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February 6, 2025

BY RESS

Ms. Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON
M4P 1E4

Dear Ms. Marconi:

RE: Lakeland Power Distribution Ltd.
EB-2024-0039
2025 Cost of Service Rate Application – Interrogatory Responses

Lakeland Power Distribution Ltd. ("**LPDL**") is submitting its responses to the interrogatories received from Board Staff, VECC and SEC regarding its application for the 2025 Distribution Rates utilizing the 2025 Cost of Service. All responses can be found in this document with the respective appendices and models filed separately.

An electronic copy of these responses (pdf and models in excel) will be submitted through the OEB e-Filing services.

LPDL is filing with the Ontario Energy Board ("OEB") certain information in its interrogatory responses that is confidential and/or not relevant. LPDL is hereby requesting confidential treatment of the information in the table below pursuant to sections 10.01 and 10.02 of the OEB's *Rules of Practice and Procedure* (revised March 6, 2024) and sections 5.1.1, 5.1.2 and 11 of the OEB's *Practice Direction on Confidential Filings* (revised December 17, 2021, "**Practice Direction**").

Reference	Reason for Confidentiality
1-SEC-1 Appendix D PDF Pages 14-17, 23-26 1-SEC-9 Appendix G	Section 11 of the Practice Direction – No Relevance These records contain some information that is relevant and other information that is not relevant to the Proceeding. The redacted information includes business plans and strategies for competitive affiliates of LPDL that are not regulated by the OEB. The business activities of these affiliates are not relevant to the OEB's determination on rates for the regulated entity, LPDL.

PDF Pages 12-14, 19-21	Section 5 – Information is Confidential In the alternative, the redactions are confidential material that is consistently treated in a confidential manner by LPDL's affiliates. These affiliates engage in competitive business activity that could be impaired and prejudice their competitive position should this information be publicly posted.

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

Respectfully submitted,

Dawn Punkari

Dawn Punkari
Interim CFO
Lakeland Holding Ltd.

Table of Contents

Exhibit 1 – Administration

OEB Staff

1-Staff-1

Updated Revenue Requirement Work Form (RRWF) and Models

Upon completing all interrogatories from Ontario Energy Board (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), 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.

In addition, please file an updated set of models that reflects the interrogatory responses. Please ensure the models used are the latest available models on the OEB's 2025 Electricity Distributor Rate Applications webpage.

LPDL has updated the RRWF with the rate changes summarized below. Other models updated in response to IR's have been summarized as well. Excel versions have been posted to RESS.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 2,358,907	6.60%	$ 35,741,053	$ 42,178,437	$ 3,163,383	$ 2,032,770	$ 133,457	$ 6,580,856	$ 11,174,660	$ 1,140,879	$ 10,033,782	$ 797,356
1		Update Rates - Cost of Capital , RTSR, UTR, RPP, WMS	$ 2,340,731	6.57%	$ 35,636,282	$ 40,781,487	$ 3,058,612	$ 2,032,770	$ 134,121	$ 6,580,856	$ 11,157,148	$ 1,140,879	$ 10,016,270	$ 779,844
		Change	-$ 18,176	-0.03%	-$ 104,771	-$ 1,396,950	-$ 104,771	$ -	$ 664	$ -	-$ 17,512	$ 0	-$ 17,512	-$ 17,512
2		Update Fixed Asset & Acc Dep 2024 and 2025 forecast	$ 2,344,242	6.57%	$ 35,689,735	$ 40,790,519	$ 3,059,289	$ 2,037,643	$ 151,486	$ 6,580,856	$ 11,182,897	$ 1,173,880	$ 10,009,017	$ 772,591
		Change	$ 3,511	0.00%	$ 53,453	$ 9,032	$ 677	$ 4,873	$ 17,365	$ -	$ 25,749	$ 33,001	-$ 7,253	-$ 7,253

