LakelandPower
200 – 395 Centre St N, Huntsville, ON P1H 2M2
Phone (705) 789-5442 Toll Free 1-888-282-7711
Fax (705) 789-3110 service@lakelandpower.on.ca

February 1, 2019

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-2018-0050
2019 Cost of Service Rate Application – Interrogatory Responses

Lakeland Power Distribution Ltd is submitting its responses to the interrogatories received from Board Staff, VECC and SEC regarding its application for the 2019 Distribution Rates utilizing the 2019 Cost of Service. All responses can be found in this document with the respective appendices and models filed separately.

An electronic copy of these reponses (pdf, and models in excel) will be submitted through the OEB e-Filing services and two hard copies via courier.

If you have any further questions, please do not hesitate to contact me.

Respectfully submitted,

Margaret Maw
CFO
Lakeland Holding Ltd.

Exhibit 1 – Administration

1-Staff-1
Letters of Comment
Following publication of the Notice of Application, the OEB received a letter of comment. Sections 2.1.7 of the Filing Requirements state that distributors will be expected to file with the OEB their response to the matters raised within any letters of comment sent to the OEB related to the distributor's application. If the applicant has not received a copy of the letters or comments received at the community meetings, they may be accessed from the public record for this proceeding.

Please file a response to the matters raised in the letters of comment referenced above. Going forward, please ensure that responses to any matters raised in subsequent comments or letter are filed in this proceeding. All responses must be filed before the argument (submission) phase of this proceeding.

LPDL has responded to the customer, posted the response to RESS, and provided a copy in Appendix A.

1-Staff-2
Updated Revenue Requirement Work Form (RRWF)
Upon completing all interrogatories from OEB staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the populated version of the RRWF filed in the initial applications. Entries for changes and adjustments should be included in the middle column on sheet 3 Data_Input_Sheet. Sheets 10 (Load Forecast), 11 (Cost Allocation), 12 (Residential Rate Design) and 13 (Rate Design) should be updated, as necessary. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note. Such notes should be documented on Sheet 14 Tracking Sheet, and may also be included on other sheets in the RRWF to assist understanding of changes.

LPDL has updated the RRWF model. An excel version has been posted to RESS. Adjustments to be made:

- Change rate for MicroFit in revenue (IR # 3.0-VECC-20 - +$3150)
- Change building rent for Bracebridge Generation in revenue (IR # 4.0-VECC-27 - $16,500)

- Remove $8,750 from expense for Post Retiree as indicating no request for recovery – IR #4-Staff-65 - $8,750)
- Change LV charge from $923,433 to $1,008,383 using most recent H1 charges (IR #8-Staff-78 and 8.0-VECC-42 - $84,950)
- Change Gross Fixed Assets and Accumulated Depreciation for 2018 actual (IR # 2-SEC-11 - $(370,709))

1-Staff-3
Community Information Sessions
Ref: Exhibit 1 – Administrative Documents, p. 85-86
Lakeland Power hosted information sessions presenting the five year capital plan to customers and then had open discussions, questions, and input from customers.

a) Did Lakeland Power present specific capital projects to customers or was it a general presentation of capital spending?

LPDL presented capital projects and project spending during the 2016 Customer Information events. Slides 42-50 of the LPDL Customer Information Event Presentation 2016 (**Appendix B**) depicts Capital Projects from 2017 to 2021. For example, slide 50 detailed the following capital projects for 2021:

- Meadow Heights - Bracebridge U/G cable replacement voltage conversion
- MS3 Bracebridge - decommission 4Kv substation
- Golden Beach Substation/old MS3 site - Prep Old MS3 site to accommodate a 27.6 Kv substation. Move Golden Beach Substation to the MS3 site and install 3-27.6 Kv feeders from the new substation site.
- MS5 Parry Sound -install viper reclosers on all feeders
- Station St - Parry Sound, Florence St – Huntsville - replace poles, wires and transformers
- Pole changes greater than 40 years old in Sundridge, Magnetawan, Burks Falls

Brian Elliott, Operations Manager for Lakeland Power then expanded on the above-mentioned projects. Please find below an extract taken from Brian Elliott's speaking notes.

"Replace aging underground primary cables, transformers and convert subdivision to 27.6Kv. This will remove this subdivision from the Hydro One 12.5kv system. Reducing Lakeland Power's shared DS charges with Hydro One.

All load on the MS3 substation as been converted to the 27.6 Kv system and is no longer required.

Moving Golden Beach substation to the Old MS3 site will give Lakeland Power the ability to run multiple feeders from the new site and create several tie points with existing Cent. Substation and Douglas substation. The new substation site will also be connected to the Muskoka M3 feeder giving Lakeland Power the ability to feed its customers in Bracebridge from both the Muskoka M7 feeder and Muskoka M3 feeder.
Install viper reclosers on all feeders in MS5 Parry Sound and remove oil reclosers. These reclosers will be a part of our SCADA system.

Install new poles, wires and transformers on Station St between Church St and Salt Docks Rd. This project will replace aging assets as well as convert from 4kv to 12.5kv reducing the load on MS4 Parry Sound."

b) If there were presentations for specific capital projects, what was the customers' feedback on each project?

Brian Elliott, Operations Manager for LPDL presented on specific capital plans for 2017-2021. Even though limited feedback was received, during three of the municipal sessions, the repeated question was underground vs overhead investments to improve reliability.

Please find below an extract from notes taken during the Customer Information Session resulting from the following projects proposed for 2021;

- Station St - Parry Sound, Florence St – Huntsville - replace poles, wires and transformers
- Golden Beach Substation/old MS3 site - Prep Old MS3 site to accommodate a 27.6 Kv substation. Move Golden Beach Substation to the MS3 site and install 3-27.6 Kv feeders from the new substation site.

A resulting question from this proposed capital project was;

"We live in an area that suffers frequent storms and adverse weather. Has Lakeland considered underground vs aboveground? When the Town is digging up the road shouldn't this be discussed? … Should combine road works at same time as pushing lines underground?"

See LPDL Customer Event Summary Document – 2016 (**Appendix C**), pg.8-12 for further event specific details.

1-Staff-4
Large User Information Sessions
Ref: Exhibit 1 – Administrative Documents, p. 88

Lakeland Power hosted a large user information session, which was similar to the community information sessions and included regional planning, review of system reliability, and identification of potential reliability mitigation measure.

a) Is there any documentation on the discussions large users had brought up or a list of questions/input from large users? If so, please provide

The LPDL management team, IESO and Cornerstone Hydro Electric Concept presented specific segments throughout the Large User information session. Please find attached the LPDL Customer Event Summary Document – 2015 (**Appendix D**) that encompasses all elements of the day. Please refer to page 2 of the attached document to review the events agenda. Pages 3 and 4 provide a summary of questions posed by the attendees.

1-Staff-5
OEB Scorecard
Ref: Exhibit 1 – Administrative Documents, Table 30 – 2013-2017 OEB Scorecard for Lakeland Power

In Lakeland Power's scorecard the total cost per km of line has been trending upwards since 2014.

a) Please provide an explanation to the drivers that caused this increase and what has changed since 2013.

LPDL merged with Parry Sound in 2014. The costs in the former PSP area were much higher with a smaller number of kms being added. LPDL added the former PSP area into its GIS resulting in approximately 70km of line reduction due to more accurate data. LPDL has experienced high levels of failures in PS area due to lack of maintenance over the preceding years (2015 & 2016).

LPDL has worked on turning this around and in 2017 total cost per km of line reduced by $1,286/km or $460K, putting LPDL into cohort 2. LPDL anticipates remaining in this cohort.

1-Staff-6
Current Ratio
Ref: Exhibit 1 – Administrative Documents, Table 27 – Financial Ratios from Scorecard
Ref: Exhibit 1 – Administrative Documents, p. 121

Lakeland Power's current ratio has been increasing year-over-year starting in 2012 and currently has a current ratio of 1.8 in 2017. Lakeland Power stated that a higher current ratio represents a higher safety margin for Lakeland Power to its short-term debt and financial obligations.

a) Does Lakeland Power assess the typical current ratio for an electric utility company? How does Lakeland Power's current ratio compare?

LPDL has reviewed the OEB consolidated LDC scorecard for 2017 to compare its current ratio to other utilities. The current ratios range between 0.37 (Algoma) and 4.95 (Fort Frances), with the vast majority of LDCs having a current ratio between 0.5 and 2.0. LPDL's preliminary ratio for 2018 is 1.67.

b) With an improved current ratio over the years due to improved receivable and cash management, is the increased current asset cash? If so, how does Lakeland Power assess the level of cash it should hold on hand?

LPDL's change in current ratio was current cash in order to get closer to 60/40 debt/equity and it was a timing difference at yearend. Normally, LPDL has 2 months x H1 bill plus 50% of current year capital needs in cash, approximately $4.0-$5.0 M.

c) Are there debt covenants for Lakeland Power's short-term debt that it must meet? If not, how does Lakeland Power assess the risk it can take to cover its short-term debt?

2017 was an anomaly as under IFRS; one tranche of the long term debt was reclassed to short term until the new interest rates were renewed. This was just a timing change for presentation purposes under IFRS. The tranche was renewed and now classed as long term effective March, 2018.

1-Staff-7
Return on Equity
Ref: Exhibit 1 – Administrative Documents, Table 31 – Return on Equity Table

Lakeland Power provided the approved return on equity (ROE) and the achieved ROE in Table 31.

a) Please provide the return on equity in terms of dollars for both approved and achieved and the equity base used for each year.

	Actual					Actual				
OEB ROE Calculations	2012 - LPDL only	2013 Approved - LPDL only	2011 Approved - PSP only	Approved - Blended	Approved with Proxy adj	2013	2014	2015	2016	2017
Rate base	19,570,370	20,006,245	5,885,842	25,892,087	25,917,267	26,347,114	27,616,916	29,471,824	30,866,171	30,793,375
Deemed Equity	7,828,148	8,002,498	2,354,337	10,356,835	10,366,907	10,538,846	11,046,766	11,788,730	12,346,468	12,317,350
Total Adjusted regulated net income	761,483	714,626	225,546	940,172	941,092	1,127,656	1,389,670	1,167,071	1,340,995	1,562,657
Regulated Rate of Return on Deemed Equity	9.73%	8.93%	9.58%	9.08%	9.08%	10.70%	12.58%	9.90%	10.86%	12.69%

LPDL has demonstrated strong performance arising from prudent management and efficiencies gained through the PSP amalgamation.

1-Staff-8
Distribution Consolidation
Ref: Exhibit 1 – Administrative Documents, p. 129-130

As a result of the amalgamation of Lakeland Power and Parry Sound there were forecasted annual savings of $354k. This included reduction in operations and administrative costs and renegotiated interest rates. Lakeland Power listed the forecasted cost synergies on p. 130.

a) Please provide a cross reference table for each cost synergy to an OM&A driver provided in Appendix 2-JC.

Description	Annual Cost	% Savings	Year 1 - Annual Savings	Year 2 - Annual Savings	OM&A Driver from Appendix 2-JC
Staff reduction & retirement	$ 100,000	100%	$ 100,000	$ 100,000	Customer service/Exec/Fin
Shared resources for accounting/exec/regulatory	$ -		$ -	$ -	Corporate allocation
Billing System consolidation	$ 50,000	75%	$ 37,500	$ 37,500	Customer Service
Cancellation of 3rd party billing system - bring in house		100%	-$ 160,000	$ -	Customer Service
Rate application process - consolidated	$ 40,000	75%	$ 30,000	$ 30,000	Exec, Fin, Legal, Prof services
RFP process for tree trimming/outside services	$ 20,000	50%	$ 10,000	$ 10,000	Vegetation mgmt
Reduction of audit fees	$ 15,000	75%	$ 11,250	$ 11,250	Exec, Fin, Legal, Prof services
Sync operator/Smart Meter billing - bring in house	$ 10,000	100%	$ 10,000	$ 10,000	Customer Service
Cancellation of 3rd party sync operator/SM data		100%	-$ 10,000	$ -	Customer Service
IT support and computer systems - bring in house	$ 85,000	50%	$ 42,500	$ 42,500	Exec, Fin, Legal, Prof services
Cancellation of current 3rd party IT support		100%	-$ 10,000	$ -	Exec, Fin, Legal, Prof services
Improved purchasing rates	$ 200,000	10%	$ 20,000	$ 20,000	All categories
Renegotiate 3rd party interest rate	$ 175,000	45%	$ 78,750	$ 78,750	N/A
Combined training sessions	$ 5,000	100%	$ 5,000	$ 5,000	Training
Reduce number of Directors	$ 15,000	60%	$ 9,000	$ 9,000	Exec, Fin, Legal, Prof services
Legal/consulting for merger - one time charge		100%	-$ 100,000	$ -	Exec, Fin, Legal, Prof services
Total			**$ 74,000**	**$ 354,000**	
OM&A savings only			**-$ 4,750**	**$ 275,250**	

b) Please provide a table of forecasted savings and actual savings realized over the last five years.

The forecasted savings were as indicated in Table 34 on Page 131 and above. Once these measures were in place, they are sustainable as a base load but do not increase or move over time. Once the program reduction is achieved through headcount reduction or consolidation of services, the base is now at the lower level. Originally the merger was expected to take place January 1, 2014 so the Year 1 savings would be in 2014, Year 2 in 2015. However, due to the date change to July 1, there were little to no savings achieved in 2014 and delays in converting systems resulted in headcount changes being put off until 2015-2016. 2018 is the first full year of synergy savings. Expected synergy savings in MADD application were estimated before due diligence and adjusted for probability of occurrence. The actual synergy savings were higher than estimate with staff reduction greater due to skills assessment, greater reduction in audit fees as LPDL books and records were better maintained, and fees for outside contractors/consultants were effectively eliminated.

Description	Annual Cost	% Savings	MADD Year 1 - Annual Savings	MADD Year 2 - Annual Savings	OM&A Driver from Appendix 2-JC	Achieved Savings 2014	2015	2016	2017	2018	Change from MADD
							$ -	$ -	$ -	$ -	
Staff reduction & retirement	$ 100,000	100%	$ 100,000	$ 100,000	Customer service/Exec/Fin	$ -	$ 84,952	$ 10,612	$ 213,380	$ 241,428	69%
Shared resources for accounting/exec/regulatory	$ -		$ -	$ -	Corporate allocation	$ -	$ -	$ -	-$ 72,801	-$ 72,801	
Billing System consolidation	$ 50,000	75%	$ 37,500	$ 37,500	Customer Service	$ -	$ -	$ -	$ 57,000	$ 57,000	52%
Rate application process - consolidated	$ 40,000	75%	$ 30,000	$ 30,000	Regulatory costs	$ -	$ 36,000	$ 36,000	$ 36,000	$ 36,000	20%
RFP process for tree trimming/outside services	$ 20,000	50%	$ 10,000	$ 10,000	Vegetation mgmt	$ -	$ -	$ 12,800	$ 12,800	$ 12,800	28%
Reduction of audit fees/payroll	$ 15,000	75%	$ 11,250	$ 11,250	Exec, Fin, Legal, Prof services	$ -	$ -	$ -	$ 22,200	$ 22,200	97%
Sync operator/Smart Meter billing - bring in house	$ 10,000	100%	$ 10,000	$ 10,000	Customer Service	$ -	$ -	$ -	$ 10,400	$ 10,400	4%
IT support and computer systems - bring in house	$ 85,000	50%	$ 42,500	$ 42,500	Exec, Fin, Legal, Prof services	$ -	$ -	$ 46,000	$ 46,000	$ 46,000	8%
Improved purchasing rates	$ 200,000	10%	$ 20,000	$ 20,000	All categories	$ -	$ -	$ 25,000	$ 25,000	$ 25,000	25%
Use of in house engineering	$ -		$ -	$ -	Operations & engineering	$ -	$ -	$ -	$ 33,600	$ 33,600	
Renegotiate 3rd party interest rate	$ 175,000	45%	$ 78,750	$ 78,750	N/A	$ 61,670	$ 123,339	$ 123,339	$ 118,481	$ 113,623	44%
Combined training sessions	$ 5,000	100%	$ 5,000	$ 5,000	Training	$ -	$ -	$ -	$ 5,000	$ 5,000	0%
Reduce number of Directors	$ 15,000	60%	$ 9,000	$ 9,000	Exec, Fin, Legal, Prof services	$ -	$ 9,000	$ 9,000	$ 9,000	$ 9,000	0%
							$ -	$ -	$ -	$ -	
Total			**$ 74,000**	**$ 354,000**		**$ 61,670**	**$ 253,291**	**$ 262,751**	**$ 516,060**	**$ 539,250**	
OM&A savings only			**-$ 4,750**	**$ 275,250**		**$ -**	**$ 129,952**	**$ 139,412**	**$ 397,579**	**$ 425,627**	

1.0-VECC-1

Reference: Exhibit 1, pg. 168

a) Please provide the (preliminary) 2018 Scorecard results.

Performance Outcomes	Performance Categories	Measures	2013	2014	2015	2016	2017	2018
Customer Focus	Service Quality	New Residential/Small Business Connected on Time	100.00%	94.60%	98.00%	99.20%	100.00%	100.00%
		Scheduled Appointments Met On Time	95.60%	99.80%	97.60%	98.60%	100.00%	100.00%
		Telephone Calls Answered on Time	95.00%	97.30%	92.70%	90.60%	88.20%	93.00%
	Customer Satisfaction	First Contact Resolution		99.89%	99.93%	99.98%	99.95%	99.97%
		Billing Accuracy		99.99%	94.39%	99.86%	99.94%	99.92%
		Customer Satisfaction Survey Results		Completed	86.50%	74.50%	74.50%	
Operational Effectiveness	Safety	Level of Public Awareness			82.50%	82.50%	83.80%	83.80%
		Level of Compliance with Ontario Reg 22/04	C	C	C	C	C	C
		Serious Electrical Incident Index: Number of General Public Incidents	0	0	0	0	0	0
		Serious Electrical Incident Index: Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted	2.06	1.00	1.74	2.01	1.46	2.82
		Average Number of Times that Power to a Customer is Interrupted	0.82	0.39	0.82	0.73	0.83	1.50
	Asset Management	Distribution System Plan Implementation Progress		In Progress	In Progress	In Progress	In Progress	Submitted
	Cost Control	Efficiency Assessment	2	3	3	3	2	2
		Total Cost per Customer	$ 700	$ 741	$ 756	$ 734	$ 697	$ 725
		Total Cost per Km of Line	$ 22,852	$ 26,216	$ 27,506	$ 27,559	$ 26,273	$ 27,400
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	0.86	1.28	1.12	1.70	1.80	1.67
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	0.41	0.40	0.31	1.13	1.00	1.12
		Profitability: Regulatory Return on Equity: Deemed (included in rates)	8.93%	8.93%	9.08%	9.08%	9.08%	9.08%
		Profitability: Regulatory Return on Equity: Achieved	10.70%	12.50%	9.90%	10.86%	12.69%	12.70%

1.0-VECC-2

Reference: Exhibit 1, Business Plan, pgs. 169-

a) Lakeland has had a modest decline in telephone calls answered on time and a small increase in complaints as compared to 2013. Please explain what steps the Utility is taking over the term of the rate plan to improve its performance in these areas.

LPDL's indices are well above the Industry target (40-50% better). The reason for the decline is two-fold, the first being the addition of PSP customers in 2014 increasing volume while over the period of 2015-2017, billing staff was reduced by almost 50%. At the same time, newly released programs such as Fair Hydro Plan and ODSP, took longer on each call to explain to customers as they no longer understood their bill and were looking for the publicized exact percentage savings i.e. 24% savings.

The second discussion point would be reporting methods. Prior to the amalgamation, PSP estimated the information as they did not have an IVR system nor a call tracking system. Once the two systems were fully merged, improved reporting data was obtained. Comparability of 2013 to 2017 is not possible due to the changes made in order to improve tracking. LPDL believes that 2018 results will show an improvement now that processes have been streamlined.

2018 results are showing preliminary indices of 93%.

1-SEC-1

[Ex.1, p.50] Please provide copies of the material provided to the Applicant's Board of Directors in which it sought approval of the application and the underlying test year budgets.

Through the 18 month process, the board was provided with regular verbal updates during the scheduled meetings regarding: timelines, proposed rates, proposed customer impact, etc.

March 31, 2017 – M. Maw updated the Board on the rate application and S. Davidson inquired about the process and workloads, all of which are under control.
May 19, 2017 – M. Maw updated Board on Cost of Service application and that it is on schedule
June 22, 2017 – M. Maw updated the Board on the pros and cons of submitting a detailed Cost of Service application to the Ontario Energy Board this year. All agreed that a delay should submitted.
July 31, 2017 – M. Maw advised that she has had conversation with OEB Board staff regarding deferral of CoS and is still awaiting decision – work on the application continues as it will be required in any event
September 29, 2017 – M. Maw advised that the OEB has granted the request for delay until 2018.
October 16, 2017 – M. Maw provided an overview of LPDL's IRM rate application to the OEB – approved.
December 11, 2017 – M. Maw reviewed the 2018 Budget with the Board:

> Upon motion duly made by P. Matthews, and unanimously carried, IT WAS RESOLVED that, the 2018 budget is approved as presented.

March 2, 2018 – M. Maw advised that the Cost of Service application is going well as regular meetings are being held to keep everyone on schedule.

April 24, 2018 – M. Maw updated the Board on the Cost of Service application and advised that it may result in a rate reduction for customers and she is on track to submit in the summer.
May 25, 2018 – M. Maw provided an update on the Cost of Service rate application. At this point she is concerned that the decrease in rates may decrease the ability for capital spending which would delay distribution system upgrades.
July 27, 2018 – M. Maw provided an update on the detailed Cost of Service application for the OEB. She advised that filing requirements continue to change that adds work on all staff associated with the application. Most distribution companies have deferred their applications, potentially more scrutiny on LPDL, need to ensure a complete and fulsome application.
September 17, 2018 – M. Maw provided an update on the Cost of Service application which will be submitted over the coming days. Having already sent out the Distribution System Plan, and rate application including upcoming budget, M. Maw discussed lower revenue sought, merger synergy savings and the rate impacts for each service territory.

> Upon motion duly made by B. Flowers and seconded by R. Alexander, and unanimously carried, IT WAS RESOLVED that, the Cost of Service application for the Ontario Energy Board is approved as submitted.

The full application was given to the Board of Directors to read and approve. The budget for 2019 was submitted as a standalone extract of capital and expense, which is provided as Appendix E

1-SEC-2
[Ex.1] Please provide copies of all benchmarking studies, reports, and analysis that the Applicant has undertaken or participated in since 2014 that are not already included in the application.

LPDL does not have any additional studies that it has reviewed to include at this time.

1-SEC-3
[Ex.1] Please provide a list of measurable outcomes that ratepayers can expect the Applicant to achieve during the test year. Please explain how those outcomes are incremental and commensurate with the rate request the Applicant is seeking in this application.

LPDL expects to hold steady for 2019 without much movement in any one area in order to reset and stabilize the company. The merged entity has been in upheaval since 2014 due to lack of resources, lack of higher skill levels, poor prior maintenance coming to a head in the PS area, as well as ever increasing regulatory compliance.

1-SEC-4

[Ex.1] Please provide details of all productivity and efficiency measures the Applicant has taken since 2014 that are not a direct result of the amalgamation between LDPL and PSP. Please quantify the savings achieved.

All the measures taken were in conjunction with the amalgamation as limited resources only allowed the staff to work on achieving the required savings stated in the MAADs application.

1-SEC-5

[Ex.1] Please provide details of all productivity and efficiency measures the Applicant plans to take in the test year. Please quantify the forecast savings.

LPDL has struggled to fill and maintain staff positions in recent years however, current standing looks promising. 2019 is expected to be a steady state year, allowing staff to catch their breath and reduce their overtime (unpaid) now that key positions are mostly filled. The synergy savings that were achieved are fully in place and now LPDL can reset to normalized levels. LPDL has achieved Cohort 2 and is very proud of this achievement and its ability to pass these savings on in the form of a requested rate decrease.

1-SEC-6

[Ex.1, p.116] Please provide a copy of the 2018 year-end results of the metrics listed for the Applicant's 2018 balanced scorecard.

This is not currently available as LPDL prepares the final balanced scorecard after the audited results are available in April. LPDL has prepared the preliminary OEB scorecard as shown in the response to 1.0-VECC-1.

1-SEC-7

[Ex.1, p.131] Please add a column to table 34 to show the actual savings achieved. Please explain any variances +/- 10%.

See response to 1-Staff-8

1-SEC-8

[Ex.1, p.132] The Applicant states: "In addition to the above savings, LPDL was able to eliminate the promissory note that former PSP had with its shareholder at 7.25% and replaced it with third party bank debt at an interest rate of 3.04%, a savings of $113,000 annually." What was the relationship between the replacement of the promissory note and the merger? Would PSP have been able to replace the note if no merger had occurred?

LPDL had the borrowing capacity and a proven track record to allow the replacement of the promissory note with third party debt. The former PSP was unable to borrow due to poor financials and lack of qualified staff. The former PSP was unable to secure funds for capital projects due to poor reporting.

1-SEC-9

[Ex.1] With respect to customer engagement:

a. [Ex. 1, p.85] Please provide a copy of any presentations and/or materials that were provided or shown during the four 2016 customer information sessions.

Please find attached a PDF copy of the LPDL Customer Information Event Presentation – 2016 (**Appendix B**) that was presented for the four 2016 customer information sessions.

Please refer to the attached the Customer Information Event Summary – 2016 (**Appendix C**), pg.4-7 for the materials that were provided or shown during the four 2016 customer information sessions.

b. [Appendix 2-AC] Please explain any changes the Applicant made to its application as a result of its customer consultation activities.

As a result of LPDL's customer consultation activities, customer recommendations were taken into consideration during the preparation of the application. Of particular note was a request for improved outage map information online to avoid having to call in for updates on restoration. To this end, LPDL has planned to invest in improving SCADA as well as an outage management system. This would meet the customer request with the added benefit of helping to dispatch crews faster and more effectively resulting in improved reliability.

Exhibit 2 – Rate Base
2-Staff-9
Service Quality Indicators
Ref: Exhibit 2 – Rate Base, p.71
The System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) appear to be trending upward, in particular outages including loss of supply.

a) The SAIDI for 2017 including loss of supply is 23.0, which is significantly higher than other years. Please provide an explanation for this.

LPDL's service area is supplied by Hydro One's Muskoka TS, Parry Sound TS and several Hydro One Distribution Stations. During most storm events Hydro One feeders that service LPDL trip causing LPDL to lose its supply. These feeders cannot be restored to service until Hydro One responds to the outage. LPDL has no control of Hydro One feeders. The majority of the loss of supply issues are at Muskoka TS which services LPDL's customers in Bracebridge, Huntsville, Burk's Falls Magnetawan and Sundridge.

b) What has Lakeland Power done to improve the reliability due to loss of supply from Hydro One?

LPDL is in constant communication with Hydro One for loss of supply issues however have no authorization to influence Hydro One's plans to address the issue.

c) Please provide plans that Hydro One has to improve reliability, if any, and the timeline on its expected in-service dates.

LPDL does not have access to Hydro One's plans to improve reliability therefore LPDL cannot comment on an estimated timeline.

2-Staff-10
Overview of Projects
Ref: Overview of Projects/Initiatives to Address Customer Expectations (5.2.2): Distribution System Plan (DSP)/pp. 30-32.

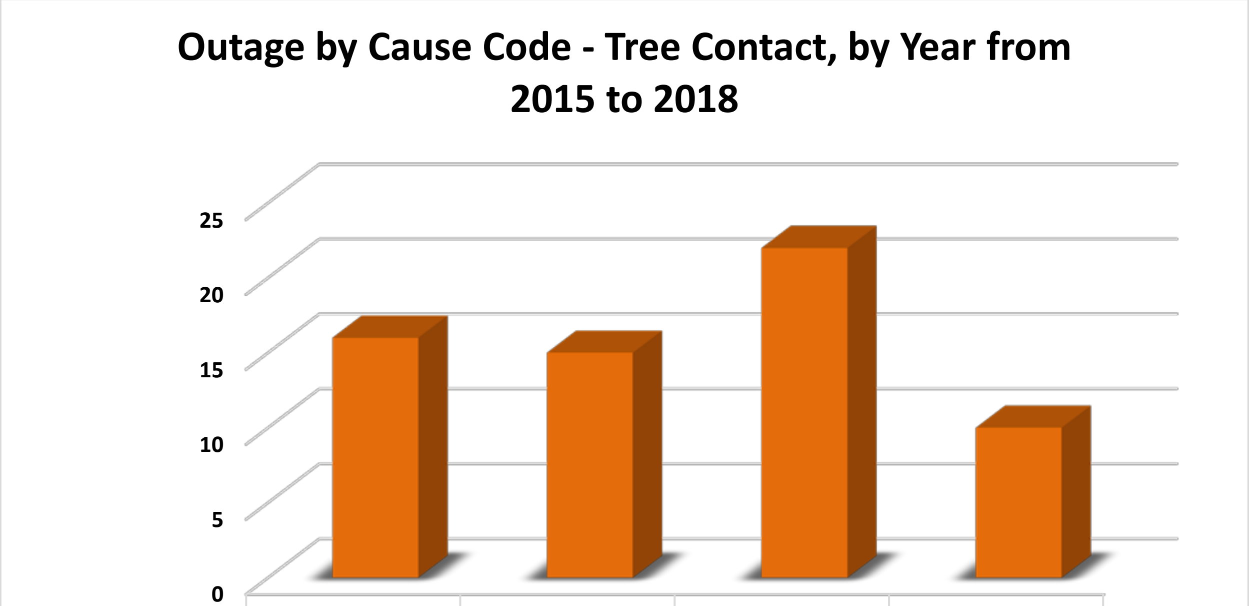
It is indicated on page 31 that Lakeland Power has modified its tree-trimming program and shortened the cycle on this program from 7 to 6 years. Lakeland Power also indicated that this will assist in reducing outages due to tree contact.

a) Please provide the following information:
   1) When was the schedule shortened from 7 to 6 years?

LPDL's tree trimming schedule was shortened to 6 years in 2014 following the amalgamation with Parry Sound.

   2) What have been the improvements in the SAIDI and SAIFI indices that could be ascribed to this modified schedule since the modification?

LPDL has not gone through a full 6 year cycle since the schedule modification, however trouble calls by tree contact since 2014 are shown below. 2017 was higher due to 2 major storms that passed through LPDL's service territory.



	2015	2016	2017	2018
Tree Contact	16	15	22	10

   3) What are the estimated projected yearly improvements in the SAIDI and SAIFI indices that you would ascribe to this modified schedule over the next 5 years?

LPDL does not have the resources or capacity to quantify the improvements.

4) What is the projected yearly increase in O & M costs over the next 5 years as a result of the enhanced tree-trimming program?

LPDL goes out for RFP and locks in a 3 year tree trimming contract with the vendor. 2019 will be the 2nd year in the current contract and will be going out for RFP beginning in the 2021 fiscal year.
The table below shows the historical and forecasted O&M costs related to tree trimming. The previous vendor that provided tree trimming services from 2015-2017 realized their quote was too low and did not bid on the current contract as LPDL's service territory is heavily forested.

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Tree Trimming Expenses	$174,710	$194,720	$135,701	$146,715	$193,642	$200,569	$204,580	$210,597	$214,609	$214,609

2-Staff-11
O&M Costs
Ref: DSP Overview (5.2.1); DSP/p. 27/Table 2-2; DSP/pp. 28, 29; Justifying Capital Expenditure (5.4.2); DSP/pp. 188-189/Figure 4-13.

At DSP/p.27/Table 2-2, Lakeland Power proposes to increase capital spending over the period 2018 to 2023 for both “System Renewal”, and “System Service”.
On DSP/ p. 28, under “System Renewal”, Lakeland Power indicates that such investments will lead to reduced costs where it states in part:

These capital investments will meet LPDL's following objectives:
• provide customers with a safe and reliable supply of electricity;
• consult with customers to ensure that customer priorities are identified and met;
• operate effectively and efficiently, reducing costs and achieving lower rate where feasible;
• continually improve methods, procedures and explore innovative ways to improve efficiencies, reduce outages, accelerate power restoration times.

On DSP/ p. 29, addressing “System Service”, Lakeland Power indicates that such investments will lead to reduced costs where it states in part:

Other projects include investments into reclosers and SCADA technology. [..] These devices will reduce both length of outages and the number of customers affected by outages as well as minimizing resources required to restore power. LPDL plans to deploy a network of line sensors which will result in approximately 84 sensors to assist with outage management and improving grid efficiency. The line sensors provide a cost-effective solution in reporting and locating outages. This would result in faster response for trouble calls reducing outage statistics and saving resources required to locate the problem.

On DSP/p.188, Lakeland Power in addressing "Forecast Impact of System Investment on System O&M Costs" states in part that:

Over the historical period, LPDL's system O&M cost was fluctuating between $1.53M to $1.67M. Based on the proposed investment plan, system O&M costs have been forecast to have a slow increasing trend due to inflation.

Figure 4-13, at DSP/p. 189 titled "Actual and Forecast O&M Costs", covering the period 2013 to 2023, depicts increases that appears to be higher than normally forecasted inflation rates. The Table below is calculated using the amounts in the noted Figure 4-13, and shows the O&M Cost Change (+/-), Year-Over-Year, starting with Test Year-Over-2018.

Year-Over-Previous Year	2018/2017	2019/2018	2020/2019	2021/2020	2022/2021	2023/2022
Percentage Change in O&M	6.59%	3.37%	3.26%	3.68%	3.55%	3.43%

a) Please provide the source document of the inflation forecast that Lakeland Power relied on to justify Lakeland Power statement that "system O&M costs have been forecast to have a slow increasing trend due to inflation".

LPDL has inserted the table below that shows the forecasted increase to system O&M. LPDL has estimated future costs with inflationary factors for payroll, vendors and outside contractors.

Reporting Basis					
	2019	2020	2021	2022	2023
	Merged	Merged	Merged	Merged	Merged
Operations	$ 360,000.00	$ 380,000.00	$ 400,000.00	$ 420,000.00	$ 440,000.00
Maintenance	$ 1,465,000.00	$ 1,515,000.00	$ 1,565,000.00	$ 1,615,000.00	$ 1,665,000.00
SubTotal	**$ 1,825,000.00**	**$ 1,895,000.00**	**$ 1,965,000.00**	**$ 2,035,000.00**	**$ 2,105,000.00**

b) If it is Lakeland Power's position that the projected O & M spending already reflects proposed project efficiencies, what would have been the projected O & M spending if the proposed projects were not carried out?

LPDL cannot reliably estimate what projected O&M costs would be if the proposed projects are not carried out. The projects planned are related to voltage conversion or replacing assets at the end of their useful life which will reduce maintenance and improve reliability.

c) Can Lakeland Power further breakdown its forecasted O & M spending into the reactive and planned components?

LPDL is unable to forecast O&M into reactive or planned components.

2-Staff-12
DSP Overview
Ref: DSP Overview (5.2.1); DSP/p. 29.

Lakeland Power indicates on page 29 that it plans to implement projects using SCADA technology, reclosers, line sensors and the necessary communication infrastructure in order to assist with and to improve outage management. In this regard Lakeland Power asserts that such projects will reduce the length of outages, reduce the number of customers affected by outages and reduce the resources (crews, vehicles) needed to manage these outage occurrences.

a) Given these noted assertions, could Lakeland Power provide an estimate of the following:

At this time LPDL cannot reliably estimate customer outages minutes, crew time utilized or vehicle usage requirements. However, with investments in the SCADA system, LPDL will be able to improve the outage map for customer awareness and respond to outages remotely to reduce customer outage minutes, crew time utilized and vehicle usage.

1) The projected reduction in customer outage minutes and the projected improvement in the SAIDI index;
2) The projected reduction in crew time utilized to locate and manage these outages; and,
3) The projected reduction in vehicle usage requirements to manage outages and trouble calls.

2-Staff-13

DSP Overview

Ref: DSP Overview (5.2.1); DSP/p. 33; Justifying Capital Expenditure (5.4.2); DSP/p. 191.

On DSP/p. 33, Lakeland Power stated in part that:

> *Over the forecast period, LPDL has budgeted for several voltage conversion projects. Once all 4.2 kV voltage conversion projects complete in Bracebridge, the MS3 substation will no longer be required.*

On DSP/p. 191, Lakeland Power states in part that:

> *LPDL is continuing with voltage conversion projects such that the 4.2 kV substations in Bracebridge and Parry Sound can be decommissioned in future reducing overall maintenance costs. These projects will reduce distribution losses, improve system operability and efficiency.*

OEB staff wishes to receive a more complete assessment of the value of these projects.

a) Please provide an estimate of the projected savings for all conversion projects where LV equipment is removed from service, whether such equipment are expected to be in-service within the 5 year DSP horizon (2019-2023) or beyond 2023.

LPDL cannot reliably project the savings due to conversion projects that are planned over the 5 year plan. Conversion projects are needed to reduce duplicated assets avoid inevitable major maintenance costs. LPDL's substations identified are failing and annual maintenance is increasing. Equipment related to the conversion projects planned in the 5 year horizon will be in service once completed.

b) Please provide an estimate of the projected reduction in line losses for all conversion projects where LV equipment is removed from service, whether these conversion projects are expected to be in-service within the 5 year DSP horizon (2019-2023) or beyond 2023.

LPDL has not performed a detailed analysis of line losses for all areas where conversion projects are planned. Planned projects within the 5 year horizon will be in service, however LPDL has additional voltage conversion projects scheduled beyond 2023 in the Parry Sound area.

2-Staff-14
Priority Ranking
Ref: Justifying Capital Expenditure (5.4.2); DSP/p. 193/Table 4-12;
Asset Lifecycle Optimization Policies and Practices (5.3.3); DSP/pp. 144-146;
Tools and Methods for Project Selection (5.4.1) DSP pp. 163-164.

At DSP/p, 193, with regard to the projects shown on Table 4-12, it is indicated in the System Service category that the project titled "Muskoka Road Bracebridge Manitoba St to Shire St" project has a Priority Ranking of 8 and that the project titled "Self Healing Components - SCADA " has a Priority Ranking of 10.

At DSP/pp. 144-146 and pp.163-164 Lakeland Power indicated that the Priority Rank is a product of the Health Index, the Risk Consequence of Failure and the Corporate Objectives Ranking.

a) Could Lakeland Power provide the detailed calculations showing all the components so as to show how the Priority Ranking for these two projects was established and to show specifically what differentiates these two projects as to rank.

	Objective	Public health & safety.	Environmental concerns.	Meet regulatory and legal obligations	Replace end-of-life assets/ Reliability.	Improve operational efficiency.	Mitigate rate impact to customers.	
	Weight (a)	10	8	8	7	6	5	
Self Healing Components - SCADA	Risk Factor (b)	2	2	0	8	8	2	
	Score (axb)	20	16	0	56	48	10	150
Muskoka Rd. Bracebridge - Manitoba St. to Shire St.	Risk Factor (b)	7	3	0	11	11	2	
	Score (axb)	70	24	0	77	66	10	247

a - Weights between 0-10 are assigned to the asset management objectives
b – A Risk Factor is estimated for the individual project. For each of the 6 objectives, a Risk Factor is estimated according to the asset class and how the asset relates to the 4 risk areas (Reliability, Safety, Environment, Efficiency)
Total Score equals weight x risk factor.

The assignment of scores is an engineering estimate and not purely mathematical. A numerical risk based assessment is a more in depth phase of planning that LPDL is planning on developing, however the current methodology involves engineering assumptions.

2-Staff-15
Parry Sound Project
Ref: DSP Overview (5.2.1); DSP/p. 30; DSP/p.43.
On DSP/p.30, Lakeland Power stated in part that:

> *The Township of Parry Sound is seeking to become a sustainable community through the use of distributed energy resources (DER's). To address this request, LPDL has collaborated with a third party developer of flexible clean energy infrastructure. Both companies entered into a Memorandum of Understanding with the Town of Parry Sound, agreeing to collaborate in assisting Parry Sound in meeting its sustainability goals.*

On DSP/p. 43, Lakeland Power further confirmed the objective of the Township of Parry Sound of becoming a sustainable community through sourcing 100% of the electricity requirement for both its operations and the needs of its residents and business from renewable energy, and further stated in part that:

> *[..]With LPDL guidance the Town of Parry Sound signed an MOU with a third-party organization to initiate this plan/project. This project would include grid-modernization aspects, and would alleviate the constraints on the Parry Sound TS.*

a) In regard to the Township of Parry Sound and the MOU with the third party, please provide a summary of Lakeland Power's resources that were used in 2018 as well as for each year of the 5 year DSP.

Minimal LPDL resources have been used in 2018. The Town of Parry Sound approached LPDL with the sustainable community idea, and LPDL recommended a third party consultant for them to approach. LPDL has not included any resources for this in the 5 year DSP as the project is still in discussion stages.

b) In regard to grid-modernization being included as part of the "Project," is that noted third party acting as consultant to Lakeland Power or to the Township of Parry Sound? Please clarify the consultancy arrangement, and if the third party is retained as a consultant to Lakeland Power, please provide a scoping summary of the proposed "Project".

The third party is a consultant to the Town of Parry Sound and not LPDL.

2-Staff-16

Customer Engagement

Ref: DSP Overview (5.2.2); DSP/pp. 44-47; Customer Engagement Report (Exhibit 2, Part 2/Appendix F/p.79 - pdf); Performance Measurement for Continuous Improvement (5.2.3); DSP/p. 61.

At DSP/pp. 44-47, Lakeland Power reported on the results of the 2017 “Customer Surveys”. Lakeland Power further indicated that a telephone survey of about 400 randomly selected interviews of Lakeland Power customers was conducted by media professionals.

At Exhibit. 2, Part 2/Appendix F, it is reported that the response rate is about 10%. However, 400 respondents is less than 3% of Lakeland Power’s customers. Using inferential statistics, samples from a population must be valid, i.e. non-respondents are assumed to fall into the same distribution as respondents. Normally, to address “non-response bias”, practitioners use follow-up surveys of non-respondents.

On DSP-page 61, the Performance Measures listed are quite comprehensive, where 7 areas are identified under ”Customer Satisfaction”, including “Power Quality and Reliability”.

a) Given the issue of non-respondents noted above, please provide information as to whether the hired media professionals that conducted the telephone survey raised that issue with Lakeland Power?

The CHEC group of utilities uses the same hired media professionals to conduct the mandated CSS Survey. Neither CHEC nor LPDL has identified this as an issue.

b) As reliability is generally better in higher density areas than in lower density areas, is it possible for the 2017 Survey, to summarize the results by separating the responses, into two groups? The first group of respondents would be those located within high-density areas (e.g., Towns) and the second group of respondents would be those located in Rural areas.

Summarizing the results for the 2017 Survey into high-density and rural areas would not be possible for LPDL. Our customer information is not segregated in this manner.

2-Staff-17

Outage Statistics

Ref: Performance Measurement for Continuous Improvement (5.2.3); DSP/p. 84/Table 2-18 and DSP/p. 68.
On DSP/p. 84/Table 2-18, titled "Major Event – Outage Statistics By Year", shows

Table 2-18: Major Event - Outage Statistics by Year

Major Event Code 10	Number of Interruptions	Number of Customer Hours Interrupted	Number of Customers Interrupted
2017	37	18544.000	168833

On DSP/p. 68, Lakeland Power states in part that:

> *In 2017, there were two Major events that occurred. The first major storm was May 18, 2017 with 8,990 customers affected, and a total of 35,697 customer hours interrupted. The second major storm was July 7, 2017 causing 9553 customers to be affected and a total of 133,134.48 customer hours interrupted. These numbers include Loss of Supply.*

a) Please clarify how the information in the two sources relate?

