and accurately report a concern. At the same time, it is serious and unacceptable to make false allegations.

III. INTEGRITY OF RECORDS AND SOUND ACCOUNTING PRACTICES

Lakeland takes very seriously the accuracy of its financial records and financial statements. All Company records are to be prepared with care and honesty and in compliance with Lakeland's accounting and internal control procedures, record keeping policy and with Canadian generally accepted accounting principles and all standards, laws and regulations for accounting and financial reporting of transactions, estimates and forecasts.

All Employees involved in preparing or providing information for inclusion in any reports or documents which Lakeland is required to file with any governmental or regulatory agency or any public communications are responsible for ensuring that (i)

information provided is complete, accurate and current, and (ii) reports and documents are prepared in a timely manner. If an Employee becomes aware of a materially inaccurate or misleading statement in a public communication, the Employee must report it immediately to the Chief Executive Officer of Lakeland or the chairman of the Audit Committee of the Board. Making false or misleading statements to external auditors can be a criminal act that can result in severe penalties. No Employee may directly or indirectly take any action to fraudulently influence, coerce, manipulate or mislead Lakeland's independent public auditors for the purpose of rendering Lakeland's financial statements misleading.

IV. MAINTENANCE OF ASSETS

All Employees have a responsibility to protect Lakeland's assets against loss, theft, abuse and unauthorized use or disposal. Lakeland's assets include all property whether tangible, intangible or electronic in form, which includes the Company's products, equipment, vehicles, computers, and software and telephone systems. All Lakeland's assets must only be used for legitimate business purposes.

Employees should report any suspected incident of fraud or theft to their immediate supervisor for investigation. Company assets should not be used for non-Company business, though incidental personal use is permitted, provided that such use is not in violation of applicable law or in advancement of any illegal purpose, personal or financial gain. There should be no expectation of personal privacy in respect of the use of any of the Company's assets.

V. CONFIDENTIALITY

Employees must preserve and protect the confidentiality of information entrusted to them by the Company, Stakeholders and third parties, except when disclosing information is approved or legally mandated. Confidential information encompasses proprietary information which is not in the public domain that could be of use to investors or competitors, or that could harm the Company, its employees, its customers or suppliers if disclosed. Employees must be aware that the responsibility to protect confidential information continues outside the workplace. Employees should not discuss confidential information in public places, such as elevators, public transportation or restaurants.

Employees must also not use or disclose to the Company any proprietary information or trade secrets of any former employer or other person or entity with whom obligations of confidentiality exist.

VI. CONFLICT OF INTEREST

The Company requires that each Employee disclose any situations that reasonably would be expected to give rise to a conflict of interest. If you suspect that you have a conflict of interest, or something that others could reasonably perceive as a conflict of interest, you must report it to your supervisor, the CEO, or Chairman of the Finance Committee who

will work with you to determine where you have a conflict of interest and, if so, how best to address it. Employees must take care to ensure that they identify and avoid any situation of actual or apparent conflict of interest, whether the situation involves the Employee directly or a member of the Employee's immediate family.

A "conflict of interest" occurs when an Employee's personal interests interfere, or appear to interfere, in any way with the interests of the Company. Business decisions and actions must be made in the best interests of the Company and should not be influenced by personal considerations or relationships. A conflict situation can arise when an Employee of Lakeland takes actions or has interest that may make it difficult to perform his or her Company work objectively and effectively. Conflicts of interests may also arise when an Employee, or members of his or her family, receives improper gifts, entertainment or personal benefits as a result of his or her position in the Company. Improper gifts, entertainment or personal benefits of greater than nominal value or that are material to the Employee. One item on its own may not be material but a series from the same person or company may be material and therefore, improper.

Giving gifts and entertainment to customers, suppliers and other business associates is also prohibited by Lakeland when the gifts or entertainment are of greater than nominal value or are intended to bribe or influence the recipient, or when the law prohibits them. An employee may not give or receive a gift, benefit or entertainment when they know that doing so will violate the business practices of the other party.