Explanation of Change	Model Impacted	IR Reference
As per below	RRWF Model	1-Staff-1
Cost of Power - RPP Price Report rates updated	RRWF Model	2-Staff-8
Cost of Power - OER rate updated	RRWF Model	2-Staff-8
Cost of Power - RTSR & UTR rates updated	RRWF Model	2-Staff-8
Cost of Power - WMS & RRRP rates updated	RRWF Model	8-Staff-69
Cost of Capital - DLTDR rate updated	RRWF Model	5-Staff-58
Cost of Capital - DSTDR rate updated	RRWF Model	5-Staff-58, 60
Cost of Capital - ROE rate updated	RRWF Model	5-Staff-58, 61
Cost of Capital - Prescribed Interest rates updated	RRWF Model	5-Staff 60
2024 Estimate and 2025 Forecast Capital & Accum Dep updated *(see Note 1 below)*	RRWF Model	2-Staff-6
2025 HONI UTR and RTSR rates updated	RTSR Model	8-Staff-72
RRWF model updates	Cost Allocation Model	1-Staff-1
RRWF model updates	Test Year Income Tax PILS Model	1-Staff-1
RPP/TOU Rates	Tariff Schedule and Bill Impact Model	8-Staff-70
OER Rate	Tariff Schedule and Bill Impact Model	8-Staff-70
DRP Rate	Tariff Schedule and Bill Impact Model	8-Staff-70
Pole Attachment Charge and Inflation Factor	Tariff Schedule and Bill Impact Model	8-Staff-70
WMS & RRRP Rates	Tariff Schedule and Bill Impact Model	8-Staff-70
RRWF model updates	Tariff Schedule and Bill Impact Model	1-Staff-1
2024 Estimates and 2025 Forecast updated *(see Note 1 below)*	Chapter 2 Appendices - Tab 2-AA	2-Staff-6
2024 Estimates and 2025 Forecast updated *(see Note 1 below)*	Chapter 2 Appendices - Tab 2-AB	2-Staff-6
2024 Estimates and 2025 Forecast updated *(see Note 1 below)*	Chapter 2 Appendices - Tab 2-BA	2-Staff-6
2024 Estimates and 2025 Forecast updated *(see Note 1 below)*	Chapter 2 Appendices - Tab 2-C	2-Staff-6
2024 Actuals updated	Chapter 2 Appendices - Tab 2-H	6-Staff-62
2024 Actuals updated *(see Note 2 below)*	Chapter 2 Appendices - Tab 2-JA	4-Staff-32
2024 Actuals updated	Chapter 2 Appendices - Tab 2-JB	4-Staff-32
2024 Actuals updated *(see Note 2 below)*	Chapter 2 Appendices - Tab 2-JD	4-Staff-32
Pricing Methodology and % of Corporate Costs updated	Chapter 2 Appendices - Tab 2-N	4-Staff-52
Cost of Capital - DSTDR and ROE rates updated	Chapter 2 Appendices - Tab 2-OA	5-Staff-58, 60
Actual Rate % provided and formatted; Term on Loan-11 updated for 2022	Chapter 2 Appendices - Tab 2-OB	5-VECC-31
Cost of Power - RPP Price Report rates updated	Chapter 2 Appendices - Tab 2ZA	2-Staff-8
Cost of Power - RTSR, WMS, RRRP, OER rates updated	Chapter 2 Appendices - Tab 2ZB	2-Staff-8, 8-Staff-69
Prescribed Interest Rates	DVA Continuity Schedule	9-Staff-74
Account to Dispose updated from Y to N (1595-2020 and 1595-2021)	DVA Continuity Schedule	9-Staff-74
Prescribed Interest Rates	1592 Accelerated CCA Calculation	9-Staff-74
2024 Actual Customer Count and 2025 Customer Forecast updated	Load Forecast Model	3-Staff-28
2024 Actual Consumption and 2025 Consumption Forecast updated	Load Forecast Model	3-Staff-29

Note 1 - 2025 Forecast has been revised to include an increase of $180K for System Service-SCADA (postponed from 2024 and shifted to 2025) as well as a decrease of $200K in Contributed Capital due to upcoming DSC changes to Facilitate the Connection of Housing Developments. 2026-2029 Contributed Capital have also been decreased by $150K/year for the upcoming DSC change eff Mar/25.