The 2 Major events were added together to give the 2017 results for number of customers and customer hours. 37 interruptions were caused during the 2 major events in 2017.

2-Staff-18
Performance Measurement
Ref: Performance Measurement for Continuous Improvement (5.2.3); DSP/p. 66.
On DSP/p. 66 Lakeland Power indicated that power system analysis was carried out to improve power factor and minimize system losses.

a) Did Lakeland Power consider the installation of switchable capacitors on its system in key areas to address this issue since such installations normally provide for cost-effective solutions to such concerns?

Yes, LPDL did consider switchable capacitors, however LPDL is working with Hydro One to move open points on the sub transmission feeders which LPDL believes is a more cost effective solution.

2-Staff-19
Outage by Cause
Ref: Exhibit 2 – Distribution System Plan, p.80

Lakeland Power provided outage by cause codes for the years 2014-2017. For Cause Code 1 – Scheduled Outages and Cause Code 6 – Adverse Weather, the number of customers and the number of customer hours interrupted has been trending upwards.

a) Please provide an explanation for the upwards trend.

Cause code 1, scheduled outages are being reported more accurately now with an improved reporting system.
Cause code 6, the LPDL area has experienced more adverse weather conditions over the 4 year window

b) Does Lakeland Power have the capability to back feed supplies during station outages? Are the scheduled outages during off hours to minimize inconvenience to customers?

LPDL owned stations have the ability to back feed customers during scheduled outages. LPDL communicates scheduled outages with the affected customers to minimize inconvenience, however attempts to schedule outages during regular business hours to minimize costs.

c) Does Lakeland Power anticipate the scheduled outages interruptions to continue to increase? How has Lakeland Power tried to mitigate this?

LPDL expects scheduled outages to remain constant and not increase.

d) What is the threshold for Major Events and what is the methodology Lakeland Power uses to calculate the Major Event threshold? When did Lakeland Power start reporting Major Events?

LPDL uses the IEEE Standard 1366 to calculate the major event threshold.
LPDL began reporting Major events in 2017 based on this standard.

e) Does Lakeland Power anticipate the Adverse Weather interruptions to continue to increase? How has Lakeland Power tried to mitigate this?

LPDL expects Adverse Weather to continue and are attempting to mitigate interruptions by making the Distribution System as robust as possible to withstand Adverse Weather.

2-Staff-20
Incorporating Performance Trends Into DSP
Ref: Exhibit 2 – Distribution System Plan, p. 97
Ref: Appendix J – System Loss Reduction Report - Bracebridge

Lakeland Power stated that a line loss study was completed for the Bracebridge area and going forward it may employ a third-party vendor to do line loss studies for other service areas. The Bracebridge report identified three methods to reduce losses: balancing the phases; switching network optimization; and placing capacitors.

a) Has Lakeland Power implemented any of the recommendations from the Bracebridge report? What were the outcomes?

LDPL is continuing to work with Hydro One regarding line losses. LPDL have begun implementing other recommendations with no results to report as of yet.

b) Why has Lakeland Power only chosen Bracebridge to complete a line loss study and not all other service territories?

Bracebridge is the largest and most complex area in LPDL's service territory.

c) Does Lakeland Power have the capability to run CYME studies as provided in the report?

No LPDL does not have the capability and uses a third party to conduct CYME studies.

d) Has Lakeland Power implemented the three strategies identified for the Bracebridge area to other areas? If not, why?

LPDL has not implemented the strategies to the other areas at this time. LPDL is waiting for results from the Bracebridge area to determine the benefits. Along with voltage conversion projects, LPDL is planning on implementing these strategies if proven to be beneficial to assist in line losses across the entire service territory.

2-Staff-21
Ranking Capital Projects

Ref: DSP Overview (5.2.2); DSP/pp. 44-47; DSP/p. 89; DSP Overview (5.2.1); DSP/p. 27/Table 2-2; DSP/p. 29; Performance Measurement for Continuous Improvement (5.2.3); DSP/p. 99; Asset Management Objectives (5.3.1); DSP/p. 99/Figure 3-1; Justifying Capital Expenditure (5.4.2); DSP/pp. 188-189/Figure 4-13.

In the DSP/pp. 44 – 47 dealing with the 2017 "Customer Surveys", it indicates that price is the highest ranked in terms of importance to customers, followed closely by reliability as the second highest in rank. At DSP/p.89 reporting on previous surveys, it also indicates in part that in the 2016 survey, the issue of price had overtaken system reliability as the most important facet of Lakeland Power "business" to the consumer. Referring to DSP/p. 27/Table 2-2, it is noted that the amount of the proposed investments following the 2019 test year included investments in discretionary projects (e.g., self-healing SCADA systems and computer software upgrades). On DSP/p. 29 the Lakeland Power narrative and rationale for discretionary investments include improvement in power restoration (e.g, reliability), yet the rate-payer appears not to be benefitting from an expected lowered increases in O&M costs, as evidenced at DSP/p.189/Figure 4-13. In that noted Figure 4-13, and the table below (based on that same Figure 4-13) shows that the O&M Cost Change (+/-), Year-Over-Year, starting with Test Year-Over-2018 is increasing at a rate that appears to be higher than inflation.

Year-Over-Previous Year	**2018/2017**	**2019/2018**	**2020/2019**	**2021/2020**	**2022/2021**	**2023/2022**
Percentage Change in O&M	**6.59%**	**3.37%**	**3.26%**	**3.68%**	**3.55%**	**3.43%**

a) Given the evidence noted above in regard to the 2017 "Customer Surveys" indicating that price is the highest ranked in terms of importance to customers, please elaborate on the apparent inconsistency evidenced in DSP/p. 99/Figure 3-1 where Lakeland Power's Objectives lists "Replace end-of-life assets" and "Improves operational efficiency" ahead of "Mitigate rate impact to customers".

LPDL is aware that price is the highest ranked item of importance to the sample customers when asked how to rank activities and/or important facets regarding LPDL's business.

LPDL is diligent in attempting to mitigate rate impacts wherever possible, however believes the objectives and their rankings stated in DSP/p. 99 are correct. The weights assigned to the objectives are engineering assumptions with other factors that are taken into consideration.

2-Staff-22
Capital Expenditures
Ref: OEB Chapter 5 - Consolidated Distribution System Plan Filing Requirements, Section 5.4 Capital Expenditure Plan (page 16); OEB Chapter 5 - Consolidated Distribution System Plan Filing Requirements, Section 5.4.3.2, A. General information on the project/program (page 21); Lakeland Power Exhibit 2, Section 2.1.1 Key Elements of the DSP, Table 2-2 (page 27); DSP, Appendix A1 Capital Project Narratives Test Year 2019.

In the Filing Requirements OEB states “a DSP must include information on prospective investments over a minimum five year forecast period”. The OEB describes the information to be provided for any material project or program in section 5.4.3.2.

In section 2.1.1. of the DSP Lakeland Power has provided forecast capital expenditures for 2018 to 2023 organized by project category and totaled by year. In Appendix A1 Lakeland Power has provided a listing and project/activity narratives of material projects for the first year (2019) of the planning period from 2019 to 2023, but not for the remaining years from 2020 to 2023. From the information provided, it can be assumed that the project narratives provided for 2019 will equally apply for the projects or programs for each of the subsequent years. The project narratives also indicate the expected capital expenditures for each project for the forecast period from 2019 to 2023. However, the capital expenditures for the same period indicated for the System Renewal and System Service category of projects in section 2.1.1. is typically significantly higher than the capital expenditures in Appendix A. The table below shows the difference between the capital expenditures projected in the project narratives in Appendix A1 and the capital expenditure summary in Table 2-2 for each category for each year.

	System Access	System Renewal	System Service	General Plant
2019 Project Total	$380,000	$1,210,000	$485,000	$625,000
2019 Summary	$380,000	$1,210,000	$485,000	$650,000
Difference	**$0**	**$0**	**$0**	**$25,000**
2020 Project Total	$350,000	$150,000	$190,000	$335,000
2020 Summary	$350,000	$830,000	$1,265,000	$375,000

Difference	**$0**	**$680,000**	**$1,075,000**	**$40,000**
2021 Project Total	$350,000	$150,000	$210,000	$360,000
2021 Summary	$350,000	$1,570,000	$560,000	$425,000
Difference	**$0**	**$1,420,000**	**$350,000**	**$65,000**
2022 Project Total	$350,000	$150,000	$190,000	$475,000
2022 Summary	$350,000	$1,200,000	$1,000,000	$515,000
Difference	**$0**	**$1,050,000**	**$810,000**	**$40,000**
2023 Project Total	$350,000	$150,000	$210,000	$438,000
2023 Summary	$350,000	$1,125,000	$1,360,000	$504,000
Difference	**$0**	**$975,000**	**$1,150,000**	**$66,000**

a) In Appendix A1, for the period from 2020 to 2023, please include descriptions (narratives) for all material System Renewal and System Service projects/programs that are not extensions of the projects or programs included, or if detailed planning is not available for this period, please provide the information used to justify the expected capital expenditure differences identified in the table above.

Detailed narratives are not available for projects in the period 2020 to 2023 which are not direct extensions to the 2019 narratives. LPDL notes that it is only seeking approval for 2019 rates, and thus the 2019 narratives are directly relevant to this application. Many of the estimated projects planned from 2020 to 2023 in the System Renewal and System Service category are extensions of the 2019 narratives. LPDL plans to continue voltage conversion projects and the increase/decrease in $ value is subject to the street/subdivision that LPDL is planning on upgrading and the amount of assets in that location.

b) In Appendix A1, for General Plant projects, no material project capital expenditures are indicated for the Computer Hardware Updates project (GP 004) after 2019 implying that no material capital expenditures will be made in that area during that period. Please provide project/program narratives for any material General Plant capital expenditures expected for the period from 2020 to 2023.

LPDL has provided its fleet management policy as Appendix I as fleet is the largest material expenditure anticipated over the period to 2023. LPDL has also estimated material expenditures to computer software/hardware in anticipation of being compliant with cyber security mandates. LPDL is unable to provide an accurate narrative at this time as these general plant expenditures will be re-evaluated on an annual basis.

2-Staff-23
System Renewal
Ref: Appendix A1 Capital Project Narratives Test Year 2019, SR-006
Ref: LPDL 2019_Filing_Requirements_Chapter2_Appendices_20180927, App.2 AA capital projects

Lakeland Power has forecasted a program for Reactive and Maintenance Based Replacement. The corresponding program is provided in Chapter 2 appendices 2-AA.

a) Please confirm that program name in appendix 2-AA is incorrect and should be Reactive and Maintenance Based Replacement.

LPDL confirms that the description in 2-AA is incorrect.

b) Please provide a table of historical programs and costs that would fall under this program.

System Renewal	System Renewal		2013 - Consolidated	2014 - Consolidated	2015	2016	2017	2018
2016-00122	Upgrade Replacements due to inspections - Parry Sound		$0	$0	$1,885	$275,246	$4,968	
2015-35316	Asset Replacement From Inspections		$0	$0	$151,892	$0	$0	
2014-27443	Asset Replacements Pole Inspection 2014		$0	$86,845	$6,254	$0	$0	
2018-SR Aging Assets	Aging Asset Replacements Due To Inspections							$132,142

2-Staff-24
System Renewal
Ref: Appendix A1 Capital Project Narratives Test Year 2019, SS-001

Lakeland Power has forecasted $120k over 5 years to replace 13 Hydro One metering points with IESO meter points in Burk's Falls and Sunridge.

a) Will Lakeland Power be installing 13 IESO meter points?

LPDL is working with a third party and Hydro One to determine the optimal solution for purchasing the meter points.

b) What is the unit cost of each installations?

LPDL received a quote of approximately $25,000 for materials per meter point and is estimating approximately $25,000 in labor for installation of each meter point.

2-Staff-25
Performance Measures
Ref: Performance Measures for Continuous Improvement (5.2.3) DSP section 2.3.3.7 (pages 91-92) Figures 26 and 27; OEB Chapter 5 Filing Requirements for Electricity Distribution Rate Applications ("Filing Requirements"), 5.2.3 (a), page 10; OEB Statistical Yearbooks 2013-2017.

The Filing Requirements indicate that distributors are not limited to the metrics listed in section 5.2.3. Lakeland Power chooses to focus on costs/customer and costs/km. Lakeland Power notes that Fig 26 is not consistent with the benchmark methodology referred to in Appendix 5-A of the Filing Requirements. Looking instead at revenues, which represent the total cost to consumers, comparisons on the basis of different categories of costs may be avoided. The table below provides total revenues from 2013 to 2017, along with average revenues per delivered MWh. 2014 is highlighted as the first year in which Lakeland was merged with the former Parry Sound.

	2013	**2014**	**2015**	**2016**	**2017**
Revenues ($M)	8.599	8.508	8.416	7.986	8.141
% change		-1.06	-1.08	-5.11	1.94
Revenues/MWh	$29.3	$28.55	$29.2	$28.5	$29.3
% change		-2.77	2.28	-2.41	2.56

Total revenues have fallen over the past 5 years by 5.3%, or an average of 1.09% per annum, while average revenues per delivered MWh have remained unchanged. This, of course, simply reflects the decline of load. However, the annual changes reveal possible anomalies in terms of departures from the 5-year average. Revenues fell by 5.11% from 2015 to 2016 but increased by 1.94% from 2016 to 2017, while per MWh revenues changed by -2.41% and + 2.56%, respectively.

a) Please reconcile the above data with the metrics chosen by Lakeland Power.

LPDL is unable to reconcile the above data with the metrics chosen by LPDL in Appendix 5-A. The above table displays Revenues ($M) as Revenue from Services plus Other Operating Revenue for 2013 to 2015 however the 2016 to 2017 values do not align to LPDL's actuals..
Appendix 5-A metrics chosen by LPDL displays total capital expenditures, plus total operating and maintenance costs.

b) In particular, what explains the 5.11% fall in revenues from 2015 to 2016 and the subsequent increase of 1.94% from 2016 to 2017?

A revised table is shown below with the actual Revenue from Services and Other Operating Revenue from 2013 to 2017.
The 5.11% fall in revenue is not correct and was calculated as such due to an error in the above table. However, the 2.18% increase is related to the shift to fully fixed charges as per the OEB's Residential Rate Design policy as discussed in Section 3.3 of Exhibit 3.

	2013	2014	2015	2016	2017
Revenue from Services	8.194	8.148	7.974	8.039	8.194
Other Operating Revenue	0.405	0.361	0.442	0.566	0.579
Total	**8.599**	**8.508**	**8.417**	**8.605**	**8.774**
% Change		-1.07%	-1.09%	2.18%	1.93%
Revenues/mWh	29.3	28.6	29.1	30.7	31.5
% Change		-2.50%	1.85%	4.98%	2.51%

c) Have there been corresponding changes to the revenues derived from the different customer classes?

LPDL would like to reference Exhibit 3 Section 3.3 for the annual revenue change derived from the respected customer classes.

2-Staff-26
Asset Management Plan
Ref: Exhibit 2, 2.4.2, Capital Expenditures – Required Information,p 49
Capital Expenditure Summary (5.4.2) DSP, p174; Case EB-2010-0140, Exhibit 2, Tab 3, Schedule 2, Appendix A

Lakeland Power states at Line 6, p49: "Appendix 2-AB, shown below in Table 32, includes capital expenditures from 2013 to 2017 and projections for 2018 to 2023. Lakeland Power or PSP did not file a DSP in their last CoS, however both did file an individual Asset Management Plan ("AMP")."

Lakeland Power states at second last paragraph p174: "Appendix 2-AB, shown below, includes capital expenditures for 2013 to 2017 and projections for 2018 to 2023. Lakeland Power or PSP did not file a DSP in their last COS, however both did file an individual Asset Management Plan ("AMP")."

a) Please explain whether an Asset Management Plan (AMP) was prepared and included with this DSP submission and, if so, please point to a section in this DSP, where it can be found.

The concept of an Asset Management Plan was replaced with a more fulsome DSP. Please refer to Section 3 of the DSP for a description of LPDL's asset management process.

b) The Asset Management Plan prepared for Parry Sound Power (PSP) on September 14, 2010 (by Rodan Energy Solutions People) contained specific recommendations for Inspections, Maintenance and Information Management. Please explain whether the recommendations included in this 2010 Asset Management Plan were incorporated in this DSP submission. If so, would you please describe the main changes reflected in this DSP?

The recommendations prepared for the former PSP were reviewed however were not included in the DSP. Since the amalgamation LPDL reviewed the recommendations prepared by Rodan and have completed some of the projects described in the AMP by the 2018 fiscal year. In the current DSP for the 5 year forecast, LPDL will not be implementing any other recommendations provided by Rodan.

2-Staff-27

Asset Management Process

Ref: Asset Management Process Overview (5.3.1.) DSP p99.

Lakeland Power states on page 99: Lakeland Power's asset management program incorporates the organization's Vision and Mission, which are summarized in Section 1.3.1. Lakeland Power's asset management methodology incorporates the objectives of the OEB's RRFE (see Section 1.1).

The following outlines the key objectives of Lakeland Power's approach to asset management. These objectives aim to maximize the safety, capacity, reliability and security aspects of the distribution system by:

1. Public health & safety.
2. Environmental concerns.
3. Meet regulatory and legal obligations
4. Replace end-of-life assets.
5. Improve operational efficiency.
6. Mitigate rate impact to customers

Lakeland Power states on page 100: Replacing end of life assets is an objective that ties into all others. These tangible distribution assets make up the backbone of our service and their maintenance is central to providing safe reliable service.

Lakeland Power also states on page 100: Lakeland Power is currently examining the possibility of working with a consultant to create a formal Asset Condition Assessment, which would become the basis of future decision-making processes. While Lakeland Power has confidence in its current Asset Management and Project Prioritization strategy, it recognizes improvements can always be made.

a) It is not possible to simultaneously maximize multiple factors. Would Lakeland Power agree that the aim might be better stated here as "to optimize" rather than maximize, consistent with the scores and weightings proposed Lakeland Power for the various factors?

LPDL agrees that optimize is a better description for the various factors.

b) Would you please confirm that the following points have been included in asset management objectives:
    a. Employee safety
    b. Reliability
    c. Optimization of life cycle costs and replacement decisions

LPDL confirms that the points identified are inherently included in the asset management objectives.

c) Bullet 4 refers to “Replace end of life assets”. Would you please confirm that this activity is part of an overall Lakeland Power process of “Optimizing the use of resources amongst maintenance, refurbishment/upgrading and replacement”?

LPDL confirms that this is part of an overall process.

d) In Figure 3-1 “Prioritization of Lakeland Power Objectives”, numerical values are assigned to the Lakeland Power Objectives. Please point to a discussion explaining how these weights were assigned. Maintenance is not included in Fig 3-1. Please explain its absence or confirm how it is included.

Figure 3-1 is an Engineering Estimate provided by Metsco.

e) Please confirm whether reliability centered maintenance (RCM) has been included as one of the asset management tools within Lakeland Power, e.g. a process described in the SAE JA1011 Standard for Reliability Centered Maintenance (RCM)? If so, please point to a section in this DSP, where it can be found. If not, please explain whether Lakeland Power plans to initiate RCM and indicate the intended time frame?

LPDL has not included RCM as an asset management tool. At this time LPDL does not plan to initiate RCM as it does not have the resources available.

f) With regards to Lakeland Power replacing end of life assets, please refer to the Lakeland Power AM investment objectives and to the list of asset types managed included in this DSP. Please advise whether there are Lakeland Power AM governance documents (i.e. policy, strategy, asset management plan) that include the end of life (EOL) criteria, criteria descriptions and EOL measures for each asset managed and point to this discussion. If not, please indicate if Lakeland Power plans to include this in future and the anticipated timeline.

LPDL does not have governance documents regarding EOL criteria at this time. As LPDL continues to work the Utility Standards Forum and Cornerstone Hydro Electric Concepts regarding Asset Condition Assessments, LPDL will consider implementing EOL governance documents at the same time.

g) Asset Condition Assessment is an essential enhancement to Asset Management. In general, Best Asset Management Practice involves systematic development and use of Asset Condition Assessment as the most appropriate means to define the health of assets and asset classes (System Health). See Figure 1, below. Please point to a discussion that describes and underpins Lakeland Power's confidence in its current Asset Management. If Lakeland Power's intent is to formalize Condition Assessment, please provide the timeline for the Asset Condition Assessment implementation.

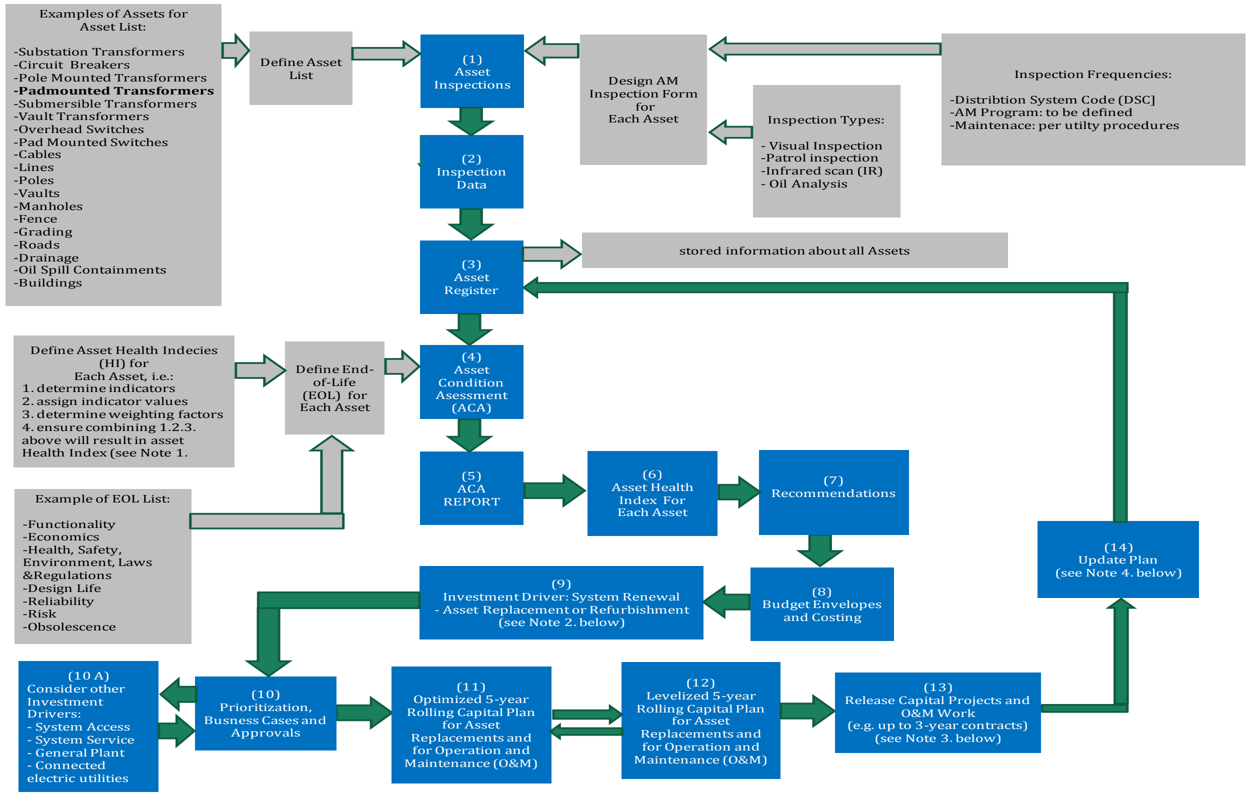
The Asset Management Summary on page 100 of the DSP describes LPDL's current process for Asset Management Assessments. LPDL agrees that a formal ACA is the most appropriate means to define the health of assets and is currently working with USF to develop a formal ACA. LPDL is following the lead provided by USF and a formal timeline is unknown at this time.

h) Is there an expectation that capital plans envisioned under the current submission will be impacted by the contemplated implementation of a formal Asset Condition Assessment (i.e. increase or reduce capital requirement plans)?

LPDL does not expect a formal ACA to provide results significantly different than the current capital plans. LPDL has identified the voltage conversion projects a priority and believes an ACA will support this decision.

i) The Institute of Asset Management (IAH) makes available to its members a guide for self-administered evaluation of Asset Management (AM) maturity scale e.g. 0 to 5 (innocent, aware, developing, competent, optimizing and excellent). Please explain if Lakeland Power undertook this or any similar self-assessment and if so, what were the conclusions of this exercise? If not, would LDPL consider such self-evaluation in the future?

LPDL did not undertake a self-assessment in this rate application. LPDL will take this into consideration while working with USF for developing a formal ACA.



Notes

1. Health index of an asset is established from multiple factors that are then combined by weighting them.
2. To determine required rates of replacement over time in order to maintain or improve the overall health of the asset class (System Health), an appropriate sequence of steps would be to:
    1)Determine the "Health" of an individual asset
    2)Combine the indices for all assets in a class,
    3)Analyze the resultant curve
    4) Determine required rates of replacement over time
3. Carry out the work in-house and/or contract out
4. Include new asset information, work released but not started and work not completed.

Figure 1. AM FLOWCHART: ILLUSTRATIVE EXAMPLE (referred to in paragraph (vii), above)**.** [Source: Training Course "Meeting Chapter 5 Filing", The MEARIE Group, January 16, 2018]

2-Staff-28
Asset Management Process
Ref: Asset Management Process Overview (5.3.1) DSP p105, Figure 3-4: Asset Management Process Flowchart

Lakeland Power states on page 101: Lakeland Power's asset management plan requires a team effort and is the combined responsibility of the Manager of Operations, Lines Supervisor, engineering staff, lines department, GIS/IT support personnel and financial department. Generally, these responsibilities include:

- Ensuring schedules for inspection and maintenance are adhered to.
- Reviewing and ensuring the inspection data is complete and thorough in order to be useful.
- Reviewing and analyzing the inspection data to plan for system maintenance and upgrades.
- Analyzing inspection data and trouble call trends to identify and prioritize future areas for capital and operating and maintenance budgets.
- Reviewing and updating the inspection and maintenance program as required, to incorporate changing regulations, standards and system facilities and to enhance the value of the inspection result data.
- Ensure the proposed capital expenditures are financially feasible and support the established budgetary parameters

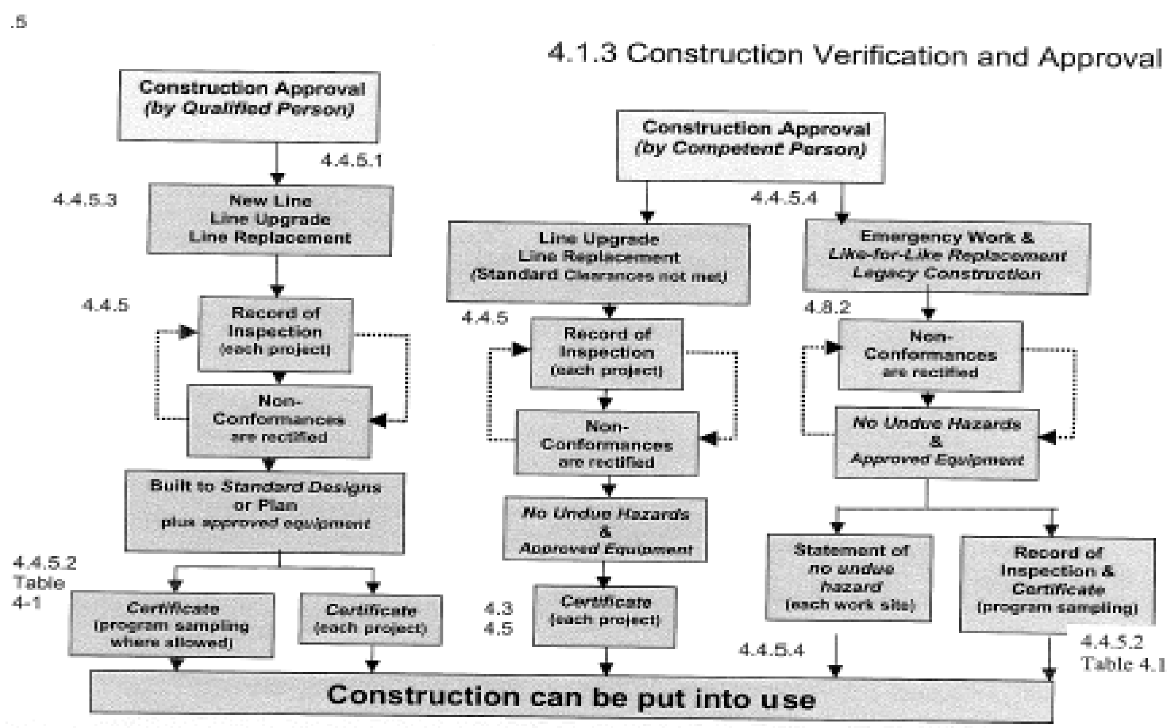
Lakeland Power states on page 102: This computerized work order system allows Lakeland Power to effectively plan, prioritize, allocate and schedule the appropriate labour, equipment and material resources to each job or work project. The availability of this work order data, with the querying/reporting tools, provides the ability to identify areas that show a trend of repeat visits or trouble calls from which high-risk areas or aging areas can be identified to be addressed in the capital asset plan.

Lakeland Power states on page 103: Lakeland Power uses Fulcrum, a mobile data collection platform that allows Lakeland Power to easily build mobile forms & collect data anywhere, anytime with our mobile devices. Lakeland Power uses Fulcrum to inspect poles, transformers, and substations.

Lakeland Power states on page 104: Figure 3-4 illustrates the Asset Management Process from technical data input through to several outcomes, including future review or maintenance, and culminating in the creation of the capital plan, including plan drivers.

a) Please provide a current Lakeland Power organization chart, or point to a section in this DSP, which would include the Lakeland Power staff in the Asset Management organization as well as any external contractors with assigned roles in the organization. Please show the Asset Management reporting structure, descriptions of roles and responsibilities for all key personnel and identify who has the overall responsibility for the Asset Management Program development and application.

LPDL does not have a formal Asset Management reporting structure as it is a small utility. LPDL uses a team approach where management relies on the engineering and operation department as well as external contractors to input information to the work management and GIS systems.
Below is an example of the construction verification process as approved by ESA which identifies the responsibilities of LPDL's staff.



b) In the list of responsibilities (stated on page 101), asset replacement is not listed. Please confirm that this is included (e.g. in bullet 3).

LPDL confirms that asset replacement is implied as the result in bullet 3

c) There is no mention of Lakeland Power's effort to incorporate industry best-practice and lessons learned. Please confirm if this is part of the Lakeland Power's Asset Management process and explain (or point to) any efforts to share experience (and data) on asset performance with neighbouring utilities.

LPDL confirms that this is part of the Asset Management process. As stated within the DSP in section 2.1.3, LPDL is an active member of USF and CHEC. LPDL collaborates with USF and CHEC to share experience, knowledge, resources and efficiencies. LPDL also has active consultations with Hydro One as stated in section 2.2.1.1.

d) With reference to Fig 3-2 "Sample of SAIDI/SAIFI/CAIFI report", please confirm that SAIDI and SAIFI values are per customer per year. If so, please describe the process for tabulating and checking the values indicated, as the numerical values given seem quite low (e.g. < 1/5y interruptions per customer). If these refer only to those outages under Lakeland Power control, please make this clear in the text and describe the impact and sources of outages not included here.

LPDL confirms that Fig 3-2 is not the values per customer per year. Fig 3-2 is purely a statistical sample that is taken from LPDL's Worktech work management system, and the sample that is shown in Fig 3-2 was a monthly snapshot for demonstrative purposes.

e) Lakeland Power uses its Work Order system and mobile platform technology to track and integrate asset information. With regards to identifying "high risk areas or aging areas" is this capability exploited (or planned) for tracking individual assets and asset classes? In particular, please clarify if this capability has been fully integrated with GIS (p103) and if an asset's condition information inputs would be retrievable for Lakeland Power future asset condition assessments, along with its "physical characteristics such as age, make, model and serial number" as stated in the description of GIS.

LPDL's work management system is integrated with the GIS. The asset number is the unique identifier in both systems. The GIS system stores all physical characteristics, however, the health index rating is not fully integrated and not stored in the GIS.

f) With respect to Figure 3-4 Asset Management Process Flowsheet:
    1) The boxes for "Historical Failure Data on Similar Assets" and "Calculate Health Index Rating" are not connected. Please explain if they are (in fact) connected?

In Figure 3-4 LPDL has attempted to display their process where a health index rating is captured on all assets. If LPDL receives a customer request for an upgrade as an example, the health index rating has already been calculated for that asset, therefore is not part of the flowchart.

2) An example of an Asset Management Flowchart is shown on Figure 1, above. This flowchart illustrates various components of asset management process as well as interconnections among the AM "process boxes", so that a common approach across all asset classes is possible and allows the use of collected information for renewal capital allocation. Would you please compare the LDPL Figure 3-4 "Asset Management Process Flowchart" against Figure 1 above, and identify changes that would be need to Figure 3-4 to achieve agreement between the two flowcharts?

LPDL agrees that the flowchart shown on Figure 1 is more detailed and identifies areas some steps that are currently missing in LDPL's figure 3-4. LPDL believes that once an asset condition assessment is implemented, the steps for the asset management process will be very similar, and LPDL can revise their flowchart to reflect this.

2-Staff-29
Assets Management
Ref: Overview of Assets Managed (5.3.2) DSP p106-7; Page 3 of the Muskoka Community Foundation Vital Signs® Report 2018[1]

Lakeland Power states on page 106:

> *Wind storms pose the greatest threat of LPDL's distribution system. Overhead lines run thoroughly heavily wooded areas. Tree trimming exercises occur on a rotating basis, but inclement weather can be unpredictable. LPDL has taken steps, through tree trimming and the identification of past problems area, to mitigate the effect of storms and to prepare for future issues.*
>
> *Environmental and climate change considerations are important to LPDL. Anticipating the results of Climate Change (more frequent extreme weather events) helps prepare LPDL to mitigate potential large outage events in the future. LPDL also takes its role as a utility that affects and influences the environment directly around it seriously and promotes conservation and sustainability efforts in the communities*

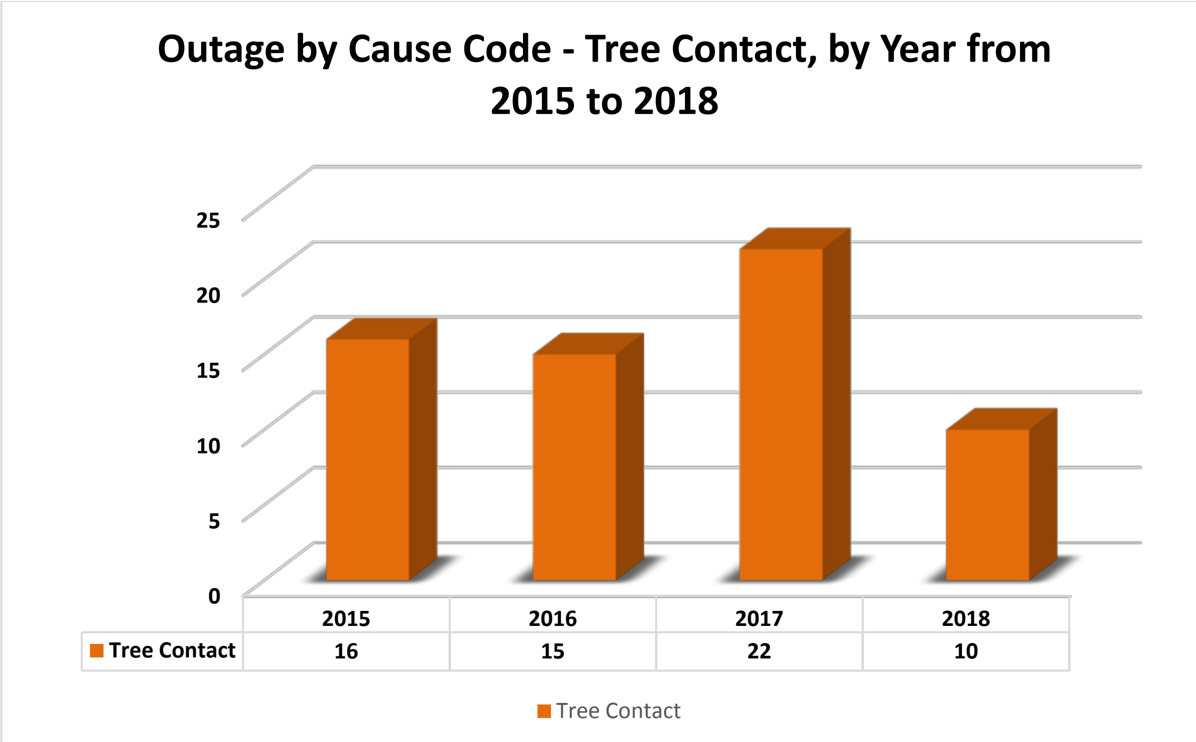
[1] http://muskokacommunityfoundation.ca/wp-content/uploads/2018/11/msk-vitalsigns-web.pdf

Lakeland Power states on page 107:

> *Muskoka is an area experiencing little growth in terms of permanent population. LDPL's six municipalities served have shown no significant population growth trends in the past 10 years according to recent data from Statistics Canada. LPDL is expecting minimal customer growth.*

a) Tree trimming occurs on a "rotating" basis (but the frequency and means to establish it is not described here). Has Lakeland Power analyzed the effectiveness/adequacy of existing tree-trimming in limiting outages and asset damage from storms? If so, please point to (or describe) these efforts. In particular would more frequent and aggressive tree trimming be cost-effective in mitigating outage and asset damage potential?

After amalgamation with Parry Sound, LPDL has implemented the 6 year tree trimming cycle that has resulted in a noticeable decrease in outages due to tree contact, with the exception of 2017 due to 2 major storm events causing large trees to break.
LDPL coordinates tree trimming with local forestry crews and has implemented an aggressive tree trimming program and believes that very little can be done to further mitigate outage or potential asset damage. The reason that LPDL has little control to mitigating future outages is that LPDL's service territory is heavily forested with trees > 100' in height.



b) Has Lakeland Power attempted to determine if the frequency and intensity of storms (wind damage) is increasing with time, as might be expected from climate change? If so could you please add (or point to) discussion of this?

LPDL has not attempted to determine the intensity of storms. LPDL's objective is to make their distribution system as robust as possible to prepare for unforeseen storms.

c) Regarding the stated low growth in permanent population, is there evidence of significant growth (or decline) in population (or other sources of load) in any of areas served by Lakeland Power? Does this correlate with feeder-loads? As input to this discussion, reference to the Muskoka District Plan (referenced in paragraph (iv), below) is suggested.

LPDL's projection of low growth corelates with the Parry Sound and Muskoka regional plan in section 5.3. LPDL does not recognize Muskoka Community Foundation Vital Signs report as being a reliable source for expected growth as the majority of the projection map is not LPDL service territory.

d) Page 3 of the Muskoka Community Foundation Vital Signs® Report 2018 includes information which seem to indicate a significant projected growth over the next 20 years in both permanent and seasonal population. Please indicate if the projected capital expenditures are adequate in each of the four categories to address these levels of growth in Table 1-5: "Capital investment drivers over the forecast period" on page 25 should such projected growth be realized?

LPDL reiterates that the Muskoka Community Foundation Vital Signs report growth projections are outside of LPDL service territory, therefore capital expenditures have not been planned in correlation to this report.

2-Staff-30
Re: Overview of Assets Managed (5.3.2) DSP p114-5.
Lakeland Power states on page 114: Table 3-3 presents Lakeland Power's major asset types, their counts, and age distribution. Lakeland Power does not have an Asset Condition Assessment report and instead relies on asset age and inspection results, as presented below for each asset class.

a) Please explain whether each of the nine (9) asset types shown in Table 3-3 "Asset counts by age grouping as of Dec 17"will be considered for asset condition assessment, establishment of asset Health Indices and subsequently managed using asset management principles and methods?

Substation Transformers

- These are inspected individually on a monthly basis. Due to the limited number of them and their importance to the electrical network, adding them to the Asset Condition Assessment/Health Index inspection schedule would be redundant.

Poles

- The current inspection program provides a health index rating for poles based on standards created by USF. LPDL anticipates further developing this program in the future.

Overhead Transformers

- Current Health Index program for transformers has been developed in house using data available from our mobile data collection app, Fulcrum.

- LPDL anticipates improving this process and adopting a transformer inspection Health Index based on USF standards (currently in development)

Vaults

- There are no current plans to add Vaults to an Asset Condition Management plan.

Padmount transformers

- Current Health Index program for transformers has been developed in house using data available from our mobile data collection app, Fulcrum.
- LPDL anticipates improving this process and adopting a transformer inspection Health Index based on USF standards (currently in development).

Switch Gear

- There are no current plans to add Switch Gears to an Asset Condition Management plan.

Junction Cubicle

- There are no current plans to add Junction cubicles to an Asset Condition Management plan.

Overhead Primary Line

- Overhead line is inspected on a rotating five-year basis. Any issues found during an inspection are immediately addressed.

Underground Primary Line

- The nature of this asset disqualifies it from an Asset Condition Management plan.

b) Please provide an additional Table, similar to the Table 3-3 “Asset counts by age grouping as of Dec 17”, which would indicate the proportions of LPDL data available to identify asset failures within each asset class and how many assets were inspected (e.g. columns showing asset class, % inspection data available to identify asset failure, and an additional column showing % assets inspected)?

ALL INSPECTION RECORDS -FULCRUM HEALTH INDEX											
Asset Type	<1978					Total Count					
	>40yrs	# Inspected	% Inspected	# Failed Inspection	% Failed Inspection out		# Inspected	% Inspected	# Failed Inspection	% Failed Inspection of out all	
Substation Transformer	2	2	100.00%	0	0.00%	11	11	100.00%	0	0.00%	
Poles	2,267	110	4.85%	1	0.04%	6,411	442	6.89%	26	0.41%	Failure Score is <.7
Overhead Transformers	696	184	26.44%	1	0.14%	2,098	616	29.36%	1	0.05%	Failure Score is <.7
Vaults	66	30	45.45%	n/a	n/a	541	204	37.71%	n/a	n/a	
Padmount Transformers	54	25	46.30%	3	5.56%	543	291	53.59%	3	0.55%	*Failure is score <.7
Switch Gear	0	n/a	n/a	n/a	n/a	18	n/a	n/a	n/a	n/a	
Junction Cubicle	5	n/a	n/a	n/a	n/a	63	n/a	n/a	n/a	n/a	
Overhead Primary (m)	173,790	29,293	16.86%	0	0.00%	272,129	45,978	16.90%	0	0.00%	
Underground Primary (m)	5,457	n/a	n/a	n/a	n/a	87,762	n/a	n/a	n/a	n/a	

NOTE: We have limited data available for transformers, as we only just developed the Transformer Health Index in the 2nd half of 2018.
This is expected to develop further this year as we coordinate with other USF members to create a cohesive method of measuring inspection results, similar to that of the pole health index.
*vaults in GIS that are <5m from an inspected TX are included in this count. No Health Index system exists for vaults.