It is almost always a conflict of interest for an Employee to be a director of, obtain loans or guarantees of personal obligations from, work simultaneously for, provide services to or have a personal or family financial interest (ownership or otherwise) in a competitor, customer or supplier. Employees are not permitted to work for a consultant or Board member. The best policy is for Employees to avoid any direct or indirect business contact with Lakeland's customers, suppliers or competitors, except on behalf of Lakeland. This guideline does not prohibit arms-length transactions with banks, brokerage firms or other financial institutions.

No Employee should serve on a board of directors or trustees or on a committee of any entity (whether for profit or not) whose interests reasonably would be expected to conflict with those of Lakeland's.

Conflicts of interest are prohibited as a matter of Company policy, unless waived by the Board.

VII. COMPETITION AND FAIR DEALING

Lakeland seeks to outperform its competition fairly and honestly and to obtain competitive advantages through superior performance, never through unethical or illegal business practices. Stealing proprietary information, possessing trade secret information that was wrongfully obtained, or inducing such disclosures by past or present employees of other companies, is prohibited. Each Employee should respect the rights of and deal

fairly with Lakeland's customers, suppliers, competitors and other Employees. No Employee should take improper advantage of anyone through manipulation, concealment, abuse of proprietary information, misrepresentation of material facts, or any other intentional improper-dealing practice.

VIII. CORPORATE OPPORTUNITIES

Employees owe a duty to Lakeland to advance its legitimate interests when the opportunity to do so arises. Employees are prohibited from taking for themselves personal opportunities that properly belong to Lakeland or that are discovered through the use of Lakeland property, information or position. Employees must not use corporate property, information or position for personal gain or to compete with Lakeland.

IX. LAWS, STATUTES AND REGULATIONS

It is the policy of Lakeland to comply, not merely with the letter, but also with the spirit of the law. Violation of the law can affect Lakeland's reputation and ability to carry on business. Each employee is responsible for knowing and understanding the laws, rules and regulations applicable to the performance of his or her duties at Lakeland and complying with both the letter and spirit of these laws, rules and regulations. Ignorance of the law is not a valid defense if the law has been contravened. Employees must not knowingly or actively assist in activity that is criminal in the jurisdictions in which Lakeland Holding conducts business. Employees who encounter situations where the requirements of the Code appear to conflict with local requirements must advise their supervisor.

X. WAIVERS AND INTERPRETATION OF THE CODE

Any waiver of this Code may be only by the Board of Directors of Lakeland Holding Ltd. and will be promptly disclosed as required by law or regulation. The Board has the exclusive responsibility for the final interpretation of this Code. This Code may be revised, changed or amended at any time by the Board.

XI. RELATIONSHIP TO OTHER POLICIES

If you are an Employee of Lakeland, all Company policies apply to you. If you are a director, the guidelines of the Board of Directors will guide you procedurally in your position as a director.

XII. COMPLIANCE PROCEDURES

All employees have a responsibility to understand and follow this Code of Ethics and Business Conduct. In addition, all Employees are expected to perform their work with honesty and integrity in any areas not specifically addressed by the Code. A violation of this Code may result in appropriate disciplinary action including the possible termination from employment with the Company, without additional warning. This determination

will be based upon the facts and circumstances of each particular situation. An Employee accused of violating this Code will be given an opportunity to present his or her version of the events at issue prior to any determination of appropriate discipline. Employees who violate the law or this Code may expose themselves to substantial civil damages, criminal fines and prison terms. The Company may also face substantial fines and penalties and may incur damage to its reputation and standing in the community. Your conduct as a representative of the Company, if it does not comply with the law or with this Code, can result in serious consequences for both you and the Company. The Company may be required to report certain types of breaches of the Code to regulatory authorities in which case the Employee may be subject to criminal or civil penalties. Nothing in this Code prohibits or restricts the Company from taking any disciplinary action on any matters pertaining to employee conduct, whether or not they are expressly discussed in this Code.

Failure to read the Code does not exempt an Employee from his or her responsibility to comply with the Code, applicable laws, rules, regulations, and all Lakeland policies and guidelines.

Questions concerning this Code should be referred to an Employee's immediate supervisor, the CEO, or Chairman of the Finance Committee. In the case of directors, questions should be directed to the Chairman of the Board.

Approved, by the Board, the 22nd day of May, 2007.