Note 2 - 2025 Forecast Total OM&A has remained the same however $35K was shifted from Account 5315 to Account 5085 (see 1-Staff-5)

1-Staff-2
Internal Scorecard
Ref: Exhibit 1, Part 1 of 2, Appendix A, PDF pp. 112-114

Preamble:
At the above reference, Lakeland Power provides its internal "2024, 2025, 2026 Balanced Scorecard" showing various Key Performance Indicators and associated timelines.

Questions:
(a) If available, please provide the 2024 results of this scorecard. If not available, please provide a summary of the expected results.

lakeland POWER

2024 BALANCED SCORECARD

1 **Environmental Health & Safety**

	Key Performance Indicator	Timeline	Improvement Same/Yes/No	Responsibility	Update
a	Zero Loss Time Accidents Annually	2024-2027	Same	Brian/Andrew/ Jordan/Sharon	Drilled to eaves re: ice in parking lot - replacing pole bunks
b	Cyber attack - no loss of customer information and/or money	2024-2027	Same	Brian/Andrew/ Jordan/Sharon	0
c	AI & ES Committees	2024-2027	Yes	Brian/Andrew/ Jordan/Sharon	Going well
d	Compliance Science at least 95%	2024-2027	TBD	Brian/Andrew/ Jordan/Sharon / Taylor	Transferred to Bamboo platform no scoring available as of yet

2 **Team**

	Key Performance Indicator	Timeline	Improvement Same/Yes/No	Responsibility	Update
a	1 Vacant linesperson?	2024	Same	Brian/Andrew	Eng Supv position filled
b	New Meter Technician Apprenticeship?	2024	Same	Brian/Jordan / Taylor	Delayed to 2025

3 **Customer Service & Investments**

	Key Performance Indicator	Timeline	Improvement Same/Yes/No	Responsibility	Update
a	Ensure in top 10% of most reliable distribution companies in Ontario. Annual average number of times that power to a customer is interrupted = <0.77	2024-2027	Same	Jordan/Muhammad/ Andrew	0.77
b	Ensure in top 10% of most reliable distribution companies in Ontario. Annual average number of hours that power to a customer is interrupted = <1 hour34 minutes	2024-2027	No	Jordan/Muhammad/ Andrew	3 hour 58 minutes - heavy snow storm over several days end of November early December

	Key Performance Indicator	Timeline	Improvement Same/Yes/No	Responsibility	Update
c	Improve PowerAssist 24-hour outage assistance - TextPower	2024	Yes	Sharon/Jordan / Andrew	Improvements continue - 'Welcome' text sent out - real outage worked well - 3262 phone signed up. Best during storms that outage map taken back by Lakeland to keep current.
d	Implement Customer Education Plan to improve satisfaction	2024-2025	Same	Sharon/Jordan	Educational in nature - successfully surveyed Cost of Service plan comments from customers
e	Install at least 2 new Smart Switches annually to increase smart grid operations	2024-2027	Yes	Jordan/Muhammad/ Andrew	3 installed in Bracebridge and 2 in Parry Sound
f	Annual operations: continue porcelain switch replacements, IR scanning, implement asset management plan, tree trimming	2024-2027	Yes	Jordan/Muhammad/ Andrew	Scan found rotted pole that was replaced among other items
g	Northstar Billing Upgrade	2024/2025	Yes	Sharon	New refreshed bill design completed and being utilized
h	New M3 Substation replacement to connect more customers to local Bracebridge TS improving reliability vs Utterson	2024 = engineering	Yes	Jordan/Muhammad/ Andrew	Topographic surveying completed. Geogechnical study completed. Ground testing study completed. Transformer tender has been received, and the formal design plans by Costello have begun. Damaged transformer out for inspection.

4 Financial

	Key Performance Indicator	Timeline	Improvement Same/Yes/No	Responsibility	Update
a	Complete Cost of Service Application to Ontario Energy Board	2024	Yes	Darren/Sharon /Jordan/Muhammad / Andrew	Completed and with OEB
b	Annually ensure are in 10% lowest controllable cost per customer distribution companies in Ontario	2024 = <$347	Yes	Jordan/Muhammad/ Andrew/Sharon	~$343 forecasted
c	Annually increase Ebilling - reducing costs by proactively engaging customers to enroll	2024 = 44%	Yes	Sharon	50% current - mail strike assisted in getting additional customers signed up
d	Annual Days Sales Outstanding = <30	2024-2027	Yes	Sharon	~29 days
e	Annual Return on Capital Employed = >8%	2024-2027	Yes	Jordan/Darren	~9.5% forecasted

(b) Does Lakeland Power expect the Key Performance Indicators and targets to evolve over time?