LPDL would like to note that from 2014-2017, before health indexes were calculated, 1,679 additional poles were inspected without a health index rating. Of the 1,679 poles, 280 were > 40 years of age.

2-Staff-31

Ref: Overview of Assets Managed (5.3.2) DSP p116 (substation transformers), p118 (pole mounted and pad mounted transformers) and p122 (overhead primary conductors)

Lakeland Power states on page 116: The TUL of substation transformers is 40 years.

Lakeland Power states on page 117: Substation transformer condition also largely depends upon operating conditions such as loading cycles and moisture ingress. Table 3-4 lists recommendations based on Dissolved Gas Analysis ("DGA"), oil quality and Furan Test results of substation transformers. MS4 and MS1 in Parry Sound are of some concern indicating overheating. Using the age data and the recommendations information, a preliminary Health Index ("HI") analysis is performed. This analysis determined Parry Sound MS1 to be in Very Poor HI condition and Parry Sound MS4 and Bracebridge MS3 to be in Poor HI Condition, Parry Sound MS2 is showing signs of leaking and will be removed from service.

Lakeland Power states on page 117: Based on the inspection results (of 580 transformers), 15% of them have one or the other damages such as rust, cracks, etc. Figure 3-17 presents the timelines within a year to take necessary actions on pad-mount and pole-mount transformers with damages.

Lakeland Power states on page 123: Overhead conductors have a TUL of 60 years. Lakeland Power has 135,736 m of primary overhead conductors greater than forty years old (represents 63% of primary overhead conductor in service).The graph below shows more than 25,000 m of conductors exceeding 60 years of age. These conductors need to be replaced before they fail.

a) Please refer to the document from which the TUL of 40 years was established and explain how this 40 year value was adjusted for Lakeland Power systems, equipment and climatic conditions and how it correlates to the substation transformer remaining useful life?

LPDL follows the Kinectrics standard for establishing TUL.

b) Please explain (or point to a section in the DSP where it is explained) the differences are between the description of Very Poor HI (i.e. Very Poor Health Index), Poor HI (i.e. Poor Heath Index) conditions and the recommendations shown in Table 3-4 for Parry Sound MS1, MS2 and MS4 and Bracebridge MS3. In particular, Parry Sound MS2 has no mention of HI and in the text it is identified for replacement while a recommendation in Table 3-4 states “resume regular testing schedule”. Also, please explain (or point to a relevant section) how these differences between the HI ratings and recommendations in Table 3-4 have been resolved and included in the investment renewal costs of this DSP submission.

Table 3-4 Parry Sound MS2 has been removed from service and should not have that description.
The Health Index rating and recommendations in Table 3-4 are provided by Metsco Energy Solutions based on inspection data provided by LPDL.
LPDL’s 5 year capital plan is focused on voltage conversion projects which will give LPDL the ability to eliminate the 4kV stations in Parry Sound and Bracebridge that are identified in this table with a poor health rating.

c) Figure 3-17 presents inspection results which may be considered for corrective maintenance. Please explain which of these inspections would LDPL consider relevant to the planned asset condition assessment, comparison with the end of life criteria (EOL) and subsequent trending of the transformers condition in future?

LPDL believes that all inspections are considered relevant to the planned asset condition assessment. Figure 3-16 displays the reasons for the inspections results which determines the damages and determines if maintenance or replacements are needed.

d) When summarizing the vertical bars on Figure 3-21 for the period until 1958 (i.e. 60 years TUL), the total is 49,000 m. Please explain how the 25,000 m of conductors exceeding 60 years of age was obtained?

During the annexation of Hydro One the asset registry did not exist. LPDL performed a valuation of assets in service in 2010 with Suncorp. Where age of wire was unknown, LPDL used the pole date stamp for classification. For underground cable unknown, LPDL determined the age of the subdivision construction as the age of underground.

2-Staff-32
Assets Managed
Ref: Asset Lifecycle Optimization Policies and Practices (5.3.3) DSP p127-39.
Lakeland Power states on page 127: Lakeland Power replaces wires, poles, and transformers that are over 40+ years old and have used that as a bench mark for planning the O&M work. Lakeland Power tends to prioritize voltage conversion to their capital expenditures but do budget a certain amount for each town for “Assets over 40 years old”.

Lakeland Power states on page 134: Since 2012 LPDL has worked to improve the quality of its asset evaluation data. Lakeland Power has implemented a system of in-field inspections and monitoring that combined with our knowledge of the age and status of assets allows us to plan for the replacement and updating of Lakeland Power infrastructure. Poles are inspected and given a HI rating, which can be compared to the importance of the pole in the overall distribution network. This determines pole status and priority. Transformers are visually inspected and replaced when they fail or appear to be damaged. They are given a HI rating that is a combination of inspection results and age.

Lakeland Power states on page 139: A perfect score would be 1. Transformer A is slightly lower than preferred but would not be given high priority for replacement

a) Does Lakeland Power make use of the statistical properties of the Age Distribution of assets (as discussed in the Kinectrics report referenced on page 129, section 3.3.1.2 below) to estimate the rates of replacement of assets in an asset class and their associated capital requirements based on remaining useful life?. For example, Figure 3-18: “Poles Count by Age”, and Figure 3-21 “Overhead Primary Conductor Length by Age” illustrate a steep ramp-up in number of poles reaching 50 years and 49 km of conductor reaching 60y over the upcoming 5 and 10y periods. Please point to the calculations showing how this was carried out, for which Asset Classes and the estimated impacts on capital spending

Yes LPDL uses the Kinetrics report to assist in potential future projects for assets approaching end of life. LPDL does not have calculations showing the pole count or length of conductor due for replacement in the upcoming 10 year period. For these assets acquired by LPDL during inception, LPDL uses pole stamp dates for age of pole and year a subdivision was constructed for age of underground materials.

b) Health Indices for assets are shown for some Asset Classes, but it is not obvious that System Health is determined for all Asset Classes systematically. For example Poles appear to be assigned a Health Index based on Condition, number of circuits and configuration (par 1, p135) and pole component scores (Table 3-7). Elements of Condition appear to include physical tests (hammer impact, coring) for which correlation to remaining useful life is possible. By contrast, Transformer Condition Assessment involves a number of seemingly non life-limiting parameters such as paint, locks, grading and access (Table 3-10). Please point to or explain how these diverse approaches are used to calculate consistent replacement rates and capital costs for the upcoming financial planning period.

LPDL believes that the 2 assets being questioned have distinctively different characteristics for determining their health index rating. LPDL currently uses simple physical tests to determine the health rating of wooden poles, however there are several items that must be taken into consideration when determining the health index of a transformer. These non life-limiting parameters are weighted accordingly as shown in table 3-10, however must be taken into consideration when determining the health index.

c) Please confirm whether the scores resulting from the scoring method indicated on page 139 would be comparable across all Asset Classes, (for example would total overall score of 0.78 for transformer inspection be comparable to a score 0.78.) For other assets, please indicate whether the weight factors (e.g. Condition Assessment weigh of 0.6) will be periodically reviewed to reflect the latest experience within Lakeland Power and within other similar utilities and whether Lakeland Power intends to expand this scoring method to include additional end of life (EOL) criteria (e.g. function/purpose, economic, safety, design, reliability, risk, obsolescence) for replacement of the Lakeland Power assets.

LPDL continues to work with USF on condition assessments for all Asset Classes, currently poles and transformers have been completed and will be working on the other asset classes moving forward. The weigh factors will be reviewed periodically within the USF group

2-Staff-33
Strategic Plan

Ref: Exhibit 1 – Administrative Documents, Page 13, Line 1.
Annually, senior management meet to brainstorm and prepare a 3-year strategic plan. It is unclear whether there is a separate overarching longer-term strategic plan, and within that plan, an annual business plan.

a) Please confirm whether there is an overarching long-term strategic document guiding the organization?

LPDL does not have a long-term strategic document other than the 3 year business plan. The DSP has potential long term projections beyond the current year business plan.

b) Please confirm whether there is a separate annual business plan that fits within the context of a longer-term strategic plan?

LPDL confirms that the annual budget presented to its board is part of the 3 year strategic/business plan presentation.

2-Staff-34
Capital Budget Variance reporting
Ref: Exhibit 1 – Administrative Documents, Page 52, Lines 5-7 and page 53, lines 20-23; Exhibit 2 - Distribution System Plan, Page 65, Table 2.5; Exhibit 2 - Distribution System Plan, Page 162.
Lakeland Power stated that *"If Lakeland Power anticipates exceeding the Capital Budget by $50,000 during a fiscal year, a Capital Expenditure Report must be prepared and presented to the Board of Directors for approval."* The capital and operating budgets are prepared annually by management and reviewed and approved by the Board of Directors. Once approved, the budget is only revised if a material change in plan is required. In such cases, the revised budget is once again approved by the Board of Directors. Lakeland Power also maintains targets and metrics for capital project completion.

a) Does Lakeland Power also report budget shortfalls to its Board?

LPDL's Board receives a monthly report that details the current month actual financials, year to date financials, and a status update of current year projects.

b) Is the $50,000 budget overage calculated on an aggregate basis, or on an item by item basis?

The $50,000 is calculated on an aggregate basis.

c) Is the Board only advised if total Capital Budget is exceeded, or if specific projects are exceeded?

As noted in part a) LPDL's Board is advised on a project status summary each month along with financials. The Board is advised on a cumulative basis for Capital Expenditures.

2-Staff-35
Capital Justification
Ref: Exhibit 1 – Administrative Documents, Page 94, Lines 16-20.
Lakeland Power states *"Knowing customers' expectation for increased reliability and price, capital has been budgeted annually for asset replacement identified through reactive preventative and proactive replacement programs. These programs allow for the replacement of deteriorated poles and transformers and those at the end of their useful life, preventing them from becoming a safety hazard to the public, causing plant failures, or power outages, and mitigating failure costs."*

a) Why is the replacement of assets at the end of their useful life classified as being related to customer expectations vs. system reliability?

LDPL believes this sentence was taken out of context and did not classify the replacement of assets as customer expectations. LPDL is stating that customers expect a reliable supply of power delivered to their door, therefore this will involve being proactive of replacing end of life assets before they fail.

b) Please explain how Lakeland Power makes the distinction between customer and system reliability classification of projects?

LPDL relies on health indexes and inspections when determining the reliability of its assets and uses customer's reliability expectations as a supporting factor when determining project prioritization.

2-Staff-36
Customer Service - Capital Costs related to Parry Sound Office
Ref: Exhibit 1 – Administrative Documents, page 95, lines 7-14; Capital Expenditure Plan (5.4) DSP p157.
Lakeland Power states that keeping an office for walk-ins was requested by the Town of Parry Sound and its ratepayers. The hours of the office have since been scaled back.

a) Does Lakeland Power track the number of discrete drop ins at the Town of Parry Sounds office?

LPDL would like to clarify that the office in Parry Sound is owned by LPDL, not the Town of Parry Sound. LPDL does not track the number of discrete drop ins.
The building in Parry Sound is shared between operations and billing, and is required as an operations site. The geographic service area in LPDL territory is very large and the Parry Sound building is used by operations to service the northwest area.

b) Has an assessment been made of the cost of keeping the office open on a per visitor cost basis?

LPDL has not prepared an assessment based on a per visitor cost basis, as the building is needed as a location for operations staff.

2-Staff-37
Cyber Security
Ref: Exhibit 1 – Administrative Documents, Page 96, lines 19-20; Capital Expenditure Planning Process Overview, DSP p162.
Lakeland Power indicates that *"Investment in cyber security from 2018 through 2023 will allow LPDL to comply with OEB cyber security guidelines."* Lakeland Power also states, *"LPDL takes cyber-security very seriously and ensures that every digitally connected tool is connected with security in mind. LPDL is following the OEB Cyber Security guidelines and is investing the equivalent of one full time employee for two years to ensure that all recommended standards are exceeded."*

a) Please confirm whether sufficient ongoing cyber security capital expenditures have been included in the application, beyond the initial two-year period.

LPDL does not confirm that it has included sufficient cyber security capital expenditures at this time. LPDL has full intention of being compliant with OEB standards however is unsure of the expenditures required at this time.

2-Staff-38
Service Quality

Ref: Exhibit 1 – Administrative Documents, Page 104, lines 6-5; Exhibit 2 – Rate Base, Page 71, Lines 11 12 (table 40 below); Performance Measures for Continuous Improvement (5.2.3) DSP p62, section 2.3.1.5.

From the period of 2013-2017, Lakeland Power's service quality results have always exceeded OEB's targets and its trend is showing continuous improvements. The increase in the period 2015-2017 was the result of improved tracking and scheduling systems. Lakeland Power continues to update its work process and management system to maintain the OEB mandated threshold. This is demonstrated in the table below.

Service Quality

Indicator	OEB Minimum Standard	2013	2014	2015	2016	2017
Low Voltage Connections	90.0%	100.0%	94.6%	98.0%	99.2%	100.0%
High Voltage Connections	90.0%	N/A	N/A	N/A	100.0%	N/A
Telephone Accessibility	65.0%	97.5%	97.3%	92.7%	90.6%	88.2%
Appointments Met	90.0%	97.8%	99.8%	97.6%	98.6%	100.0%
Written Response to Enquires	80.0%	100.0%	100.0%	100.0%	95.9%	96.6%
Emergency Urban Response	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Emergency Rural Response	80.0%	100.0%	0.0%	100.0%	100.0%	100.0%
Telephone Call Abandon Rate	10.0%	0.4%	0.6%	1.3%	2.0%	1.7%
Appointment Scheduling	90.0%	99.2%	100.0%	94.3%	99.8%	100.0%
Rescheduling a Missed Appointment	100.0%	100.0%	100.0%	100.0%	100.0%	0.0%
Reconnection Performance Standard	85.0%	100.0%	100.0%	100.0%	100.0%	100.0%

a) Has Lakeland Power assessed the incremental cost of exceeding vs. meeting OEB's standard?

LPDL has not assessed the incremental cost of exceeding vs meeting OEB's standard as we believe customer service is a core objective for all LDC's.

b) Has an analysis been completed on what premium customers are prepared to pay for these higher ratings?

LPDL has not conducted an analysis on what premium customers are prepared to pay for these higher ratings. LPDL has achieved these higher ratings with reduced staff, reduced OM&A meeting cohort 2, and increased customer base with the amalgamation with Parry Sound.

2-Staff-39
Planned Capital Expenditures
Ref: Exhibit 2 – Rate Base, Page 50, Table 32: Appendix 2-AB.
Table 32 does not present historical planned capital expenditures (2013-2018) on a category by category level, but rather only on an aggregate basis.

a) Please confirm whether the Lakeland Power board approved prior budgets on a category by category basis on or a cumulative basis.

LPDL budget prior to 2019 have been approved by the board on a cumulative basis that is provided on a summarized individual project level.

b) Please confirm whether underspending vs. budget significantly impacted any one particular category, or whether it was generally spread across all categories.

LPDL cannot reliably comment on this question as historical budgets were based on a cumulative basis based on projects proposed. Projects were not classified into a category until the preparation of the DSP.

2-Staff-40
Deferral of Capital Projects related to amalgamation
Ref: Exhibit 2 – Rate Base, Page 57, Lines 2-5.
In 2014, expenditures in the historical period were below budget. It was indicated that this was primarily due to the amalgamation with PSP, as some projects were either cancelled or deferred to a later date.

a) Please confirm whether all deferred or cancelled projects were completed within the previous historical period.
    1) If Projects were not completed with the previous period, what impact did the deferral or cancellation of projects in the 2013-2018 (due to amalgamation) period have on the current application period (were any projects deferred into the current application)?

As mentioned on page 57 of Exhibit 2 – Rate Base, the pole line rebuild project on Muskoka Rd was deferred due to amalgamation and alteration of project prioritization. This project has been revised and scheduled for 2019, and has been included in Appendix A1 of the DSP as project SS-002

    2) Were any projects deferred past 2023?

No projects have been deferred past 2023

b) Please describe the impact of deferring/cancelling projects in the prior period projects on the Asset Management Plans.

The impact is that 4kV conversion projects in Bracebridge have been delayed due to the need to implement asset replacements in the Parry Sound area as they were determined to be more important.

2-Staff-41
Subject: Asset Counts
Ref: Overview of Assets Managed (5.3.2) DSP p115, Table 3-3 and p 121.
Asset Lifecycle Optimization Policies and Practices (5.3.3) p136, Table 3-9.
The figures presented in Table 3-3 and 3-9 do not match. In the case of the poles, the difference in poles over 40 years is approximately 4%.

	Table 3-3	Table 3-9	Sec 3.2.3.3
Poles (total)	6,411	6,475	
Poles (40+)	2,267	2,179	2,176

a) Please confirm correct figures and impact, if any, on capital plans resulting from incorrect figures.

Correct figures vary day to day as projects in the field are completed or newer information is discovered. This GIS (data source for these figures) is considered a live representation of the electrical network. Table 3-3 was a snapshot as of Dec 31, 2017 where Table 3-9 was produced in 2018 while compiling data for the DSP
Impact of capital plans is minimal as the GIS is continually changing as information is inputted, and this knowledge is taken into consideration when creating capital plans.

b) Please validate whether there are other discrepancies in supporting tables for other assets.

Transformer count is slightly different between Table 3-3 and Table 3-13 due to different interpretations of what should be included in the count (i.e. Transformers currently in yard,

or scrapped transformers, etc.) as well as difference in the times the figures were drawn from the GIS.
For the purposes of our comparisons of Inspection Data/Age of Assets/Assets to be Replaced, Table 3-3 of the DSP original document will be taken as a correct count at the time it was compiled (September 2018). It contains only in service transformers/poles (those that were in the field at the time the data was compiled).

c) Regardless of the specific numbers, approximately 35% of poles are in the range of qualifying for replacement. What percentage of poles over 40 years old are anticipated to be replaced in the current application period, and what percentage is deferred to the subsequent (i.e. post 2023) periods?

In the 5 year horizon as part of the current application, LPDL is planning on replacing approximately 200 poles that are > 40 years of age. These 200 poles are part of specific projects planned and do not take into consideration assets that will be replaced due to annual inspections requiring action.

2-Staff-42
Variance in Capital Expenditures in Historical Period
Ref: Capital Expenditures Summary (5.4.2) DSP p176.
Over the 2013-2017 period, capital expenditures were below budget by $408,000.

a) Please confirm whether the work related to the budget deficit was cancelled altogether, or deferred to future period.

Capital expenditures being cumulative below budget by $408,000 can be explained mostly by 2 reasons. First is that the Muskoka Rd. project planned in 2014 has been deferred to 2019. The other reason is that projects were lower than budget due to less rock drilling than expected.

b) If deferred to future periods, please confirm if it will be completed in 2018, or in the application period.

See answer to part a)

c) What has been the operational impact of deferring $408,000 in capital projects?

There have not been any significant impacts on operations for deferring the Muskoka Rd. project.

2-Staff-43
Useful life of wood poles
Ref: Capital Expenditures Summary (5.4.2) DSP p 121; Justifying Capital Expenditures (5.4.3) DSP APPENDIX A1: Capital Project Narratives Test Year 2019, p12.
There are conflicting references to wood poles having a TUL of 45 years (which matches the amortization period in Lakeland Power's financial statements) (ref a), and that the typical useful life of poles is 40 years (ref b).

a) Please confirm which TUL (40 vs. 45 years) was utilised in formulating the plan, and please confirm the impact of using a 40 vs. 45 year TUL for poles.

LPDL has not prepared its plan using a pole TUL of 40 years. The project narrative on p12 is referencing the transformers that are in need of replacement for this project. Section 5.4.2 also identifies pole TUL as 45 years, however, indicates that poles being in service > 40 years to be a higher risk for replacement.

b) Please confirm if other such differentials have been included in the application.

LPDL does not believe this to be a differential.

2-Staff-44
General Plant Investments
Ref: Justifying Capital Expenditures (5.4.3) DSP APPENDIX A1: Capital Project Narratives Test Year 2019 Project narrative – GP004: Investment Category: General Plant, Computer Hardware Upgrades, page 65; Exhibit 1 – Administrative Documents, Page 96, lines 19-20.
$26,000 in capital costs are planned for 2018 and $50,000 in capital costs are planned for 2019. There are no additional capital costs planned for the duration of the application period for computer hardware upgrades for overall computer upgrades related to operations and cyber security, despite references in the Cost of Service document to investment in cyber security from 2018 through 2023.

a) Please confirm that no additional capital requirements are anticipated for the duration of the application period.

LPDL cannot reliably anticipate capital investments to computer hardware be greater than $50,000 in any year therefore has not included it in the narrative. LPDL has full intentions in being compliant to cyber security mandates and anticipates computer hardware investments to be below the threshold of $50,000 annually.

b) If no additional capital requirements are anticipated, please confirm the organization's plans to keep current with computer, privacy and cyber security requirements in accordance with OEB's requirements, and in particular, in the 2020-2023 period.

As noted above, LPDL has full intentions of being compliant with OEB requirements, however, anticipates investments to computer hardware to be below the $50,000 threshold.

c) The 'Test Year Expenditure Timing' table (page 66) shows expenditures of $81,250 per quarter, or $325,000 for the year. This does not agree to the amounts referenced in the 'Historical and Future Capital and Related O&M Expenditures' table on page 65. Please confirm which figure is accurate, and whether the error has any impact on the rate application.

LPDL states that the table on page 66 is an error and displays the quarterly spending for computer software. GP004 of $50,000 is correct and will be distributed over Q2 and Q3 in 2019. This error will have no impact on the rate application.

2-Staff-45
General Governance
Ref: Exhibit 1 – Administrative Documents, p 14 and 37.

All Board governance policies which listed approval dates, indicated approved between May 22, 2007 and Nov 23, 2010 (with exception of M&A committee, which was tied to the amalgamation date). Risk and asset management do not appear to be specifically identified.

a) As there does not appear to be a Risk Board committee, which Committee is responsible for Risk Management, and in particular cyber risk?

The CEO leads the Risk Evaluation of the company on an annual basis. The Management team meets in January of each year, updates the Risk Assessment matrix, reviews it with the Environment Health & Safety Chair, finalizes the results and presents it the Board for further review and updates which will take place on March 1, 2019.

b) Which Board committee is responsible for oversight of the organization’s asset management program?

The asset management program is reviewed annually as part of the strategic plan and ultimately the annual budget approvals process.

c) Given that many Board policies have not been updated in over ten years, are there plans to review and update policies, and if so, when?

The Board of Directors is currently updating its board structure to meet OEB governance recommendations. As part of this update all Committee Charters are being reviewed and updated by the Governance Chair to ensure they meet OEB recommendation and Shareholder Agreement mandates. It is expected that this process will be completed in 2019.

2-Staff-46
Amalgamation impact on Policy
Accounting and other policies, including asset management, were harmonized subsequent to the amalgamation of the utilities.

a) How did the harmonization of policies resulting from the amalgamation impacted accounting policies, asset values, cost of service, etc. for the amalgamated entity?

Amalgamation has streamlined processes to provide consistent data collection and reporting.

b) Were there other (non accounting) policies (replacement, asset management, etc.) which may have been impacted through the amalgamation, and specifically, what impact did these changes, if any, have on capital plans?

There were no other changes as the former PSP did not have defined policies in place.

2.0 RATE BASE (EXHIBIT 2)

2.0-VECC -3

Reference: Exhibit 2, pg.43

a) Please provide a list of all buildings (leased or owned) showing the capital improvements for each location for each year 2013 through 2023.

Location	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Parry Sound Office	$ 2,996	$ 4,534	$ 341,650		$ 81,697	$ 10,271					
Bracebridge Operations		$ 21,045	$ 22,119				$ 50,000	$ 50,000	$ 25,000	$ 50,000	$ 50,000
Bracebridge Operations Disposal					-$ 10,000	-$ 31,653					
Total	**$ 2,996**	**$ 25,579**	**$ 363,769**	**$ -**	**$ 71,697**	**-$ 21,382**	**$ 50,000**	**$ 50,000**	**$ 25,000**	**$ 50,000**	**$ 50,000**

2.0-VECC-4

Reference: Exhibit 2, Appendix 2-AA

a) Please update Appendix 2-AA to show 2018 actual year-end (unaudited) capital expenditures.

Reporting Basis Projects	Reporting Basis Projects	USoA	NEWGAAP 2013 - Consolidated	NEWGAAP 2014 - Consolidated	MIFRS 2015	MIFRS 2016	MIFRS 2017	MIFRS 2018	MIFRS 2019
System Access	**System Access**								
SA-001	New Services - Forecasted customer new service requests							$269,728	$250,000
SA-002	Meter changes, single phase/ three phase, gate keeper upgrades							$246,896	$130,000
2018-Gen	General Service Work							$169,317	
BBCap-SA	Asset Replacements Bracebridge Capital		$76,339	$70,240	$92,809	$150,292	$101,355		
2016-31895	Conversion Robert Dollar Upgrade to 27.6 kv		$0	$0	$0	$134,136	$61,650		
PSCap-SA	Asset Replacements Parry Sound Capital		$0	$28,547	$34,016	$64,516	$47,476		
2014-27143	MS1 Huntsville		$0	$168,347	$0	$0	$0		
PSP5I	New Service Parry Sound Connect Service's		$97,070	$56,793	$0	$0	$0		
2015-34393	Conversion Hwy 118 W Ecclestone to E.P. Lee DrBracebridge		$0	$0	$0	$137,272	$0		
2015-32705	Lofthouse Manufacturing – Burks Falls		$0	$0	$25,666	$109,262	$0		
2014-27664	Centennial Substation reclosers- Bracebridge		$37,769	$83,070	$11,171	$0	$0		
HuntsCap-SA	Asset Replacements Huntsville Capital		$16,563	$10,092	$38,758	$31,783	$20,099		
2017-428	New Service 2017		$0	$0	$0	$0	$112,271		
JU	Joint Use Projects on LPDL Assets		$1,823	$2,654	$33,535	$6,141	$63,201		
2014-30726	Bowes St- Parry Sound		$0	$0	$53,768	$43,941	$0		
2015-28694	Albert St, High St. and Park Hill Rd – Sundridge		$0	$0	$84,553	$0	$0		
2016-PW142	New Service -King William St. – Huntsville		$0	$0	$0	$52,134	$0		
Misc < $50K	Total of all individual Projects < $50,000		$34,297	$99,512	$4,631	$7,479	$17,065	$28,327	
	Sub-Total System Access		**$263,861**	**$519,255**	**$378,908**	**$736,956**	**$423,118**	**$714,268**	**$380,000**
	Contributed Capital/Deferred Revenue on for custom bui		**-209,703**	**-281,052**	**-194,049**	**-551,703**	**-365,698**	**-347,817**	**-250,000**
	NET-Total System Access		**54,158**	**238,204**	**184,859**	**185,253**	**57,420**	**366,451**	**130,000**

System Renewal	System Renewal		2013 - Consolidated	2014 - Consolidated	2015	2016	2017	2018	2019
2014-30676	UpGrade MS3 – Parry Sound		$0	$74,550	$618,248	$84,419	$102,064		
Transformer Stock	Transformer Stock purchased for projects		$171,498	$150,608	$100,656	$157,627	$297,483	$196,769	
SR-002	Brofoco Dr- Bracebridge		$0					$184,653	$280,000
2018-SR Aging Assets	Aging Asset Replacements Due To Inspections							$132,142	
2018-9663	MS2 Huntsville Primary Feeder Replacement							$110,800	
2018 - TCCAP	Capital Storm Damage / Trouble Call							$76,960	
2013-26840	Conversion Wilshire Blvd. - Bracebridge		$7,085	$307,497	$186,502	$0	$0		
Meter Stock	Meter materials held in inventory		$47,828	$69,347	$74,317	$126,924	$135,995		
2017-3434	Great North Rd Parry Sound		$0	$0	$0	$0	$426,544		
2016-1123	Conversion Hillcrest Ave. and William St. – Parry Sound		$0	$0	$0	$341,286	$1,960		
2015-31185	Cedar Lane New 27kv		$0	$0	$226,635	$88,341	$0		
2016-00122	Upgrade Replacements due to inspections - Parrr Sound		$0	$0	$1,885	$275,246	$4,968		
2013-23951	Conversion Golf Course Rd, Curling Rd and South Muskoka Dr Bracebridge		$277,398	$0	$0	$0	$0		
SR-003	Forest St. Parry Sound- Parry Sound Rd to Bowes St. - replace poles/w		$0						$265,000
2017-06330	Parry Sound Rd Conversion		$0	$0	$0	$0	$1,766	$130,094	
SR-004	York St/Bird Lane/Toronto St./ Richard St - Bracebridge		$0						$225,000
BBCap-SR	Asset Replacement Bracebridge Capital		$38,993	$108,419	$8,647	$1,136	$4,747		
SR-006	Sundridge, Burks Falls, Magnetawan, Parry Sound, Bracebridge, Hunts\		$0						$195,000
SR-001	Young St and Milton St. - Bracebridge voltage conversion replace poles		$0						$181,000
2014-27137	Conversion Wellington Court		$29,058	$92,017	$53,935	$0	$0		
2014-28919	Conversion Addie St. – Parry Sound (PSP2B)		$0	$132,108	$40,402	$0	$0		
2016-35291	Conversion Sadler Dr/ Palmer Dr/ Maple Dr in Bracebridge		$0	$0	$16,649	$36,634	$100,973		
2015-35316	Asset Replacement From Inspections		$0	$0	$151,892	$0	$0		
2018-6351	Main St. Sundridge		$0					$169,329	
2014-27139	Upgrade Paget St – Sundridge		$0	$44,329	$101,561	$0	$0		
2017-3384	Asset Replacement Centre Street in Huntsville		$0	$0	$0	$0	$43,078	$62,300	
PSP1	MSI / MS2 Replacement		$116,824	$17,599	$0	$0	$0		
2016-35221	Conversion Pinewood Dr and Sherwood Dr.- Bracebridge		$0	$0	$1,824	$127,546	$2,758		
LP19266	Conversion Maple St. Bracebridge		$122,743	$0	$0	$0	$0		
PSP5D	Pole Replacement - Capital Reserve		$98,390	$13,262	$0	$0	$0		
2013-21007	Conversion Armstrong St – Bracebridge		$89,347	$17,420	$0	$0	$0		
2017-03729	Conversion Dawsonwood Rd in Bracebridge		$0	$0	$0	$0	$102,938		
2016-00503	Upgrade Birchwood Dr/Edgar St. – Sundridge		$0	$0	$0	$100,712	$0		
2017-3737	Pole Replacement - Parry Sound		$0	$0	$0	$0	$98,377		
2014-27443	Asset Replacements Pole Inspection 2014		$0	$86,845	$6,254	$0	$0		
2016-31726	Conversion Granite Bluffs – Bracebridge		$0	$0	$0	$89,348	$0		
HuntsCap-SR	Asset Replacement Huntsville Capital		$44,569	$960	$324	$1,588	$752		
2017-3734	Pole Replacement - Bracebridge		$0	$0	$0	$0	$87,305		
2016-35291	Sadler Dr Palmer Dr. Maple Dr Bracebridge		$0					$108,374	
PSCap-SR	Asset Replacement Parry Sound Capital		$0	$0	$2,614	$2,996	$0		
2013-21808	Upgrade MS1 Huntsville		$63,506	$5,322	$0	$0	$0		
2018-4211	Veteran's Way - Huntsville		$0					$101,405	
SR-005	Menominee St - Huntsville Primary underground / pole/ transformer		$0						$64,000
2017-2683	Asset Replacement Walpole & Mary St Huntsville		$0	$0	$0	$1,388	$57,785		
2017-3738	Isabella st - Parry Sound -		$0					$66,117	
2018-5585	Bracebridge - Kirk Line East > 2018 TCCAP		$0						
Misc < $50K	Total of all individual Projects < $50,000		$2,496	$12,646	$26,147	$44,811	$126,539	$0	$0
	Sub-Total System Renewal		**1,109,735**	**1,132,930**	**1,618,491**	**1,480,003**	**1,596,023**	**1,338,943**	**1,210,000**

System Service	System Service	2013 - Consolidated	2014 - Consolidated	2015	2016	2017	2018	2019
SS-003	Lakeland SCADA System	$185,229	$79,676	$35,362	$86,366	$8,938		$75,000
2015-31243	Ecclestone Dr - Bracebridge	$0	$0	$130,777	$47,030	$5,516	$135,169	
SS-002	Muskoka Rd - Bracebridge Manitoba St. to Shire St	$0						$290,000
2015-30766	New Generation Cascade St	$0	$0	$220,878	$41,148	$12,843		
2017-3811	Voltage Conversion James St, BB Move line edge of property	$0	$0	$0	$0	$51,340	$110,160	
2018-6418	WoodwardSt./Front St/ Alice St. Bracebridge.	$0					$6,940	
2013-22688	Robert Boyer Ln – Bracebridge	$85,534	$71,315	$0	$0	$0		
2013-25124	Holditch St. - Bracebridge	$0	$81,430	$67,644	$0	$0		
2014-27185	River Rd. – Bracebridge	$0	$121,176	$15,479	$0	$0		
SS-001	Hydro One Primary meter point conversion to IESO	$0						$120,000
BBCap-SS	Asset Replacement Bracebridge Capital	$19,163	$9,577	$22,610	$13,381	$13,869		
2012-21515	Voltage Conversion Victoria St and Dill St – Bracebridge	$59,303	$6,712	$0	$0	$0		
2016-01265	Voltage Conversion River St at Seguin river Parry Sound	$0	$0	$0	$58,739	$0		
2017-3809	Voltage Conversion Southband Dr Bracebridge	$0	$0	$0	$0	$42,491		
2013-24233	Voltage Conversion James St and Chubb Downey Lane – Bracebridge	$39,731	$0	$0	$0	$0		
2013-24002	Voltage Conversion Liddard St and Macdonald St. – Bracebridge	$33,508	$0	$0	$0	$0		
PSP6H	Substation MS6	$29,540	$0	$0	$0	$0		
2013-25944	Asset Replacement Westvale Dr – Bracebridge	$28,905	$0	$0	$0	$0		
PSCap-SS	Asset Replacement Parry Sound Capital	$0	$0	$110	$9,156	$6,566		
BFCap-SS	Asset Replacement Burks Falls	$0	$302	$602	$0	$0		
SunCap-SS	Asset Replacement Sundridge Capital	$380	$241	$0	$0	$0		
MagCap-SS	Asset Replacement Manetawan Capital	$0	$101	$142	$0	$0		
Misc < $50K	Total of all individual Projects < $50,000	$132,065	$645	$854	$9,156	$49,057		
	Sub-Total System Service	**481,294**	**370,531**	**493,604**	**255,820**	**141,563**	**252,269**	**485,000**

General Plant	General Plant	2013 - Consolidated	2014 - Consolidated	2015	2016	2017	2018	2019
161101 - GP-001	Computer Software	$38,967	$139,786	$22,771	$4,625	$45,266	$5,006	$325,000
161201	Land Rights	$4,031	$2,227	$18,121	-$7,500	$0		
180801 - GP-003	Buildings - Distribution	$2,996	$4,534	$341,650	$0	-$10,000	-$14,153	$50,000
190501	Land	$0	$0	$25,346	$0	$0		
190801	Buildings & Fixtures - General	$0	$21,045	$22,119	$0	$81,697	-$7,229	
191001	Leasehold Improvements to Parry Sound Office	$69,346	$24,942	-$141,540	$0	$0		
191501	Office Furniture & Equipment	$0	$3,558	$21,524	$0	$0	$11,528	
192002 - GP004	Computer Equipment - Hardware	$76,141	$25,724	$4,409	$6,105	$3,421	$20,216	$50,000
193001 - GP-002	Transportation Equipment	$372,243	$243,124	$267,746	$26,238	$127,913	$94,046	$200,000
194001	Tools, Shop & Garage Equipment	$0	$20,060	$15,770	$0	$0	$25,244	$25,000
195501	Communications Equipment	$645	$296	$0	$0	$0		
	Sub-Total General Plant	**564,369**	**485,296**	**597,916**	**29,468**	**248,297**	**134,658**	**650,000**
Total Capital Expenditures Net of Contributed Capital		**2,209,556**	**2,226,961**	**2,894,871**	**1,950,543**	**2,043,303**	**2,092,321**	**2,475,000**

2-VECC-5

Reference: Exhibit 2, Appendix 2-G, pg.7 / DSP, pgs. 69-

a) Lakeland appears to have significant issues with respect to loss of supply (see for example Figure 2-11 of DSP, pg.70). Please explain the nature of these issues and any specific problematic transformation stations accessed by the Utility.

Please refer to OEB response 2-Staff-9

b) What programs has Lakeland instituted to reduce the duration of outages (SAIDI)?

Please refer to OEB response 2-Staff-9

2-VECC-6

Reference: Exhibit 2, DSP, pg. 35

a) Please provide the outage management program budget for 2018 – 2023

The outage management program is part of LPDL's project SS 003 which describes

LPDL's investment to enable a self-healing grid.

Category		2018	2019	2020	2021	2022	2023
System Service	Innovation Enabling Projects - SCADA/Line Loss /smart grid/etc.	$ -	$ 75,000	$ 70,000	$ 90,000	$ 70,000	$ 90,000

2-VECC-7

Reference: Exhibit 2, DSP, pg. 37

a) Please explain the USF Component Condition Factors inspection process. Does this process apply only to poles or also to other distribution asset categories?

LPDL is a member of USF who has developed recommendations for their members to assist in inspection processes. These recommendations are based on industry best practices for asset management, inspection and testing data collection, rating, and development of a health index.

Recommended patrols and data collection are provided for the assets that are typically reported on in the Distribution System Plan, including: wood poles, transformers, switchgear, underground cables, overhead conductors (primary and secondary), overhead switches, SCADA, and subsurface chambers.

The driver for offering these recommendations is for consistency in terminology and approach, and for sharing of the data. This collaboration and ability to analyze assets on an industry basis is only possible if members inspect and assess their assets in the same manner, with the same rating system

2-VECC-8

Reference: Exhibit 2, DSP, pg. 41

a) How many customers are currently part of a long-term load transfer (LTLT)?

During the LTLT process LPDL and Hydro One submitted a joint service area amendment to the OEB to eliminate all LTLT customers. Refer to EB-2017-0177 for details.

3 LTLT customers were missed and LPDL and Hydro One have recently submitted another joint service area amendment in 2019 EB-2019-0013 for these customers.

b) What is the cost of transferring these customers to their respective physical service utility?

The cost for LPDL to purchase the Hydro One assets related to the remaining 3 customers is $5,893 plus taxes.

c) Is Lakeland building any new infrastructure to accommodate exist LTLT customers? If yes, what are those capital expenditures over the 2019-2023 period?

LPDL is not building any new infrastructure related to LTLT customers.

2-VECC-9

Reference: Exhibit 2, DSP, pg. 43

a) For each year 2019 through 2023 what are the annual capital expenditures and OM&A costs related to the Town of Parry Sound project to source 100% of its energy needs from renewable sources?

There are no capital or OM&A costs related to the Town of Parry Sound project.

b) Please explain how these initiatives are funded.

LPDL is not aware of how the initiatives of this project will be funded by the Town of Parry Sound.

2-VECC-10

Reference: Exhibit 2, DSP, Section 3.2.3, pg.115

a) For each of the asset categories listed in Table 3-3 please create a new table which shows whether the Health index is based on: (1) age; (2) asset condition testing; (3) combination of both age and testing

Asset Type	Age	Asset Condition Testing	Combination	Health Index Rating Created?
Substation Transformer	Yes	Yes	Yes	No
Poles	Yes	Yes	Yes	Yes
Overhead Transformers	Yes	Yes	Yes	Yes
Vaults	Yes	No	No	No
Padmount Transformers	Yes	Yes	Yes	Yes
Switch Gear	Yes	No	No	No
Junction Cubicle	Yes	No	No	No
Overhead Primary (m)	Yes	No	No	Yes
Underground Primary (m)	Yes	No	No	Yes

b) For those asset categories where testing is identified as a health index derivative please provide a brief description of the type of testing carried out (for example transformer oil gas level test) and include the frequency of testing.

Poles:

Health Index Score: The pole inspection program provides each pole with an Asset Condition Factor (1-10). This rating comes from a visual assessment of several different components of a pole, which are weighted according to their importance to pole strength and reliability. The Asset Condition Factor is the result of a visual inspection process. The results of this inspection are combined with previously known information on the age of the pole and its importance to the electrical network. For example, a transformer pole is given a higher priority than a service pole. The result is considered the final Health Index Score for the pole. This process is taken from the USF pole inspection standards, as developed in 2018. LPDL conducts these inspections as part of its 5 year rotating inspection schedule.

In 2018, LPDL contacted Gtel Engineering to conduct a test run of its Polux pole testing on 200 LPDL poles.

Polux technology uses two physical values to estimate the residual strength of the pole and the risk of active bio-degradation.

Polux Non- Destructive Testing Procedure-Polux uses two insulated probes that are driven into the pole simultaneously at the ground line which is the most vulnerable point where decay is most likely to be present.

Polux takes two measurements per pole and the average is used as the complete reading and is not affected by daily fluctuations (rain, weather conditions) in the surface condition of the pole nor by its treatment (preservative).

In addition to the measurements of hardness and moisture content, other pole variables are collected and recorded that contribute to the strength of the wood. Pole species, circumference of the pole, height, cumulative knot circumferences in a 1- foot section of the pole, age and mechanical damage are factored into the remaining strength of the pole.
Visual factors such as surface decay, pole top decay, insect damage is also noted. along with third party wiring and accessories. The data is then transferred to an Excel

Transformers:

LPDL currently conducts visual inspections of its transformer assets. Transformers are given a pass/fail rating on several possible defect areas. These are then used to give the transformer a condition assessment score, by applying a weighted multiplier to the results.

This number is then combined with the known age of the asset, to create a final Health Index Score. LPDL is looking to follow USF transformer inspection standards when they are developed for transformers in the coming years. LPDL conducts these inspections as part of its 5 year rotating inspection schedule.

Primary Conductor (Overhead):

A health index rating is developed for LPDL's overhead conductor inventory using stored information on the wire type (copper, aluminum, etc.) and the age of the asset. LPDL also visually inspects its overhead conductor on a rotating 5 year basis.

Primary Conductor (Underground):

A health index rating is developed for LPDL's underground conductor inventory using stored information on the wire type (copper, aluminum, etc.) and the age of the asset. The nature of the asset prevents visual inspection.

c) For each category please also list the total count of assets and the percentage of assets subject to testing.

Asset Type	Total Count	% Eligible for Testing
Substation Transformer	11	100%
Poles	6411	100%
Overhead Transformers	2098	100%
Vaults	541	100%
Padmount Transformers	543	100%
Switch Gear	18	100%
Junction Cubicle	63	100%
Overhead Primary (m)	272129	100%
Underground Primary (m)	87762	100%

LPDL plans to complete a full inspection of all assets every 5 years.

2-VECC-11

Reference: Exhibit 2, DSP, pg. 172

a) Lakeland is proposing a significant increase in its annual capital budget during the 2019-2023 rate term as compared to the previous 5 years (approximately \$2.97 vs \$2.30 million on average). What would be the consequence if Lakeland were required to plan within an annual capital budget of $2.6 million (on average) for the 5 year period of the rate plan?