Chair of Board

Chair of Committee

Appendix B

Revised Exhibit 3
Tab 2
Schedules 1 and 2

This exhibit discusses the methodology used to determine Lakeland Power Distribution Ltd's customer and load forecast. Lakeland Power Distribution Ltd has provided projections for the number of customers in each customer class for both the 2008 Bridge Year and the 2009 Test Year. Historical data for the annual number of customers in each rate class is available for 2001 through to 2007. Due to significant restructuring, accurate customer data prior to May 2002 is not currently available.

WEATHER NORMALIZED LOAD AND CUSTOMER/CONNECTION FORECAST

The purpose of this evidence is to present the process used by LPDL to prepare the weather normalized load and customer/connection forecast used to design the proposed distribution rates. In summary, LPDL reviewed the various processes used by the 2008 cost of service applicants and is proposing to adopt a weather normalization forecasting method similar to the one used by Toronto Hydro Electric System Ltd in its 2008, 2009 and 2010 rate application (EB-2007-0680). Table 1, 2 and 3 below provides a summary of the weather normalized load and customer/connection forecast used in this application

Table 1
Summary of Load and
Customer/Connection Forecast

Year	Billed (GWh)	Growth (GWh)	Percent Change	Customer/ Connection Count	Growth	Percent Change (%)
2001	210.2			8,749		
2002	224.4	14.2	6.75%	8,834	85	0.97%
2003	226.9	2.5	1.12%	8,927	93	1.05%
2004	229.7	2.8	1.24%	8,987	60	0.67%
2005	231.4	1.7	0.74%	9,049	62	0.69%
2006	225.2	-6.1	-2.65%	9,102	53	0.59%
2007	227.2	2.0	0.87%	9,160	58	0.64%
2008 (B)	226.2	-1.0	-0.44%	9,231	71	0.78%
2009 (T)	225.9	-0.3	-0.12%	9,303	72	0.78%

2001 to 2007 are weather actual and 2008 and 2009 are weather normalized. LPDL currently does not have a process to adjust weather actual data to a weather normal basis. However, based on the process outlined in this Exhibit a process to forecast energy on a weather normalized basis has been developed and used in this application.

Total Customers are as of year-end and streetlight, sentinel lights and unmetered loads are measured as connections.

On a rate class basis actual and forecasted billed amount and number of customers are shown in Table 2

Table 2

Billed Energy and Number of Customers by Rate Class

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights	Unmetered Loads	Total
Energy (GWh)								
2001	74.9	46.4	86.7	0.0	1.9	0.03	0.3	210.2
2002	81.2	51.0	51.6	38.3	1.9	0.04	0.3	224.4
2003	84.8	47.7	53.5	38.5	2.0	0.05	0.3	226.9
2004	84.9	48.9	54.0	39.5	2.0	0.04	0.3	229.7
2005	85.5	49.4	55.3	38.8	2.0	0.04	0.3	231.4
2006	80.9	47.1	55.4	39.6	2.0	0.04	0.3	225.2
2007	82.8	47.9	57.1	37.2	2.0	0.04	0.3	227.2
2008 (B)	84.8	48.5	53.7	36.9	2.0	0.04	0.3	226.2
2009 (T)	87.0	49.2	50.7	36.7	2.0	0.04	0.2	225.9
Number of Customers/Connections								
2001	7,062	1,462	94	0	7	49	75	8,749
2002	7,147	1,465	89	6	7	49	71	8,834
2003	7,251	1,455	89	6	7	49	70	8,927
2004	7,300	1,474	87	6	7	44	69	8,987
2005	7,354	1,478	90	6	7	47	67	9,049
2006	7,403	1,488	87	6	7	45	66	9,102
2007	7,434	1,527	91	6	7	44	51	9,160
2008 (B)	7,498	1,538	91	6	7	43	48	9,231
2009 (T)	7,562	1,549	91	6	7	42	45	9,303