Yes, LPDL Key Performance Indicators and targets will continually evolve as priorities change moving forward, with a focus on maintaining a balanced scorecard.

1-Staff-3
Paperless Billing
Ref 1: Exhibit 1, Part 1 of 2, Section 1.1.2, p. 11
Ref 2: Exhibit 1, Part 1 of 2, Appendix A, PDF p. 114 of 238

Preamble:
One of Lakeland Power's strategic priorities for 2024 onwards is to increase the number of customers on paperless billing. Reference 2 includes Lakeland Power's internal

scorecard showing a Key Performance Indicator to annually increase e-billing, thereby "reducing costs by proactively engaging customers to enroll". The 2025 target is 47%.

Questions:

(a) Please provide the cost savings associated with an increase of three percent in enrollment of customers on e-billing (i.e., target of 44% in 2024 to 47% in 2025) and explain how the savings were calculated.

LPDL has estimated a cost savings associated with an increase of three percent in enrollment of customers on e-billing of $4K annually. This savings was calculated using 47% of 2025 forecasted residential customers less 44% of current residential customers multiplied by $1.05 multiplied by 12 months.

(b) Has Lakeland Power incorporated any anticipated OM&A savings in the 2025 test year related to its 2025 target to have fewer customers on paper billing? If not, please explain why.

Yes, LPDL has incorporated any anticipated OM&A savings into the 2025 test year. Any savings from the increase in e-bill customers will help to offset other costs beyond LPDL's control, such as unforeseen regulatory changes requiring system updates. Most customers on e-billing also use the online portal where they have many options to self-serve. Increasing customer self-service reduces call volume providing room for efficiencies within the Billing department to maintain the work at a manageable for our current staffing level.

1-Staff-4
Application Specific Customer Engagement
Ref 1: Exhibit 1, Part 1 of 2, Section 1.4.3, p. 58
Ref 2: Exhibit 1, Part 1 of 2, Appendix I

Preamble:
Lakeland Power completed an application specific customer engagement survey. The purpose of the engagement was to gather and consider the feedback received on Lakeland Power's Distribution System Plan filing and proposed investment plan.

Reference 2 shows a summary of options presented to customers as statements (e.g., affordability of electricity), and asked customers to select their respective top five in terms of importance to them.

Questions:

(a) Please confirm whether specific capital projects were presented to customers to gather feedback.

No, specific capital projects were not presented to customers to gather feedback. The focus of the survey engagement was to ascertain where customer focus lies to help direct LPDL's project choices when building the DSP.

(b) If the answer is (a) is yes, what was the customers' feedback on each project?

Not applicable.

1-Staff-5
Activity and Program-Based Benchmarking - Billing O&M
Ref: Exhibit 1, Section 1.5.4, p. 76

Preamble:
Lakeland Power has an average Billing O&M cost that is higher than the industry average by 31%. Lakeland Power states that COVID and bad debt are the drivers for the cost abnormalities.

Question:

(a) Please provide detailed explanations to the impact of bad debt on Billing O&M unit cost since the bad debt USoA shouldn't be included in the calculation.

LPDL confirms that Billing O&M, as reported in the Activity and Program-Based Benchmarking, only includes account 5315 activity and does not include Bad Debt. LPDL's bad debt expense is recorded in account 5335 and has no impact on Billing O&M unit cost. LPDL's Billing O&M in account 5315 includes PowerAssist, LPDL's outage management communication tool, for $30K/yr and Elster meter service costs for firmware upgrades and meter network communication issues for $24K/yr. LPDL has confirmed with other LDC's that they record these costs in operations expense and meter reading expense rather than billing. LPDL would only be higher than <20% which would be more reflective of utilities of our size. LPDL has realigned these expenses to operations and meter reading expenses, in 2024 and onward, to reflect these costs in the appropriate accounts.