The consequences of planning with a budget of $2.6 million is that projects that are currently planned would be deferred or cancelled, which will delay the voltage conversion plan to eliminate the 4kV substations. LPDL's voltage conversion projects will improve reliability and reduce maintenance costs.

b) What is the estimated cost of the new 27.6 kV substation (current site of MS3) to be built in 2023?

LPDL's estimate to upgrade the site to accommodate the 27.6 kV substation, move the Golden Beach MS to the new MS3 site and install 3 27.6 kV feeders is approximately $500,000

2-SEC-10

[Ex.2] Please provide the 2011 and 2012 PSP continuity schedules.

Fixed Asset Continuity Schedule - CGAAP/ASPE/USGAAP - including Parry Sound for all years

Parry Sound ONL Year 2011 CGAAP - with no changes to policies

		-290108	Cost				Accumulated Depreciation						
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value	AVG Gross Bal	AVG AccDep
12	1611	Computer Software (Formally known as Account 1925)	$ 91,984	$ 6,450	$ -	$ 98,434	$ 21,885	$ 49,213	$ -	$ 71,098	$ 27,336	$ 95,209	$ 46,492
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ 35,048		$ -	$ 35,048	$ 34,688	$ 20	$ -	$ 34,708	$ 340	$ 35,048	$ 34,698
N/A	1805	Land	$ 74,305		$ -	$ 74,305	$ -	$ -	$ -	$ -	$ 74,305	$ 74,305	$ -
47	1808	Buildings			$ -	$ -			$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 1,843,857	$ 1,994	$ -	$ 1,845,851	$ 1,059,361	$ 47,352	$ -	$ 1,106,713	$ 739,138	$ 1,844,854	$ 1,083,037
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,828,597	$ 75,917	$ -	$ 1,904,514	$ 1,104,406	$ 59,092	$ -	$ 1,163,498	$ 741,016	$ 1,866,556	$ 1,133,952
47	1835	Overhead Conductors & Devices	$ 2,384,877	$ 61,218	$ -	$ 2,446,095	$ 1,608,982	$ 73,484	$ -	$ 1,682,466	$ 763,629	$ 2,415,486	$ 1,645,724
47	1840	Underground Conduit	$ 599,154	$ 302	$ -	$ 599,456	$ 354,767	$ 22,982	$ -	$ 377,749	$ 221,707	$ 599,305	$ 366,258
47	1845	Underground Conductors & Devices	$ 803,906	$ 6,983	$ -	$ 810,889	$ 455,829	$ 31,011	$ -	$ 486,840	$ 324,049	$ 807,398	$ 471,335
47	1850	Line Transformers	$ 2,241,882	$ 118,846	$ -	$ 2,360,728	$ 1,507,495	$ 70,892	$ -	$ 1,578,388	$ 782,340	$ 2,301,305	$ 1,542,942
47	1855	Services (Overhead & Underground)	$ 1,328,361	$ 11,180	$ -	$ 1,339,541	$ 896,555	$ 42,635	$ -	$ 939,190	$ 400,351	$ 1,333,951	$ 917,873
47	1860	Meters	$ 403,760	$ 8,221	-$ 137,360	$ 274,621	$ 60,252	$ 15,716	$ -	$ 75,968	$ 198,653	$ 339,190	$ 68,110
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures		$ -	$ -	$ -			$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -	$ 5,342	$ -	$ 5,342	$ -	$ -	$ -	$ -	$ 5,342	$ 2,671	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 10,062	$ 4,948	$ -	$ 15,010	$ 1,006	$ 2,260	$ -	$ 3,266	$ 11,744	$ 12,536	$ 2,136
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 24,998	$ 10,264	$ -	$ 35,262	$ 6,759	$ 7,875	$ -	$ 14,634	$ 20,628	$ 30,130	$ 10,697
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 264,736	$ 28,172	$ -	$ 292,909	$ 21,896	$ 45,553	$ -	$ 67,450	$ 225,459	$ 278,823	$ 44,673
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 1,955	$ -	$ -	$ 1,955	$ 195	$ 391	$ -	$ 586	$ 1,368	$ 1,955	$ 391
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment			$ -	$ -			$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)			$ -	$ -			$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -		$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Propert	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 835,036	-$ 74,067	$ -	-$ 909,103	-$ 168,503	-$ 33,989	$ -	-$ 202,492	-$ 706,611	-$ 872,070	-$ 185,498
	1610	Miscellaneous intangigle Plant	-$ 290,108	$ -	$ 290,108	$ -	$ -	$ -	$ -	$ -	$ -	-$ 145,054	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	2055	Construction in Process	$ 2,121	$ 13,387	$ -	$ 15,508	$ -	$ -	$ -	$ -	$ 15,508	$ 8,815	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 10,814,457**	**$ 279,159**	**$ 152,748**	**$ 11,246,364**	**$ 6,965,574**	**$ 434,488**	**$ -**	**$ 7,400,062**	**$ 3,846,302**	$ 11,030,410	$ 7,182,818
		Less Socialized Renewable Energy				$ -				$ -	$ -		
		Less Other Non Rate-Regulated Utility				$ -				$ -	$ -		
		Total PP&E	**$ 10,814,457**	**$ 279,159**	**$ 152,748**	**$ 11,246,364**	**$ 6,965,574**	**$ 434,488**	**$ -**	**$ 7,400,062**	**$ 3,846,302**		
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
		Total						**$ 434,488**					

		Less: Fully Allocated Depreciation	
10	Transportation	Transportation	-$ 45,553
8	Stores Equipment	Stores Equipment	
8	Tools, Shop	Tools, Shop	
8	Meas/Testing	Meas/Testing	
8	Communication	Communication	
		Net Depreciation	$ 388,935

Parry Sound ONL | Year 2012 | CGAAP - with no changes to policies

			Cost				Accumulated Depreciation						
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value	AVG Gross Bal	AVG AccDep
12	1611	Computer Software (Formally known as Account 1925)	$ 98,434	$ 122,931	$ -	$ 221,365	$ 71,098	$ 50,191	$ -	$ 121,290	$ 100,075	$ 159,899	$ 96,194
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ 35,048		$ -	$ 35,048	$ 34,708	$ 20	$ -	$ 34,728	$ 320	$ 35,048	$ 34,718
N/A	1805	Land	$ 74,305		$ -	$ 74,305	$ -	$ -	$ -	$ -	$ 74,305	$ 74,305	$ -
47	1808	Buildings	$ -		$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 1,845,851	$ -	$ -	$ 1,845,851	$ 1,106,713	$ 44,505	$ -	$ 1,151,218	$ 694,633	$ 1,845,851	$ 1,128,965
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,904,514	$ 103,337	-$ 960,317	$ 1,047,534	$ 1,163,498	$ 60,899	-$ 960,317	$ 264,080	$ 783,454	$ 1,476,024	$ 713,789
47	1835	Overhead Conductors & Devices	$ 2,446,095	$ 107,454	-$ 1,320,120	$ 1,233,429	$ 1,682,466	$ 74,177	#########	$ 436,306	$ 797,124	$ 1,839,762	$ 1,059,386
47	1840	Underground Conduit	$ 599,456	$ 30	-$ 169,832	$ 429,654	$ 377,749	$ 22,829	-$ 169,832	$ 230,746	$ 198,908	$ 514,555	$ 304,248
47	1845	Underground Conductors & Devices	$ 810,889	$ 1,503	-$ 412,761	$ 399,631	$ 486,840	$ 30,979	-$ 412,761	$ 105,058	$ 294,573	$ 605,260	$ 295,949
47	1850	Line Transformers	$ 2,360,728	$ 92,385	-$ 509,139	$ 1,943,974	$ 1,578,388	$ 71,414	-$ 509,139	$ 1,140,662	$ 803,311	$ 2,152,351	$ 1,359,525
47	1855	Services (Overhead & Underground)	$ 1,339,541	$ 19,164	$ -	$ 1,358,705	$ 939,190	$ 41,956	$ -	$ 981,147	$ 377,558	$ 1,349,123	$ 960,168
47	1860	Meters	$ 274,621	$ 9,521	$ -	$ 284,142	$ 75,968	$ 16,283	$ -	$ 92,250	$ 191,891	$ 279,381	$ 84,109
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ 5,342	$ 41,911	$ -	$ 47,252	$ -	$ -	$ -	$ -	$ 47,252	$ 26,297	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 15,010	$ 470	$ -	$ 15,480	$ 3,266	$ 2,558	$ -	$ 5,824	$ 9,656	$ 15,245	$ 4,545
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 35,262	$ 5,207	$ -	$ 40,469	$ 14,634	$ 8,138	$ -	$ 22,772	$ 17,697	$ 37,865	$ 18,703
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 292,909	$ -	$ -	$ 292,909	$ 67,450	$ 41,132	$ -	$ 108,582	$ 184,327	$ 292,909	$ 88,016
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 1,955	$ -	$ -	$ 1,955	$ 586	$ 391	$ -	$ 977	$ 977	$ 1,955	$ 782
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -		$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -		$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Propert	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 909,103	-$ 32,413	$ -	-$ 941,516	-$ 202,492	-$ 37,609	$ -	-$ 240,101	-$ 701,415	-$ 925,310	-$ 221,297
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	2055	Construction in Process	$ 15,508	$ 101,962	$ -	$ 117,470	$ -	$ -	$ -	$ -	$ 117,470	$ 66,489	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 11,246,364**	**$ 573,461**	**-$ 3,372,169**	**$ 8,447,655**	**$ 7,400,062**	**$ 427,864**	**#########**	**$ 4,455,540**	**$ 3,992,116**	$ 9,847,009	$ 5,927,801
		Less Socialized Renewable Energy				$ -				$ -	$ -		
		Less Other Non Rate-Regulated Utility				$ -				$ -	$ -		
		Total PP&E	**$ 11,246,364**	**$ 573,461**	**-$ 3,372,169**	**$ 8,447,655**	**$ 7,400,062**	**$ 427,864**	**#########**	**$ 4,455,540**	**$ 3,992,116**		
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
		Total						**$ 427,864**					
						-$ 0							
						Less: Fully Allocated Depreciation							
10		Transportation				Transportation		-$ 41,132					
8		Stores Equipment				Stores Equipment							
8		Tools, Shop				Tools, Shop							
8		Meas/Testing				Meas/Testing							
8		Communication				Communication							
						Net Depreciation		$ 386,732					

2-SEC-11

[Ex.2] Please revise the following appendices to include 2018 year-end actuals:

a. 2-AA

Reporting Basis Projects	Reporting Basis Projects	USoA	NEWGAAP 2013 - Consolidated	NEWGAAP 2014 - Consolidated	MIFRS 2015	MIFRS 2016	MIFRS 2017	MIFRS 2018	MIFRS 2019
System Access	**System Access**								
SA-001	New Services - Forecasted customer new service requests							$269,728	$250,000
SA-002	Meter changes, single phase/ three phase, gate keeper upgrades							$246,896	$130,000
2018-Gen	General Service Work							$169,317	
BBCap-SA	Asset Replacements Bracebridge Capital		$76,339	$70,240	$92,809	$150,292	$101,355		
2016-31895	Conversion Robert Dollar Upgrade to 27.6 kv		$0	$0	$0	$134,136	$61,650		
PSCap-SA	Asset Replacements Parry Sound Capital		$0	$28,547	$34,016	$64,516	$47,476		
2014-27143	MS1 Huntsville		$0	$168,347	$0	$0	$0		
PSP5I	New Service Parry Sound Connect Service's		$97,070	$56,793	$0	$0	$0		
2015-34393	Conversion Hwy 118 W Ecclestone to E.P. Lee DrBracebridge		$0	$0	$0	$137,272	$0		
2015-32705	Lofthouse Manufacturing – Burks Falls		$0	$0	$25,666	$109,262	$0		
2014-27664	Centennial Substation reclosers- Bracebridge		$37,769	$83,070	$11,171	$0	$0		
HuntsCap-SA	Asset Replacements Huntsville Capital		$16,563	$10,092	$38,758	$31,783	$20,099		
2017-428	New Service 2017		$0	$0	$0	$0	$112,271		
JU	Joint Use Projects on LPDL Assets		$1,823	$2,654	$33,535	$6,141	$63,201		
2014-30726	Bowes St- Parry Sound		$0	$0	$53,768	$43,941	$0		
2015-28694	Albert St, High St. and Park Hill Rd – Sundridge		$0	$0	$84,553	$0	$0		
2016-PW142	New Service -King William St. – Huntsville		$0	$0	$0	$52,134	$0		
Misc < $50K	Total of all individual Projects < $50,000		$34,297	$99,512	$4,631	$7,479	$17,065	$28,327	
	Sub-Total System Access		**$263,861**	**$519,255**	**$378,908**	**$736,956**	**$423,118**	**$714,268**	**$380,000**
	Contributed Capital/Deferred Revenue on for custom bui		**-209,703**	**-281,052**	**-194,049**	**-551,703**	**-365,698**	**-347,817**	**-250,000**
	NET-Total System Access		**54,158**	**238,204**	**184,859**	**185,253**	**57,420**	**366,451**	**130,000**
System Renewal	**System Renewal**		**2013 - Consolidated**	**2014 - Consolidated**	**2015**	**2016**	**2017**	**2018**	**2019**
2014-30676	UpGrade MS3 – Parry Sound		$0	$74,550	$618,248	$84,419	$102,064		
Transformer Stock	Transformer Stock purchased for projects		$171,498	$150,608	$100,656	$157,627	$297,483	$196,769	
SR-002	Brofoco Dr- Bracebridge		$0					$184,653	$280,000
2018-SR Aging Assets	Aging Asset Replacements Due To Inspections							$132,142	
2018-9663	MS2 Huntsville Primary Feeder Replacement							$110,800	
2018 - TCCAP	Capital Storm Damage / Trouble Call							$76,960	
2013-26840	Conversion Wilshire Blvd. - Bracebridge		$7,085	$307,497	$186,502	$0	$0		
Meter Stock	Meter materials held in inventory		$47,828	$69,347	$74,317	$126,924	$135,995		
2017-3434	Great North Rd Parry Sound		$0	$0	$0	$0	$426,544		
2016-1123	Conversion Hillcrest Ave. and William St. – Parry Sound		$0	$0	$0	$341,286	$1,960		
2015-31185	Cedar Lane New 27kv		$0	$0	$226,635	$88,341	$0		
2016-00122	Upgrade Replacements due to inspections - Parrr Sound		$0	$0	$1,885	$275,246	$4,968		
2013-23951	Conversion Golf Course Rd, Curling Rd and South Muskoka Dr Bracebridge		$277,398	$0	$0	$0	$0		
SR-003	Forest St. Parry Sound- Parry Sound Rd to Bowes St. - replace poles/w		$0						$265,000
2017-06330	Parry Sound Rd Conversion		$0	$0	$0	$0	$1,766	$130,094	
SR-004	York St/Bird Lane/Toronto St./ Richard St - Bracebridge		$0						$225,000
BBCap-SR	Asset Replacement Bracebridge Capital		$38,993	$108,419	$8,647	$1,136	$4,747		
SR-006	Sundridge, Burks Falls, Magnetawan, Parry Sound, Bracebridge, Hunts\		$0						$195,000
SR-001	Young St and Milton St. - Bracebridge voltage conversion replace poles		$0						$181,000
2014-27137	Conversion Wellington Court		$29,058	$92,017	$53,935	$0	$0		
2014-28919	Conversion Addie St. – Parry Sound (PSP2B)		$0	$132,108	$40,402	$0	$0		
2016-35291	Conversion Sadler Dr/ Palmer Dr/ Maple Dr in Bracebridge		$0	$0	$16,649	$36,634	$100,973		
2015-35316	Asset Replacement From Inspections		$0	$0	$151,892	$0	$0		
2018-6351	Main St. Sundridge		$0					$169,329	
2014-27139	Upgrade Paget St – Sundridge		$0	$44,329	$101,561	$0	$0		
2017-3384	Asset Replacement Centre Street in Huntsville		$0	$0	$0	$0	$43,078	$62,300	
PSP1	MSI / MS2 Replacement		$116,824	$17,599	$0	$0	$0		
2016-35221	Conversion Pinewood Dr and Sherwood Dr.- Bracebridge		$0	$0	$1,824	$127,546	$2,758		
LP19266	Conversion Maple St. Bracebridge		$122,743	$0	$0	$0	$0		
PSP5D	Pole Replacement - Capital Reserve		$98,390	$13,262	$0	$0	$0		
2013-21007	Conversion Armstrong St – Bracebridge		$89,347	$17,420	$0	$0	$0		
2017-03729	Conversion Dawsonwood Rd in Bracebridge		$0	$0	$0	$0	$102,938		
2016-00503	Upgrade Birchwood Dr/Edgar St. – Sundridge		$0	$0	$0	$100,712	$0		
2017-3737	Pole Replacement - Parry Sound		$0	$0	$0	$0	$98,377		
2014-27443	Asset Replacements Pole Inspection 2014		$0	$86,845	$6,254	$0	$0		
2016-31726	Conversion Granite Bluffs – Bracebridge		$0	$0	$0	$89,348	$0		
HuntsCap-SR	Asset Replacement Huntsville Capital		$44,569	$960	$324	$1,588	$752		
2017-3734	Pole Replacement - Bracebridge		$0	$0	$0	$0	$87,305		
2016-35291	Sadler Dr Palmer Dr. Maple Dr Bracebridge		$0					$108,374	
PSCap-SR	Asset Replacement Parry Sound Capital		$0	$0	$2,614	$2,996	$0		
2013-21808	Upgrade MS1 Huntsville		$63,506	$5,322	$0	$0	$0		
2018-4211	Veteran's Way - Huntsville		$0					$101,405	
SR-005	Menominee St - Huntsville Primary underground / pole/ transformer		$0						$64,000
2017-2683	Asset Replacement Walpole & Mary St Huntsville		$0	$0	$0	$1,388	$57,785		
2017-3738	Isabella st - Parry Sound -		$0					$66,117	
2018-5585	Bracebridge - Kirk Line East > 2018 TCCAP		$0						
Misc < $50K	Total of all individual Projects < $50,000		$2,496	$12,646	$26,147	$44,811	$126,539	$0	$0
	Sub-Total System Renewal		**1,109,735**	**1,132,930**	**1,618,491**	**1,480,003**	**1,596,023**	**1,338,943**	**1,210,000**

System Service	System Service	2013 - Consolidated	2014 - Consolidated	2015	2016	2017	2018	2019
SS-003	Lakeland SCADA System	$185,229	$79,676	$35,362	$86,366	$8,938		$75,000
2015-31243	Ecclestone Dr - Bracebridge	$0	$0	$130,777	$47,030	$5,516	$135,169	
SS-002	Muskoka Rd - Bracebridge Manitoba St. to Shire St	$0						$290,000
2015-30766	New Generation Cascade St	$0	$0	$220,878	$41,148	$12,843		
2017-3811	Voltage Conversion James St, BB Move line edge of property	$0	$0	$0	$0	$51,340	$110,160	
2018-6418	WoodwardSt./Front St/ Alice St. Bracebridge.	$0					$6,940	
2013-22688	Robert Boyer Ln – Bracebridge	$85,534	$71,315	$0	$0	$0		
2013-25124	Holditch St. - Bracebridge	$0	$81,430	$67,644	$0	$0		
2014-27185	River Rd. – Bracebridge	$0	$121,176	$15,479	$0	$0		
SS-001	Hydro One Primary meter point conversion to IESO	$0						$120,000
BBCap-SS	Asset Replacement Bracebridge Capital	$19,163	$9,577	$22,610	$13,381	$13,869		
2012-21515	Voltage Conversion Victoria St and Dill St – Bracebridge	$59,303	$6,712	$0	$0	$0		
2016-01265	Voltage Conversion River St at Seguin river Parry Sound	$0	$0	$0	$58,739	$0		
2017-3809	Voltage Conversion Southband Dr Bracebridge	$0	$0	$0	$0	$42,491		
2013-24233	Voltage Conversion James St and Chubb Downey Lane – Bracebridge	$39,731	$0	$0	$0	$0		
2013-24002	Voltage Conversion Liddard St and Macdonald St. – Bracebridge	$33,508	$0	$0	$0	$0		
PSP6H	Substation MS6	$29,540	$0	$0	$0	$0		
2013-25944	Asset Replacement Westvale Dr – Bracebridge	$28,905	$0	$0	$0	$0		
PSCap-SS	Asset Replacement Parry Sound Capital	$0	$0	$110	$9,156	$6,566		
BFCap-SS	Asset Replacement Burks Falls	$0	$302	$602	$0	$0		
SunCap-SS	Asset Replacement Sundridge Capital	$380	$241	$0	$0	$0		
MagCap-SS	Asset Replacement Manetawan Capital	$0	$101	$142	$0	$0		
Misc < $50K	Total of all individual Projects < $50,000	$132,065	$645	$854	$9,156	$49,057		
	Sub-Total System Service	**481,294**	**370,531**	**493,604**	**255,820**	**141,563**	**252,269**	**485,000**

General Plant	General Plant	2013 - Consolidated	2014 - Consolidated	2015	2016	2017	2018	2019
161101 - GP-001	Computer Software	$38,967	$139,786	$22,771	$4,625	$45,266	$5,006	$325,000
161201	Land Rights	$4,031	$2,227	$18,121	-$7,500	$0		
180801 - GP-003	Buildings - Distribution	$2,996	$4,534	$341,650	$0	-$10,000	-$14,153	$50,000
190501	Land	$0	$0	$25,346	$0	$0		
190801	Buildings & Fixtures - General	$0	$21,045	$22,119	$0	$81,697	-$7,229	
191001	Leasehold Improvements to Parry Sound Office	$69,346	$24,942	-$141,540	$0	$0		
191501	Office Furniture & Equipment	$0	$3,558	$21,524	$0	$0	$11,528	
192002 - GP004	Computer Equipment - Hardware	$76,141	$25,724	$4,409	$6,105	$3,421	$20,216	$50,000
193001 - GP-002	Transportation Equipment	$372,243	$243,124	$267,746	$26,238	$127,913	$94,046	$200,000
194001	Tools, Shop & Garage Equipment	$0	$20,060	$15,770	$0	$0	$25,244	$25,000
195501	Communications Equipment	$645	$296	$0	$0	$0		
	Sub-Total General Plant	**564,369**	**485,296**	**597,916**	**29,468**	**248,297**	**134,658**	**650,000**
Total Capital Expenditures Net of Contributed Capital		**2,209,556**	**2,226,961**	**2,894,871**	**1,950,543**	**2,043,303**	**2,092,321**	**2,475,000**

b. 2-AB

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated

First year of Forecast Period: *2019*

CATEGORY				Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2013 - Proxy			2014			2015			2016			2017			2018			2019	2020	2021	2022	2023
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access		264			519	--		379	--		737	--	-	423	--	400	714	78.6%	380	350	350	350	350
System Renewal		1,110			1,133	--		1,618	--		1,480	--	-	1,596	--	1,246	1,339	7.5%	1,210	830	1,570	1,200	1,125
System Service		481			371	--		494	--		256	--	-	142	--	713	252	-64.6%	485	1,265	560	1,000	1,360
General Plant		564			485	--		598	--		29	--	-	248	--	301	135	-55.3%	650	375	425	515	504
TOTAL EXPENDITURE	3,230	2,419	-25.1%	2,816	2,508	-10.9%	2,959	3,089	4.4%	1,800	2,502	39.0%	1,950	2,409	23.6%	2,660	2,440	-8.3%	2,725	2,820	2,905	3,065	3,339
Capital Contributions	- 40	- 210	424.3%		- 281	--		- 194	--		- 552	--		- 366	--	- 250	- 348	39.1%	- 250	- 250	- 250	- 250	- 250
Net Capital Expenditures	3,190	2,210	-30.7%	2,816	2,227	-20.9%	2,959	2,895	-2.2%	1,800	1,951	8.4%	1,950	2,043	4.8%	2,410	2,092	-13.2%	2,475	2,570	2,655	2,815	3,089
System O&M	$ 1,519	$ 1,532	0.9%	$ 1,677	$ 1,689	0.7%	$ 1,705	$ 1,656	-2.9%	$ 1,577	$ 1,633	3.5%	$ 1,681	$ 1,671	-0.6%	$ 1,784	$ 1,879	5.3%	$ 1,839	$ 1,895	$ 1,965	$ 2,035	$ 2,105

c. 2-BA

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year 2018

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 974,838	$ 5,007	$ -	$ 979,844	-$ 873,642	-$ 46,887	$ -	-$ 920,530	$ 59,315
CEC	1612	Land Rights (Formally known as Account 1906)	$ 567,931	$ -	$ -	$ 567,931	-$ 49,975	-$ 20	$ -	-$ 49,995	$ 517,936
N/A	1805	Land	$ 74,305	$ -	$ -	$ 74,305	$ -	$ -	$ -	$ -	$ 74,305
47	1808	Buildings	$ 2,177,990	-$ 14,153	$ -	$ 2,163,837	-$ 632,979	-$ 80,847	$ -	-$ 713,825	$ 1,450,012
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 6,504,751	$ -	$ -	$ 6,504,751	-$ 2,666,083	-$ 126,163	$ -	-$ 2,792,246	$ 3,712,506
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 10,068,259	$ 756,453	$ -	$ 10,824,712	-$ 4,228,242	-$ 236,225	$ -	-$ 4,464,466	$ 6,360,246
47	1835	Overhead Conductors & Devices	$ 6,551,763	$ 333,423	$ -	$ 6,885,186	-$ 2,177,280	-$ 142,165	$ -	-$ 2,319,445	$ 4,565,741
47	1840	Underground Conduit	$ 4,685,019	$ 200,924	$ -	$ 4,885,942	-$ 2,217,516	-$ 99,236	$ -	-$ 2,316,753	$ 2,569,189
47	1845	Underground Conductors & Devices	$ 3,655,627	$ 235,448	$ -	$ 3,891,075	-$ 1,139,355	-$ 103,540	$ -	-$ 1,242,895	$ 2,648,180
47	1850	Line Transformers	$ 10,707,036	$ 454,801	$ -	$ 11,161,837	-$ 4,620,136	-$ 246,404	$ -	-$ 4,866,540	$ 6,295,297
47	1855	Services (Overhead & Underground)	$ 2,292,495	$ 45,821	$ -	$ 2,338,316	-$ 1,272,142	-$ 29,954	$ -	-$ 1,302,096	$ 1,036,220
47	1860	Meters	$ 3,897,214	$ 260,214	$ -	$ 4,157,428	-$ 1,611,245	-$ 248,456	$ -	-$ 1,859,701	$ 2,297,727
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 303,801	$ -	$ -	$ 303,801	$ -	$ -	$ -	$ -	$ 303,801
47	1908	Buildings & Fixtures	$ 304,467	$ 10,271	-$ 17,500	$ 297,238	-$ 112,541	-$ 12,907	$ 933	-$ 124,515	$ 172,723
13	1910	Leasehold Improvements	-$ 0	$ -	$ -	-$ 0	$ -	$ -	$ -	$ -	-$ 0
8	1915	Office Furniture & Equipment (10 years)	$ 272,605	$ 11,528	$ -	$ 284,133	-$ 226,670	-$ 12,506	$ -	-$ 239,176	$ 44,956
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 575,128	$ 20,216	$ -	$ 595,344	-$ 613,516	-$ 17,290	$ -	-$ 630,806	-$ 35,462
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 1,813,010	$ 29,197	-$ 128,850	$ 1,713,356	-$ 1,150,957	-$ 127,956	$ 47,623	-$ 1,231,290	$ 482,066
8	1935	Stores Equipment	$ 10,960	$ 64,850	$ -	$ 75,810	-$ 10,960	-$ 3,243	$ -	-$ 14,203	$ 61,607
8	1940	Tools, Shop & Garage Equipment	$ 299,412	$ 25,633	-$ 31,590	$ 293,455	-$ 257,939	-$ 11,654	$ 29,221	-$ 240,373	$ 53,082
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 189,661	$ -	$ -	$ 189,661	-$ 187,304	-$ 1,753	$ -	-$ 189,057	$ 604
8	1955	Communication Equipment (Smart	$ 410,583	$ -	$ -	$ 410,583	-$ 410,583	$ -	$ -	-$ 410,583	-$ 0
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 339,115	$ 506	$ -	$ 339,621	-$ 116,217	-$ 33,937	$ -	-$ 150,154	$ 189,468
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 8,661,436	-$ 347,817	$ -	-$ 9,009,253	$ 2,272,088	$ 193,447	$ -	$ 2,465,534	-$ 6,543,719
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	2055	Construction in Process	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 48,014,532**	**$ 2,092,322**	**-$ 177,940**	**$ 49,928,914**	**-$ 22,303,194**	**-$ 1,387,695**	**$ 77,777**	**-$ 23,613,113**	**$ 26,315,801**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 48,014,532**	**$ 2,092,322**	**-$ 177,940**	**$ 49,928,914**	**-$ 22,303,194**	**-$ 1,387,695**	**$ 77,777**	**-$ 23,613,113**	**$ 26,315,801**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,387,695**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 127,956
Stores Equipment	
Net Depreciation	-$ 1,259,739

2-SEC-12

[Ex.2, Appendix 2-AB; Ex1, p.52] The Applicant states: "If LPDL anticipates exceeding the Capital Budget by $50,000 during the fiscal year, a Capital Expenditure Report must be prepared and presented to the Board of Directors for approval".

a. Is the $50,000 variance on gross or net basis?

LPDL has also addressed this in 2-Staff-34 for additional comments. The $50,000 is on a gross basis

b. Based on the information contained in Appendix 2-AB, the $50,000 variance would have been met for 2016 and 2017 (on both a gross and net basis) and a 2016 (on a gross basis only). Please provide a copy of the Capital Expenditure Reports for these years, and 2018 (if applicable).

LPDL has attached a Capital Expenditure Report dated July 5, 2017 for roof replacement at the Parry Sound Office causing flood damages.(Appendix F)
For 2016, LDPL hired a third party contractor to conduct oil samples and transformer inspections in Parry Sound service area to determine if there were PCB transformers. During inspections, unexpected poles were changed for all PCB transformers to meet the new standards. Several rotten poles were also found during the PCB testing that required immediate attention. Appendix 2-AA has listed this unplanned project called “Upgrade Replacements due to inspections – Parry Sound” for $275K.
A specific Capital Expenditure Request was not prepared, as this project occurred throughout the fiscal year, the Board was made aware of the situation and updated status at monthly board meetings in the current action item list.

2-SEC-13
[Ex.2, DSP, p.67] Please revise table 2-7 to show similar annual costs metrics for each year between 2013 to 2018.

Metric Category	Metric	Measures						
		2013	2014	2015	2016	2017	2018	2019
Cost	Total Cost per Customer[1]	$ 284.86	$ 295.71	$ 341.91	$ 268.09	$ 276.17	$ 310.80	$ 319.73
	Total Cost per km of Line[2]	$ 8,747.69	$ 10,454.52	$ 12,403.60	$ 10,022.81	$ 10,382.41	$ 11,719.86	$ 12,056.81
	Total Cost per MW[3]	$ 61,205.88	$ 62,546.81	$ 77,125.08	$ 59,580.72	$ 62,035.70	$ 70,027.06	$ 72,040.38
CAPEX	Total CAPEX per Customer	$ 168.21	$ 168.17	$ 217.50	$ 145.94	$ 151.91	$ 178.60	$ 183.44
	Total CAPEX per km of Line	$ 5,165.41	$ 5,945.54	$ 7,890.30	$ 5,456.22	$ 5,710.90	$ 6,734.88	$ 6,917.47
O&M	Total O&M per Customer	$ 116.65	$ 127.54	$ 124.41	$ 122.15	$ 124.26	$ 132.20	$ 136.29
	Total O&M per km of Line	$ 3,582.28	$ 4,508.98	$ 4,513.31	$ 4,566.59	$ 4,671.51	$ 4,984.98	$ 5,139.35

Please note that these measures are prepared with LPDL’s 2018 budgeted numbers as actuals have not been completed at this time.

2-SEC-14
[Ex.2, DSP, p.70] With respect to reliability information:

a. Please revise tables 2-10 to 2-13 to include 2018 reliability information.

Table 2-10 Revised

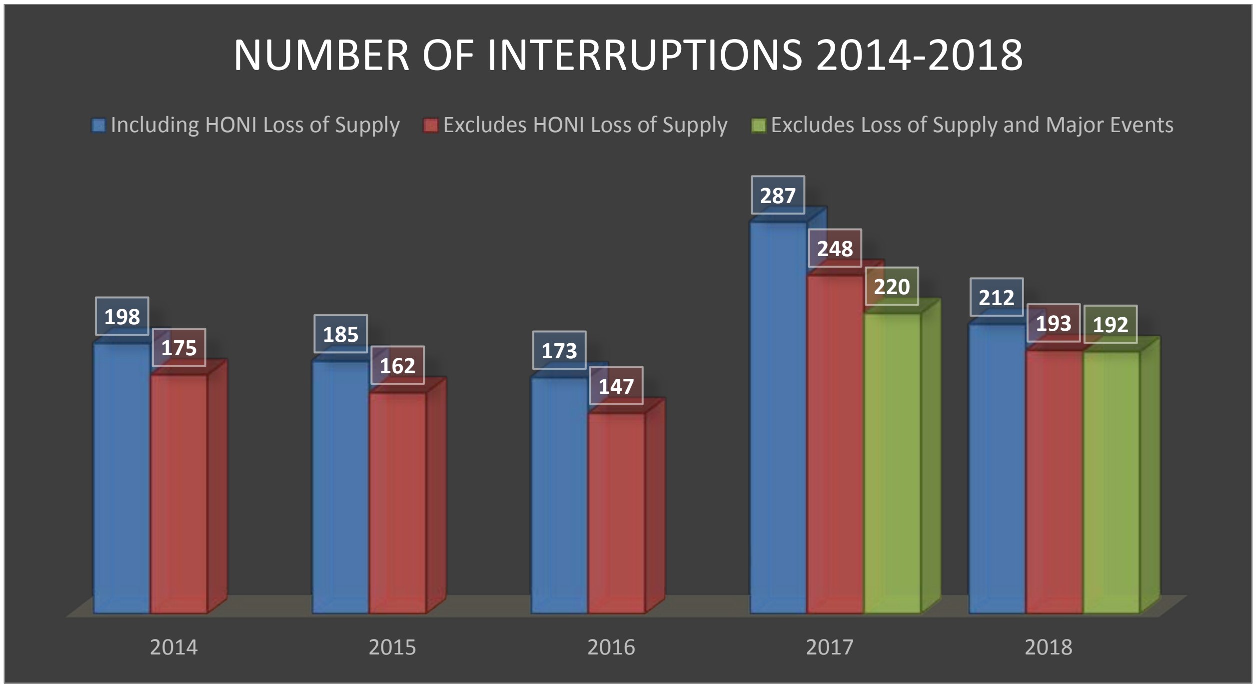


Table 2-11 Revised

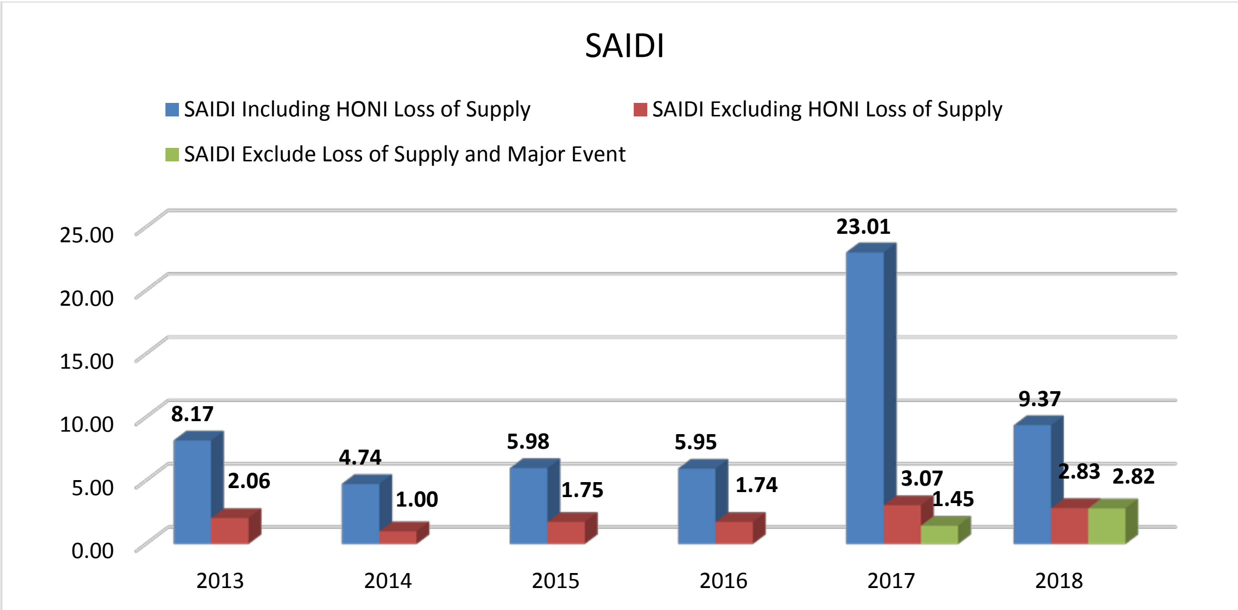


Table 2-12 Revised

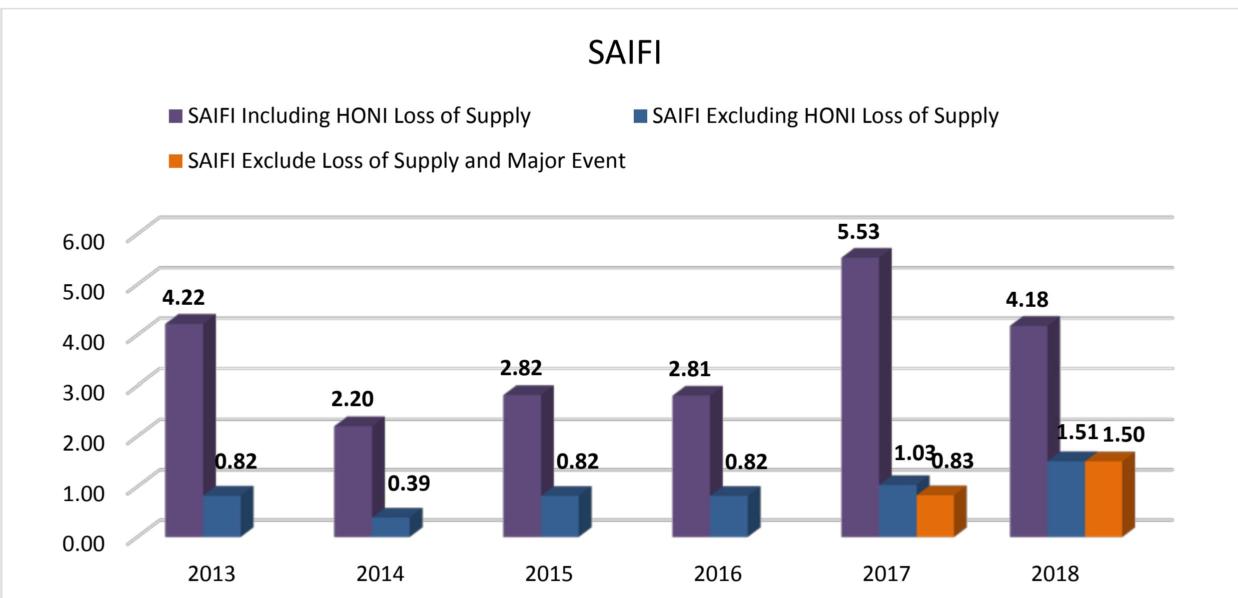
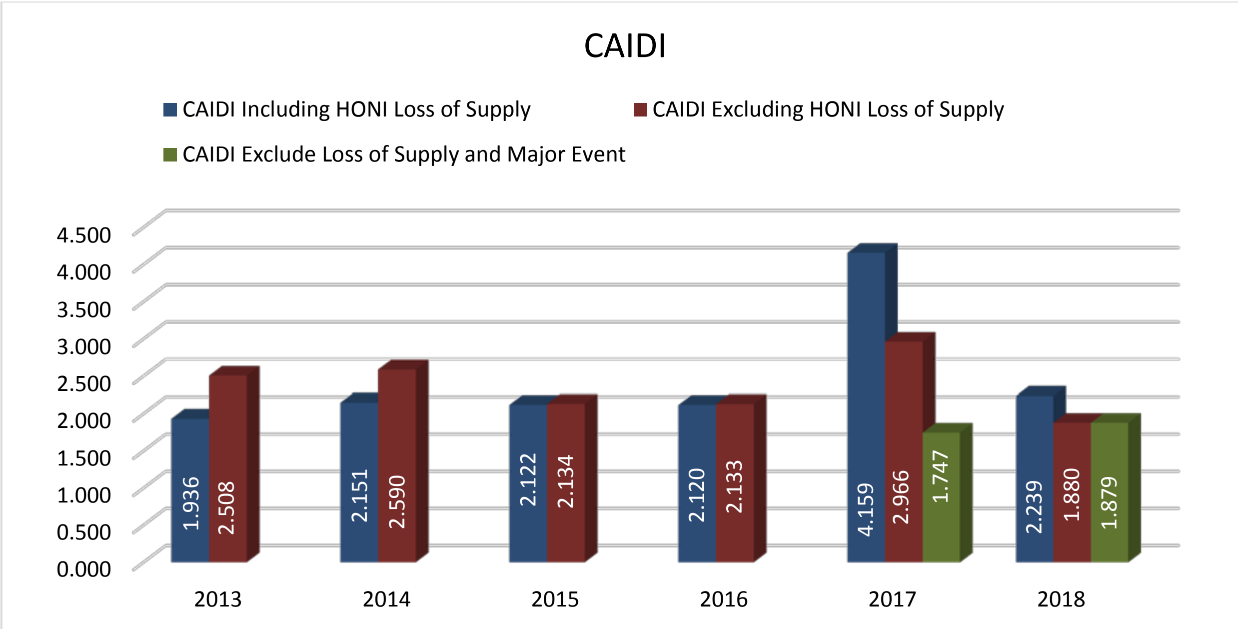


Table 2-13 Revised



b. Does the Applicant track reliability statistics for each by service territory? If so, please provide similar information in tables 2-10 to 2-13 on a service territory basis for each year including 2018.

LPDL does not directly track reliability statistics by service territory. All trouble calls that are related to reliability are entered into the work management system by town (service territory), therefore LPDL does have the information available, however will take time to retrieve this level of statistics if required.