Table 3
Annual Usage per Customer/Connection by Rate Class

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights	Unmetered Loads
Energy Usage per Customer/Connection (kWh per customer/connection)							
2001	2001	10,602	31,728	922,359		266,248	686
2002	2002	11,363	34,821	579,754	6,383,553	266,234	882
2003	2003	11,696	32,813	600,731	6,422,289	280,228	941
2004	2004	11,635	33,156	620,725	6,589,902	281,758	1,004
2005	2005	11,620	33,452	614,973	6,474,217	280,798	913
2006	2006	10,923	31,643	636,869	6,599,117	280,849	956
2007	2007	11,136	31,364	627,285	6,195,109	280,798	949
2008 (B)	2008 (B)	11,304	31,516	590,432	6,158,093	283,805	964
2009 (T)	2009 (T)	11,508	31,764	556,660	6,121,298	286,845	978
Annual Growth Rate in Usage per Customer/Connection							
2001							
2002	7.2%	9.7%	-37.1%		0.0%	28.5%	13.5%
2003	2.9%	-5.8%	3.6%	0.6%	5.3%	6.8%	-2.7%
2004	-0.5%	1.0%	3.3%	2.6%	0.5%	6.7%	-0.2%
2005	-0.1%	0.9%	-0.9%	-1.8%	-0.3%	-9.1%	-5.5%
2006	-6.0%	-5.4%	3.6%	1.9%	0.0%	4.6%	0.7%
2007	1.9%	-0.9%	-1.5%	-6.1%	0.0%	-0.7%	20.1%
2008 (B)	1.5%	0.5%	-5.9%	-0.6%	1.1%	1.5%	3.9%
2009 (T)	1.8%	0.8%	-5.7%	-0.6%	1.1%	1.5%	3.9%

LOAD FORECAST AND METHODOLOGY

LPDL's weather normalized load forecast is developed in a three-step process. First, a total system weather normalized purchased energy forecast is developed based on multifactor regression model that incorporates historical load, weather, and economic data. Second, the weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast. Finally, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer. For the rate classes that have weather sensitive load their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast that has been determined from the regression model. The forecast of customers by rate class is determined using time-series econometric methodologies. For those rate classes that use kW for the distribution volumetric billing determinant an adjustment factor is applied to class energy forecast based on the historical relationship between kW and kWh. The following will explain the forecasting process in more detail.

Purchased KWh Load Forecast

The forecast of total system purchased energy is developed using a multifactor regression model with the following independent variables: weather (heating and cooling degree days), economic output (GDP growth), number of customers and calendar variables (days in month, seasonal). The regression model uses monthly kWh and monthly values of independent variables from January 1996 to December 2007 to determine the monthly regression coefficients.

Data for LPDL's total system load is available as far back as January 2001. This provides 84 data monthly data points which is a reasonable data set for use in a multiple regression analysis. Based on the recent global activity surrounding climate change historical weather data is showing that there is a warming of the global climate system. In this regard it is LPDL's view that it is appropriate to review the impact of weather since 2001 on the energy usage and then determine the average weather conditions from 2001 to 2007 which would be applied in the forecasting process to determine a weather normalized forecast.

The multifactor regression model has determined primary driver of year-over-year changes in LPDL's load growth are economic conditions and weather. Both of these effects are captured within the multifactor regression model.

Economic growth – which encompasses customer trends in the LPDL service area as well as general economic conditions is captured in the model using an index of economic output, Ontario Real Gross Domestic Product ("GDP") and population statistics.

Weather impacts on load are apparent in both the winter heating season, and in the summer cooling season. For that reason, both Heating Degree Days (i.e. a measure of coldness in winter) and Cooling Degree Days i.e. a measure of summer heat) are modeled.

The third main factor determining energy use in the monthly model can be classified as "calendar factors". For example, the number of days in a particular month will impact energy use. The modeling of purchased energy uses number of days in the month, hours of peak load in a month, and two “flag” variables – one to capture the typically lower usage in the spring and fall months, and the other to capture the impact of the 2003 August blackout on energy use in that month.