School Energy Coalition (SEC)

SEC-1

[Exhibit 1, p. 12 and Appendix E] With respect to the Strategic Plans:

a. Please confirm that Strategic Plans are prepared for five year periods, as set forth in Appendix E, rather than three years as set forth on page 12. If not confirmed, please explain.

LPDL confirms that LHL's Strategic Plan is prepared for five years and the LPDL scorecards are three years in length to accommodate the rapidly changing industry.

b. Please provide the Strategic Plans for the periods commencing 2019 and 2022, as well as 2024 if available.

LPDL's 3-year Strat Plan for 2019 is attached as LPDL_Appendix A - 1-SEC-1 - LPDL Strat Plan Scorecard – 2019.
LPDL's 3-year Strat Plan for 2022 is attached as LPDL_Appendix B - 1-SEC-1 - LPDL Strat Plan Scorecard – 2022.
LPDL's 3-year Strat Plan for 2024 is attached as LPDL_Appendix C - 1-SEC-1 - LPDL Strat Plan Scorecard – 2024.

c. Please confirm that Appendix E is the entire Strategic Plan, rather than excerpts related to the regulated utility. If not confirmed, please provide the entire Strategic Plan.

LPDL confirms that Appendix E, as originally filed, was not the entire plan.

LPDL's full Strat Plan for 2024 is attached as LPDL_Appendix D - 1-SEC-1 - LHL Annual Shareholder Strategic Plan Update – 2023.

SEC-2

[Ex. 1, p. 25-6] Please confirm that no capital expenditure costs relating to renewable energy/connections/expansions, smart grid, and/or regional planning initiatives are currently known or anticipated. If any are known or anticipated, please provide details.

LPDL confirms that at the time of this interrogatory response, there are no known Renewable Energy Generation expenditures planned over the forecast period (see page 42 of DSP).

LPDL has Smart Grid expenditures planned under Distribution Automation. See table 2-AA or Appendix A – Material Investments in the DSP.

3. HISTORICAL AND FUTURE CAPITAL EXPENDITURES

Historical and future capital expenditures are summarized in the table below.

Category	Historical ($'000)					Bridge	Forecast ($'000)				
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
SCADA/Grid Automation	2	0	0	50	191	140	266	70	70	250	250

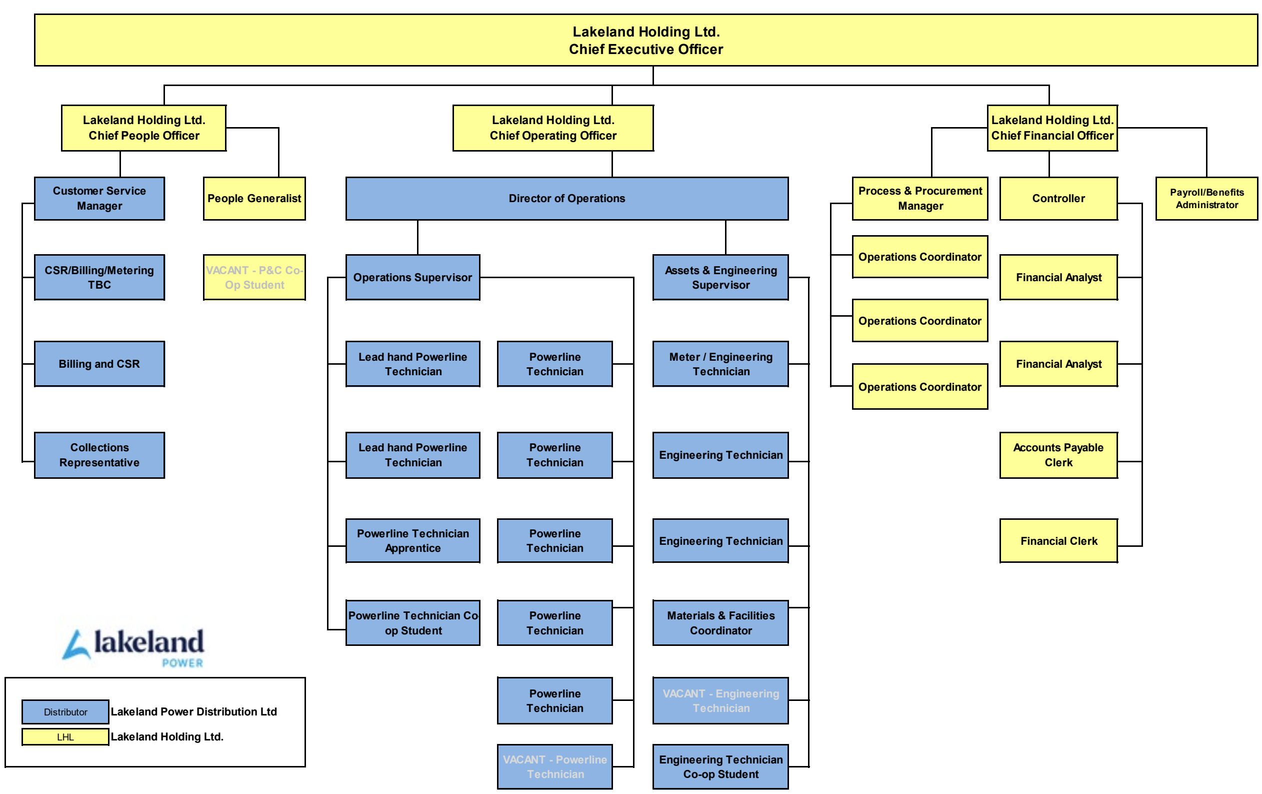
LPDL confirms there are no Regional Planning Initiative expenditures planned over the forecast period (see page 42 of DSP).