2-SEC-15

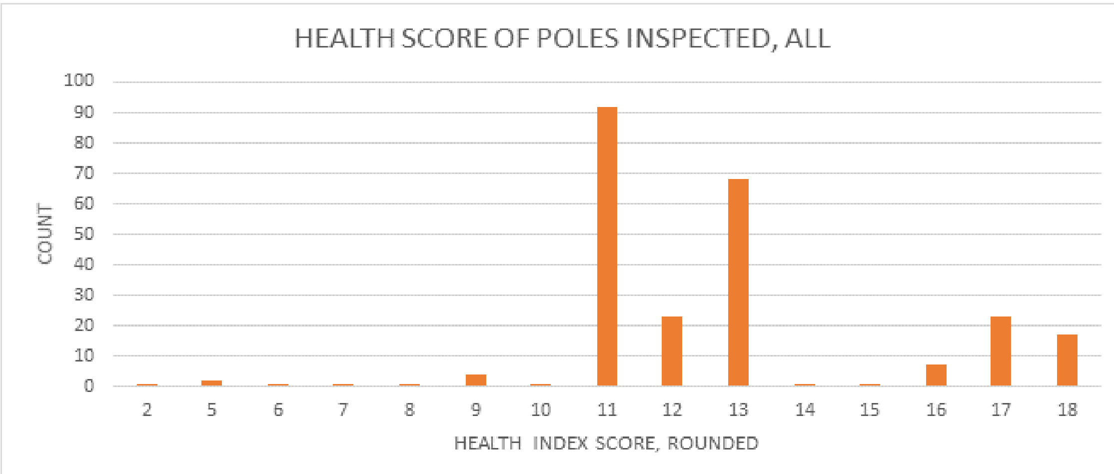
[Ex.2, DSP, p.100] The Applicant states that "LPDL is currently examining the possibility of working with a consultant to create a formal Asset Condition Assessment, which would become the basis of future decision-making processes." Please advise on the status of the Applicant's examination of this possibility.

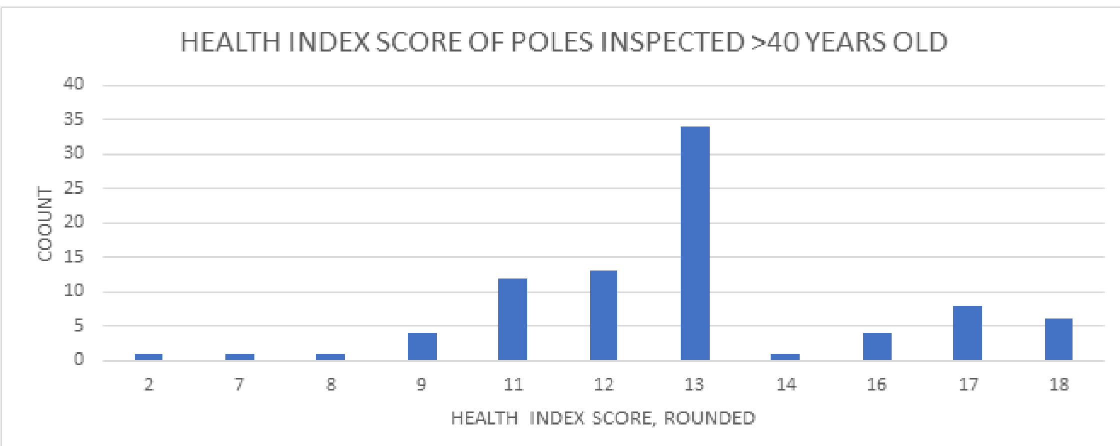
LPDL is a member of the Utility Standards Forum (USF) and is collaboratively developing guidelines for an asset condition assessment that can be shared with other members. LPDL commits to having a formal Asset Condition Assessment in place prior to the next cost of service application.

2-SEC-16

[Ex.2, DSP, p.135] With respect to poles, please provide a table showing the number of assets that are in each weighted asset score (1-10).

The graphs below demonstrate the distribution of health scores among our inspected pole assets. As this method of analyzing data has only been implemented in late 2017, we anticipate an increase in available data moving forward.





2-SEC-17

[Ex.2, DSP, p.144] Please explain how the Applicant determined the risk factors for each asset class.

The risk factors presented in Table 3-16 on p. 144 were professional engineering assumptions prepared by Metsco Energy Solutions.

2-SEC-18

[Ex.2, DSP, p.135, 145] Please explain the relationship between the health index ratings (i.e. 1-10) and the health index condition score (i.e. very good, good, fair, poor, very poor).

The Health Index Score is a ranking system generated based on information gained during a physical inspection of an
The Risk Factor is a weight assigned to an asset to demonstrate its importance to the overall electrical network.
Combined, these numbers allow LPDL to prioritize replacement and repair of assets whose potential failure would create a higher risk situation.

2-SEC-19

[Ex.2, DSP, p.165, Table 4-3] Please provide a similar table showing for each year between 2014 and 2018 the material capital investments, score and priority ranking at the time that year's plan was being developed. Please also identify if a given planned project was ultimately not completed in that given year.

LPDL is unable to provide a similar table as requested. As mentioned in the 2-Staff-14 response the total scores calculated are engineering estimates and not purely mathematical that was prepared by Metsco Energy Solutions. Also mentioned in the 2-Staff-40 response, LPDL has not completed the pole line rebuild project on Muskoka Rd and is scheduled for 2019.

2-SEC-20

[Ex.2, DSP, p.165, Table 4-3] Please provide the next step of projects, their priority rank, and their score, that were ultimately not chosen to be completed in 2019.

Below is the list of projects currently planned for LPDL to complete in 2020. As noted in OEB 2-Staff-14, priority rankings were completed for the 2019 projects by Metsco Engineering Solutions which involved engineering assumptions. LPDL does not currently have a numerical approach to rank the 2020 projects, however they are continuation of 2019 projects therefore likely would be ranked similar.

Year -2020					
Category	**Project/Program**	**Priority Rank**	**Capital Cost**	**Contributed Capital**	**Net Capital Cost**
System Access	Customer paid specific capital projects		$ 250,000.00	$ 250,000.00	$ -
	Meter changes, single phase/ three phase,		$ 100,000.00		$ 100,000.00
System Renewal	Bowes St. and Wakefield- Parry Sound. Poles/wires/ transformers. Convert to 12.5Kv		$ 330,000.00		$ 330,000.00
	James St/ Robert St/ Mary St/Ida St - Bracebridge- Change Poles/wires/transformers convert to 27.6Kv		$ 200,000.00		$ 200,000.00
	Lakeview Dr.- Sundridge replace primacy cable, vaults and transformers		$ 150,000.00		$ 150,000.00
	pole/ transformer/wire changes >40yrs old Sundridge, Burks Falls, Magnetawan, Parry Sound, Bracebridge, Huntsville		$ 150,000.00		$ 150,000.00
System Service	Meadow Heights - Bracebridge U/G cable replacement voltage conversion		$ 410,000.00		$ 410,000.00
	Woodchester Dr. Bracebridge from Taylor Rd to Muskoka Rd		$ 325,000.00		$ 325,000.00
	Hydro One Primary meter point conversion to IESO		$ 120,000.00		$ 120,000.00
	Downtown Underground Primary- Bracebridge		$ 150,000.00		$ 150,000.00
	Manitoba St - Bracebridge. Primary lines behind downtown buildings/River / Hiram St single phase		$ 190,000.00		$ 190,000.00
	Innovation Enabling Projects -SCADA/Line Loss /smart grid/etc.		$ 70,000.00		$ 70,000.00
General Plant	new vehicles -as per fleet plan		$ 200,000.00		$ 200,000.00
	Tools		$ 25,000.00		$ 25,000.00
	computer hardware		$ 15,000.00		$ 15,000.00
	Computer Software		$ 85,000.00		$ 85,000.00
	Building - Bracebridge office		$ 50,000.00		$ 50,000.00
Total:			**$ 2,820,000.00**	**$ (250,000.00)**	**$ 2,570,000.00**

2-SEC-21

[Ex.2, DSP] For each year between 2014 and 2019, please provide a table that shows the following assets replaced or forecast to be replaced:

a. Poles (#)
b. Overhead conductors (km)
c. Underground conductors (km)
d. Transformers

YEAR	POLES	TRANSFORMERS	OVERHEAD PRIMARY (meters, 3ph)	OVERHEAD PRIMARY (meters, 1ph)	OVERHEAD PRIMARY (meters, 2ph)	UNDERGROUND PRIMARY (meters)
2014	50	41	1369.63	483.88	0.00	368.80
2015	82	56	2307.70	891.24	25.01	3071.35
2016	65	43	1427.57	269.25	0.00	1087.04
2017	63	78	124.04	922.13	0.00	765.29
2018	73	91	941.09	113.63	0.00	2059.24
2019	76	34	1570.60	1359.57	n/a	1689.48

2-SEC-22

[Ex.2, DSP, Appendix A1-A2] The Applicant has provided project narratives for historical (2013-2018) material capital projects that differ significantly from the project narratives for the test year project.

a. Were the project narratives provided for the test year projects created for the purposes of the application or in the normal course does the Applicant use such documents for project planning and accountability?

The detailed narratives for the test year projects were prepared by Metsco Energy Solutions and have not historically been the normal course of action for LPDL while planning projects. LPDL is committed to providing narratives on projects on a go forward basis at this level of detail.

b. If the answer to part (a) is that they are used in the normal course, or a similar type of document is used, please provide it for all historical projects (2013-2018).

Not applicable

2-SEC-23

[Ex.2; Ex.1, p.163] The Applicant states that it retained "METSCO Energy Solutions Inc ("METSCO") to advise on and assist with the preparation of the DSP." Please explain what work METSCO undertook in preparation of the DSP? Did MESTCO provide any advice or assessment of the Applicant's capital plan or planning process? If so, please provide details.

LPDL retained METSCO to assist with writing the DSP and project narratives for the current application. METSCO provided LPDL a typical list of information required and collaboratively the DSP was written.
METCSO advised and identified the need of a formalized Asset Condition Assessment Report and Project Prioritization Process that is currently not present at LPDL.

Exhibit 3 – Operating Revenue

3-Staff-47
Load Forecast
Ref: Exhibit 3, page 12; Load Forecast Model, Rate Class Customer Model sheet
Lakeland Power has forecasted that the number of residential customers in 2019 will remain at the year-end 2017 levels, and at 2018 levels for all rate classes.

a) Please explain why Lakeland has forecasted no growth in customer connections when it has experienced a growth of 936 residential customers and 99 General Service < 50 kW customers from 2008 to 2017.

For residential customers, the change in customer count has been minimal over the past few years and LPDL expected there would be no further growth (pg 24).
For GS<50 kW customers, the change in customer count from 2008 to 2017 was primarily due to the reclass of customers between the GS<50 kW customer class and the GS>50 kW customer class so no growth was predicted. The change in these classes over the past few years directly correlate to each other. LPDL's service territory has reached its boundaries and future growth in the forecasted regional plan by municipalities is in Hydro One territory.

b) Please provide customer counts by rate class for December 2018 if that is available, or the most recent month available.

3-SEC-24 a)

Exhibit 3 - Table 31: Summary of Total Load Forecast

Updated to Include 2018 year-end actual

Table 3-28: Forecast Summary

	2013 Actual	2014 Actual	2017 Actual	2016 Actual	2017 Actual	2018 Actual	2018 Weather Normal	2019 Weather Normal
Purchases								
Actual kWh Purchases	315,512,631	319,149,657	308,961,454	302,232,068	297,287,399	309,247,473		
Predicted kWh Purchases before CDM adjustment	312,391,340	315,053,255	308,860,040	302,931,764	297,293,859		300,830,926	300,929,259
% Difference between actual and predicted purchases	(1.0%)	(1.3%)	(0.0%)	0.2%	0.0%			
Loss Factor							1.0725	1.0725
Total Billed Before CDM Adjustments							280,488,048	280,579,732
CDM Adjustment							1,316,687	3,858,056
Total Billed After Adjustments	293,263,621	297,398,397	288,752,255	280,505,070	278,833,243	288,725,647	279,171,361	276,721,676
Billing Determinants								
Residential								
Customers	10,890	10,964	11,021	11,078	11,169	11,288	11,208	11,208
kWh	113,520,550	114,433,382	108,243,956	104,348,161	103,129,632	109,418,578	104,280,349	103,566,100
General Service < 50 kW								
Customers	2,075	2,106	2,133	2,138	2,144	2,159	2,148	2,148
kWh	57,852,244	58,443,482	58,492,111	58,168,701	57,585,352	59,770,888	58,279,267	58,157,023
General Service 50 to 4,999 kW								
Customers	171	172	156	149	138	138	136	136
kWh	119,216,710	121,885,729	119,763,838	116,637,109	116,753,504	118,215,219	115,248,177	113,634,985
kW	293,433	288,261	288,082	283,796	279,963	286,041	280,141	276,220
Sentinel Lights								
Connections	59	57	53	52	46	44	44	44
kWh	51,382	50,004	49,108	48,746	44,234	40,821	42,775	42,775
kW	150	139	136	135	123	113	119	119
Street Lights								
Connections	2,843	2,844	2,766	2,679	2,848	2,849	2,849	2,849
kWh	2,441,056	2,405,635	2,029,685	1,136,285	1,154,454	1,114,031	1,154,724	1,154,724
kW	6,704	6,610	5,922	3,094	3,197	3,087	3,183	3,183
Unmetered Scattered Loads								
Connections	56	55	52	51	51	51	51	51
kWh	181,680	180,165	173,556	166,068	166,068	166,110	166,068	166,068
Total								
Customer/Connections	16,094	16,197	16,181	16,148	16,396	16,529	16,436	16,436
kWh	293,263,621	297,398,397	288,752,255	280,505,070	278,833,243	288,725,647	279,171,361	276,721,676
kW	300,287	295,010	294,141	287,026	283,282	289,241	283,444	279,523

c) Please explain the cause of the decrease in street lights from 2010 to 2016 during which time both Residential and General Service < 50 kW customer counts were increasing. Please also explain the driver of the subsequent increase in 2017.

Over the past five or so years, streetlights have been mapped into the GIS system and most municipalities have changed out most of their streetlights to LED's. During this process of changing the lights and mapping them into the GIS, LPDL was able to accurately identify all streetlights in their territory and update their billing system to current actual streetlight counts. In addition, where possible, streetlights are metered. LPDL does not see a correlation between streetlight counts and Residential and General

Service < 50 kW customer counts as LPDL's residential growth is primarily due to multi-unit complexes and rural setting neighbourhoods where if there are streetlights installed, they are metered.

3-Staff-48
Load Forecast
Ref: Exhibit 3, page 20
Lakeland Power has performed a regression model using heating degree days, cooling degree days, number of days in the month, a spring fall flag and CDM activity as explanatory variables.

a) Has Lakeland Power prepared a regression model which uses an economic indicator such as GDP or employment as an explanatory variable?
    a. If so, please provide the results and explain why it was rejected
    b. If not, please prepare a load forecast model and resulting class forecast where GDP is added as an explanatory variable.

LPDL prepared a regression model using the Ontario Real GDP as an explanatory variable. The variable was rejected as it was not statistically significant (i.e. t-stat of 1.88). The forecasted power purchased results have not been provided since they would be invalid.

b) Has Lakeland Power prepared a regression model which uses customer connections as an explanatory variable?
    a. If so, please provide the results and explain why it was rejected
    b. If not, please prepare as a scenario, a load forecast model and resulting class forecast where GDP is added as an explanatory variable.

LPDL prepared a regression model using customer connections as an explanatory variable. The variable was rejected as it was not statistically significant (i.e. t-stat of 1.21). The forecasted power purchased results have not been provided since they would be invalid.

3-Staff-49
Load Forecast
Ref: Exhibit 3, page 21
Lakeland Power states "Weather data was obtained from weather stations in the Muskoka area."

a) Please list the weather stations used.
b) Please detail the method for determining which station or stations would be used in each day. If multiple stations are used in a day, please explain the method for calculating heating degree days and cooling degree days.

For 2008 to 2015 the daily heating degree day and cooling degree day information from the Muskoka Airport weather station was used. For 2016 and 2017 daily information at the Beatrice Climate weather station was used. The information at the Muskoka Airport for 2016 to 2017 had a number of data gaps which made it unusable. Information at the Beatrice Climate weather station was the closest weather station to the Lakeland service area that had complete daily information. For 2014 and 2015, the weather data at the Muskoka Airport was on average about 95% of that at the Beatrice Climate weather station. As a result, the 2016 to 2017 heating degree day and cooling degree day data used in the load forecast is the 2016 and 2017 weather data at the Beatrice Climate weather station with a 95% factor applied to it.

3.0-VECC-12

Reference: Exhibit 3, page 11
Load Forecast Model, Purchased Power Model Tab

a) Please confirm that the purchases set out in the Purchased Power Model Tab (column B) include purchases from the IESO, Hydro One and embedded generators.

Yes, LPDL confirms that the purchases include purchases from the IESO, Hydro One and embedded generators.

3.0-VECC-13

Reference: Exhibit 3, pages 12-13 and page 17 (Table 11)
Appendix 2-IB

a) In Table 11 the actual and weather normal GWh for each year differ for the Residential, GS<50 and GS>50 classes. However, in Appendix 2-IB the actual and weather normal values are the same for these classes. Please reconcile.

The information in Table 11 is correct. Appendix 2-IB has been revised to be consistent with Table 11 and can be found in the excel version of Chapter 2 Appendices filed in RESS.

b) Please fully explain how the weather normal GWh values in Table 11 were derived for the Residential, GS<50 and GS>50 classes.

The weather normal GWh values from 2008 to 2017 are the actual values times the Weather Normal Conversion Factor outlined in the Table 15. The 2018 and 2019 weather normal values reflect the outcome of the load forecast process.

3.0-VECC-14

Reference: Exhibit 3, pages 20-21

a) Did LPDL test whether there were any activity based variables such as regional employment, GDP or customer count that would be statistically significant?

   i. If yes, what were the results?

   ii. If not, why not?

Please see response to 3-Staff-48

b) Please provide the results of an alternative load forecast model where the dependent variable is gross purchases (i.e., actual purchases plus CDM activity – where the CDM values are grossed up for losses) including the regression equation and statistics as well as projected gross purchases for 2018 and 2019 using the same explanatory variables (apart from CDM Activity) and a trend variable (if the coefficient is statistically significant)

The requested alternative load forecast model has been provided in live Excel file named “Lakeland FINAL 2019 Load Forecast 3 VECC 14”. The trend variable was tested but not included as it was not statistically significant (i.e. t-stat is -1.32). The 2019 power purchased forecast is 303,754,463 kWh in this alternative load forecast

3.0-VECC-15

Reference: Exhibit 3, pages 21-22

Load Forecast Model, CDM Activity Tab

a) Please provide the OPA/IESO reports that support the annual CDM activity values for 2008 to 2016 set out in the CDM Activity Tab.

b) In column E of the CDM Activity Tab the 2017 CDM results are "labelled" as estimated. In Table 13 (page 22) there is no reference to the IESO in heading for the column setting out the 2017 CDM Program activity. Please clarify whether the 2017 CDM values used were based on the actual 2017 verified results reported by the IESO.

   a. If not, what are the 2017 values based on?

   b. If not, please provide a copy of the IESO 2017 verified results report for LPDL and update the load forecast model accordingly.

   c. If yes, please provide a copy of the IESO 2017 verified results report for LPDL.

a) The OPA/IESO reports that support the annual CDM activity values for 2008 to 2016 set out in the CDM Activity Tab are provided in live Excel format with the following names

   i. 2006-2010 Final OPA CDM Results.Lakeland Power Distribution Ltd.

   ii. 2006-2010 Final OPA CDM Results.Parry Sound Power Corporation

   iii. Persistence Savings Lakeland 2011-2014

   iv. Final Verified 2016 Annual LDC CDM Program Results_Report_Lakeland Power Distribution Ltd._20170630

b) The 2017 CDM values used were estimated values based on the 2017 values outlined in the 2015 to 2020 CDM LPDL plan dated December 2017.

The load forecast model has been updated to reflect the IESO 2017 verified results report for LPDL and is provided in live Excel file named "Lakeland FINAL 2019 Load Forecast 3 VECC 15". The 2019 power purchased forecast is 299,570,185 kWh in this updated load forecast compared to the power purchased forecast of 300,929,259 kWh in the Application.

3.0-VECC-16

Reference: Exhibit 3, page 24

a) What is the 10-year average loss factor based on the entire period (2008-2017) used to estimate the purchased power model.

The 10-year average loss factor based on the entire period (2008-2017) used to estimate the purchased power model is 1.0710.

3.0-VECC-17

Reference: Exhibit 3, pages 24-25

a) Please provide the actual customer/connection counts for each customer class for each of the months in 2018 and the resulting average 2018 value for each class.

Please see response to 3-SEC-24.

b) Is LPDL aware of any plans for either residential or commercial/industrial developments in its service area that would increase customer/connection counts in 2019?

No, LPDL is not aware of any large residential/industrial developments in its service area that would impact customer/connection counts in 2019. Municipality growth projections are in Hydro One territory.

3.0-VECC-18

Reference: Exhibit 3, pages 27-28

a) Please provide a copy of the most recently approved 2015-2020 CDM Plan for LPDL.

The most recently approved 2015-2020 CDM Plan for LPDL has been attached as Appendix G.

b) Based on the IESO's verified results reports what are the 1-year persistence values for the savings from: i) 2015 CDM Programs, ii) 2016 CDM Programs and iii) 2017 CDM programs – for each of the Residential, GS<50 and GS>50 classes?

Per 2017 IESO Verified Results	**2015**	**2016**	**2017**
Total CDM Persistence kWh	5,426,135	2,703,972	3,736,557
Residential Customer Class	566,221	1,150,973	1,730,488
GS<50 Customer Class	2,126,929	273,962	1,113,749
GS>50 Customer Class	2,732,985	1,279,037	892,319
Total CDM Persistence kWh	5,426,135	2,703,972	3,736,557

3.0-VECC-19

Reference: Exhibit 3, pages 45-46
EB-2017-0049, HONI Dx's Response to PO11

a) In its response to EB-2017-0049, PO#11, Hydro One Networks confirmed that it was adopting the OEB's province-wide pole attachment charge of $43.63 effective January 1, 2019. What impact will this have on LPDL's forecast 2019 OM&A?

There should be no impact on LPDL's forecast 2019 OM&A as it is forecasted based on prior year rates which for Hydro One has historically been higher than the 2019 approved province wide charge. The rate stated in Hydro One's response to PO#11 was referring to a 'Joint Use TELECOM Charge' which has not applied to LPDL in the past.
Should Hydro One be approved for the rates requested for attachment in 10' power space of $76.46 (EB-2017-009), the impact to LPDL would be an additional $13 K in OM&A.

b) Has LPDL incorporated the impact of the Board's EB-2015-0304 Report regarding Energy Retailer Service Charges in its determination of the 2019 Other Revenues?
   a. If yes, please indicate where in the Application this is discussed/included.
   b. If not, what is the estimated impact on 2019 Other Revenues?

Yes, LPDL had considered the impact of the Board's EB-2015-0304 Report regarding Energy Retailer Service Charges in its determination of the 2019 Other Revenues but had not indicated that in the Application.

LPDL had forecasted that the impact of the Board's EB-2015-0304 Report regarding Energy Retailer Service Charges would be negligible on the 2019 Other Revenues. LPDL forecasted the revenue for retailer service charges for 2019 to remain consistent with 2018 revenue. LPDL's retailer revenue in 2018 was consistently reduced to match the lower retailer costs which LPDL forecasts will continue into and throughout 2019. The increase in rates will initially increase the retailer service charge revenue but will be offset by a larger variance entry that will adjust the revenue back down to match the consistent lower costs. The larger DVA variance will be returned to the customer during rate application process.

3.0-VECC-20

Reference: Exhibit 3, pages 48 and 62-63

Preamble: The referenced pages identify a number of specific service charges that are currently applied to only the former PSP service area or the former LPDL service and which are being proposed to continue for all LPDL customers as of May 1, 2019.

a) What is the impact on LPDL's forecast Other Revenue for 2019 of extending these charges to all of LPDL's customers and how has it been reflected in the current Application?

LPDL has forecasted that there will be a negligible impact on 2019 Other Revenue from the consolidation of the specific service charges from the two former service areas as they are fairly consistent. The charges are somewhat similar in nature with only a difference in terminology/interpretation. LPDL was attempting to consolidate the full list of service charges to ensure that the option to charge any of LPDL's customers, if applicable, was still available.

b) The Application proposes to almost double the microFIT service charge ($10 vs. $5.40). However, the revenues from the service charge are the same for 2018 and 2019 (see page 48). Please reconcile.

The microFIT service charge revenue would be $3,150 more for 2019 based on the $10/mth rate. This will be adjusted in the RRWF.

3-SEC-24

[Ex.3] Please revise the following to include 2018 year-end actuals:

a. Table 31
b. Appendix 2-H

Table 31 can be found in response to 3-Staff-57 and Appendix 2-H has been updated in the excel format of the Chapter 2 Appendices.

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2013 Actual²	2014 Actual²	2015 Actual²	2016 Actual²	2017 Actual	Bridge Year	Test Year
		2013	2014	2015	2016	2017	2018	2019
	Reporting Basis	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	CGAAP
4235	Specific Service Charges	$ 78,887	$ 73,249	$ 78,335	$ 91,164	$ 77,169	$ 72,963	$ 68,776
4225	Late Payment Charges	$ 100,257	$ 112,699	$ 137,082	$ 84,072	$ 93,225	$ 77,353	$ 83,700
4082	Retail Services Revenues	$ 44,892	$ 13,771	$ 10,115	$ 7,500	$ 6,899	$ 7,061	$ 7,000
4084	Service Transaction Reque	$ 68						
4086	SSS Administration Reven	$ 42,155	$ 41,834	$ 45,184	$ 45,230	$ 46,268	$ 46,987	$ 46,700
4210	Rent from Electric Property	$ 226,026	$ 174,612	$ 226,700	$ 216,154	$ 224,000	$ 230,636	$ 382,635
4355	Gain on Disposition of Utility and Other Pr		$ 12,220	$ 24,883	$ 10,142	$ 1,282	$ 31,187	
4360	Loss on Disposition of Utility and Other Property					-$ 8,736	-$ 23,631	
4375	Revenues from Non Rate-R	$ 135,141	$ 163,411	$ 80,668	$ 614,065	$ 73,621	$ 260,306	$ 33,800
4380	Expenses of Non Rate-Reg	-$ 115,719	-$ 156,395	-$ 74,223	-$ 615,054	-$ 62,150	-$ 70,926	-$ 31,400
4390	Miscellaneous Non-Operat	$ 82,605	$ 207,946	$ 107,213	$ 71,251	$ 129,141	$ 131,617	$ 77,653
4405	Interest and Dividend Inco	$ 25,529	$ 51,904	$ 52,618	$ 61,067	$ 52,851	$ 130,515	

Exhibit 4 – Operating Expenses

4-Staff-50
Parry Sound Board Approved Proxy
Ref: Exhibit 4 – Operating Expenses, Table 2
Ref: EB-2010-0140, Decision and Order, p. 17

In Table 2, Lakeland Power provided the 2011 OEB approved values for its Operating, Maintenance, and Administration (OM&A) expenses.

a) Please provide the forecasted OM&A at the time of Parry Sound's last cost of service for 2011, 2012, and 2013 and compare it to the actual operating expenses for the same time period.

LPDL's data source for PSP information is the RRR filings. As many of the records were destroyed in two building floods and no existing PSP staff, LPDL is unsure as to what was prepared for budget/forecast purposes. The only reports available, compare year over year with no reference to a forecast for OM&A.

In the Decision and Order, OEB noted that the approved OM&A was a 30.5% increase from 2010 actual levels. The OEB further stated that it normally would not approve such an increase but in this case, the OEB granted the increase because of the additional pressures of restructuring into a stand alone utility.

b) Since part of the OM&A approved in 2011 was related to restructuring into a stand alone company and the 2013 proxy is for an amalgamated utility, how has Lakeland Power taken this into account when creating the OEB approved proxy for 2013?

The cost to create the standalone entity is not related to the amalgamation, the amalgamation talks did not begin until 2013, long after PSP became a standalone entity. The costs to run the two entities separately through to July 1, 2014 would be reflective of the approved amounts included in the 2013 proxy. If LPDL had removed costs related to PSP becoming a standalone entity (which PSP did in 2011 and incurred the costs) it would in effect, be building in the synergy savings that did not occur until after the merger. Through the MADDs process, it is indicated that the application is permitted to retain the synergy savings for 5 years, until its next Cost of Service application. With this in mind, there would be no adjustment to 2013 Proxy for the Parry Sound portion other than inflationary changes that mirror the IRM rates for the respective years between 2011 and 2013; otherwise it would be taking potential synergy savings into account in 2011 to 2013

c) For comparison purposes, please provide the 2013 OEB approved proxy by using the 2010 Parry Sound actuals and applying inflation for each year until 2013.

4-Staff-51
Wireline Pole Attachment
Ref: Exhibit 4 – Operating Expenses, p.38
Lakeland Power stated part of the increase to OM&A in 2019 is due to the increase in Hydro One's pole line attachment rate. There is also an OM&A driver called Joint Use – Pole Rental.

a) Is the cost of Hydro One's pole line attachment charge the only cost in the Joint Use – Pole Rental driver?

As per the industry standard, utilities are charged for their attachment to poles which they do not own. In the application, LPDL should have indicated the increase was for both Hydro One as well as Bell Canada. The rates which LPDL used for OM&A are as below:

Rates charged to LPDL	2013	2014	2015	2016	2017	2018	2019
Hydro One	$28.61	$28.61	$46.88	$47.34	$47.82	$47.82	$49.73 (est)
Bell Canada	$27.39	$27.39	$27.39	$27.39	$27.39	$29.73	$53.47

However, LPDL has also reviewed the potential LDC-specific charge from Hydro One as per the excerpt below:

Filed: 2017-03-31
EB-2017-0049
Exhibit H1
Schedule 2
Tab 1
Page 19 of 21

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2018
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Specific Charge for LDCs Access to the Power Poles ($/pole/year)

LDC Rate for 10' of power space	$	76.46
LDC Rate for 15' of power space	$	91.75
LDC Rate for 20' of power space	$	101.95
LDC Rate for 25' of power space	$	109.23
LDC Rate for 30' of power space	$	114.69
LDC Rate for 35' of power space	$	118.94
LDC Rate for 40' of power space	$	122.34
LDC Rate for 45' of power space	$	125.12
LDC Rate for 50' of power space	$	127.44
LDC Rate for 55' of power space	$	129.40
LDC Rate for 60' of power space	$	131.08

As most of LPDL's connection on H1 poles are on 10' of power space, the OM&A costs could be understated by almost $13 K should these amounts be approved.

b) Please provide a copy of the Joint Use agreement between Lakeland Power and Hydro One.

The executed agreement can be found at Appendix H. The following is an extract from the agreement.

The initial rate filing for a 5 year plan, in application EB-2013-0416/EB-2014-0247 was not approved, but the OEB did approve new LDC joint use rates for 2015 through to 2017. The new LDC joint use rates, per pole, per attacher for **10 feet of power space** are as follows:

2005 – 2014	2015	2016	2017
$28.61	$46.88	$47.34	$47.82

4-Staff-52
Other Drivers – Innovation programs with MaRS
Ref: Exhibit 4 – Operating Expenses, p.39
Lakeland Power stated that there is $20k for innovation programs with MaRS.

a) Is this a reoccurring cost and what is the scope of the program?

LPDL joined MaRS in order to stay up to date in the area of innovation, a driver from the OEB. As LPDL did not believe that hiring staff to investigate new innovation projects was in the best interest of the ratepayer, due to the cost of new staff over a small customer base, LPDL chose to take a more cost prudent path. Staff from MaRS are also on the OEB Advisory Board on Innovation.

b) How does Lakeland Power benefit from this innovation program?

LPDL benefits in acquiring knowledge of the innovation changes occurring in our industry thus making future distribution system planning more effective. From the intelligence garnered during our connection with MaRS, we have gained contacts to assist in looking at different options to enable renewable generation, net metering, virtual net metering, battery storage and EV charging. All of this information/contact is provided to LPDL for a small fee eliminating the need to have in house resources researching, analyzing and developing our own solutions.

4-Staff-53
Community and Civic Co-ordination
Ref: Exhibit 4 – Operating Expenses, p.46
Lakeland Power stated that the increase in the Community and Civic Co-ordination program is due to the increase in customer engagement. This includes customer engagement meetings, customer satisfaction surveys, and safety surveys.

a) Are the customer engagement meetings held yearly? What are the topics of discussion at the customer engagement meetings?

LPDL holds customer engagement meetings annually. In addition, due to LPDL's demographic and geographic characteristics, events are also held via social media platforms and can be done more often. In 2018 LPDL was the first LDC to hold a Facebook Live event.

In the past, topics have been capital planning, tree trimming, outage management, outage communication and bill explanation. Please find attached Appendix B, C & D which detail the topics discussed at various meetings.

b) What is the estimated average cost per customer engagement meeting?

The average cost per meeting would be in excess of $2K however the range is large. In Appendix C the associated costs for LPDL customer engagement meetings can be found.

c) How does Lakeland Power ensure the cost of the customer satisfaction surveys is the most economical? Does the customer satisfaction survey change significantly year-over-year?

Since the implementation of the OEB mandate to complete biennial surveys, LPDL has done it's upmost to ensure they are cost effective. The completion of the Customer Satisfaction Survey went to RFP with the CHEC group of utilities, RedHead Media was selected at a discounted group rate.

The methodology will be the same year over year allowing for accurate comparisons year over year. LPDL does have the opportunity to add additional questions should they be deemed useful or required.

4-Staff-54
Operations & Engineering, Supervision
Ref: Exhibit 4 – Operating Expenses, p.46
Lakeland Power stated that the largest increase in the Operations & Engineering, Supervision program is a result of moving the Lines Supervisor to the Operations/Engineering Manager position. Another increase was due to filling the Engineering Technologist position for sophisticated processes/programs such as the implementation of SCADA and robust GIS.

a) What is the percentage salary difference between the Lines Supervisor position and the Operation/Engineering Manager position.

There is a 20% salary difference between the two positions.

b) Please provide the difference in work duties of the Lines Supervisor position and the Operation/Engineering Manager position.

The Lines Supervisor is responsible for supervising and directing the daily activities for the Linesmen, Material & Facilities Coordinator, Labourer and outside contractors. The Lines Supervisor reports to the Operations Manager. The Operations Manager oversees the entire Operations department, which includes the Lines Supervisor and their lines and facility staff, as well as supervising and directing the daily activities of the Engineering Technicians/Technologists. The Operations Manager is also responsible for budgeting, purchasing approvals, association meetings, escalated customer issues/concerns, consultations with Hydro One affecting loss of supply, regional planning, correspondence with other LDC's and for operating the entire department.

c) Please provide the number of direct reports for the Lines Supervisor position and the Operation/Engineering Manager position.

At the end of 2018, the Lines Supervisor had 9 direct reports and the Operation/Engineering Manager had 4 direct reports, in addition to the 9 indirect reports, as well as coordination with 2 affiliated administrative staff.

d) Please confirm if the Engineering Technologist position is different from previous engineering roles at Lakeland Power. If there is a difference, please provide a list of different responsibilities.

LPDL confirms that the Engineering Technologist position is different from previous engineering roles at LPDL. The role of the previous Engineering Technician was mainly a Meter Journeyperson who performed line design within the standards provided and was classified in the collective agreement as a Journeyperson. The Engineering Technologist now must have a degree in the electrical technologist discipline and have a valid membership with the OACETT (Ontario Association of Certified Engineering Technicians and Technologists). They are responsible for the design of the distribution infrastructure including all projects and connections.

The former PSP outsourced this position. As the LDC environment has changed significantly in the past 10 years, higher skill levels are required to design and manage the system.

e) What is the percentage salary difference between the Engineering Technologist position and previous engineering roles, if applicable.

All Engineering positions are part of the Union. The Engineering Technologist salary is 7% higher than the Engineering Meter Journeyperson salary as covered in the collective agreement.

4-Staff-55
Cybersecurity Costs
Ref: Exhibit 4 – Operating Expenses, p.49
Lakeland Power has stated that a large portion of the increase for the IT support, software, telecommunications, and cybersecurity program is due to the start of cybersecurity solutions for Lakeland Power, the Written Information Security Program.

a) Please provide information about the Written Information Security Program.

The Written Information Security Program (WISP) is a collection of process and procedural documentation and templates collected and purchased by the Utilities Standards Form (USF) group for the use of its members in the construction their cyber security frameworks. The documentation includes ties the NIST compliance measures required in all policy and procedure document templates for the Low, Medium, and High risk profiles. This will ensure all the policies and templates in the WISP are outlining all the items required for compliance at the Low, Medium, High risk profile levels.

b) Lakeland Power has stated that it will assess the level of risk within their systems and implement solutions that are deemed appropriate for the level of risk. Did Lakeland Power consider the risk of a reduced level of spending for this program compared to the risk of reduced spending on other OM&A programs? If so, please provide the analysis.

LPDL did not consider the risk of a reduced level of spending for this program compared to the risk of reduced spending on other OM&A programs.

c) Please provide the reoccurring costs broken down by activities related to the cybersecurity solutions.

LPDL currently does not have cyber security costs broken down by activities related to the cyber security solutions. Only once we have completed our gap analysis and assessed our risk tolerance will we be in a position to prioritize project tasks, develop a plan, and begin implementing the plan. Once LPDL has a formalized plan in place and implementation has begun, at that point we would be in a position to break down reoccurring costs related to the cyber security solutions we have put in place or are planning to put in place.

d) Has Lakeland Power completed its Cyber Security self certification requirement?

Yes, LPDL has completed the OEB mandated Cyber Security Interim Self-Certification.

e) Is the cybersecurity infrastructure on-site or cloud based?

The cyber security framework all Ontario LDC's are now mandated to be in compliance with will be a framework that touches all corners of an LDC. As such it will not be a singular framework which will be either an on-site or cloud based item, but rather a mixture of both. From human resources and training, to documentation, processes, procedures, hardware, and software, it will be the development of a cyber security and privacy culture within an LDC.

4-Staff-56
Regulatory Costs
Ref: Exhibit 4 – Operating Expenses, p. 95
Lakeland Power has stated that it included $150,000 in staff resources in 2019, which is intended for a regulatory accountant assigned specifically for regulatory related work.

a) What is the expected starting salary of the regulatory accountant?

LPDL has a placeholder of $100 K for the position as to date it has proven impossible to fill this position at the wage previously approved. LPDL will also have resource costs from other staff members in the order of $25-$50 K. LPDL believes, based on the last round of applicants/interviews that took place late in 2018 that this will not be sufficient to recruit the needed position and other potential enhancements may be required.

b) Is Lakeland Power forecasting overtime work in 2019 for this position if it was filled?

The point of hiring this position (finally filling this position) is to eliminate the current overtime being incurred by Lakeland Holding staff that is not within OM&A costs as staff are not being compensated. Currently, we have 3 staff members working an average of 30% more on a regular work week in accounting. The value or cost avoidance at this point is $139,500 in addition to the stress and burn out being incurred.

c) What is the current status of this position? (i.e. advertised, interview process, or hired)

After the interview process in December 2018, LPDL will need to look at a different way to accomplish the regulatory functions and keep up with pronouncements. To that end we are looking at a full restructuring in the accounting/billing/regulatory area with the potential hire of two less senior positions at an annual cost with benefits of $70 K each. In the interim, staff working extraneous overtime will be compensated until the restructuring is complete.

4-Staff-57
Executive, Financial, Legal, Professional and Insurance Services
Ref: Chapter 2 appendices – Tab App.2-JC_OMA Programs
Lakeland Power showed that there was approximately a 34% difference between the actual cost to proxy OEB approved value for the Executive, Financial, Legal, Professional and Insurance Services program in 2013.

a) Please explain the difference between the actual cost to proxy OEB approved value.

This was the line item that the decrease change from the settlement process (EB-2012-0145) was put into. Some of the major cost changes were; insurance costs increased with the reassessment of the operations building in Bracebridge ,start of costs related to the amalgamation, and audit costs incurred to convert to IFRS.

b) This program has also increased by approximately 25% year-over-year for 2018 and 2019. Please explain the reason for this increase.

The difference is $83 K which is the Regulatory analyst position being in place for the full year.

4-Staff-58
Employee Costs
Ref: Chapter 2 appendices – Tab App.2-K_Employee Costs
Ref: Exhibit 4 – Operating Expenses, p. 70
On a per unit basis, the unit cost increases in 2015 and 2016 for management salary and wages were significant (11% and 33% respectively). The increase for management salary for 2019 compared to 2013 actuals is also a 36% increase or 6% per year on average.

a) Please explain the reasons for the increases in 2015 and 2016.

The increase in wages for 2015 was reflective of the change made in the last half of 2014 now effective for the full year. These increases were a result of the increased scope and responsibility with the amalgamation in mid 2014 as well as a preliminary severance settlement that was paid out in December 2015 ($30K). The reason for the increase in 2016 management salary and wages was due to the final severance settlement that was paid out in early 2016 ($60K) as well as a settlement in lieu of post retiree life insurance benefit that was paid out in January 2016 ($13K).

b) How does Lakeland Power conduct and assess fair negotiations for management salary?

LPDL conducts fair negotiations for management salary by considering the total compensation program and maintaining competitive salary levels within relevant markets, comparing to like utilities (Mearie salary stats) and levels of responsibility. The management salary is based on individual performance, corporate performance, the individual's compa-ratio and the job market. Management performance is measured against pre-determined KPI's and mutually agreed upon goals and objectives that are formally reviewed each year.

c) Lakeland Power stated on p.70 of the evidence that wage increases were given to management that took on the additional scope after the elimination of the Vice

President. Please provide approximately what percentage of the Vice President's salary was redistributed to remaining management for additional work and what percentage was reduced as savings from synergies.

The wage increases that were given to management in 2014 and 2015 to compensate for the additional duties and level of responsibility were due to increased staff levels, customer base and distribution service area as a result of the amalgamation, there were no duties reallocated from the Vice President. The Vice President was transferred to Lakeland Holding and the Vice President duties would have been partially allocated to LPDL through shared services costs.

4-Staff-59
OM&A per Customer
Ref: Chapter 2 appendices – Tab App.2-L OM&A per Cust FTE
For 2018 and 2019 the increase in OM&A has outpaced the increase in customers by approximately 7% in 2018 and 3% in 2019.

a) Please provide the OM&A programs that are not directly affected by the number of customers served.

The change from 2017 to 2018 is approximately $230 K which is:
Executive, Financial, Legal, Professional and Insurance Services - $150 K for Regulatory position
IT, Software,Telecom, Cybersecurity - $50 K
Vegetation Management - $50 K

b) For these programs, does Lakeland Power have a plan to find synergies to reduce the level of OM&A spend? If so, please provide the plan.

LPDL is very proud of its status as a Group 2 utility that excels at finding and implementing operational synergies as a routine part of the way business is done. LPDL does not believe in making arbitrary cuts, is in the public interest. LPDL is implementing these changes in order to catch up in areas where prior cuts or the inability to recruit staff have fallen behind or they are regulatory prescribed changes as well as being best practises.

4-Staff-60
Regulatory Costs

Ref: Chapter 2 appendices – Tab App.2-M Regulatory Costs
Lakeland Power forecasted $58k for incremental operating expenses associated with other resources allocated to this application. Lakeland Power also forecasted $75k for intervenor costs.

a) Please provide details on the resources used for the $58k.

Public Notice	$1,500.00
Oral hearing	$30,000.00
Community Meeting	$24,000.00
Presentation to the OEB panel	$2,500.00

b) Please provide the number of assumed intervenors in estimating $75k.

The assumed number of intervenors is 3 including Board Staff, SEC & VECC at $25,000 each.