The process of developing a model of energy usage involves estimating multifactor models using different input variables to determine the best fit. Using stepwise regression techniques different explanatory variables were tested with the ultimate model being determined both by model statistics and by forecast accuracy. The model chosen as the best predictor of kWh purchased by LPDL is as follows

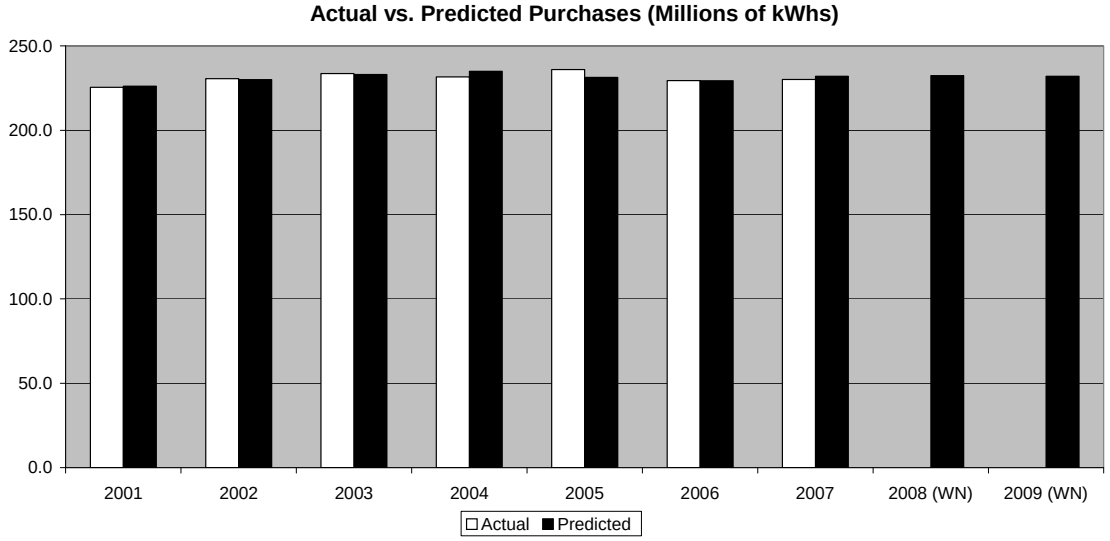
LPDL Monthly Predicted kWh Purchases
= Heating Degree Days * 9,301
+ Cooling Degree Days * 25,332
+ Ontario Real GDP Monthly Index * (93,376)
+ Number of Peak Hours * (3,725)
+ Number of Days in the Month * 646,929
+ Number of Customers * 4,807
+ Spring Fall Flag * (1,1147,301)
+ Aug 03 Blackout Flag * (1,219,942)
+ Constant of (33,095,774).

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Appendix A.

The sources of data for the various data points are:

a) Environment Canada website for monthly heating degree day and cooling degree information. Data for the Muskoka Airport weather station was used.
b) The 2008, 2009 and 2010 rate application (EB-2007-0680) for Toronto Hydro Electric System Ltd provided the Ontario real GDP monthly index and;.
c) Customer data was from the LPDL customer information system
d) The calendar provided information related to number of days in the month, number of peak hours and the spring/fall flag..

The annual results of the above prediction formula compared to the actual annual purchases from 2001 to 2007 are shown in the chart below. The prediction formula has a statistical R^2 of 91% which generally indicates the formula has a good fit to the actual data set.



The following table outlines the data that supports the above chart. In addition, the weather normalized forecast of total system purchases for LPDL is provided for 2008 and 2009.

Table 4
LPDL's Total System Purchases

	Actual	Predicted	% Difference
2001	225.5	226.1	0.26%
2002	230.5	229.9	-0.27%
2003	233.6	233.1	-0.19%
2004	231.6	234.9	1.43%
2005	236.0	231.3	-1.98%
2006	229.4	229.4	-0.03%
2007	230.1	232.0	0.83%
2008 (WN)		232.3	
2009 (WN)		232.0	

The forecasted weather normalized amount for 2008 and 2009 is determined by using a forecast of the dependent variables in the prediction formula on a monthly basis. In order to incorporate weather normal conditions, the average monthly heating degree days and cooling degree days which has occurred from

2001 to 2007 is applied in the prediction formula. The details on the average monthly heating degree days and cooling degree days is shown in Appendix A.