SEC-3

[Ex. 1, p. 40-3 and Ex. 4, p. 15] Please provide an Org. chart showing all positions within the corporate group that provide services related to the regulated utility (whether the 22 employed directly by the utility or the 75 others employed within the corporate group), and indicating for each position:

a. The legal employer of the individual.

The following Org. chart represents all LPDL and LHL employees, 22 and 15 respectively. The remaining employees, part of the above-mentioned 75, are employees of the affiliate companies, LEL and BGL.



b. The percentage of the individual's full costs (direct and indirect remuneration and benefits, overheads, and any other costs) expected to be borne in the Test Year by each of the companies in the corporate group.

LPDL has presented the percentage of corporate staff costs cross-charged to each affiliate in the table below:

LH Corporate Wages to Affiliates - By Company - 2023				
Corporate Position	Lakeland Power	Lakeland Energy	Bracebridge Generation	Total
CEO	25.0%	24.6%	50.4%	100.0%
CFO	36.8%	31.3%	31.9%	100.0%
COO	29.1%	32.6%	38.3%	100.0%
CPO	27.6%	48.1%	24.3%	100.0%
Controller	41.4%	30.9%	27.7%	100.0%
P/R, Benefits, Regulatory	47.5%	29.8%	22.7%	100.0%
Financial Analyst	47.7%	34.3%	18.0%	100.0%
Procurement Manager	37.5%	53.9%	8.6%	100.0%
Operations Coordinator	61.6%	2.0%	36.4%	100.0%
HR Generalist	36.8%	34.2%	29.0%	100.0%
A/P - Lakeland Power	80.5%	10.4%	9.2%	100.0%
A/P - Parent and Affiliate	0.0%	57.3%	42.7%	100.0%

All LHL parent company staff record their actual hours spent on each affiliate's tasks on their weekly timesheet. The corporate allocation then represents LPDL's direct portion of the LHL's executive, finance, operations support, and human resources staff costs based on the portion of their actual time and wages attributable to LPDL tasks. The allocation is variable, not fixed. LPDL's portion of LHL's costs are then cross charged as direct costs to LPDL through the management fee. As can seen above, the allocation across affiliates is based on actual time spent on each affiliate's tasks and reflects that each affiliate is charged their true portion of LH's costs thus LPDL is not burdened with the other affiliates share of LHL's costs. This, with increasing time spent on regulatory requirements and rate applications, LPDL's portion of corporate costs has increased, with a spike seen in 2019 and 2024 due to the Cost of Service applications. This direct cost allocation does not include any overtime costs as LHL staff are not compensated for overtime worked. For 2024 and January 2025, that equated to approximately $122K that was not cross charged to LPDL, which is ultimately a savings to the rate payer that can not be sustained.
The 2025 test year allocation was based on an average of historical actual allocation percentages.