4-Staff-61
Shared Services
Ref: Chapter 2 appendices – Tab App.2-N Corp Cost Allocation
Ref: Appendix C – LEL Shared Services Agreement
Lakeland Power receives three services from Lakeland Energy: GIS, ISP/Telephone, and IT Support. The cost for IT support in 2019 has increased by 90% since 2013 or 44% since 2014. The shared services agreement appears to be a lump sum agreement that encompasses a range of services offered.

a) Please provide the calculation or estimation method for the monthly compensation in the LEL Shared Services Agreement on p.9.

When LPDL merged with former PSP, it brought in all the outside services that former PSP contracted out. The offsetting savings are in Billing/Operations/Exec/Fin as indicated in the synergy savings (response to 1-Staff-8).

	PER MONTH	PER YEAR	
SERVER COSTS	$11,859.26	$142,311.18	see below
NETWORK DEVICE COSTS	$1,555.56	$18,666.67	see below
IT LABOUR COSTS	$8,936.43	$107,237.16	1100 hours annually
PHONE SYSTEM COSTS	$646.83	$7,762.00	20 phone lines/8 DID/26 units
SOFTWARE COSTS	$357.91	$4,294.95	see below
TOTALS	**$23,356.00**	**$280,271.96**	

Server Costs - Host Name	# of CPU	RAM (GB)	DISKSPACE (GB)	YEAR VIRTUAL	YEAR PHYSICAL
IT-Server	3	4	705	$ 2,490.00	
lakeebt	2	4	505	$ 7,380.00	
lakelandweb3	2	4	50	$ 1,920.00	
LAKEMAIL	8	4	605	$ 9,660.00	
LLH-GreatPlains2015	8	8	360	$ 1,920.00	
LLHWorktech	2	3	1000	$ 13,080.00	
LLN-WEBSRV02	4	8	95	$ 3,780.00	
LLPAS2-02	4	6	150	$ 3,960.00	
LLPFilesNexus	1	2	85	$ 1,680.00	
LLP-Harris-03	8	32	545	$ 18,792.00	
LLP-MAS-BACKUP	1	4	365	$ 5,520.00	
LLP-PDC01	6	16	1060	$ 4,410.00	
LLP-SCADAOMS01	2	8	90	$ 4,032.00	
LLP-SCADAOMS02	4	8	140	$ 5,184.00	
LLP-SCADASYS01	3	8	310	$ 7,416.00	
LLP-SCADASYS02	3	8	310	$ 7,416.00	
LLP-SmartMetre-Control-PC	1	2	30	$ 1,020.00	
LLP-VBDC02	4	16	1620	$ 6,000.00	
LLP-Web-04	4	4	100	$ 2,880.00	
LLP-WORKTECH	4	25	755	$ 15,780.00	
remoteoffice	4	8	110	$ 3,960.00	
workmgr	4	4	475	$ 7,380.00	
LLN-APPASSURE	12	64	50000	$ -	$ 1,708.14
VMWARE-HOST-03	12	196	0	$ -	$ 758.42
VMWARE-HOST-04	12	196	0	$ -	$ 758.42
VMWARE-HOST-05	12	196	0	$ -	$ 758.42
VMWARE-HOST-06	12	64	0	$ -	$ 758.42
PS4100 ARRAY					$ 1,909.37
Total	**$ 142,311.18**			$ 135,660.00	$ 6,651.18

Network Device Costs	VENDOR	MODEL		VALUE	36 mth life - Annual cost
Wireless Access Point	Ubiquiti	AP-Pro		$ 250.00	$ 83.33
Wireless Access Point	Ubiquiti	AP-AC		$ 250.00	$ 83.33
Wireless Access Point	Ubiquiti	AP-LR		$ 250.00	$ 83.33
Wireless Access Point	Ubiquiti	AP-Pro		$ 250.00	$ 83.33
Wireless Access Point	Ubiquiti	AP-AC		$ 250.00	$ 83.33
Wireless Access Point	Ubiquiti	AC-Pro		$ 250.00	$ 83.33
Wireless Access Point	Ubiquiti	AC-Pro		$ 250.00	$ 83.33
Wireless Access Point Controller	Ubiquiti	UniFI Cloud Key		$ 150.00	$ 50.00
Desktop Network Switch	Cisco	SG 200-26P		$ 600.00	$ 200.00
Desktop Network Switch	Ubiquiti	EdgeSwitch 48 Lite		$ 600.00	$ 200.00
Server Network Switch	Dell	PowerConnect 2724		$ 1,000.00	$ 333.33
Server iSCSI SAN Switch	Dell	PowerConnect 5424		$ 2,000.00	$ 666.67
Server iSCSI SAN Switch	Dell	PowerConnect 5424		$ 2,000.00	$ 666.67
Server Network Switch	Hewlett-Packa	2520G 24 Port PoE		$ 2,500.00	$ 833.33
Phone PoE Switch	Hewlett-Packa	2520G 24 Port PoE		$ 2,500.00	$ 833.33
Phone PoE Switch	Hewlett-Packa	2520G 24 Port PoE		$ 2,500.00	$ 833.33
Server Network Switch	Hewlett-Packa	A5120		$ 3,500.00	$ 1,166.67
VMware Server Switch	Hewlett-Packa	A5120		$ 3,500.00	$ 1,166.67
VMware Server Switch	Hewlett-Packa	A5120		$ 3,500.00	$ 1,166.67
DR Network Switch	Ubiquiti	EdgeSwitch 24 Lite		$ 400.00	$ 133.33
Lakeland Power Internet Router	Cisco	1841 Router		$ 2,000.00	$ 666.67
Lakeland Firewall	Cisco	ASA 5510		$ 16,000.00	$ 5,333.33
Server Network Switch	Cisco	Catalyst 2950		$ 3,000.00	$ 1,000.00
Desktop and Phone Network Switc	Hewlett-Packa	2520G 24 Port PoE		$ 2,500.00	$ 833.33
Desktop Network Switch	Dell	PowerConnect 2724		$ 1,000.00	$ 333.33
Desktop Network Switch	Cisco	Catalyst 2950		$ 2,500.00	$ 833.33
Desktop Network Switch	Cisco	Catalyst 2950		$ 2,500.00	$ 833.33
				$ 56,000.00	**$ 18,666.67**

b) How does Lakeland Power and Lakeland Energy establish the market rate for the services offered?

Lakeland Energy is a business in its own right that provides ISP, IT support, Telephony and GIS services to other businesses in and around Muskoka/Parry Sound/Orillia/Barrie. Lakeland Energy uses the same rate for LPDL as they do for other businesses in the Muskoka area, making it a market rate.

c) Did Lakeland Power ever put the list of services offered on p.3 of the LEL Shared Services Agreement out for tender?

LPDL has not put the list of services out for tender as there is no other company in the area that offers all the services as a bundled package. Each service would have to be sourced separately, driving costs higher. IT Support for example would be sourced from 1-3 hours away, making response time too long. The ISP (internet,data,phone) is the least expensive in the Muskoka area when comparing to Bell or Cogeco.

4-Staff-62
Corporate Cost Allocation
Ref: Chapter 2 appendices – Tab App.2-N Corp Cost Allocation
The unallocated corporate cost for Executive & Management services is $801k for 2013, $973k for 2014, and $1,206k for 2019. This represents a 34% increase since 2013.

a) Please explain the increase for Executive & Management services from 2013 to 2019.

The increase in the **Unallocated** corporate cost is due to growth in staff to support the affiliate companies not in the LDC portion. The **Allocated** Executive and Management services are based on the actual time spent working on LDC only items by the individual 12 staff. The term, "allocated", is likely a misnomer in this case as actual directly-related cost is the amount that is charged to the LDC.
If a comparison by year is made of the allocated costs, the change for 2013 versus 2019 is 27% or $123,192. 2013 is only for LPDL and does not include former PSP as they were a standalone entity so the costs associated were in the general accounts of Executive/Fin/Legal and Billing, a value of approximately $150 K. In 2017 a Human Resources officer was hired to manage union contracts, health & safety, human resources, recruitment and benefits administration. These tasks were formerly completed by CEO/COO/CFO/Supervisors, consultants or not at all. This is estimated to be a savings of $35 K. The resulting balance would be wage increases over the 6 years.

	2013	2014	2015	2016	2017	2018	2019
	$	$	$	$	$	$	$
Executive & Mgmt services	$ 456,526	$ 496,333	$ 553,824	$ 430,098	$ 559,773	$ 616,231	$ 579,718
% change	0%	9%	12%	-22%	30%	10%	-6%
% change over 2013		9%	21%	-6%	23%	35%	27%

What efforts has Lakeland Power done to minimize the Executive & Management costs paid to Lakeland Holding?

LPDL is in the midst of restructuring the finance/regulatory area in order to substitute executive work hours with staff at a lower wage relieving executive staff from tasks such as rate applications and RRR filings.

4-Staff-63
LRAMVA
Ref: Exhibit 4 – Operating Expenses, 4.11.2 – LRAMVA and associated LRAMVA Work Forms
Lakeland has requested approval of its LRAMVA in the total amount of $116,723. The LRAMVA is made up of lost revenues from CDM savings between 2011 to 2016, offset by any CDM already recovered in rates due to the inclusion in the load forecast.

The LRAMVA is made up of two components:

- Lakeland's LRAMVA amount of $92,014 related to CDM programs between 2013 to 2016
- Parry Sound's LRAMVA amount of $24,709 related to CDM programs between 2011 to 2016

a) Please indicate if the requested LRAMVA amount will be recovered on a combined basis from all customers, or if separate LRAMVA amounts will be collected from each rate zone.
LPDL wishes to withdraw its request for recovery of LRAMVA at this time pending the adjustments to be made based on the 2017 Final Verified CDM Results report.

b) Please provide the Final IESO Verified CDM Results Reports related to 2015 and 2016 programs.

Please find the Final IESO Verified CDM Results Reports related to 2015 and 2016 programs in Appendix I and J. The final 2017 Verified Annual LDC CDM program results can be found in Appendix K.

c) Please confirm that no LRAMVA amount is being requested for CDM savings in 2017.

LPDL confirms that no LRAMVA pertaining to 2017 is being requested..

d) As part of the 2017 Final Verified CDM Results Report are adjustments to 2016 CDM savings. Please indicate if Lakeland would like to maintain its request for lost revenues in 2016. The OEB's policy indicates that LDCs cannot seek recovery of LRAMVA amounts related to savings adjustments for a year in which the corresponding LRAMVA amount has been approved by the OEB on a final basis.[2] As Lakeland has not included 2016 adjustments in this application, if it proceeds with requesting approval of its 2016 LRAMVA amount, it will be unable to claim 2016 adjustments in 2016 as part of a future application.

LPDL wishes to withdraw its request for recovery of LRAMVA at this time pending the adjustments to be made based on the 2017 Final Verified CDM Results report.

e) Please reconcile the following savings values included in the LPDL_LRAMVA Workform. The requested savings values were compared to the savings values shown in the IESO Verified CDM Results Reports found on the IESO website.[3]

The IESO verified CDM Results report is a combination of Lakeland & Parry Sounds CDM Savings. Until our rates are harmonized we need to submit a separate LRAMVA for both components so the CDM savings have been split between Lakeland & Parry Sound based on the town in the project listing or another reasonable allocation basis if the town is not available (Ex: Coupon programs – split based on our number of customer). Please see below for the reconciliation of the CDM Savings for 2015 & 2016.

2015 CDM Savings (LRAMVA WF Tab 5 (2015-2020 LRAM), IESO Verified Results LDC Progress Tab)

i. Appliance Retirement

   i. LRAMVA WF: 14,467 kWh (D44)
   ii. IESO Report: 18,029 kWh (BK10)

LP - 14,467
PS - 3,562

ii. HVAC Incentives

   i. LRAMVA WF: 32,577 kWh (D47)
   ii. IESO Report: 37,387 kWh (BK11)

LP – 32,577

[2] Chapter 2 Filing Requirements, Lost Revenue Adjustment Mechanism, 2.4.6.1
[3] Lakeland Power Distribution Ltd.'s 2015 CDM Results, 2016 CDM Results

PS – 4,810

iii. Equipment Replacement Incentive

i. LRAMVA WF: 2,642,644 kWh (D57)
ii. IESO Report: 3,780,980 kWh (BK17)

LP – 2,642,644
PS – 1,138,336

iv. Equipment Replacement Incentive – Adjustments (From 2016 IESO Verified Report)

i. LRAMVA WF: 277,555 kWh (D58)

IESO Report: 285,759 kWh (CB98)
LP – 277,555
PS – 8,204

v. Direct Install Lighting and Water Heating

i. LRAMVA WF: 144,108 kWh (D60)

IESO Report: 176,499 kWh (BK18)
LP – 144,108
PS – 32,391

vi. Low Income

i. LRAMVA WF:84,934 (D80)

IESO Report: 98,540 kWh (BK30)
LP – 84,934
PS – 13,606

2016 CDM Savings

vii. Energy Coupon

i. LRAMVA WF: 720,084 kWh (D288)

IESO Report: 973,086 kWh (CD8)
LP – 720,084
PS – 253,002

viii. Energy Audit

i. LRAMVA WF: 13,143 kWh (D301)

IESO Report: 26,285 kWh (CD15)
LP – 13,143
PS – 13,143

ix. Energy Retrofit

i. LRAMVA WF: 1,104,460 kWh (D304)
IESO Report: 1,231,374 kWh (CD16)
LP – 1,104,460
PS – 126,914

x. Small Business lighting

i. LRAMVA WF: 115,748 kWh (D307)
IESO Report: 125,554 kWh (CD17)
LP – 115,784
PS – 9,770

f) Please update the Parry Sound LRAMVA workform. The LRAMVA threshold should reflect the OEB Decision in EB-2010-0140. The OEB indicated Parry Sound should use 10% of its 2011-2014 Cumulative Net Energy Savings target (or 416,000 kWh) as its CDM adjustment to its load forecast, as opposed to the originally proposed 1,000,000 kWh which has been used in the LRAMVA WF.

LPDL wishes to withdraw its request for recovery of LRAMVA at this time pending the adjustments to be made based on the 2017 Final Verified CDM Results report. During the next rate application and request to recover LRAMVA, LPDL will use 416,000 kWh for former Parry Sound.

g) In the LRAMVA WF, new savings from programs implemented in 2015 and 2016 are included. However, no supporting documentation has been provided. Please provide all IESO Verified CDM Results Reports that fully document Parry Sound Power's new, incremental CDM activity in 2015 and 2016.

With the changes from the 2017 Final Verified CDM Results Report that are affecting prior years, particularly for former PSP, LPDL is requesting to withdraw its request for recovery for LRAM.

4-Staff-64
OM&A
Ref: Exhibit 4, Section 4.4.8 Benefit Program Costs

All Lakeland Power's employees are part of the OMERS pension plan. Lakeland Power is seeking to recover $191,016 in pension costs for the test period.

a) Please confirm that the amount of pension costs being sought for the test period represents the estimated employer contributions to the OMERS plan for 2019.

LPDL confirms that the amount of pension costs being sought for the test period represents the estimated employer contributions to the OMERS plan for 2019.

b) Using the OMERS pension contribution formula for 2019, please provide the calculation that underpins the test period contribution amount. Wherever possible, please reference the input to that formula (i.e. salaries and wages, headcount etc.) to the relevant sections of the application where the where the test period amount can be found.

The OMERS pension contribution formula for 2019 is:

9% of salary up to YMPE $57,400

14.6% of Salary > YMPE $57,400

The 2019 OMERS contribution being sought, of $191,016 was estimated using 2019 salaries and wages identified in Appendix 2-K, at the average OMERS benefit % incurred in the prior year (OMERS contribution rates were the same). A reasonability calculation is provided below that applies the 2019 OMERS contribution rates, Annual YMPE and 2019 management and non-management salaries and FTE per Appendix 2-K. The calculation below shows that the 2019 estimate of $191,016 is reasonable compared to test calculation result of $199,695.

OMERS Pension Contribution Formula TEST for 2019

	2019 Salaries	2019 # of FTE	Average Salary/FTE	Annual YMPE for the FTE's	Remaining Salary Over YMPE	OMERS Contributions 9%	14.6%	TOTAL
				YMPE $57,400				
Management Salaries	$ 358,394	3.0	$ 119,465	$ 172,200	$ 186,194	$ 15,498	$ 27,184	$ 42,682
Non-Management Salaries	$ 1,502,549	19.4	$ 77,451	$ 1,113,560	$ 388,989	$ 100,220	$ 56,792	$ 157,013
Total Salaries per App 2-K	$ 1,860,943			$ 1,285,760	$ 575,183	$ 115,718	$ 83,977	$ 199,695
			OMERS Rate	9%	14.6%			
			OMERS Contribution	$ 115,718	$ 83,977			$ 199,695
				vs OMERS Employer Contribution 2019 Forecast				$ 191,016

4-Staff-65
OM&A
Ref: Exhibit 4, Section 4.4.9 Other Post Employment Benefits

At the above reference, Lakeland Power discusses its Other Post Employment Benefit costs. Lakeland Power has indicated that the cost of these post-retiree health and dental benefits is expensed once the employee retires and is eligible for the benefit.

The benefits discussed in this section are health and dental only for the period from retirement to age 65. There is no life insurance component for retirees, it was eliminated. Upon ratifying the first collective agreement of the merged entity, some of the benefits that former PSP employees had were now available to LPDL employees, thus the initial true up of $104,488. Subsequent to that, small amounts have been booked from the actuarial valuation. LPDL has chosen to eliminate the amount from any recovery and will adjust the RRWF for $8,750, the amount in OM&A for 2019 Test Year.

a) Does Lakeland offer OPEBs to all of its employees and are they just limited to post retirement health and dental benefits?

The benefit is limited to health and dental only for the period from retirement to age 65.

b) Did Lakeland Power always offer OPEBs to its employees or were they only implemented recently?

They were implemented upon the ratification of the first collective agreement after the amalgamation in 2014.

c) How and when does an employee become eligible to participate in the OPEB plan?

It is a continuation of their current health and dental plan, until age 65.

d) Isn't an amount expensed annually over the service life of an employee with respect to OPEBs (accrual accounting) representing what the employee earned in that in that particular year? If so, why is the Applicant stating that these benefits are only expensed once the employee retires.

LPDL was not clear in its discussion. LPDL has only had these benefits for a few years and had expensed the initial setup in 2016 based on the actuarial valuation. After that, each year the expense is per the valuation which takes into account the actual benefits paid as well as any changes to the current employee complement/age/demographic.

e) In section 4.4.9 Lakeland states that the initial set up for the value of the benefit was derived from a valuation report done in 2016 and totaled $104,488. Please clarify exactly what this amount is and what relates to. What needed to be set up (is it referring to the life insurance benefit that only the PS employees had but was given to all employees upon merger, please clarify).

This was the value of the health and dental benefits that the current complement of employees and retirees would potential get based on prior years earned service life as the benefit was not offered to LPDL employees previously.

f) It is not clear if the Applicant is actually seeking to recover this $104K anywhere in this application. Please confirm if the Applicant is seeking to recover this amount in the test period revenue requirement.

LPDL is not seeking to recover any costs related to post retiree health and dental benefits as the cost is immaterial.

g) It is also not clear what other amounts are being sought in this application with respect to OEPBs. Is the Applicant seeking to recover any amounts in the test period revenue requirement with respect to the annual service cost for the OPEB plan as dictated by an actuarial valuation? Please clarify what the Applicant is seeking to include in the test period revenue requirement.

LPDL is not seeking to recover any costs in the test period.

h) Based on the response provided above, please also clarify how what the Applicant is seeking to recover in the revenue requirement with respect to its OPEB costs is consistent with the recent OEB Report on the Regulatory Treatment of Pension and Other Post-Employment Benefit Costs (EB-2015-0040).

LPDL is not seeking to recover any costs in the test period revenue requirement.

4-Staff-66
OM&A
Ref: Exhibit 4, Section 4.10 PILs, PILs Workbook, Chapter 2 Appendices Workbook Tab 2-BA_FA Cont. 2019

For purposes of calculating taxable income for the test year in the tab “T1 Taxable Income Test Year”, Lakeland Power has added back an amount of $1,652,955 associated with the amortization of tangible capital assets.

a) Per the test year capital asset continuity schedule filed in Tab 2-BA of the Chapter 2 Appendices Workbook, Lakeland Power shows test year depreciation expense of $1,337,805 compared to the $1,652,955 being added back in the taxable income calculation. Please explain why there would be a discrepancy. If this is an error, please update the PILs calculation to reflect the appropriate number.

The difference is the amortization related to transportation ($116,972) which is included in other accounts based on where the trucks were used and the amount for amortization of Contributed Capital which is included in revenue ($198,178).

Tab 2-BA – Net depreciation	$1,337,805
Transportation that was allocated	116,972
1995-Contributions (in revenue)	198,178
Total	$1,652,955

4.0 OPERATING COSTS (EXHIBIT 4)

4.0 -VECC -21
Reference: Exhibit 4, Section 4.1.4, pg. 13

a) Please explain the reasons for the increase in Community Relations from approximately 34k in 2013 to 80k in 2019.

The increase in Community Relations is due to survey costs that were not in 2013 (ESA safety as well as Customer Satisfaction) as well as numerous customer engagement activities such as large user group meetings, regional planning meetings, customer interface meetings, Facebook Live sessions and other forms of community engagement.

4.0 -VECC -22
Reference: Exhibit 4, pg. 45, Appendix 2-JC OM&A Progams Table

a) Please update Appendix 2-JC to show 2018 actuals (unaudited).

LPDL has updated Chapter 2 appendices to reflect 2018 actuals for OM&A in Appendix 2-JC. Chapter 2 Appendices have been filed as an excel document in RESS.

Programs	2013 Board Approved Proxy	2013	2014	2015	2016	2017	2018	2019
Customer Focus								
Community and Civic Co-ordination	$34,647	$42,577	$44,176	$28,900	$67,785	$61,722	$51,737	$80,000
Customer Service, Mailing Costs, Billing and Collections	$963,595	$1,047,398	$1,145,552	$1,071,996	$912,597	$835,878	$861,806	$861,780
Bad Debts	$40,287	$156,460	$138,752	$64,860	$63,012	$44,236	$30,086	$45,000
Meter reading	$135,921	$98,706	$77,320	$72,414	$59,173	$57,906	$59,210	$69,380
Sub-Total	$1,174,450	$1,345,141	$1,405,800	$1,238,170	$1,102,567	$999,742	$1,002,839	$1,056,160
Operational Effectiveness								
Distribution Station -operating and maintenance costs	$77,966	$95,358	$73,699	$44,763	$51,932	$91,412	$55,272	$80,830
Meters operation & maintenance	$77,084	$103,256	$118,136	$91,009	$94,674	$104,758	$117,370	$109,613
Overhead lines, conductors, devices & services - O&M	$329,544	$394,204	$369,588	$326,133	$316,565	$359,800	$423,685	$360,921
Underground lines, conductors, devices & services - O&M	$128,202	$152,179	$177,519	$164,352	$136,551	$159,686	$193,559	$175,716
Distribution transformers - O&M	$66,518	$65,167	$64,952	$53,700	$147,675	$77,192	$72,005	$85,070
Vegetation management - tree trimming	$224,470	$165,196	$174,710	$194,720	$135,701	$146,715	$193,642	$200,569
Storm & Trouble calls	$175,000	$176,062	$210,266	$233,490	$198,644	$213,120	$215,000	$220,000
Operations & engineering ,supervision	$249,256	$199,641	$260,566	$311,015	$307,669	$316,970	$372,278	$357,550
GIS - SCADA	$155,500	$157,302	$196,476	$201,720	$197,786	$155,984	$188,416	$180,539
Joint Use - Pole rental	$35,557	$23,993	$42,970	$34,984	$45,312	$45,782	$47,694	$68,000
Training	$130,000	$137,082	$156,683	$146,252	$166,852	$101,165	$120,000	$141,000
Executive, Financial , Legal, Professional and Insurance Services	$453,817	$609,068	$365,487	$275,354	$259,903	$274,915	$259,853	$353,595
Corporate allocation	$675,221	$685,882	$642,929	$754,946	$759,124	$713,100	$792,094	$755,097
Employee pensions and benefits - not OPEB	$1,352	$1,626	-$29,664	$127,078	$21,781	$36,372	$0	$0
Office building & security costs	$173,315	$191,931	$211,141	$223,077	$139,359	$176,204	$180,107	$147,965
IT, software, telecommunications , cybersecurity, office supplies	$399,129	$431,231	$474,783	$469,628	$432,507	$424,447	$484,400	$487,053
Collection charges recovered from customers	-$18,000	-$25,410	-$10,980	-$8,865	-$3,435	-$53,220	-$47,129	$0
Sub-Total	$3,333,932	$3,563,768	$3,499,261	$3,643,356	$3,408,601	$3,344,402	$3,668,247	$3,723,518
Public and Regulatory Responsiveness								
Regulatory & Compliance	$214,021	$244,667	$204,333	$178,606	$196,813	$216,622	$274,782	$255,289
Electrical Safety Authority	$13,500	$13,523	$13,679	$15,915	$19,993	$17,628	$15,455	$18,000
LEAP Funding	$9,104	$6,127	$9,293	$12,097	$9,175	$9,175	$9,175	$10,000
Sub-Total	$236,625	$264,317	$227,304	$206,617	$225,981	$243,426	$299,412	$283,289
TOTAL OM&A	**4,745,006**	**5,173,226**	**5,132,366**	**5,088,143**	**4,737,149**	**4,587,569**	**4,970,498**	**5,062,968**

b) Please identify separately any amounts in the 2017 and 2018 OM&A related to the cost of this Application.

Regulatory Cost Category	2017	2018	2019
Legal costs for regulatory matters			$ 20,000
Consultants' costs for regulatory matters	$ 25,509	$ 48,053	$ 56,439
Operating expenses associated with other resources allocated to regulatory matters [1]	$ 519	$ 1,771	$ 35,710
Intervenor costs			$ 75,000
Total	$ 26,027	$ 49,824	$ 187,149
Cummulative Total			$ 263,000

4.0 -VECC -23

Reference: Exhibit 4, Table 5, pg. 19

a) Please explain what the Smart Grid/EV research/MaRS costs are related to in 2013. Are any of these types of costs ongoing in 2019?

There are $0 in 2013 for Innovation. Innovation will be ongoing in this industry moving towards Smart Grid, more electric vehicles and other methods of distribution to assist with reducing energy consumption while providing consumers with the electricity they want to have Smart Homes/EVs, etc without damaging the current distribution system.

4.0 -VECC -24
Reference: Exhibit 4, pg. 136

a) For each of the years 2013 through 2019 please provide the percentage of residential customers on ebilling or prepayment plans.

	2012	2013	2014	2015	2016	2017	2018
eBilling	5%	5.55%	5.61%	10.2%	17.04%	21.43%	26.1%
PAP	40.08%	40.44%	41.55%	41.18%	42.48%	43.9%	44.37%

b) Does Lakeland have any specific objective over the term of the rate plan to decrease the number of customers paying by mail or in-person?

This has been a struggle for LPDL as customers do not trust LDCs based on news reports of LDCs taking $000's out of their accounts. A significant number of customers want to come to the window, talk to a CSR and hand over a cheque or cash. Customers have continually expressed that they like the local presence and compare us to 'bigger' players that are very impersonal. LPDL is planning on running an incentive to have more customers convert to electronic billing once the new portal is up and running, provided the project in the rate application is approved.

4.0 -VECC -25
Reference: Exhibit 4, Appendix 2-K pg. 63

a) Please amend Appendix 2-K to show year end actual FTEs.

Please see response to 4-SEC-28 (a)

b) Please provide the hiring status of the two positions (Substation/Engineering Technologist and Junior Linesman) which Lakeland is recruiting in 2018.

The Substation/Engineering Technologist position still currently remains vacant due to the lack of acceptable applicants. In November 2018 LPDL instead hired a full-time Labourer to assist the Material & Facilities Coordinator and lines staff. The Junior Linesman is still forecasted to be hired this coming May 2019 and recruitment will begin this spring.

c) Please also add a row to show the total amount of compensation capitalized in each year.

Please see response to 4-SEC-28 (b)

4.0 -VECC -26
Reference: Exhibit 4, pg. 74

a) Please explain why in 2019 the budget for non-union wages (3%) exceeds the unionized increase of 1.25%.

The unionized increase is 1.25% at January 1 and 1.25% at July 1 of each year of the contract (2.5% split into two changes). The 3% increase budgeted for non-union wages in 2019 allows for recognition of performance against pre-determined goals, for individual compa-ratios and is line with non-union wage increases over the past several years. The union contract is up for renewal and expect that there will be increased pressure to change the rate increase.

4.0 -VECC -27
Reference: Exhibit 4, Appendix 2-N Shared services

a) Why has the rent for Lakeland Energy ($31,500) and Bracebridge Generation ($16,500) not increased since 2013 and notwithstanding that the building rent allocated from Lakeland Holding to Lakeland Power has increased during the same period?

The contract was for 5 years (2013-2018). Bracebridge Generation has since moved out of the building in December 2018 (this will now be a loss of revenue for 2019 onwards of $16,500) and Lakeland Energy is looking for alternate space as LPDL needs more room (loss of revenue in Q3 of 2019). The building rent allocated from Lakeland Holding to LPDL is a function of the amount of staff hours spent in each company based on weekly timesheets. Allocation is variable, not fixed. LPDL will adjust the RRWF and Ex 3 revenue to reflect the reduction in Building rent revenue.

b) Please explain why the corporate allocations for executive and management services have increased to $554,843 in 2019 from $456,526 in 2013 and notwithstanding the allocation has dropped from 57% to 41% during the same period.

The former PSP had the functions of accounting/finance, treasury, purchasing, accounts payable, payroll and regulatory within the LDC as they were a standalone entity. These positions were eliminated within the LDC and job tasks were taken on by the Lakeland Holding staff (eliminating any duplication). 2013 executive and management services did not include the former PSP functions as they were charged within other accounts (G&A and Operations). If the comparison was made using the same posting accounts, there would be a decrease overall (the decrease is built into the synergy savings).

c) Please describe the executive and management services provided by Lakeland Holding.

Services provided are:

- CEO, COO, CFO based on timesheet hours
- Payroll and benefits management, accounting, accounts payable, insurance management, – based on timesheet hours
- Regulatory filing, purchasing, statistical tracking – based on timesheet hours

d) Are these executive and management costs represented as FTEs in Appendix 2-K? If so please identify the number of FTEs in 2019 represented by these services. Please identify separately FTEs represented by services provided to Lakeland from any other affiliates.

No they are not included in Appendix 2-K. Depending on the time spent working on tasks related to LPDL, there are currently 17 people in Lakeland Holding and the average time spent on LDC related work is approximately 50% (FTE of 8.5) not including overtime. With overtime (currently unpaid), it is closer to 55% or an FTE equivalent of 9.5.

4.0 -VECC -28
Reference: Exhibit 4, pg. 93

a) Please provide (separately) the annual dues/fess for Lakeland’s participation in CHEC and the EDA (if any) for each year 2013 through 2019.

Please find below a table of the annual dues for both CHEC and EDA

	2013	2014	2015	2016	2017	2018
CHEC (LP & PSP)	$ 44,055	$ 44,295	$ 41,118	$ 41,370	$ 41,717	$ 41,822
EDA (LP & PSP)	$ 23,524	$ 24,600	$ 32,200	$ 32,500	$ 32,800	$ 33,500
Total combined	**$ 67,579**	**$ 68,895**	**$ 73,318**	**$ 73,870**	**$ 74,517**	**$ 75,322**

4.0 -VECC -29
Reference: Exhibit 4, pg. 96

a) Please provide a breakdown of the $263,000 in Application Related One-Time Costs (Appendix 2-M) into the following categories: (1) legal costs; (2) consulting costs; (3) internal costs; (4) intervenor costs; (5) other – please specify.

Application Consulting - (TESI)	$40,000.00
Application DSP (Metsco)	$35,000.00
Application - Auditor	$10,000.00
Application - Legal Review	$5,000.00
Interogatories Consulting - (TESI)	$15,000.00
Interogatories DSP (Metsco)	$2,500.00
Interogatories - Auditor	$2,500.00
Interogatories - Legal Review	$5,000.00
Settlement Consulting - (TESI)	$5,000.00
Settlement - Legal Review	$10,000.00
Public Notice	$1,500.00
Oral hearing	$30,000.00
Community Meeting	$24,000.00
Presentation to the OEB panel	$2,500.00
Intervenor costs (25k/intervener)	$75,000.00
Total Cost of Service Filing costs	$263,000.00

There are no internal costs in the referenced $263,000. The internal costs associated with the rate application are part of the Corporate allocation based on timesheets, not including unpaid overtime.

b) Please provide the actual Application costs (broken down as above) incurred to date.

	Forecast	Actual to Date
Application Consulting	$40,000.00	$53,354.16
Application DSP	$35,000.00	$10,800.00
Application - Auditor	$10,000.00	
Application - Legal Review	$5,000.00	$9,407.00
Interogatories Consulting	$15,000.00	
Interogatories DSP	$2,500.00	
Interogatories - Auditor	$2,500.00	
Interogatories - Legal Review	$5,000.00	
Settlement Consulting	$5,000.00	
Settlement - Legal Review	$10,000.00	
Public Notice	$1,500.00	$1,771.00
Oral hearing	$30,000.00	
Community Meeting	$24,000.00	
Presentation to the OEB panel	$2,500.00	
Intervenor costs (25k/intervener)	$75,000.00	
Total Cost of Service Filing costs	$263,000.00	$75,332.16

4.0-VECC-30
Reference: Exhibit 4, pg. 116

a) Please provide a table showing the actual PILs paid for each year 2013 through 2018 (forecast).

	2013	2014	2015	2016	2017	2018 EST
PILs	$169,653	$372,722	$381,098	$442,485	$477,335	$495,000

4-SEC-25
[Ex.4] Please revise the following appendices to include 2018 year-end actuals:

a. 2-JA

	2013 Board Approved Proxy	2013	2014	2015	2016	2017	2018	2019
Operations	$275,081	$357,710	$359,120	$320,991	$340,160	$322,743	$353,649	$365,081
Maintenance	$1,244,017	$1,174,647	$1,329,762	$1,334,895	$1,292,351	$1,348,677	$1,525,272	$1,473,726
SubTotal	**$1,519,098**	**$1,532,357**	**$1,688,882**	**$1,655,887**	**$1,632,510**	**$1,671,420**	**$1,878,921**	**$1,838,807**
%Change (year over year)		0.9%	10.2%	-2.0%	-1.4%	2.4%	12.4%	-2.1%
%Change (Test Year vs Last Rebasing Year - Actual)								21.0%
Billing and Collecting	$1,121,803	$1,277,154	$1,350,644	$1,200,405	$1,031,347	$884,800	$903,973	$976,160
Community Relations	$34,647	$42,577	$44,176	$28,900	$67,785	$61,722	$51,737	$80,000
Administrative and General	$2,060,355	$2,315,029	$2,039,655	$2,192,105	$2,000,442	$1,962,178	$2,131,691	$2,158,000
LEAP Funding	$9,104	$6,127	$9,293	$12,097	$9,175	$9,175	$9,175	$10,000
SubTotal	**$3,225,909**	**$3,640,888**	**$3,443,768**	**$3,433,506**	**$3,108,749**	**$2,917,874**	**$3,096,576**	**$3,224,160**
%Change (year over year)		12.9%	-5.4%	-0.3%	-9.5%	-6.1%	6.1%	4.1%
%Change (Test Year vs Last Rebasing Year - Actual)								-0.1%
Total	**$4,745,006**	**$5,173,245**	**$5,132,650**	**$5,089,393**	**$4,741,259**	**$4,589,294**	**$4,975,498**	**$5,062,968**
%Change (year over year)		9.0%	-0.8%	-0.8%	-6.8%	-3.2%	8.4%	1.8%
%Change (Test Year vs Last Rebasing Year - Actual)								6.7%

	2013 Board Approved Proxy	2013	2014	2015	2016	2017	2018	2019
Operations	$275,081	$357,710	$359,120	$320,991	$340,160	$322,743	$353,649	$365,081
Maintenance	$1,244,017	$1,174,647	$1,329,762	$1,334,895	$1,292,351	$1,348,677	$1,525,272	$1,473,726
Billing and Collecting	$1,121,803	$1,277,154	$1,350,644	$1,200,405	$1,031,347	$884,800	$903,973	$976,160
Community Relations	$34,647	$42,577	$44,176	$28,900	$67,785	$61,722	$51,737	$80,000
Administrative and General	$2,060,355	$2,315,029	$2,039,655	$2,192,105	$2,000,442	$1,962,178	$2,131,691	$2,158,000
LEAP Funding	$9,104	$6,127	$9,293	$12,097	$9,175	$9,175	$9,175	$10,000
Total	**$4,745,006**	**$5,173,245**	**$5,132,650**	**$5,089,393**	**$4,741,259**	**$4,589,294**	**$4,975,498**	**$5,062,968**
%Change (year over year)		9.0%	-0.8%	-0.8%	-6.8%	-3.2%	8.4%	1.8%

	2013 Board-Approved Proxy	2013 Actuals	Variance 2013 Board-approved – 2013 Actuals	2014 Actuals	Variance 2014 Actuals vs. 2013 Actuals	2015 Actuals	Variance 2015 Actuals vs. 2014 Actuals	2016 Actuals	Variance 2016 Actuals vs. 2015 Actuals	2017 Actuals	Variance 2017 Actuals vs. 2016 Actuals	2018 Bridge Year	Variance 2018 Bridge vs. 2017 Actuals	2019 Test Year	Variance 2019 Test vs. 2018 Bridge
Operations	$ 275,081	$ 357,710	-$ 82,630	$ 359,120	$ 1,410	$ 320,991	-$ 38,129	$ 340,160	$ 19,168	$ 322,743	-$ 17,417	$ 353,649	$ 30,906	$ 365,081	$ 11,432
Maintenance	$ 1,244,017	$ 1,174,647	$ 69,370	$ 1,329,762	$ 155,115	$ 1,334,895	$ 5,134	$ 1,292,351	-$ 42,545	$ 1,348,677	$ 56,326	$ 1,525,272	$ 176,595	$ 1,473,726	-$ 51,546
Billing and Collecting	$ 1,121,803	$ 1,277,154	-$ 155,351	$ 1,350,644	$ 73,490	$ 1,200,405	-$ 150,239	$ 1,031,347	-$ 169,057	$ 884,800	-$ 146,547	$ 903,973	$ 19,173	$ 976,160	$ 72,187
Community Relations	$ 34,647	$ 42,577	-$ 7,931	$ 44,176	$ 1,599	$ 28,900	-$ 15,276	$ 67,785	$ 38,884	$ 61,722	-$ 6,063	$ 51,737	-$ 9,984	$ 80,000	$ 28,263
Administrative and General	$ 2,060,355	$ 2,315,029	-$ 254,674	$ 2,039,655	-$ 275,374	$ 2,192,105	$ 152,450	$ 2,000,442	-$ 191,663	$ 1,962,178	-$ 38,264	$ 2,131,691	$ 169,513	$ 2,158,000	$ 26,309
LEAP Funding	$ 9,104	$ 6,127	$ 2,977	$ 9,293	$ 3,166	$ 12,097	$ 2,804	$ 9,175	-$ 2,922	$ 9,175	$ -	$ 9,175	$ -	$ 10,000	$ 825
Total OM&A Expenses	$ 4,745,006	$ 5,173,245	-$ 428,239	$ 5,132,650	-$ 40,595	$ 5,089,393	-$ 43,257	$ 4,741,259	-$ 348,134	$ 4,589,294	-$ 151,965	$ 4,975,498	$ 386,204	$ 5,062,968	$ 87,470
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)															
Total Recoverable OM&A Expenses	$ 4,745,006	$ 5,173,245	-$ 428,239	$ 5,132,650	-$ 40,595	$ 5,089,393	-$ 43,257	$ 4,741,259	-$ 348,134	$ 4,589,294	-$ 151,965	$ 4,975,498	$ 386,204	$ 5,062,968	$ 87,470
Variance from previous year				-$ 40,595		-$ 43,257		-$ 348,134		-$ 151,965		$ 386,204		$ 87,470	
Percent change (year over year)				-1%		-1%		-7%		-3%		8%		2%	
Percent Change: Test year vs. Most Current Actual										10.32%					
Simple average of % variance for all years										-2.13%					-0.25%
Compound Annual Growth Rate for all years															-0.31%
Compound Growth Rate (2013 vs. 2017 Actuals)										-2.37%					

b. 2-JB

OM&A	Last Rebasing Year (2013 Actuals)	2015 Actuals	2016 Actuals	2017 Actuals	2018 Bridge Year	2019 Test Year
Reporting Basis	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Opening Balance²	$ 4,745,006	$ 5,132,649	$ 5,089,392	$ 4,741,257	$ 4,589,292	$ 4,970,496
Merger/Integration costs	$ 145,000	$ 10,436	-$ 105,008			
Amalgamation savings		-$ 129,952	-$ 9,460	-$ 128,218		
Headcount changes and vacant positions	-$ 87,890	-$ 97,817	-$ 90,915	-$ 214,370	$ 82,738	$ 178,789
Wage & merit increase		$ 36,420	$ 34,441	$ 34,245	$ 31,482	$ 34,223
Vacant positions Offset - outside services - Corp Allocati	$ 73,737	$ 70,516	-$ 129,373	$ 114,269	$ 9,932	-$ 47,905
Bad debt	$ 116,174	-$ 73,892	-$ 1,848	-$ 18,776	-$ 14,150	$ 14,914
OH/UG Maintenance and Trouble Calls - PSP in disrepai	$ 97,844	-$ 52,329	-$ 32,162	$ 65,352	$ 77,888	-$ 56,849
Information Systems Technology (Support/Licenses/IT se	$ 27,393	$ 54,736	-$ 5,143	$ 3,530	$ 67,682	
Increased utility bills for buildings	$ 15,281	$ 4,850	$ 8,196	-$ 7,188	-$ 8,000	
Tree trimming better contract pricing - larger area in 2015	-$ 59,274	$ 20,010	-$ 59,019	$ 11,014	$ 46,927	$ 6,927
SCADA system - maintenance contract/licenses					$ 16,245	
Joint Use Pole rental charge		-$ 7,986	$ 10,328		$ 1,912	$ 20,306
Regulatory charges - intervenor charges/rate applications	$ 60,646	-$ 50,957	$ 15,110	$ 19,809	$ 58,160	-$ 57,934
Transformer testing in Parry Sound & transformer disposal			$ 93,975	-$ 70,483		
Union negotiations	$ 20,809					
IFRS audit increase & dual audit - 5630	$ 18,500	$ 15,000	-$ 15,000			
Property insurance increase with full identification of assets			$ 40,180			
Innovation - Smart Grid/ EV research/MaRS				$ 20,000		
PS Office damage - clean up				$ 36,645	-$ 36,645	
Employee costs - ie. Severance		$ 157,708	-$ 102,437	-$ 17,794	-$ 6,187	
OPEB Valuation						
Collection of account charges removed - EB-2017-0183					$ 53,220	
	$ 19					
Closing Balance²	$ 5,173,245	$ 5,089,392	$ 4,741,257	$ 4,589,292	$ 4,970,496	$ 5,062,967

c. 2-JC

Programs	Last Rebasing Year (2013 Board-Approved)	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Actuals	2017 Actuals	2018 Bridge Year	2019 Test Year	Variance (Test Year vs. 2017 Actuals)	Variance (Test Year vs. Last Rebasing Year (2013 Board-
Reporting Basis										
Customer Focus										
Community and Civic Co-ordinatio	34,647	42,577	44,176	28,900	67,785	61,722	51,737	80,000	18,278	45,353
Customer Service, Mailing Costs, E	963,595	1,047,398	1,145,552	1,071,996	912,597	835,878	861,806	861,780	25,902	-101,815
Bad Debts	40,287	156,460	138,752	64,860	63,012	44,236	30,086	45,000	764	4,713
Meter reading	135,921	98,706	77,320	72,414	59,173	57,906	59,210	69,380	11,474	-66,541
									0	0
Sub-Total	1,174,450	1,345,141	1,405,800	1,238,170	1,102,567	999,742	1,002,839	1,056,160	56,418	-118,290
Operational Effectiveness										
Distribution Station -operating and	77,966	95,358	73,699	44,763	51,932	91,412	55,272	80,830	-10,582	2,864
Meters operation & maintenance	77,084	103,256	118,136	91,009	94,674	104,758	117,370	109,613	4,855	32,529
Overhead lines, conductors, devic	329,544	394,204	369,588	326,133	316,565	359,800	423,685	360,921	1,121	31,377
Underground lines, conductors, de	128,202	152,179	177,519	164,352	136,551	159,686	193,559	175,716	16,030	47,514
Distribution transformers - O&M	66,518	65,167	64,952	53,700	147,675	77,192	72,005	85,070	7,878	18,552
Vegetation management - tree trin	224,470	165,196	174,710	194,720	135,701	146,715	193,642	200,569	53,854	-23,901
Storm & Trouble calls	175,000	176,062	210,266	233,490	198,644	213,120	278,388	220,000	6,880	45,000
Operations & engineering ,supervi	249,256	199,641	260,566	311,015	307,669	316,970	372,278	357,550	40,580	108,294
GIS - SCADA	155,500	157,302	196,476	201,720	197,786	155,984	188,416	180,539	24,555	25,039
Joint Use - Pole rental	35,557	23,993	42,970	34,984	45,312	45,782	47,694	68,000	22,218	32,443
Training	130,000	137,082	156,683	146,252	166,852	101,165	56,613	141,000	39,835	11,000
Executive, Financial , Legal, Profe	453,817	609,068	365,487	275,354	259,903	274,915	259,853	424,613	149,698	-29,204
Corporate allocation	675,221	685,882	642,929	754,946	759,124	713,100	792,094	674,469	-38,631	-752
Post employment costs	1,352	1,626	-29,664	127,078	21,781	36,372	0	0	-36,372	-1,352
Office building & security costs	173,315	191,931	211,141	223,077	139,359	176,204	180,107	147,965	-28,239	-25,350
IT, software, telecommunications ,	399,129	431,231	474,783	469,628	432,507	424,447	484,400	487,053	62,606	87,924
Collection charges recovered from	-18,000	-25,410	-10,980	-8,865	-3,435	-53,220	-47,129	0	53,220	18,000
Sub-Total	3,333,931	3,563,768	3,499,261	3,643,356	3,408,600	3,344,402	3,668,247	3,713,908	369,506	379,977
Public and Regulatory Responsiveness										
Regulatory & Compliance	214,021	244,667	204,333	178,606	196,813	216,622	274,782	264,900	48,278	50,879
Electrical Safety Authority	13,500	13,523	13,679	15,915	19,993	17,628	15,455	18,000	372	4,500
LEAP Funding	9,104	6,127	9,293	12,097	9,175	9,175	9,175	10,000	825	896
									0	0
									0	0
Sub-Total	236,625	264,317	227,305	206,618	225,982	243,425	299,412	292,900	49,475	56,275
Total	**4,745,006**	**5,173,226**	**5,132,366**	**5,088,143**	**4,737,149**	**4,587,569**	**4,970,498**	**5,062,968**	**475,399**	**317,962**

4-SEC-26

[Ex.4, p.33] Please explain what is meant by 'Vacant positions Offset - outside services - Corp Allocation'.