Billed KWh Load Forecast

To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast is adjusted by a historical loss factor. As outlined in the table below, historically the LPDL loss factor on average has been 2.7%

Table 5
Historical Loss Factor

(GWh)	Actual Purchases	Actual Billed	Loss Factor
2001	225.5	210.2	7.3%
2002	230.5	224.4	2.8%
2003	233.6	226.9	2.9%
2004	231.6	229.7	0.8%
2005	236.0	231.4	2.0%
2006	229.4	225.2	1.9%
2007	230.1	227.2	1.3%
Average			2.7%

With this average loss factor the total weather normalized billed energy will be 226.2 (GWh) for 2008 (i.e. 232.3/1.027) and 225.9 (GWh) for 2009 (i.e. 232.0/1.027)

Billed KWh Load Forecast and Customer/Connection Forecast by Rate Class

Since the total weather normalized billed energy amount is known this amount needs to be distributed by rate class for rate design purposes taking into consideration the customer/connection forecast and expected usage per customer by rate class.

The next step in the forecasting process is to determine a customer/connection forecast. The customer/connection forecast is based on reviewing historical customer/connection data that is available as shown in the following table.

Table 6
Historical Customer/Connection Data

	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights	Unmetered Loads	Total
Number of Customers/Connections								
2001	7,062	1,462	94	0	7	49	75	8,749
2002	7,147	1,465	89	6	7	49	71	8,834
2003	7,251	1,455	89	6	7	49	70	8,927
2004	7,300	1,474	87	6	7	44	69	8,987
2005	7,354	1,478	90	6	7	47	67	9,049
2006	7,403	1,488	87	6	7	45	66	9,102
2007	7,434	1,527	91	6	7	44	51	9,160

From the historical customer/connection data the growth rate in customers/connections can be evaluated which is provided on the following table. The geometric mean growth rate in number of customers is also provided. The geometric mean approach provides the average growth rate on a compounding basis.

Table 7
Growth Rate in Customer/Connections

	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights	Unmetered Loads
Growth Rate in Customer/Connection							
2001							
2002	1.20%	0.21%	-5.32%		0.00%	0.00%	-5.33%
2003	1.46%	-0.68%	0.00%	0.00%	0.00%	0.00%	-1.41%
2004	0.68%	1.31%	-2.25%	0.00%	0.00%	-10.20%	-1.43%
2005	0.74%	0.27%	3.45%	0.00%	0.00%	6.82%	-2.90%
2006	0.67%	0.68%	-3.33%	0.00%	0.00%	-4.26%	-1.49%
2007	0.42%	2.62%	4.60%	0.00%	0.00%	-2.22%	-22.73%
Geometric Mean	0.86%	0.73%	-0.54%	0.00%	0.00%	-1.78%	-6.23%

Except for the General Service > 50 to 999 kW class, the resulting geometric mean is applied to the 2007 customer/connection numbers to determine the forecast of customer/connections in 2008 and 2009. In the case of the General Service > 50 to 999 kW class LPDL believes it is more reasonable to hold the customer numbers constant for 2008 and 2008 than to forecast a decline.

Table 8
Customer/Connection Forecast

	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights	Unmetered Loads	Total
Forecast number of Customers/Connections								
2008	7,498	1,538	91	6	7	43	48	9,231
2009	7,562	1,549	91	6	7	42	45	9,303

The next step in the process is to review the historical customer/connection usage and to reflect this usage per customer in the forecast. The following table provides the average annual usage per customer by rate class from 2001 to 2007.

Table 9
Historical Annual Usage per Customer

	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights	Unmetered Loads
Annual kWh Usage Per Customer/Connection							
2001	10,602	31,728	922,359	0	266,248	686	4,087
2002	11,363	34,821	579,754	6,383,553	266,234	882	4,638
2003	11,696	32,813	600,731	6,422,289	280,228	941	4,512
2004	11,635	33,156	620,725	6,589,902	281,758	1,004	4,504
2005	11,620	33,452	614,973	6,474,217	280,798	913	4,255
2006	10,923	31,643	636,869	6,599,117	280,849	956	4,283
2007	11,136	31,364	627,285	6,195,109	280,798	949	5,143

From the historical usage per customer/connection data the growth rate in usage per customer/connection can be reviewed which is provided on the following table. The geometric mean growth rate has also been shown.