SEC-4

[Ex. 1, p. 45] Please provide specifics as to the aspects of "the Cost Allocation and Demand Profile methodology" that the Applicant is asking the OEB to approve.

LPDL's Cost Allocation and Demand Profile methodologies are detailed in Exhibit 7, sections 7.1.2 and 7.1.3 specifically.

SEC-5

[Ex. 1, p. 55-6] With respect to the new customer portal:

a. Please confirm that the portal will be integrated with the Green Button program.

LPDL confirms that Green Button integration will be a requirement for its customer portal.

b. Please describe the extent, if any, to which the Applicant is leveraging its relationship with the CHEC Group to reduce the cost and/or increase the functionality of the portal.

At the time of this COS application, there had not been CHEC involvement regarding customer portals. In Q1 2025, CHEC is hosting a meeting regarding customer portals. LPDL will be involved in the discussion with other LDC's who are interested in moving to a new portal if feasible.

c. Please provide details as to which customer classes will be able to use the functionality of the customer portal.

LPDL will be looking for a portal that will support all customer classes.

SEC-6

[Ex. 1, p.72 and Ex.4, p. 6] Please provide the total cost per customer for each of the years 2019-2023 (actual) and 2024-2025 (forecast).

LPDL has provided the actual total cost per customer for 2019 to 2023 as calculated on the OEB Scorecard for LPDL. LPDL will provide data required for the 2024 scorecard results to the OEB by the OEB's Apr 30/25 due date.

Scorecard - Lakeland Power Distribution Ltd. 8/14/2024

Performance Outcomes	Performance Categories	Measures	2019	2020	2021	2022	2023	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time	100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Scheduled Appointments Met On Time	100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Telephone Calls Answered On Time	89.61%	89.90%	90.81%	90.21%	93.38%		65.00%	
	Customer Satisfaction	First Contact Resolution	99.97	99.97%	99.96%	99.96%	99.93			
		Billing Accuracy	99.94%	99.92%	99.92%	99.64%	99.92%		98.00%	
		Customer Satisfaction Survey Results	75.5	77%	77%	77%	75			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness	83.80%	82.40%	82.40%	82.60%	82.60%			
		Level of Compliance with Ontario Regulation 22/04 [1]	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]	1.29	5.79	2.62	3.84	1.30			1.81
		Average Number of Times that Power to a Customer is Interrupted [2]	0.66	1.40	1.48	1.30	0.66			0.85
	Asset Management	Distribution System Plan Implementation Progress	In Progress	In Progress	In Progress	In Progress	In Progress			
	Cost Control	Efficiency Assessment	2	2	2	2	2			
		Total Cost per Customer [3]	$730	$718	$715	$795	$893			
		Total Cost per Km of Line [3]	$28,074	$28,361	$27,856	$29,642	$33,833			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Connection of Renewable Generation	New Micro-embedded Generation Facilities Connected On Time							90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	1.69	1.58	0.92	1.31	0.72			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	1.18	1.24	1.14	1.15	1.33			
		Profitability: Regulatory Return on Equity: Deemed (included in rates)	8.98%	8.98%	8.98%	8.98%	8.98%			
		Profitability: Regulatory Return on Equity: Achieved	11.51%	6.07%	12.06%	11.82%	11.02%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.

Legend: 5-year trend: up, down, flat. Current year: target met, target not met.

SEC-7

[Ex. 1, p. 75] Please provide an estimate of the average unit cost of Stations CAPEX for each of 2023, 2024, 2025, and 2026.

USoA [1820] Capital Additions																	
Cost ($1,000)						Scale (Total MVA)						Unit Cost ($/MVA)					
2023	2024	2025	2026	2027	Average	2023	2024	2025	2026	2027	Average	2023	2024	2025	2026	2027	Average
272.4	150.0	120.0	1,000.0	2,000.0	708.5	75.5	75.5	75.5	70.5	80.5	75.5	3,607	1,987	1,589	14,184	24,845	9,242.55

The incremental costs in 2026 and 2027 are for the removal of the existing 5MVA Bracebridge MS3 station and replacement with a larger 10MVA station.