The Regulatory functions in accounting, reporting and compliance have been completed by a variety of Lakeland Holding corporate staff. LPDL has tried repeatedly to fill the Regulatory Analyst/Accountant to take on the combined tasks that are currently being completed piecemeal by a number of executives and senior staff. It is expected that this will reduce the Corporate charge once the position is up to speed, eliminate burn out of current staff working excess overtime and realign tasks to more appropriate staff. Up until 2019, these functions were budgeted in LPDL as a current FTE but actually being performed by corporate staff and cross charged in the corporate allocation at cost. Overtime has not been included in the costs as management staff are not compensated. For 2018, that equated to approximately $137 K that was not cross charged to LPDL – ultimately a savings to the rate payer that can not be sustained.

4-SEC-27

[Ex.4, p.38] Please explain why the increase in the pole attachment charge has an impact on operating costs?

Please see response to 4-Staff-51

4-SEC-28

[Ex.4, p.63] With respect to Appendix 2-K:

a. Please revise to include 2018 actuals.
b. Please add two rows to show the allocation of total compensation costs to each of capital & OMA.

	Board Approved PROXY	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
	2013	2013	2014	2015	2016	2017	2018 ACTUAL	2018	2019
	Merged	Merged	Merged	Merged	Merged	Merged	Merged	Merged	Merged
Number of Employees (FTEs including Part-Time)[1]									
Management (including executive)	6.0	5.0	4.5	4.0	3.0	3.0	3.0	3.0	3.0
Non-Management (union and non-union)	23.2	21.0	20.5	18.8	17.8	17.3	16.3	17.5	19.4
Total	29.2	26.0	25.0	22.8	20.8	20.3	19.3	20.5	22.4
Total Salary and Wages including ovetime and incentive pay									
Management (including executive)	$498,528	$438,610	$419,826	$412,713	$411,657	$344,296	$399,021	$376,016	$358,394
Non-Management (union and non-union)	$1,540,506	$1,259,453	$1,353,719	$1,253,407	$1,244,040	$1,201,864	$1,216,663	$1,296,866	$1,502,549
Total	$2,039,034	$1,698,064	$1,773,545	$1,666,120	$1,655,697	$1,546,160	$1,615,684	$1,672,882	$1,860,943
Total Benefits (Current + Accrued)									
Management (including executive)	$143,406	$119,625	$109,477	$104,507	$83,655	$84,852	$102,091	$94,004	$89,599
Non-Management (union and non-union)	$438,158	$371,341	$370,058	$318,537	$424,154	$318,451	$329,267	$337,374	$387,055
Total	$581,564	$490,966	$479,535	$423,044	$507,809	$403,303	$431,358	$431,378	$476,653
Total Compensation (Salary, Wages, & Benefits)									
Management (including executive)	$641,934	$558,235	$529,304	$517,221	$495,312	$429,148	$501,112	$470,020	$447,993
Non-Management (union and non-union)	$1,978,664	$1,630,795	$1,723,776	$1,571,944	$1,668,194	$1,520,315	$1,545,930	$1,634,240	$1,889,603
Total	$2,620,598	$2,189,030	$2,253,080	$2,089,164	$2,163,506	$1,949,463	$2,047,042	$2,104,260	$2,337,596
Allocation Employee Compensation Costs to Capital & OM&A									
Capital		$397,066	$514,610	$412,092	$589,087	$555,169	$575,301	$591,382	$656,958
OM&A		$1,791,963	$1,738,470	$1,677,072	$1,574,419	$1,394,294	$1,471,741	$1,512,878	$1,680,637
Total		$2,189,030	$2,253,080	$2,089,164	$2,163,506	$1,949,463	$2,047,042	$2,104,260	$2,337,596

4-SEC-29

[Ex.4, p.74] Please explain the reasonableness of the management year-over-year compensation increases when compared to the non-management year-over-year compensation increases.

The union negotiated increase is 1.25% at January 1 and July 1, while the non-management increase is 3% at January 1. LPDL has struggled to keep qualified management staff as other utilities (namely H1) offer far higher wages. Current management staff has constantly had to work excess hours in order to meet budgets and reporting requirements. Current management is expected to assist line staff during emergencies without compensation, unlike line staff.

The management year over year compensation increases are reasonable due to the significant increase in responsibility for management with the merge with Parry Sound in 2014. Workload and staff supervision increased over 2014 and 2015 and their compensation was adjusted to reflect this incremental increase accordingly. The non-management staff increases were based mostly on union rates as negotiated in the collective agreement.

Exhibit 5 – Cost of Capital

5-Staff-67
Debt Instruments
Ref: Chapter 2 appendices – Tab App.2-OB Debt Instruments
Lakeland Power has all of its long-term debt with TD Bank and most recently renewed $11.1M worth of loan at 3.62%.

a) Did Lakeland Power negotiate with other banks for a better rate for the most recently renewed load?

LPDL did not negotiate with other banks. LDPL has not yet renewed the $11.1M at 3.62%. That rate (3.62%) was the last one negotiated on the last tranche that renewed in March 2018. For the balance of debt coming due in 2019 an estimator of 3.62% was put in place. $4.0 M comes due in February 2019 and $8.0 M in July 2019. Based on the most recent trends in interest rates, this will likely be higher. LPDL preference would be to put in the placeholder at the OEB deemed rate of 4.13% as we believe renewals will be indicative of this.

b) Are there cost savings for Lakeland Power by having all its debt at TD Bank?

LPDL believes that building a strong relationship with its lender has resulted in fair rates, significantly below the OEB deemed rate, lower than posted rates and lower than entities such as Infrastructure Ontario. LPDL periodically reviews what other LDCs are paying in our same size and discuss any abnormalities with our lender.

5.0 COST OF CAPITAL AND RATE OF RETURN (EXHIBIT 5)

5.0-VECC-31

Reference: Exhibit 5, Appendix 2-OA (Table 3)

a) Please update Appendix 2-OA for the OEB's revised cost of capital parameters (November 2, 2018).

Year: 2019

Particulars	Capitalization Ratio			Cost Rate	Return
	(%)		($)	(%)	($)
Debt					
Long-term Debt	56.00%		$16,834,013	3.11%	$523,538
Short-term Debt	4.00%	(1)	$1,202,429	2.82%	$33,909
Total Debt	60.0%		$18,036,442	3.09%	$557,446
Equity					
Common Equity	40.00%		$12,024,295	8.98%	$1,079,782
Preferred Shares			$ -		$ -
Total Equity	40.0%		$12,024,295	8.98%	$1,079,782
Total	100.0%		$30,060,737	5.45%	$1,637,228

Without any other considered changes, the new parameters result in an increase of $3,968. With all changes considered from IR process, the revised return is as below.

2019

Particulars	Capitalization Ratio		Cost Rate	Return
	(%)	($)	(%)	($)
Debt				
Long-term Debt	56.00%	$16,629,577	3.11%	$517,180
Short-term Debt	4.00%	$1,187,827	2.82%	$33,497
Total Debt	60.0%	$17,817,404	3.09%	$550,677
Equity				
Common Equity	40.00%	$11,878,269	8.98%	$1,066,669
Preferred Shares		$ -		$ -
Total Equity	40.0%	$11,878,269	8.98%	$1,066,669
Total	100.0%	$29,695,674	5.45%	$1,617,345

5.0-VECC-32

Reference: Exhibit 5, Appendix 2-OB

a) Please explain why Lakeland has chosen short to mid-term debt instruments (i.e. 2- 5 years) in contrast to longer term (10-20 year) debt instruments. What risk evaluation has the Utility done to understand its exposure to the potential for increased borrowing rates in the future?

LPDL has only been offered 1-5 year rates for interest only tranches. The amortization period on the principal and interest payment type loans are 10-15 years. LPDL does not have a full time treasury department and manages to the best of its ability securing interest rates that it believes are quite low and significantly lower than the deemed rate from OEB. We believe this has been and continues to be a significant savings to our ratepayers without the added burden of more staff.

b) Please explain why all Lakeland's debt is only with one institution (TD Bank). How does the Utility ensure it is achieving the best possible rates?

LPDL believes that building a strong relationship with its lender has resulted in fair rates, significantly below the OEB deemed rate, lower than posted rates and lower than entities such as Infrastructure Ontario. LPDL periodically reviews what other LDCs are paying in our same size and discuss any abnormalities with our lender.

5-SEC-30

[Ex.5] Please provide the actual 2018 regulatory ROE.

Please see response to 1.0-VECC-1

Exhibit 6 – Revenue Deficiency/Sufficiency

6-Staff-68
Distribution Revenue at Proposed Rates
Ref: Exhibit 6 – Revenue Requirement, Table 3: Distribution Revenue at Proposed Rates – 2019 volumes
Ref: Exhibit 8 – Rate Design, Table 11: 2019 Proposed Rates at Proposed F/V split

Lakeland Power provided proposed rates in Exhibit 6 - Table 3 and Exhibit 8 - Table 11 but the rates do not match.

a) Please reconcile the two tables.

The table used in Exhibit 8 (Table 11), was an incorrect version. Table 3 in Exhibit 6 correctly displayed the proposed rates and the rates for which the bill impacts were calculated. The corrected Table 11 for Exhibit 8 before any adjustments made through the interrogatory process is below:

2019 Rates at 2019 Load	Test Year Projected Revenues @ proposed rates							
	Test Year Projected Revenue from Proposed Variable Charges							
Customer Class Name	Variable Distribution Rate	per	Test Year Volume	Gross Variable Revenue	Transform. Allowance Rate	Transform. Allowance kW's	Transform. Allowance $'s	Net Variable Revenue
Residential	$0.0000	kWh	103,566,100	$2			$0	$2
General Service < 50 kW	$0.0095	kWh	58,157,023	$554,304			$0	$554,304
General Service 50 to 4999 kW	$2.6573	kW	276,220	$734,003	-0.60	129265	-$77,559	$656,444
Unmetered Scattered Load	$0.0000	kWh	166,068	$0			$0	$0
Sentinel Lighting	$0.0000	kW	119	$0			$0	$0
Street Lighting	$0.0000	kW	3,183	$0			$0	$0
Total Variable Revenue			**162,168,713**	**$1,288,309**		129265	-$77,559	$1,210,750

2019 Rates at 2019 Load								
	Test Year Projected Revenue from Proposed Fixed Charges							
Customer Class Name	Fixed Rate	Customers (Connections)	Fixed Charge Revenue	Variable Revenue	TOTAL	% Fixed Revenue	% Variable Revenue	% Total Revenue
Residential	$33.55	11,208	$4,511,964	$2	$4,511,966	100.00%	0.00%	56.38%
General Service < 50 kW	$43.02	2,148	$1,108,775	$554,304	$1,663,079	66.67%	33.33%	20.78%
General Service 50 to 4,999 kW	$284.85	136	$464,877	$656,444	$1,121,321	41.46%	58.54%	14.01%
Unmetered Scattered Load	$14.86	51	$9,096	$0	$9,096	100.00%		0.11%
Sentinel Lighting	$10.75	44	$5,678	$0	$5,678	100.00%		0.07%
Street Lighting	$10.17	2,849	$347,632	$0	$347,632	100.00%		4.34%
Total Fixed Revenue		**16,436**	**$6,448,022**	**$1,210,750**	**$7,658,772**			

Exhibit 7 – Cost Allocation

7-Staff-69
Cost Allocation
Ref: Cost Allocation Model, Tab I3 TB Data

Lakeland Power has entered the Revenue Requirement of $8,340,985. The cost allocation model has calculated a revenue requirement of $8,339,235 based on the provided trial balance.

a) Please reconcile the $1750 difference.

This data entry error has been corrected in the revised cost allocation model.

7-Staff-70
Cost Allocation
Ref: Exhibit 7, page 10; Exhibit 8, page 12; Cost Allocation Model, Tab I6.1 Revenue

Lakeland Power states that "Sheet I6.1 Revenue has been populated with the 2019 Test Year forecast data as well as existing rates. However, the rates populated are neither the approved rates for the Lakeland Power except for the former Parry Sound Power service area, nor the former Parry Sound Power service area. For example, the 2018 approved residential fixed charge in the Lakeland Power except for the former Parry Sound Power service area is $30.51, the residential fixed charge in the former Parry Sound Power service area is $34.69, while the cost allocation model is populated with $31.61. At exhibit 8, Lakeland Power indicates that the existing charge for "former LPDL" is $33.48, and for "former PSP" is $34.69.

a) Please provide a source or derivation for the existing rates used in sheet I6.1 Revenue.

In Exhibit 8, the value of $33.48 refers the sub-total A in the bill impact model for Residential which is both fixed and variable.

In order to determine the 2018 revenue at current rates, a weighted rate was used. The 2018 load forecast data was split based on the volume by service area by class from 2017 (data filed in RRR). The split volumes were then multiplied by the 2018 current rates by service area by class. The resulted dollars were added together and divided by the total volume by rate class to determine the weighted average rate.

2018 Load Forecast and 2019 Load Forecast split by area by class based on 2017 actual:

kWh

Load Forecast by Service Area	2017 LPDL	2017 PSP	Total	2018 LPDL	2018 PSP	Total	2019 LPDL	2019 PSP	Total
Residential	74,763,267	28,366,364	103,129,631	75,597,473	28,682,875	104,280,349	75,079,683	28,486,417	103,566,100
General Service < 50 kW	40,513,996	17,071,356	57,585,352	41,002,198	17,277,069	58,279,267	40,916,194	17,240,830	58,157,023
General Service > 50 to 4,999 kW	86,744,716	30,008,788	116,753,504	85,626,299	29,621,878	115,248,177	84,427,741	29,207,245	113,634,985
Sentinel Lights	37,097	7,135	44,232	35,876	6,900	42,775	35,876	6,900	42,775
Street Lights	805,699	348,756	1,154,455	805,886	348,838	1,154,724	805,886	348,838	1,154,724
Unmetered Loads	109,956	56,112	166,068	109,956	56,112	166,068	109,956	56,112	166,068
		-	-		-	-		-	-
Total	**202,974,731**	**75,858,511**	**278,833,242**	**203,177,689**	**75,993,672**	**279,171,361**	**201,375,335**	**75,346,341**	**276,721,676**

kW

Load Forecast by Service Area	2017 LPDL	2017 PSP	Total	2018 LPDL	2018 PSP	Total	2019 LPDL	2019 PSP	Total
Residential			-						
General Service < 50 kW			-						
General Service > 50 to 4,999 kW	208,206	71,758	279,964	208,338	71,804	280,141	205,422	70,798	276,220
Sentinel Lights	104	20	124	100	19	119	100	19	119
Street Lights	2,189	1,010	3,198	2,178	1,005	3,183	2,178	1,005	3,183
Unmetered Loads			-						
			-						
Total	**210,498**	**72,787**	**283,285**	**210,616**	**72,827**	**283,444**	**207,700**	**71,822**	**279,523**

Customers

Load Forecast by Service Area	2017 LPDL	2017 PSP	Total	2018 LPDL	2018 PSP	Total	2019 LPDL	2019 PSP	Total
Residential	8,243	2,926	11,169	8,272	2,936	11,208	8,272	2,936	11,208
General Service < 50 kW	1,596	548	2,144	1,599	549	2,148	1,599	549	2,148
General Service > 50 to 4,999 kW	95	43	138	94	42	136	94	42	136
Sentinel Lights	40	6	46	38	6	44	38	6	44
Street Lights	1,785	1,063	2,848	1,786	1,063	2,849	1,786	1,063	2,849
Unmetered Loads	34	17	51	34	17	51	34	17	51
			-						
Total	**11,793**	**1,129**	**16,396**	**11,822**	**1,128**	**16,436**	**11,822**	**1,128**	**16,436**

2018 Split volumes multiplied by respective rates from 2018 Tariff Sheets:

LPDL

LPDL Rates Only

2018 Rates at 2018 Load — **Bridge Year Projected Revenues @ LPDL current rates on LPDL volume**

	Bridge Year Projected Revenue from Existing Variable Charges							
Customer Class Name	**Variable Distribution Rate**	**per**	**Bridge Year Volume**	**Gross Variable Revenue**	**Transform. Allowance Rate**	**Transform. Allowance kW's**	**Transform. Allowance $'s**	**Net Variable Revenue**
Residential	$0.0038	kWh	75,597,473	$287,270			$0	$287,270
General Service < 50 kW	$0.0093	kWh	41,002,198	$381,320			$0	$381,320
General Service 50 to 4,999 kW	$2.8961	kW	208,338	$603,368	-0.60	129,265	-$77,559	$525,809
Unmetered Scattered Load	$0.0060	kWh	109,956	$660			$0	$660
Sentinel Lighting	$22.6765	kW	100	$2,275			$0	$2,275
Street Lighting	$16.5322	kW	2,178	$36,009			$0	$36,009
Total Variable Revenue				**$1,310,902**		129265	-$77,559	$1,233,343

2018 Rates at 2018 Load — Lakeland

	Bridge Year Projected Revenue from Existing Fixed Charges							
Customer Class Name	**Fixed Rate**	**Customers (Connections)**	**Fixed Charge Revenue**	**Variable Revenue**	**TOTAL**	**% Fixed Revenue**	**% Variable Revenue**	**% Total Revenue**
Residential	$30.51	8,272	$3,028,465	$287,270	$3,315,736	91.34%	8.66%	41.43%
General Service < 50 kW	$45.73	1,599	$877,455	$381,320	$1,258,775	69.71%	30.29%	15.73%
General Service 50 to 4,999 kW	$322.06	94	$361,827	$525,809	$887,636	40.76%	59.24%	11.09%
Unmetered Scattered Load	$13.08	34	$5,337	$660	$5,996	89.00%	11.00%	0.07%
Sentinel Lighting	$6.55	38	$3,007	$2,275	$5,282	56.93%	43.07%	0.07%
Street Lighting	$5.39	1,786	$115,494	$36,009	$151,503	76.23%	23.77%	1.89%
Total Fixed Revenue		**11,822**	**$4,391,586**	**$1,233,343**	**$5,624,929**			

PSP

PSP Rates Only

2018 Rates at 2018 | **Bridge Year Projected Revenues @ PSP current rates on PSP volume**

	Bridge Year Projected Revenue from Existing Variable Charges							
Customer Class Na	**Variable Distribution Rate**	**per**	**Bridge Year Volume**	**Gross Variable Revenue**	**Transform. Allowance Rate**	**Transform. Allowance kW's**	**Transform. Allowance $'s**	**Net Variable Revenue**
Residential	$0.0076	kWh	28,682,875	$217,990			$0	$217,990
General Service < 50	$0.0144	kWh	17,277,069	$248,790			$0	$248,790
General Service 50 t	$4.0690	kW	71,804	$292,169			$0	$292,169
Unmetered Scattered	$0.1421	kWh	56,112	$7,974			$0	$7,974
Sentinel Lighting	$17.6167	kW	19	$338			$0	$338
Street Lighting	$29.0019	kW	1,005	$29,139			$0	$29,139
Total Variable Revenue				**$796,399**		0	$0	$796,399

2018 Rates at 2018 PSP

	Bridge Year Projected Revenue from Existing Fixed Charges							
Customer Class Na	**Fixed Rate**	**Customers (Connections)**	**Fixed Charge Revenue**	**Variable Revenue**	**TOTAL**	**% Fixed Revenue**	**% Variable Revenue**	**% Total Revenue**
Residential	$34.69	2,936	$1,222,288	$217,990	$1,440,278	84.86%	15.14%	18.00%
General Service < 50	$35.16	549	$231,644	$248,790	$480,433	48.22%	51.78%	6.00%
General Service 50 t	$202.64	42	$103,047	$292,169	$395,215	26.07%	73.93%	4.94%
Unmetered Scattered	$24.35	17	$4,967	$7,974	$12,941	38.39%	61.61%	0.16%
Sentinel Lighting	$4.55	6	$313	$338	$651	48.13%	51.87%	0.01%
Street Lighting	$2.90	1,063	$37,005	$29,139	$66,145	55.95%	44.05%	0.83%
Total Fixed Revenue		**4,614**	**$1,599,265**	**$796,399**	**$2,395,663**			

LPDL added to PSP

Blended Rates

2018 Rates at 2018 Load | **Bridge Year Projected Revenues @ current rates**

	Bridge Year Projected Revenue from Existing Variable Charges							
Customer Class Name	**Variable Distribution Rate**	**per**	**Bridge Year Volume**	**Gross Variable Revenue**	**Transform. Allowance Rate**	**Transform. Allowance kW's**	**Transform. Allowance $'s**	**Net Variable Revenue**
Residential	$0.0048	kWh	104,280,349	$505,260			$0	$505,260
General Service < 50 kW	$0.0108	kWh	58,279,267	$630,110			$0	$630,110
General Service 50 to 4,999 kW	$3.1967	kW	280,141	$895,536	-0.60	129,265	-$77,559	$817,977
Unmetered Scattered Load	$0.0520	kWh	166,068	$8,633			$0	$8,633
Sentinel Lighting	$21.9542	kW	119	$2,613			$0	$2,613
Street Lighting	$20.4675	kW	3,183	$65,148			$0	$65,148
Total Variable Revenue				**$2,107,300**		129265	-$77,559	$2,029,741

2018 Rates at 2018 Load

	Bridge Year Projected Revenue from Existing Fixed Charges							
Customer Class Name	**Fixed Rate**	**Customers (Connections)**	**Fixed Charge Revenue**	**Variable Revenue**	**TOTAL**	**% Fixed Revenue**	**% Variable Revenue**	**% Total Revenue**
Residential	$31.61	11,208	$4,250,754	$505,260	$4,756,014	89.38%	10.62%	59.43%
General Service < 50 kW	$43.03	2,148	$1,109,098	$630,110	$1,739,209	63.77%	36.23%	21.73%
General Service 50 to 4,999 kW	$284.85	136	$464,874	$817,977	$1,282,851	36.24%	63.76%	16.03%
Unmetered Scattered Load	$16.84	51	$10,304	$8,633	$18,937	54.41%	45.59%	0.24%
Sentinel Lighting	$6.29	44	$3,321	$2,613	$5,933	55.97%	44.03%	0.07%
Street Lighting	$4.46	2,849	$152,500	$65,148	$217,648	70.07%	29.93%	2.72%
Total Fixed Revenue		**16,436**	**$5,990,851**	**$2,029,741**	**$8,020,592**			

2019 Load at 2018 Blended Rates as calculated above to determine 2019 Load at current rates

2018 Rates at 2019 Load — Test Year Projected Revenues @ current weighted rates

Customer Class Name	Test Year Projected Revenue from Existing Variable Charges							
	Variable Distribution Rate	per	Test Year Volume	Gross Variable Revenue	Transform. Allowance Rate	Transform. Allowance kW's	Transform. Allowance $'s	Net Variable Revenue
Residential	$0.0048	kWh	103,566,100	$501,800			$0	$501,800
General Service < 50 kW	$0.0108	kWh	58,157,023	$628,789			$0	$628,789
General Service 50 to 4,999 kW	$3.1967	kW	276,220	$883,002	-0.60	129265	-$77,559	$805,443
Unmetered Scattered Load	$0.0520	kWh	166,068	$8,633			$0	$8,633
Sentinel Lighting	$21.9542	kW	119	$2,613			$0	$2,613
Street Lighting	$20.4675	kW	3,183	$65,148			$0	$65,148
Total Variable Revenue			**162,168,713**	**$2,089,984**		129265	-$77,559	$2,012,425

2018 Rates at 2019 Load

Customer Class Name	Test Year Projected Revenue from Existing Fixed Charges							
	Fixed Rate	Customers (Connections)	Fixed Charge Revenue	Variable Revenue	TOTAL	% Fixed Revenue	% Variable Revenue	% Total Revenue
Residential	$31.61	11,208	$4,250,754	$501,800	$4,752,553	89.44%	10.56%	59.38%
General Service < 50 kW	$43.03	2,148	$1,109,098	$628,789	$1,737,887	63.82%	36.18%	21.71%
General Service 50 to 4,999 kW	$284.85	136	$464,874	$805,443	$1,270,317	36.60%	63.40%	15.87%
Unmetered Scattered Load	$16.84	51	$10,304	$8,633	$18,937	54.41%	45.59%	0.24%
Sentinel Lighting	$6.29	44	$3,321	$2,613	$5,933	55.97%	44.03%	0.07%
Street Lighting	$4.46	2,849	$152,500	$65,148	$217,648	70.07%	29.93%	2.72%
Total Fixed Revenue		**16,436**	**$5,990,851**	**$2,012,425**	**$8,003,275**			

b) Please reconcile the rates in exhibit 8 with the rates from Lakeland Power's 2018 tariff of rates and charges.

The rates are the blended rates of the LPDL and PSP tariff sheets as described and derived above.

7-Staff-71
Cost Allocation
Ref: Cost Allocation Model, Tab I6.2 Customer Data; EB-2012-0145 Cost Allocation Model, Tab I6.2 Customer Data

For the Street Light class, the provided Cost Allocation model has been populated with 2,849 for customers, connections, devices, and secondary customer base, and the number of bills has been populated with 34,188 reflecting one bill per month per customer. In the cost allocation model in support of its 2013 rate application, Lakeland Power indicated that it expected to issue 84 bills per year for street lighting.

a) Please confirm the number of customer accounts, and street lighting bills per month.

The billing for Streetlighting is based on the number of connections which is 2,849. The number of customers is 8 for the number of bills per month which means the number of bills should be 96.

b) Please update the cost allocation model as required..

Completed with revised data using 8 bills per month.

7-Staff-72
Cost Allocation
Ref: Cost Allocation Model, Tab I7.1 Meter Capital; Tab I7.2 Meter Reading
Lakeland Power has entered meter counts indicating that the General Service < 50 kW rate class uses a mix of single phase 200A meters and demand meters without instrument transformers while the General Service > 50 kW rate class uses demand meters with instrument transformers exclusively.

a) Please explain Lakeland Power's practice on the frequency and criteria for reclassification of customers between the General Service < 50 kW and General Service > 50 kW rate classes.

LPDL follows the Distribution System Code (DSC) mandates with regards to reclassifications of accounts (pg 38 of DSC)

b) If Lakeland power routinely reclassifies customers, please explain how all customers in the General Service > 50 kW rate class use a different type of meters from all customers in the General Service < 50 kW rate class, or revise the cost allocation model as required.

During reclassification of a customer between the GS >50 and GS <50 rate classes, LPDL completes a meter change to accommodate the mandated billing requirements which are different for both GS>50 and GS<50 customer classes. GS>50 customers are billed based on the Hourly Ontario Energy Price (HOEP), as well as their monthly demand (kW), requiring interval meters with channels to record the kilowatt hours (kWh) and kW reads. GS<50 customers are billed kWh only at Time-of-Use (TOU) rates, with the billing quantities retrieved from the provincial Meter Data Management and Repository (MDM/R), a process requiring a REX meter.

7-Staff-73
Cost Allocation
Ref: Cost Allocation Model, Tab I7.2 Meter Reading
Lakeland power has assigned a weighting factor of 0.22 to the meter reads required for interval meters. This is applied to all meter reads for the General Service > 50 kW rate class, and not to meter reads for any other rate class.

a) Please provide a derivation of the meter reading weighting factor for interval.

The weighting factor of 0.22 was the same value used in the prior Cost Allocation model. LPDL does not spend as much time on GS>50 kW meter reads as it does on classes such as Residential in order to validate smart meter data, upload to MDMR, correct no-read signals, etc.

7-Staff-74
Cost Allocation
Ref: Cost Allocation Model, Tab I8 Demand Data
The secondary non-coincident peaks (NCPs) entered in the cost allocation model are greater than line transformer NCP for the general service > 50 kW rate class. For example, the Line Transformer 4NCP has been entered as 32,360 kW while the Secondary 4NCP has been entered as 59,489 kW.

a) Please explain why the secondary NCPs are greater than the line transformer NCP and correct the model as required.

The data was inversely inputted. The model has been updated to reflect the correct information.

7-Staff-75
Cost Allocation
Ref: Exhibit 7, page 26; Revenue Requirement Work Form, Tab 11 Cost Allocation
Lakeland Power is proposing to reduce the revenue to cost ratio for the Residential rate class from 98.67% to 97.95%.

a) Please provide the rationale for reducing the revenue to cost ratio for the residential class when it is already below 100%, and necessitates a larger increase to the Street Lighting rate class.

The model has now been corrected and new revenue to cost ratios have been aligned to the model results as below:

Name of Customer Class	Previously Approved Ratios Most Recent Year: 2013 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
Residential	97.92%	93.22%	96.97%	85 - 115
General Service <50kW	95.71%	94.12%	96.97%	80 - 120
General Service >50kW	115.48%	134.48%	120.00%	80 - 120
Sentinel lights	78.65%	124.58%	120.00%	80 - 120
Street lights	94.13%	224.35%	120.00%	80 - 120
Unmetered Scattered load	102.89%	195.47%	120.00%	80 - 120

7.0 COST ALLOCATION (EXHIBIT 7)

7.0 – VECC –33

Reference: Exhibit 7, pages 5-7

a) Do the 4NCP values for LPDL and PSP in Table 3 represent: i) the 4NCP as used on the Cost Allocation models filed by each utility in the referenced COS Applications or ii) the 4NCP values from the 2004 load profiles for each utility?

The 4NCP values represented only the 2004 load profile for LPDL. LPDL has now added the 2004 hourly data for both entities and recalculated the 4NCP and revised the Cost Allocation model.

b) If the former, please explain why this is appropriate when the load profile scaling factors (per Table 2) are calculated relative to the 2004 weather normal usage.

See above

c) Please explain why it is appropriate to simply add the values for the two former utilities in order to obtain the Blended values. Won't the 4NCP values for each of the former utilities occur at different times during the year?

LPDL has re-evaluated the blended values and has gone back to the 2004 hourly load data which has been combined by hour by class, then scaled to the 2019 load forecast and new 4NCP values determined.

d) Please explain how the 2019 4NCP values for each class were determined and provide the supporting calculations.

See explanation above

1. 2004 hourly data by class for LPDL added to 2004 hourly data by class for PSP
2. Divided by the total of LPDL plus PSP 2004 total kwh for 2004
3. Multiplied by the 2019 Load forecast volume for the rate class

	LPDL	PSP	Total
Hour 1 in GWh for Residential	.0112	.0050	.0162
Total GWh for Residential	88.4740	38.5697	127.0437
Blended Hour 1 in GWh for Residential			0.0162/127.0437 = .000127574
2019 Load Forecast for Residential (kWh)			103,566,100
Scaled 2019 Hour 1 in GWh for Residential			.00127574 x 103566100 = 13212 kWh for hour 1 Residential

The following is the resulting data by month (2004 hourly data scaled to 2019 Load Forecast). The yellow highlighted values are the ones used for the CP and NCP values.

2019 Load Forecast	Residential	GS>50kW	Street Lighting	Sentinel Lighting	GS<50kW	USL	Total
Total	103566100	113634985	1154724	42775	58157023	166068	276721676
	0	0	0	0	0	0	0
Jan	29,186	18,289	264	12	14,908	37	54,925
Feb	27,822	17,599	264	11	13,993	35	52,746
Mar	24,279	17,260	264	12	12,080	34	46,078
Apr	20,317	15,804	264	11	10,766	31	43,771
May	16,506	14,964	264	8	13,322	22	36,945
Jun	12,204	16,256	264	7	12,216	19	36,463
Jul	12,918	16,496	264	8	14,341	19	38,633
Aug	12,654	15,524	264	7	14,147	19	36,824
Sep	13,869	16,813	264	8	11,545	20	35,007
Oct	20,333	16,418	264	8	11,955	22	38,765
Nov	22,842	16,358	264	11	13,270	28	45,555
Dec	25,331	17,741	264	11	15,831	35	52,203
1NCP	**29,186**	**18,289**	**264**	**12**	**15,831**	**37**	**63,619**
4NCP	**106,618**	**70,889**	**1,057**	**47**	**59,226**	**141**	**237,978**
12NCP	**238,261**	**199,522**	**3,171**	**115**	**158,375**	**322**	**599,766**
Jan	24,537	17,112	220	10	13,010	37	54,925
Feb	26,860	15,846	0	4	10,004	32	52,746
Mar	17,605	16,666	0	12	11,762	33	46,078
Apr	18,904	15,089	0	11	9,736	31	43,771
May	11,615	14,486	0	7	10,817	21	36,945
Jun	8,608	15,722	0	7	12,108	18	36,463
Jul	8,876	15,854	0	7	13,876	19	38,633
Aug	8,542	14,111	0	7	14,147	18	36,824
Sep	13,624	14,021	0	5	7,337	20	35,007
Oct	19,499	12,728	0	3	6,513	22	38,765
Nov	17,921	14,539	89	6	12,975	25	45,555
Dec	24,684	14,663	119	8	12,694	35	52,203
1CP	**24,537**	**17,112**	**220**	**10**	**13,010**	**37**	**54,925**
4CP	**93,686**	**64,286**	**339**	**34**	**47,470**	**137**	**205,952**
12CP	**201,275**	**180,835**	**428**	**85**	**134,979**	**313**	**517,916**

e) Please explain how the 2019 12CP values for each class were determined and provide the supporting calculations.

The 12CP values were determined using the total of the monthly values for 12 months. The individual month used the highest hour within the month based on the total of all classes for the month rather than the highest hour within the class.

f) With respect to Table 4, please explain why, for the GS>50 class, the NCP values for Line Transformer are less than those for Secondary:

This was input inversely. This has been corrected in the revised version.

7.0 – VECC –34

Reference: Exhibit 7, page 12

a) Please confirm that, in the case of Street Lighting, each device is separately connected to LPDL's distribution system. If not, please revise the number of connections vs. devices.

LPDL has revised the data in the Cost Allocation model.

7.0 – VECC –35

Reference: Cost Allocation Model, Tab I7.1 – Meter Capital and Tab I7.2 – Meter Reading

a) Please explain why, in Tab I7.1, the number of meters in each of the Residential, GS<50 and GS>50 classes does not equal the number of customers forecast for 2019.

LPDL input the last year of actuals filed in RRR (2017). This has been adjusted in a revised version of the Cost Allocation model.

b) Please explain why, in Tab I7.2, the number of meter reading units in each of the Residential, GS<50 and GS>50 classes does not equal the number of customers forecast for 2019.

LPDL input the last year of actuals filed in RRR (2017). This has been adjusted in a revised version of the Cost Allocation model.

7-SEC-31

[Ex.7, p.25-26] Please explain why the Applicant is reducing the revenue to cost ratios for residential classes.

This has been corrected with the revised cost allocation model. There was an error with streetlight data. The revised version is utilizing the following revenue to cost ratios;

Name of Customer Class	Previously Approved Ratios Most Recent Year: 2013 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
Residential	97.92%	93.22%	96.97%	85 - 115
General Service <50kW	95.71%	94.12%	96.97%	80 - 120
General Service >50kW	115.48%	134.48%	120.00%	80 - 120
Sentinel lights	78.65%	124.58%	120.00%	80 - 120
Street lights	94.13%	224.35%	120.00%	80 - 120
Unmetered Scattered load	102.89%	195.47%	120.00%	80 - 120

Exhibit 8 – Rate Design

8-Staff-76
Specific Service Charges
Ref: Exhibit 8 – Rate Design, p. 35-37
Lakeland Power is proposing to apply the following formerly approved specific service charges for Parry Sound to all of Lakeland Power's service territories: account history, credit reference/credit check, charges to certify cheque, meter dispute charge, temporary service – install & remove – underground – no transformer, temporary service – install & remove – overhead – with transformer, and Service call – customer owned equipment.

a) Does Lakeland Power, except for the former Parry Sound, service territory currently provide the above services? If so, how does Lakeland Power currently recover costs?

See chart below

b) What is the difference between Account History, a service offered by the former Parry Sound, and Statement of Account, a service offered by Lakeland Power?

There is no difference between the two services.

c) What is the historical average time to install & remove a temporary service, the number of employees required, and the equipment required?

This chart was on the PSP tariff sheet however, it was never used.
LPDL merged all the Specific Service Charges into one table in order to create a single tariff sheet. In terms of the services indicated above, LPDL has a service type that would be the same, just different terminology.

LPDL	Former PSP

Statement of account	Account history
Account set up charge	Credit reference/credit check
N/A – does not do this	Charges to certify chq (PSP does not use this either)
Time and materials	Meter dispute charge plus Measurement Canada
Charges specific to temporary service	Neither LDC have used this code
Service call – customer owned equipment	Neither LDC have used this code
For services after hours – disconnect/reconnect/collection	Former PSP would have used time and materials

8-Staff-77
Specific Service Charges
Ref: Exhibit 8 – Rate Design, p. 35-37
Lakeland Power is proposing to apply the following formerly approved specific service charges for Lakeland Power, except Parry Sound, to all of Lakeland Power's service territories: statement of account, request for other billing information, income tax letter, collection of account charge – no disconnection – after regular hours, disconnect/reconnect at meter – after regular hours, disconnect/reconnect at pole – after regular hours, install/remove load control device – after regular hours.

a) Does the former Parry Sound service territory currently provide the above services? If so, how does the former Parry Sound currently recover costs?

They would provide them if required. For the after hours tasks, the assumption is that the recovery would be using time and materials. To date there is no evidence of these services being completed after hours.

b) What were Parry Sounds historical labour rates compared to Lakeland Power for the same time period?

On average, former PSP labour rates were very close to LPDL, particularly for linepersons as the union locals were the same.

c) What are Lakeland Power's overtime labour rates?

LPDL's overtime rates are 1.5x normal wage.

d) Please provide a breakdown of the costs for disconnects/reconnects and install/remove load control devices.

LPDL currently does not have any load control devices. The cost for disconnects/reconnects is dependent on the location of the customer. Some customers are over an hour away. The hourly cost rate for two men and a truck is $150/hr during regular hours, which means the costs could be as high as $350 at the meter and $450 at the pole.

8-Staff-78
Low Voltage Charges
Ref: Exhibit 8 – Rate Design, Table 24: Calculation of Proposed Low Voltage Charges

Lakeland Power stated that the 2018-2019 estimates for low voltage charges were based on an average of 2014-2017 but the numbers provided in Table 24 appear to be a historical five year rolling average.

a) Please confirm the methodology used to forecast the 2018 and 2019 low voltage charges.

LPDL used the average of 2014-2017 to calculate the value for 2018 then used 2014-2018 to calculate the value for 2019. It then used the calculated value allocated by rate class based on the transmission connection revenues then divided by the 2019 Load forecast to develop the rate.

b) Please calculate the 2019 low voltage charge based the latest Hydro One tariff sheet and 2019 load forecast volumes.

LPDL is unable to calculate this as the charge from H1 is based on kW plus monthly charges fixed and variable charges by meter point. LPDL does not have 2019 load forecast data by kW by rate class. This is why LPDL used the calculation in part (a) as a proxy for the charge, similar to other applications.