Table 10
Growth Rate in Usage Per Customer/Connection

	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights	Unmetered Loads
Growth Rate in Usage Per Customer/Connection							
2001							
2002	7.18%	9.75%	-37.14%			28.51%	
2003	2.93%	-5.77%	3.62%	0.61%	5.26%	6.78%	-2.72%
2004	-0.52%	1.04%	3.33%	2.61%	0.55%	6.68%	-0.18%
2005	-0.13%	0.89%	-0.93%	-1.76%	-0.34%	-9.05%	-5.53%
2006	-6.00%	-5.41%	3.56%	1.93%	0.02%	4.63%	0.65%
2007	1.95%	-0.88%	-1.50%	-6.12%	-0.02%	-0.66%	20.10%
Geometric Mean	0.82%	-0.19%	-6.22%	-0.60%	1.07%	1.49%	3.91%

For the forecast of usage per customer/connection the historical geometric mean was used applied to the 2007 value to determine the forecast for 2008 and 2009.

Table 11
Forecast Annual kWh Usage per Customer/Connection

	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights	Unmetered Loads
Forecast Annual kWh Usage per Customers/Connection							
2008	11,227	31,304	588,246	6,158,093	283,805	964	5,344
2009	11,320	31,243	551,637	6,121,298	286,845	978	5,553

With the preceding information the non-normalized weather billed energy forecast can be determine by applying the forecast number of customer/connection from Table 8 by the forecast of annual usage per customer/connection from Table 11. The resulting non-normalized weather billed energy forecast is shown in the following table.

Table 12
Non-normalized Weather Billed Energy Forecast

	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights	Unmetered Loads	Total
Non-normalized Weather Billed Energy Forecast (GWh)								
2008	84.2	48.1	53.5	36.9	2.0	0.0	0.3	225.1
2009	85.6	48.4	50.2	36.7	2.0	0.0	0.2	223.2

The non-normalized weather billed energy forecast has been determined but this needs to be adjusted in order to be aligned with the total weather normalized billed energy forecast. As previously determined, the total weather normalized billed energy forecast is 226.2 (GWh) for 2008 and 225.9 (GWh) for 2009.

The difference between the normalized forecast and non-normalized and is 1.1 (GWh) in 2008 (i.e. 226.2 – 225.1) and 2.7 GWh in 2009 (i.e. 225.9 – 223.2). This difference will be assigned to those rate classes that are weather sensitive. Based on the weather normalization work completed by Hydro One for LPDL for the cost allocation study, which has been used to support this rate application, it was determined the weather sensitivity by rate classes is as follows.

Table 13
Weather Sensitivity by Rate Class

Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights	Unmetered Loads
Weather Sensitivity						
100%	100%	55%	0%	0%	0%	0%

As a result, the difference between the non-normalized and normalized forecast has been assigned on a prorate basis to each rate classes based on the above level of weather sensitivity. The following tables outline how the weather sensitive rate classes have been adjusted to align the non-normalized forecast with the normalized forecast

Table 14
Alignment of Non-normal to Weather Normal Forecast

	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights	Unmetered Loads	Total
Non-normalized Weather Billed Energy Forecast (GWh)								
2008	84.2	48.1	53.5	36.9	2.0	0.0	0.3	225.1
2009	85.6	48.4	50.2	36.7	2.0	0.0	0.2	223.2
Adjustment for Weather (GWh)								
2008	0.6	0.3	0.2	0.0	0.0	0.0	0.0	1.1
2009	1.4	0.8	0.5	0.0	0.0	0.0	0.0	2.7
Weather Normalized Billed Energy Forecast (GWh)								
2008	84.8	48.5	53.7	36.9	2.0	0.0	0.3	226.2
2009	87.0	49.2	50.7	36.7	2.0	0.0	0.2	225.9

Billed KW Load Forecast

There four rate classes that charge volumetric distribution on per kW basis. These include General Service > 50 to 999 kW, General Service > 1000 to 4999 kW, Streetlights and Sentinel Lights. As a result, the energy forecast for these classes needs to be converted to a kW basis for rate setting purposes. The forecast of kW for these classes is based on a review of the historical ratio of kW to kWhs and applying the average ratio to the forecasted kWh to produce the required kW.

The following table outlines the annual demand units by applicable rate class for the years that data is available (i.e. 2001 to 2007)

Table 15
Historical Annual kW per Applicable Rate Class

	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights
2001	218,604	0	5,108	93
2002	133,615	82,038	5,146	120
2003	140,738	79,080	5,152	128
2004	142,691	81,702	5,152	123

2005	139,729	79,544	5,152	119
2006	143,054	85,943	5,153	119
2007	152,875	81,423	5,152	116

The following is the historical ratio of kW/kWh as well as the average ratio from 2000 to 2007

Table 16
Historical kW/KWh Ratio per Applicable Rate Class

kW/kWh	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights
2001	0.2521%		0.2741%	0.2767%
2002	0.2590%	0.2142%	0.2761%	0.2778%
2003	0.2632%	0.2052%	0.2626%	0.2775%
2004	0.2642%	0.2066%	0.2612%	0.2784%
2005	0.2525%	0.2048%	0.2621%	0.2772%
2006	0.2582%	0.2171%	0.2621%	0.2767%
2007	0.2678%	0.2191%	0.2621%	0.2777%
Average	0.2596%	0.2112%	0.2658%	0.2774%

The average ratio was applied to the weather normalized billed energy forecast in Table 14 to provide the forecast of kW by rate class as shown below.

Table 17
kW Forecast by Applicable Rate Class

	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights
2008	139,466	78,019	5,280	116
2009	131,489	77,552	5,336	115

Lakeland Power Weather Normal Load Forecast for 2009 Rate Application

	2001 Actual	2002 Actual	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Weather Normal	2009 Weather Normal
Actual kWh Purchases	225,517,680	230,549,922	233,560,670	231,616,153	235,965,914	229,437,606	230,101,606		
Predicted kWh Purchases	226,110,738	229,933,504	233,106,316	234,937,132	231,286,518	229,362,899	232,012,446	232,323,214	232,047,061
% Difference	0.3%	-0.3%	-0.2%	1.4%	-2.0%	0.0%	0.8%		
Billed kWh	210,163,368	224,358,489	226,871,814	229,675,942	231,381,375	225,242,085	227,199,266	226,190,208	225,921,346
By Class									
Residential									
Customers	7,062	7,147	7,251	7,300	7,354	7,403	7,434	7,498	7,562
kWh	74,872,006	81,210,271	84,806,055	84,934,906	85,452,762	80,863,556	82,783,542	84,753,044	87,027,546
General Service < 50 kW									
Customers	1,462	1,465	1,455	1,474	1,478	1,488	1,527	1,538	1,549
kWh	46,385,766	51,012,650	47,743,433	48,871,256	49,442,157	47,084,579	47,892,487	48,475,435	49,211,450
General Service > 50 to 999 kW									
Customers	94	89	89	87	90	87	91	91	91
kWh	86,701,745	51,598,080	53,465,016	54,003,103	55,347,560	55,407,643	57,082,919	53,729,308	50,656,101
kW	218,604	133,615	140,738	142,691	139,729	143,054	152,875	139,466	131,489
General Service > 1000 to 4999 kW									
Customers	0	6	6	6	6	6	6	6	6
kWh	0	38,301,320	38,533,735	39,539,411	38,845,302	39,594,703	37,170,652	36,948,556	36,727,786
kW	0	82,038	79,080	81,702	79,544	85,943	81,423	78,019	77,552
Streetlights									
Customers	7	7	7	7	7	7	7	7	7
kWh	1,863,735	1,863,641	1,961,598	1,972,304	1,965,588	1,965,944	1,965,588	1,986,637	2,007,912
kW	5,108	5,146	5,152	5,152	5,152	5,153	5,152	5,280	5,336
Sentinel Lights									
Connections	49	49	49	44	47	45	44	43	42
kWh	33,614	43,196	46,125	44,187	42,927	43,004	41,771	41,641	41,511
kW	93	120	128	123	119	119	116	116	115
Unmetered Loads									
Connections	75	71	70	69	67	66	51	48	45
kWh	306,502	329,331	315,852	310,775	285,079	282,656	262,307	255,587	249,040
kW									
Total									
Customer/Connections	8,749	8,834	8,927	8,987	9,049	9,102	9,160	9,231	9,303
kWh	210,163,368	224,358,489	226,871,814	229,675,942	231,381,375	225,242,085	227,199,266	226,190,208	225,921,346
kW from applicable classes	223,805	220,919	225,098	229,668	224,544	234,269	239,566	222,880	214,493