Looking at the actual data for LV charge from H1 for 2018 and the actual load forecast data to create a dollar value per kwh and applying to 2019 load forecast, the LV charge would be $1,008,383 for 2019 assuming that the rates charged in 2018 are the same as those in 2019.
Common ST lines $1.20520 per kW non-adj
LVDS-Low $1.54640 per kW adj

LV monthly charge $492.55 per month
Meter charge $764.01 per meter

	2018 Actual	2018 Actual	2019 Forecast	2019 Forecast
4075-Billed - LV	-774,309	Volume	Volume	
4750-Charges - LV	1,052,126	288,725,647	276,721,676	1,008,383

	ALLOCATON BASED ON TRANSMISSION-CONNECTION REVENUE				
Customer Class Name		**RTSR Rate**	**Uplifted Volumes**	**Revenue**	**% Alloc**
Residential	kWh	**$0.0044**	111,049,415	$488,617	39.29%
General Service < 50 kW	kWh	**$0.0041**	62,359,241	$255,673	20.56%
General Service > 50 to 4999 kW	kW	**$1.7895**	276,220	$494,296	39.75%
Unmetered Scattered Load	kWh	**$0.0041**	178,067	$730	0.06%
Sentinel Lighting	kW	**$1.2724**	119	$151	0.01%
Street Lighting	kW	**$1.2610**	3,183	$4,014	0.32%
other	0	**$0.0000**	1	$0	0.00%
TOTAL			**173,866,246**	**$1,243,481**	**100%**

	PROPOSED LOW VOLTAGE CHARGES & RATES				
Customer Class Name	**% Allocation**	**Charges**	**Not Uplifted Volumes**	**Rate**	**per**
Residential	39.29%	$ 396,237	103,566,100	$0.0038	kWh
General Service < 50 kW	20.56%	$ 207,334	58,157,023	$0.0036	kWh
General Service > 50 to 4999 kW	39.75%	$ 400,842	276,220	$1.4512	kW
Unmetered Scattered Load	0.06%	$ 592	166,068	$0.0036	kWh
Sentinel Lighting	0.01%	$ 123	119	$1.0336	kW
Street Lighting	0.32%	$ 3,255	3,183	$1.0226	kW
other					
TOTAL	**100.00%**	$ 1,008,383	**162,168,713**		

8-Staff-79
Rate Design
Ref: Exhibit 8, page 14-18

Lakeland Power is proposing to increase the proportion of revenue to be collected from the fixed charge for all rate classes. It states that its process to adjust fixed to variable split involves:

1) Determining what the newly calculated rates would be if Lakeland Power maintained its existing fixed to variable split;
2) Look at each class individually to see if the fixed rate falls within the Minimum and Maximum range;
3) Adjusted rates for each class accordingly.[4]

After determining the fixed and variable charges for the General Service < 50 kW and General Service > 50 kW rate classes, in step 1), Lakeland Power "opted to stay with the current fixed rate"[5].
For the Street Lighting, Unmetered Scattered Load and Sentinel Lighting rate classes, Lakeland Power has decided to adjust the fixed charge to recover 100% of the required revenue. In each case, it explains that it "was set as to meet the maximum charge or existing rate from the Cost Allocation model (Minimum System with PLCC adjustment)."[6]
For all three unmetered rate classes, the fixed charge that would result from maintaining the existing fixed charge would fall between the minimum and maximum fixed charges as calculated by the cost allocation model.

a) In explaining its chosen fixed to variable split for the General Service < 50 kW rate class and General Service > 50 kW rate class, Lakeland Power quoted the filing requirement statement "There is no requirement to lower the fixed charge to the ceiling".[7] Does Lakeland Power confirm it interprets that quotation as being prescriptive in that fixed charges must not be reduced from their current level?
b) If part a) is not confirmed, please explain why, after calculating the rates that would result from maintaining the existing fixed to variable split per step 1) in its process above; Lakeland Power decided increased the proportion of revenue to be collected from the fixed charge.
c) After calculating the rates that would result from maintaining the existing fixed to variable split per step 1) in its process above, why did Lakeland Power decide to go with fully fixed rates for the Street Lighting, Unmetered Scattered Load and Sentinel Lighting rate classes?

When LPDL was preparing the rate design portion of the application, it was utilizing data from the Cost Allocation model that had incorrect information input for Street Lighting. This in turn affected the other classes in order to realign revenue to cost ratios. As the

[4] Exhibit 8, page 15.
[5] Exhibit 8, page 16.
[6] Exhibit 8, page 17.
[7] Exhibit 8, pages 16, 17.

Cost Allocation model is now corrected, the rate design has been corrected and shown below:

Name of Customer Class	Previously Approved Ratios Most Recent Year: 2013 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
Residential	97.92%	93.24%	96.97%	85 - 115
General Service <50kW	95.71%	94.12%	96.97%	80 - 120
General Service >50kW	115.48%	134.34%	120.00%	80 - 120
Sentinel lights	78.65%	124.33%	120.00%	80 - 120
Street lights	94.13%	224.37%	120.00%	80 - 120
Unmetered Scattered load	102.89%	195.56%	120.00%	80 - 120

8-Staff-80

Bill Impacts

Ref: Tariff and Bill Impact Models (for Lakeland Power and PSP)

The proposed tariff and bill impact models (for both service areas) omit a volume count for the monthly service charge for Unmetered Scattered Load, Sentinel Lighting, and Street Lighting. This has the effect of excluding the impact in changes in the fixed charge from the bill impact calculation.

For the Street Light rate class, Lakeland Power has forecasted 2849 street light devices, 1.15 GWh and 3183 kW per year. This implies an average of 34 kWh and 0.093 kW per street light device per month. Lakeland Power has completed the tariff and bill impact models using 100 kWh and 0.25 kW per month.

a) Please revise the Tariff and Bill impact models as required to correct the issues identified above.

In LPDL's original submission, the move in rate design was to 100% fixed for those classes resulting in no volume component. After revising the Cost Allocation model as well as rate design, there is now a volume component for those classes listed above. New models for Tariff and Bill impact will be submitted.

8.0 –VECC - 40

Reference: Exhibit 8, page 38
Exhibit 3, page 63

a) For the $10 fee per MicroFIT meter point, what services does Utilismart provide LPDL with respect to its MicroFIT customers?

The monthly service fee of $10/month per MicroFIT meter point from Utilismart covers the cost of importing the meter data from the meter program and converting it into an hourly interval data file that is imported in to LPDL's CIS billing software so settlement can be calculated with the customer each month. As well, Utilismart provides settlement data for each of the MicroFIT accounts that LPDL uses to settle the difference between WAP and the MicroFIT contract price.

b) Does LPDL provide any MicroFIT services (e.g., billing, meter maintenance, etc.) internally? If yes please outline: i) what these services/activities) are, ii) what is the monthly cost per MicroFIT meter point to provide these services/activities, and iii) why aren't these costs also included in the MicroFIT service charge?

Yes, LPDL provides internal services to any MicroFIT services which include monthly billing, monthly settlement and meter maintenance if required. LPDL has not included additional internal costs in the MicroFIT service charge as they are minimal in the amount of time that is required to provide the above internal services.

c) LPDL is requesting (Exhibit 8, page 38) a change to the MicroFIT rate class to include Net Metering Accounts. Please address the following: i) how many Net Metering Accounts does LPDL currently have, ii) why is it appropriate to include Net Metering Accounts in the MicroFIT rate class, and iii) does the Other Revenue forecast for 2019 also include the additional revenues from applying the MicroFIT service charge to Net Metering Accounts?

LPDL had stated in Exhibit 8, page 38, that Net Metering accounts would be included in the MicroFIT rate class but at the time of the rate application, LPDL did not have any of these accounts yet. Since the rate application was submitted, LPDL has now connected 3 Net Metering accounts and LPDL confirms that they are not included in the MicroFIT rate class, they are included in the customer class that the net metering service is connected to (i.e. 1 residential, 1 GS<50 kW and 1 GS>50 kW). LPDL confirms there is no revenue from Net Metering accounts included in Other Revenue forecast for 2019.

8.0 –VECC - 41

Reference: Exhibit 8, pages 41-42

d) Please explain more fully how the forecast 2019 LV charges (per Table 24) were determined.

Please see response to 8-Staff-78

8.0 –VECC - 42

Reference: Exhibit 8, page 44

a) Please explain why the forecast LV charges for 2019 are $959,657 but the amount added to the power supply expense is only $923,433.

LPDL inadvertently used uplifted values to create the rate instead of non-uplifted then applied the rate to non-uplifted data. This has been corrected in the revisions now being submitted.

8.0 –VECC - 43

Reference: Exhibit 8, page 46

a) Please provide the calculation supporting the Supply Facilities Loss Factors set out for the years 2013-2017.

The Supply Facilities Loss Factors is the ratio between the Wholesale kWh billed (uplifted) and the Wholesale kWh metered. For IESO supply (which is billed by the IESO but actually supplied by Hydro One), the loss factor is 1.034, for embedded generation it is 1.0000, and for Hydro One it is a mix depending on the supply point on the totalization table of which most are 1.034 but one large meter point is 1.0000. The calculation supporting the Supply Facilities Loss Factors for 2013 and 2017 are provided below.

Appendix 2-R
Loss Factors

Lakeland and Parry Sound combined

		Historical Years					5-Year Average
		2013	2014	2015	2016	2017	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	315,528,677	319,149,657	308,961,454	302,232,068	297,287,399	308,631,851
A(2)	"Wholesale" kWh delivered to distributor (lower value)	308,046,369	312,339,718	301,492,599	294,928,061	291,292,822	301,619,914
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	0	0	0	0	0	-
C	Net "Wholesale" kWh delivered to distributor = A(2) - B	308,046,369	312,339,718	301,492,599	294,928,061	291,292,822	301,619,914
D	"Retail" kWh delivered by distributor	292,453,312	298,508,987	288,960,599	280,448,073	278,833,243	287,840,843
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	0	0	0	0	0	-
F	Net "Retail" kWh delivered by distributor = D - E	292,453,312	298,508,987	288,960,599	280,448,073	278,833,243	287,840,843
G	Loss Factor in Distributor's system = C / F	1.0533	1.0463	1.0434	1.0516	1.0447	1.0479
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0243	1.0218	1.0248	1.0248	1.0206	1.0232
	Total Losses						
I	Total Loss Factor = G x H	1.0789	1.0691	1.0692	1.0777	1.0662	1.0722

		2013	2014	2015	2016	2017
A(1) Wholesale kWh delivered to Distributor WITH Loss						
	Hydro One	179,794,613	173,864,623	180,057,445	173,955,663	139,844,554
	IESO	82,955,177	81,815,658	81,435,041	80,703,608	90,215,246
	Embedded Generation	52,778,887	63,469,376	47,468,968	47,572,797	67,227,599
		315,528,677	319,149,657	308,961,454	302,232,068	297,287,399
A(2) Wholesale kWh delivered to Distributor WITHOUT Loss						
	Hydro One	175,040,038	169,744,947	175,266,338	169,305,353	136,816,435
	IESO	80,227,444	79,125,395	78,757,293	78,049,911	87,248,788
	Embedded Generation	52,778,887	63,469,376	47,468,968	47,572,797	67,227,599
		308,046,369	312,339,718	301,492,599	294,928,061	291,292,822
H Supply Facilities Loss Factor = A(1) / A(2)						
	Hydro One	1.0272	1.0243	1.0273	1.0275	1.0221
	IESO	1.0340	1.0340	1.0340	1.0340	1.0340
	Embedded Generation	1.0000	1.0000	1.0000	1.0000	1.0000
	Supply Facilities Loss Factor = A(1) / A(2)	1.0243	1.0218	1.0248	1.0248	1.0206

8.0 –VECC - 44

Reference: Exhibit 8, Appendices C and D

a) In Appendices C and D, the bill impact calculations for USL, Sentinel Lighting and Street Lighting do not appear to include the monthly service charges. Please review and correct as required.

This has been corrected in the most recent version submitted with IR responses.

Exhibit 9 – Deferral and Variance Accounts

9-Staff-81
Low Voltage Charges
Ref: Exhibit 9 – Deferral and Variance, p. 43
Ref: Chapter 2 filing guidelines, 3.2.5.4 Capacity Based Recovery

Lakeland Power stated that no rate rider was produced for the balance of the CBR Class B balance and requested the balance be transferred to Account 1595 for future disposition. In the Chapter 2 filing guidelines, it states that if the rate rider generated for the CBR Class B amount is zero at the fourth decimal place then the balance will be added to Account 1580 WMS control account for disposition with the general purpose Group 1 DVA rate riders.

a) Please explain why Lakeland Power has proposed to dispose the CBR Class B balance through Account 1595.

LPDL believed that it was following the correct procedure and its intent was to follow the Chapter 2 filing guidelines.

Below is the note on the model that LPDL was following:

If the allocated Account 1580 sub-account CBR Class B amount does not produce a rate rider in one or more rate class (except for the Standby rate class), a distributor is to transfer the entire OEB-approved CBR Class B amount into account 1595 for disposition at a later date (see Accounting Guidance, Capacity Based Recovery July 25, 2016)

b) Please confirm if Lakeland Power filed the latest DVA model available from the OEB.

LPDL confirms that it filed 2019 DVA Continuity Schedule version 1.0 which was the version available at the time of the submission.

9-Staff-82
Deferral and Variance Accounts
Ref: DVA Continuity Schedule

The applicant is seeking OEB approval to harmonize its rates for the legacy Lakeland Power and Parry Sound Power service territories as part this application and has submitted a consolidated December 31, 2017 DVA continuity schedule in support of its request to dispose of these account balances.

a) Please confirm that the DVA balance and transactions up to the end of 2017 were actually compiled by service territory and not on a consolidated basis.

LPDL confirms that the DVA balances were compiled by service territory.

b) Please confirm that the IESO invoice had yet to be harmonized when the balances in the DVA continuity schedule were being compiled. If the IESO invoice has been harmonized, please indicate the date of harmonization.

The IESO invoice was partially harmonized in December 2016. The former PSP meters are on IESO invoice plus one customer from LPDL and the balance of LPDL are on H1 invoice. LPDL attempts to code everything separately but data from the respective sources is often very difficult to obtain in a timely manner.

c) From a cost causality perspective, please explain why the Applicant believes that it is more appropriate to calculate a single rate rider to be charged to customers across both rate territories when the underlying DVA account balances were accumulated by service territory[8].

From a cost causality perspective, there is no support for a single rate rider. The purpose was to achieve rate harmonization, one tariff sheet, one set of rates and the ability to bill more efficiently. Currently LPDL inputs and maintains two sets of rates in its billing system and two sets of DVA accounts in order to keep everything separate while all other costs, invoices and systems have been merged. This is extremely time consuming and inefficient and is not likely to end until DVAs are merged.

d) Please prepare and submit a DVA continuity schedule for each service territory.

LPDL has prepared two DVA models and are attached as Appendix L & M as well as in excel version on RESS.

e) Please update the Bill Impacts to reflect the rate riders calculated by service territory.

LPDL has updated the Bill Impacts to reflect the rate riders by service territory and has provided an excerpt in Appendix N & O. LPDL has also filed the excel version of each on RESS.

9-Staff-83
Deferral and Variance Accounts

[8] For example, in Section 9.2 of the application, the Applicant has indicated that the balance in Account 1576 relates entirely to the Parry Sound service territory. Therefore, is it reasonable to seek to refund that balance to all ratepayers when it relates entirely to the Parry Sound ratepayers.

Ref: Exhibit 9, Section 9.2
The Applicant is seeking to dispose of a credit of $365,471 in Account 1576, representing the impact of adopting the OEB's capitalization and depreciation policies for the Parry Sound service territory effective from January 1, 2013, and includes a projected amount for 2018.

a) Why was the Parry Sound service territory not tracking the annual impact (excluding return) in account 1576?

As staff from the previous PSP are no longer employed at LPDL we are unable to answer why it was not tracked. The lack of tracking was found during the 2019 COS process. Much of the books and records were damaged/lost during two building floods or non-existent.

b) Has the Applicant maintained both former and revised CGAAP detailed asset continuity schedules for the PSP service territory and were they used as the basis for the annual amounts and calculations presented in Appendix 2-EC?

In the original submission, a ratio, by USoA, for 2013 comparing the relationship between the new and old amortization was applied to the 2013-2018 new CGAAP amounts to approximate the amortization that would have been posted if the policy had not been changed. During the interrogatory process, LPDL has rebuilt the continuity schedules from 2013 to 2018 using the additions for former PSP. By completing this exercise, the resulting differences to be booked to Account 1576 have changed and will be reflected accordingly in the DVA continuity schedule for former PSP.

c) Please provide the detailed asset continuity schedules that support the annual balances presented in Appendix 2-EC under both former CGAAP and revised CGAAP. If these continuity schedules have not been maintained, then please explain how the Applicant calculated the amounts included in Account 1576 and why these calculations are reasonable and accurate.

	Prior Years Rebasing	2013	2014	2015	2016	2017	2018 Rebasing Year			
Reporting Basis	CGAAP	CGAAP	CGAAP	MIFRS - Note 5	MIFRS	MIFRS	MIFRS			
	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast			
		$	$		$					
PP&E Values under former CGAAP										
Opening net PP&E - Note 1		3,992,115	5,110,715	4,808,904	4,392,722	4,030,597	3,669,372			
Net Additions - Note 4		1,568,014	116,399	0	0	0	0			
Net Depreciation (amounts should be negative) - Note 4		-449,415	-418,210	-416,182	-362,125	-361,224	-346,951			
Closing net PP&E (1)		5,110,715	4,808,904	4,392,722	4,030,597	3,669,372	3,322,421			
PP&E Values under revised CGAAP (Starts from 2012)										
Opening net PP&E - Note 1		3,992,115	5,165,231	4,940,553	4,602,616	4,270,780	3,939,845			
Net Additions - Note 4		1,568,014	116,399	0	0	0	0			
Net Depreciation (amounts should be negative) - Note 4		-394,898	-341,078	-337,937	-331,836	-330,935	-316,661			
Closing net PP&E (2)		5,165,231	4,940,553	4,602,616	4,270,780	3,939,845	3,623,185			
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP		-54,517	-131,649	-209,894	-240,183	-270,473	-300,763			
Effect on Deferral and Variance Account Rate Riders										
Closing balance in Account 1576							- 300,763		**WACC**	5.45%
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2							- 16,392		**# of years of rate rider disposition period**	1
Amount included in Deferral and Variance Account Rate Rider Calculation							- 317,155			

LPDL has prepared the continuity schedules and have attached both the former and revised CGAAP versions in Appendix P

d) Can the revised CGAAP balances be reconciled to the audited financial statements and RRR filings for the respective years? If not, please explain why. Otherwise please provide this reconciliation.

After 2013, the financial statements and RRR filings are merged. The two entities no longer existed as separate companies after July 2014. At the time of the first RRR filing, LPDL confirmed with OEB staff that the RRR filings were to be as one entity.

e) In Appendix 2-EC, for years 2015-18, the applicant has not recorded any capital additions for purposes of calculating the annual difference between former and revised CGAAP. Please explain why given that the former Parry Sound had never rebased under the OEB's mandated capitalization and amortization policies.

All new capital since July 2014 was considered LPDL capital and not separated by service territory.

f) Please confirm that only the impact of adopting the OEB's mandated capitalization and amortization policies is being tracked in Account 1576. If the impact of other PPE accounting policy changes is also being tracked in this account, such as de-recognition gains and losses on disposal of pooled assets or other, then please quantify the portion of the calculated annual difference that would relate to those.

The change in service lives as an accounting policy change in advance of IFRS for former PSP is the only item in Account 1576.

9-Staff-84
Deferral and Variance Accounts
Ref: Exhibit 9, Appendix C

At the above reference the Applicant has submitted its GA Analysis Workforms and support GA Methodology description. The Applicant has prepared the GA Analysis Workform on a combined basis although the balances were actually accumulated by service territory.

a) Please prepare and submit a GA Analysis Workform by service area (legacy Lakeland and Parry Sound). A Workform must be prepared for each year since the service territory's last disposition of Account 1589. For Parry Sound that requires one for 2017 only, and for legacy Lakeland one for 2015, 2016, and 2017 is required. Please ensure each of the excel versions of the Workform are submitted.

The GA Analysis Workform consists of balances for Parry Sound service area for 2016 and 2017 and Lakeland Power legacy service area for 2015, 2016 and 2017. As of December 31, 2017, Parry Sound's GA Variance for 2016 was not yet disposed of (approved with 2018 rate order).
See 2 excel files submitted:

1) LPDL 2019 CoS GA_Analysis_Workform_20170712-3 – LP 2015 2016 2017.xlsb
2) LPDL 2019 CoS GA_Analysis_Workform_20170712-3 – PS 2016 2017.xlsb

b) The Applicant has presented reconciling adjustments in 1a and 1b of Note 5 in the versions GA Analysis Workforms that were submitted as part of this application.

   a. For 2015 and 2016, the Applicant has presented an adjustment in 1b related to a change in methodology for the calculation of Non-RPP GA. Please explain why the methodology needed to be changed. Please include details on how it was initially being done, what was changed and why, how the information required is compiled, and how the resulting adjustment was quantified. Provide the supporting calculation.

The methodology was changed to more accurately calculate the GA variance using a bottom up approach rather than a top down approach as previously used. This was needed to allocate the GA variance to only the true non-RPP customer class kWh that incur Class B GA costs. This change in methodology was recommended to us by OEB Staff during their review of our initial GA Workform Analysis submission in September 2017. The previous top down approach used Total Purchased kWh less RPP kWh to calculate the remaining kWh which we attributed to Class B GA kWh. This remaining kWh was then calculated at the Actual GA rate and compared to the amount billed to Class B GA customers at the 1st Estimate rate. However this top down approach left the system loss kWh included in the GA kWh rather than just the actual Class B GA kWh that attributed to the GA variance. The system loss kWh are now shifted to the 1588 cost of power variance rather than the 1589 GA variance. The GA variance is now based on actual non-RPP Class B GA $ billed at the 1st Estimate GA rate per month compared to the actual non-RPP Class B GA kWh at the Actual GA rate per month. The GA variance is then essentially the rate difference between the 1st Estimate rate billed versus the Actual rate paid for the non-RPP Class B GA kWh.

The following table illustrates the adjustment in the GA variance balance due to the change in methodology for 2015 (legacy Lakeland Power only) and 2016 (split between legacy Lakeland Power and Parry Sound).

	2015 LP	2016 LP	2016 PS	2016
Class B GA Variance per Original Methodology (Top-Down)	$ 122,338.94	-$ 3,414.88	-$ 22,125.31	-$ 25,540.19
Class B GA Variance per Revised Methodology (Bottom-Up)	$ 289,786.32	-$ 67,250.53	-$ 25,327.84	-$ 92,578.37
Net Adjustment due to change in Methodology	$ 167,447.38	-$ 63,835.65	-$ 3,202.53	-$ 67,038.18

b. Since the former Parry Sound service area previously disposed of its 2015 and 2016 balances in Account 1589 on a final basis, please confirm that the above methodology adjustments proposed for 2015 and 2016 only relate to the legacy Lakeland Power GA balances for those years.

The 1589 GA variance for former Parry Sound service area has been disposed of for 2015 however the 2016 balance is still included as of December 31, 2017 (approved for disposition effective January 1, 2018). Lakeland Power confirms that the above methodology adjustment for 2015 only relates to the legacy Lakeland Power service area. The 2016 adjustment relates to both the legacy Lakeland Power service area (adjustment of $(63,836) and Parry Sound service area (adjustment of $(3,203)) as can be seen in the table provided in the response to 1a) above.

b. Please explain why the Applicant believes that the new methodology outlined above is more appropriate and results in a more accurate calculation of the GA.

This change in methodology was recommended to us by OEB Staff during their review of our initial GA Workform Analysis submission in September 2017. LPDL agrees and believes this new methodology results in a more accurate calculation of the GA variance as it attributes only non-RPP Class B GA kWh and $ to the Class B GA customers who incur the Class B GA costs. Previously, the system loss kWh at the GA rate would also have been included in the GA variance account but should not have been as the system loss GA $ should be shared by all customers, not just the Class B GA customers.

d. Were the amounts presented in 1b for both 2015 and 2016 recorded in the
Applicant's G/L? If so, what period were they recorded in?

Yes, the amounts presented in 1b for 2015 and 2016 were both recorded in LPDL's G/L in December 2017.

e. In 2017 the Applicant has not recorded a similar adjustment in 1b for the change in methodology, please explain why one was not required for
2017.

A similar adjustment for the change in methodology was not required for 2017 as the new methodology was used in 2017 for calculating 2017's GA variance, so no further adjustment was required.

f. Please provide further explanation and context for the adjustments recorded in 1a for both 2015 and 2016. Have these adjustments been recorded in the Applicant's G/L, if so, in what period.

LPDL's 1a adjustment of $144,857 in 2015 was for a settlement payment made to the IESO in November 2015 for GA $ on micro/FIT embedded generation that the legacy Lakeland Power had missed remitting to the IESO for 2010 through to September 2015. This payment was made to the IESO in November 2015 and recorded in LPDL's G/L in November 2015. LPDL's 1a adjustment of $11,375 in 2016 was for GA $ paid to Hydro One for a short term load transfer that occurred in December 2015 that we only just received the invoice for from Hydro One in December 2016. This payment was made to Hydro One in December 2016 and recorded in LPDL's G/L in December 2016.

9-Staff-85
Deferral and Variance Accounts
Ref: Exhibit 9, Appendix C, GA Methodology Description

Question 2b discusses the true-ups that are required for CT 1142, and in particular, a true up for the actual GA rate, which is done in the following month after initial settlement, and a true-up of the RPP consumption values used in the IESO settlement, which is trued up every quarter.

a) Please confirm that OEB Staff's understanding of the CT 1142 true-up, as outlined above, is correct.

Yes, the OEB Staff's understanding, as outlined above, is correct.

b) If a true-up for RPP consumption is done quarterly, then please explain why the Applicant indicates in their response to 2d of Appendix A that November and December 2017 were trued up in January 2018? Based on OEB Staff's understanding, the GA rate used in the December 2017 settlement would have been trued up in their January settlement done on February 4th, and the RPP consumption true-up for the October – December 2017 settlements would also be done on this February 4th settlement. Please clarify.

LPDL's response to 2d of Appendix A stated that November and December 2017 were trued up in 2018, not in January 2018. OEB Staff's understanding is correct that the GA rate used in the December 2017 settlement would have been trued up in the January 2018 settlement done on February 4th as well as the consumption true-up for October – December 2017.

c) Please confirm that both of the above true-ups have been accrued for all three years (2015, 2016, 2017) and are all reflected within the ending December 31,
2017 balance of account 1588.

LPDL confirms that both of the above true-ups have been accrued for all three years and are reflected within the December 31, 2017 balance of account 1588.

d) Were these true-ups always done, or are they as a result of a new process that had been implemented.

These true-ups have always been done in that manner.

9-Staff-86
Deferral and Variance Accounts
Ref: Exhibit 9, DVA Continuity Schedule

The Applicant is seeking disposition of approximately $534K credit in account 1588 (refund to ratepayers).

Given that any variance between the RPP revenue and the cost of energy and GA attributable to RPP customers is settled directly with the IESO on a monthly basis, the expectation is that any remaining amounts in account 1588 would be relatively small and close to zero (primarily comprised of the difference between amounts billed at the approved total loss factor versus actual system losses for the year).

a) Given the above expectation, please explain what comprises the balance in account 1588 as at December 31, 2017.

The balance in Account 1588 as at December 31, 2017 is mainly comprised of:

- net system loss (total purchases – total sales = amount left remaining that is under/over recovered) valued at the monthly WAP and GA rates
- slight rate variance for RPP volume due to the rate differential between HOEP that we purchased that volume at from Hydro One/IESO versus the NSLS that we settle on
- slight rate variance for non-RPP volume due to the rate differential between HOEP that we purchased that volume at from Hydro One/IESO versus the interval retail that we settle on

The net 1588 activity for 2015 and 2017 reflect an over-recovery and for 2016, an under-recovery, mainly due to net system losses. The over-recovery for 2015 and 2017 correlate to the calculated loss factors where in each of those years, our actual loss factors are lower than our approved loss factor. The under-recovery for 2016 also correlates to the calculated loss factor where in that year, our actual loss factor is higher than our approved loss factor.

9-Staff-87

Deferral and Variance Accounts

Ref: Exhibit 9, Appendix C, GA Methodology Description

The response to Question 3a details how the Applicant splits CT 148 between accounts

1588 and 1589 (initially Accounts 4707 and 4705). The response to Question 3b provides detail as to how these initial splits are subsequently trued-up once a year after the year-end.

a) Please confirm if OEB Staff's understanding, as outlined below, is correct with respect to how the Applicant initially splits its CT 148 charge. If it is not correct, please clarify accordingly.

   For purposes of allocating CT 148 to Account 1589, the Applicant calculates the GA costs for its Class B Non-RPP customers based on actual meter readings (includes some estimated data for RPP eligible customers enrolled with retailers) for the month multiplied by the actual GA rate. The difference between the total CT148 GA costs and the non-RPP customer calculated GA amount is deemed to be RPP related and allocated to Account 1588.

LPDL calculates the GA costs for LPDLs Class B non-RPP customers based on actual meter readings, and estimated data for RPP eligible customers enrolled with a retailer, <u>all uplifted with approved loss factors</u> so that the billed non-RPP Class B kWh includes losses. LPDL referred to actual meter readings meaning that actual data is used for the current month, rather than prior months' data, but losses are added on.

b) If the above is correct, then under this methodology won't any difference between the approved and actual loss factors be entirely allocated to RPP customers? Will the same also holds true for any prior period billing adjustments?

Only unaccounted for system losses are allocated to RPP customers.

c) Would it be more appropriate to allocate CT 148 based on the actual sales volumes proportions for RPP and Non-RPP customers for each particular month, please explain why not?

LPDL feels it is more current and accurate to use actual current month interval customer data rather than the actual sales volumes for the month as the sales volumes are based on the prior months usage and rate (billing in the current month is based on last month's usage and rates).

c) Please provide a table that quantifies the monthly split of CT 148 based on the actual RPP vs Non-RPP consumption percentages and compare it to what was allocated based on the Applicant's existing methodology to determine if a material difference exists. This comparison should be done monthly for each year since the last disposition of accounts 1588 and 1589 (2015, 2016, 2017).

Lakeland Power - 2015

	per H1/IESO Inv CT 148 Charge	RPP Consumption%	Non-RPP Consumption%	CALCULATED Non-RPP % CT 148 Charge	BOOKED Non-RPPAlloc CT 148 Charge	
Jan-15	$ 1,199,807.78	61.1%	38.9%	$ 467,030.99	$ 467,030.98	$ 0.01
Feb-15	$ 900,102.99	61.2%	38.8%	$ 349,171.62	$ 349,171.63	-$ 0.01
Mar-15	$ 1,349,542.54	56.2%	43.8%	$ 591,116.66	$ 591,116.63	$ 0.03
Apr-15	$ 1,668,997.82	51.4%	48.6%	$ 810,807.55	$ 810,807.55	$ 0.00
May-15	$ 1,548,122.08	45.7%	54.3%	$ 840,997.29	$ 840,997.31	-$ 0.02
Jun-15	$ 1,511,223.96	44.2%	55.8%	$ 843,400.59	$ 843,400.60	-$ 0.01
Jul-15	$ 1,370,612.92	47.1%	52.9%	$ 724,931.70	$ 724,931.71	-$ 0.01
Aug-15	$ 1,392,464.37	46.9%	53.1%	$ 738,823.48	$ 738,823.46	$ 0.02
Sep-15	$ 1,035,387.67	42.0%	58.0%	$ 600,373.03	$ 600,373.06	-$ 0.03
Oct-15	$ 1,329,499.85	62.0%	38.0%	$ 504,905.50	$ 667,109.63	-$162,204.13
Nov-15	$ 2,151,734.32	40.7%	59.3%	$ 1,276,182.65	$ 1,091,733.26	$184,449.39
Dec-15	$ 1,759,796.14	56.8%	43.2%	$ 760,776.24	$ 776,030.47	-$ 15,254.23
	$ 17,217,292.44	51.3%	48.7%	$ 8,508,517.29	$ 8,501,526.29	$ 6,991.00

Lakeland Power - 2016

	per H1/IESO Inv CT 148 Charge	RPP Consumption%	Non-RPP Consumption%	CALCULATED Non-RPP % CT 148 Charge	BOOKED Non-RPPAlloc CT 148 Charge	
Jan-16	$ 1,971,835.92	59.2%	40.8%	$ 804,475.47	$ 797,197.05	$ 7,278.42
Feb-16	$ 2,039,814.24	59.1%	40.9%	$ 834,909.18	$ 834,909.19	-$ 0.01
Mar-16	$ 2,108,660.18	56.5%	43.5%	$ 916,324.61	$ 916,235.85	$ 88.76
Apr-16	$ 1,967,267.91	54.1%	45.9%	$ 903,747.33	$ 914,317.57	-$ 10,570.24
May-16	$ 1,710,008.23	49.3%	50.7%	$ 867,042.73	$ 867,042.72	$ 0.01
Jun-16	$ 1,557,811.69	46.7%	53.3%	$ 830,110.62	$ 830,110.60	$ 0.02
Jul-16	$ 1,500,316.10	50.0%	50.0%	$ 749,440.49	$ 749,440.53	-$ 0.04
Aug-16	$ 1,316,727.72	50.1%	49.9%	$ 657,601.50	$ 657,601.48	$ 0.02
Sep-16	$ 1,512,566.39	47.1%	52.9%	$ 799,903.29	$ 799,903.24	$ 0.05
Oct-16	$ 1,899,513.34	50.7%	49.3%	$ 936,838.45	$ 931,228.34	$ 5,610.11
Nov-16	$ 1,939,240.13	55.1%	44.9%	$ 870,895.83	$ 882,270.81	-$ 11,374.98
Dec-16	$ 1,743,744.16	57.8%	42.2%	$ 735,102.10	$ 749,069.23	-$ 13,967.13
	$ 21,267,506.01	53.0%	47.0%	$ 9,906,391.59	$ 9,929,326.61	-$ 22,935.02

Lakeland Power - 2017

	per H1/IESO Inv CT 148 Charge	RPP Consumption%	Non-RPP Consumption%	CALCULATED Non-RPP % CT 148 Charge	BOOKED Non-RPPAlloc CT 148 Charge	
Jan-17	$ 1,718,665.13	57.7%	42.3%	$ 726,238.18	$ 712,271.05	$ 13,967.13
Feb-17	$ 1,605,666.50	56.7%	43.3%	$ 694,682.73	$ 694,682.72	$ 0.01
Mar-17	$ 1,466,527.33	56.4%	43.6%	$ 639,561.92	$ 639,561.92	$ 0.00
Apr-17	$ 1,764,696.84	51.6%	48.4%	$ 854,080.74	$ 854,080.73	$ 0.01
May-17	$ 1,966,475.83	47.9%	52.1%	$ 1,025,437.69	$ 1,025,437.70	-$ 0.01
Jun-17	$ 1,258,535.41	46.3%	53.7%	$ 675,600.00	$ 1,007,666.86	-$332,066.86
Jul-17	$ 2,549,323.18	60.4%	39.6%	$ 1,010,270.46	$ 626,665.02	$383,605.44
Aug-17	$ 1,354,710.84	57.5%	42.5%	$ 575,519.73	$ 575,519.72	$ 0.01
Sep-17	$ 773,130.16	59.2%	40.8%	$ 315,460.68	$ 468,483.26	-$153,022.58
Oct-17	$ 1,665,758.10	60.4%	39.6%	$ 659,510.65	$ 659,510.64	$ 0.01
Nov-17	$ 1,547,218.93	66.2%	33.8%	$ 522,197.56	$ 522,197.57	-$ 0.01
Dec-17	$ 1,738,781.32	69.3%	30.7%	$ 534,493.50	$ 544,156.88	-$ 9,663.38
	$ 19,409,489.57	57.5%	42.5%	$ 8,233,053.84	$ 8,330,234.07	-$ 97,180.23

PS - 2016

	perIESO Inv CT 148 Charge	RPP Consumption%	Non-RPP Consumption%	CALCULATED Non-RPP % CT 148 Charge	BOOKED Non-RPPAlloc CT 148 Charge	
Jan-16	$ 821,050.18	65.8%	34.2%	$ 281,003.80	$ 263,922.90	$ 17,080.90
Feb-16	$ 822,793.33	65.8%	34.2%	$ 281,368.79	$ 281,368.81	-$ 0.02
Mar-16	$ 822,888.34	63.5%	36.5%	$ 300,716.46	$ 300,716.51	-$ 0.05
Apr-16	$ 765,759.29	62.4%	37.6%	$ 288,154.84	$ 312,961.21	-$ 24,806.37
May-16	$ 641,863.14	56.9%	43.1%	$ 276,818.80	$ 276,818.77	$ 0.03
Jun-16	$ 545,300.57	55.4%	44.6%	$ 243,172.42	$ 243,172.42	-$ 0.00
Jul-16	$ 527,442.06	54.1%	45.9%	$ 242,177.72	$ 242,177.69	$ 0.03
Aug-16	$ 462,544.99	54.7%	45.3%	$ 209,336.27	$ 209,336.30	-$ 0.03
Sep-16	$ 533,911.38	54.5%	45.5%	$ 242,802.52	$ 242,802.49	$ 0.03
Oct-16	$ 673,055.46	57.6%	42.4%	$ 285,238.05	$ 285,238.04	$ 0.01
Nov-16	$ 744,358.81	60.7%	39.3%	$ 292,604.41	$ 292,604.35	$ 0.06
Dec-16	$ 720,849.29	65.4%	34.6%	$ 249,310.13	$ 282,088.13	-$ 32,778.00
	$ 8,081,816.84	59.7%	40.3%	$ 3,192,704.19	$ 3,233,207.62	-$ 40,503.43

PS - 2017

	perIESO Inv CT 148 Charge	RPP Consumption%	Non-RPP Consumption%	CALCULATED Non-RPP % CT 148 Charge	BOOKED Non-RPPAlloc CT 148 Charge	
Jan-17	$ 695,277.62	66.6%	33.4%	$ 232,335.35	$ 199,399.40	$ 32,935.95
Feb-17	$ 649,681.62	64.0%	36.0%	$ 234,063.48	$ 234,061.13	$ 2.35
Mar-17	$ 598,814.70	63.6%	36.4%	$ 218,250.37	$ 218,255.28	-$ 4.91
Apr-17	$ 684,223.89	59.1%	40.9%	$ 279,792.72	$ 279,797.01	-$ 4.29
May-17	$ 729,658.56	56.8%	43.2%	$ 315,292.08	$ 315,019.22	$ 272.86
Jun-17	$ 659,247.51	53.7%	46.3%	$ 305,112.57	$ 337,000.34	-$ 31,887.77
Jul-17	$ 622,776.91	62.9%	37.1%	$ 231,057.15	$ 215,849.70	$ 15,207.45
Aug-17	$ 507,155.85	62.1%	37.9%	$ 192,077.13	$ 196,111.04	-$ 4,033.91
Sep-17	$ 342,973.77	61.2%	38.8%	$ 133,165.53	$ 170,658.26	-$ 37,492.73
Oct-17	$ 639,489.82	61.9%	38.1%	$ 243,442.19	$ 244,290.05	-$ 847.86
Nov-17	$ 612,043.78	69.3%	30.7%	$ 187,819.81	$ 190,099.51	-$ 2,279.70
Dec-17	$ 754,291.01	73.1%	26.9%	$ 202,758.44	$ 236,027.67	-$ 33,269.23
	$ 7,495,635.04	62.9%	37.1%	$ 2,775,166.82	$ 2,836,568.61	-$ 61,401.79

d) If the Applicant believes that their annual true-up process for CT 148 addresses this concern, please explain how it is achieved.

LPDL believes that the annual true-up process for CT148 addresses this concern as our annual GA reconciliation aligns the monthly actual non-RPP Class B kWh at the actual Class B GA rate and compares it to the actual consumption months non-RPP kWh Class B kWh at the 1st estimate Class B GA rate (that they were charged at). The remaining difference (Actual – 1st Estimate GA Rate for non-RPP Class B kWh) is the accurate GA variance, booked to account 1589, which attributed to non-RPP Class B customers only.

9-Staff-88
Deferral and Variance Accounts
Ref: Exhibit 9, Section 9.3.4, Account 1508, Sub-Account – OEB Annual Assessment.

The Applicant is seeking disposition of a debit of $46,326 in this account as at December 31, 2017.

a) Please provide a table that calculates the annual variance from 2016 to the end of 2017 between the OEB cost assessments that were built into rates compared to the actual cost assessments as a result of the new CAM.

1508 OEB Cost Assessment	2008		2016	2017	Balance
Invoice from OEB	$ 8,173		$ 60,558	$ 61,005	$ 129,736
Amount in last CoS - LPDL			$ 32,252	$ 32,252	$ 64,504
Amount in last CoS - PSP	$ -		$ 12,899	$ 12,899	$ 25,798
Carrying charges					$ 2,703
Net to 1548	**$ 8,173**	**$ -**	**$ 15,407**	**$ 15,854**	**$ 42,137**

9-Staff-89
Deferral and Variance Accounts
Ref: Exhibit 9, Section 9.3.4, Account 1592 PILs and Tax Variances for 2006 and Subsequent years.

The Applicant is seeking disposition of a debit of $174,184 in this account. During the former PSP EB-2012-0229, a PILs rate rider was established to return to customers the balance in Account 1562 Deferred PILs Variance Account over a 14-month period. The return to customers was over-returned and therefore a debit balance remains in this account at December 31, 2017.

a) In the EB-2012-0029 proceeding the OEB approved disposition of a credit balance of $182,992 in Account 1562 to be returned to ratepayers over a 14-month period. It appears as though the former PSP returned about double the approved amount, please explain. Please also provide supporting calculations to arrive at the amount as at December 31, 2017.

LPDL does not have any supporting data for this amount only the balance that was in the general ledger upon amalgamation. There is no staff currently employed that is aware of the composition of the account and books/records were either non-existent or lost in the two building floods. LPDL utilized data it could gather from RRR filings and documents on OEB site only.

9.0 DEFERRAL AND VARIANCE ACCOUNTS (EXHIBIT 9)

9.0 –VECC -45

Reference: Exhibit 9, pg. 12

a) Please explain the difference between the $365,471 credit in account 1576 described at page 12 of the evidence and the $364,916 shown in Table 1 at page 6 for account 1576.

The calculation of WACC was updated in RRWF to 5.43% which resulted in a return of $18,823 on $346,648 for a total of $365,471. The DVA schedule used an old version resulting in $18,268 for a return on $346,648. The correct amount is $365,471 and will be corrected in the DVA continuity schedule.

b) Please explain how the disposition methodology proposed for this account appropriately (fairly) allocates the credit to the former rate payers of Parry Sound Power and those of Lakeland Power Distribution.

The credit was proposed to be returned to all customers as LPDL was recommending one tariff sheet on a go forward basis. However, the full credit is a result of Parry Sound assets. LPDL will submit two DVA schedules, separating the respective service territories in order to determine rate riders that align.

9.0 –VECC -46

Reference: Exhibit 9, pg. 29

a) With respect to Account 1592 PILS and Tax Variance please explain how the $169,295 debit to customers is appropriately been recovered as between the former ratepayers of Parry Sound Power and those of Lakeland Power Distribution.

The amount was proposed to be charged to all customers as LPDL was recommending one tariff sheet on a go forward basis. However, the full debit is a result of Parry Sound activities.

9-SEC-32

[Ex.9] With respect to the disposition of DVA accounts:

a. Please confirm that Applicant plans to dispose of the accounts on a harmonized basis.

LPDL will be submitting revised DVA schedules by service territory in order to dispose of DVAs on a non-harmonized basis.

b. Please provide revised rate riders that would clear the DVA account balances on non-harmonized basis (LSDPL and PSP) to align with the way the balances were recorded.

See response to 9-Staff-82.