SEC-8

[Ex. 1, p. 76] Please confirm that all Billing O&M costs are incurred within the affiliated companies and charged to the utility through shared services allocations. If not confirmed, please provide a breakdown of the Billing O&M costs directly incurred by the utility as compared to those incurred by affiliates and charged to the utility.

LPDL does not use affiliated companies for shared services in Billing O&M costs. LPDL's billing and customer service labour is performed by LPDL in-house staff and included in Billing O&M costs. The remainder of Billing O&M costs include bill print services, bill inserts, Canada Post fees, bank fees, website management, outage reporting phone service, NorthStar CIS annual maintenance and upgrades required to accommodate

Ministry initiatives and Regulatory changes, which are all provided by outside 3rd party vendors.

SEC-9

[Ex. 1, p. 88] With respect to the financial statements, please provide:

a. The 2024 audited financial statements, as soon as they are available.

LPDL will provide the 2024 audited financial statements as soon as they are available.

b. The 2022, 2023, and 2024 consolidated financial statements for the parent company, together with any Annual Reports for those years by the parent company.

LPDL has provided the following consolidated financial statements and Annual Reports for LHL, the parent company:

- LPDL_Appendix E - 1-SEC-9 - 2022 FS Lakeland Holding Consolidated IFRS
- LPDL_Appendix F - 1-SEC-9 - 2023 FS Lakeland Holding Consolidated IFRS
- LPDL_Appendix G - 1-SEC-9 - LHL Annual Shareholder Strategic Plan Update - 2022
- LPDL_Appendix D - 1-SEC-1 - LHL Annual Shareholder Strategic Plan Update - 2023

LPDL's 2024 consolidated financial statements should be available mid-April 2025.

SEC-10

[Ex. 1, App. E (A), p. 10] Please describe how Board Members, Senior Executives, and Senior Managers "bear the risk of ownership just as our shareholders do" .

It is important to note that this phrase originates from the Holding company level. At Lakeland Power, Board Members and Executives do not have a financial stake or interest in the company. Their primary role is to ensure the safe and reliable distribution of electricity to our customers at fair and just rates. To fulfill this crucial responsibility, the company has implemented a robust framework of good management practices. These include comprehensive policies and procedures, annual detailed risk assessments, ongoing education, annual performance reviews of Board members and management, and continued governance education. These measures are designed to guarantee that we provide the best possible service to our Power customers, always acting in the best interest of our shareholders

SEC-11

[Ex. 1, App. E, p. 11] Please provide a copy of the “comprehensive stakeholder/influencer analysis”.

For LPDL’s 2025 COS application, results from the Customer Satisfaction, Employee Satisfaction and ESA surveys are utilized to drive safety protocols, capital spending, changes in technology, etc., rather than a specific report.

SEC-12

[Ex. 1, App. E, p. 15] Please provide a copy of the new “Human Resource Strategy”.

LPDL has attached LPDL_Appendix H - 1-SEC-12 - Human Resource Strategy 2023-2025.

Vulnerable Energy Consumers Coalition (VECC)

1.0-VECC-1

Reference: Exhibit 1, pages 47-

a) Please provide the date an acquisition/amalgamation for each of the six separate service territories of LPDL.

On September 1, 2000, LHL and its subsidiaries became incorporated companies by merging the hydro assets of the following municipalities: Bracebridge, Huntsville, Burk’s Falls, Sundridge and Magnetawan. In July 2014, Lakeland Power merged with Parry Sound Power.

1.0-VECC-2

Reference: Exhibit 1, page 65 (Table 24) and pages 69-70
Exhibit 2, Appendix A (DSP), page 48 (Table 5.2-7)

a) With respect to Table 24 (Exhibit 1), please provide the annual (2019-2023) values for LPDL’s average number of hours that power to a customer is interrupted separately for: i) the former Parry Sound service area and ii) the balance of LPDL’s service area.

Average Number of hours					
	2019	2020	2021	2022	2023
Bracebridge	1.56	2.37	1.54	3.18	1.92
Burks Falls	3.49	5.45	3.98	0.71	3.14
Huntsville	1.48	1.14	4.46	1.82	2.68
Magnetawan	4.35	1.36	7.34	2.43	1.30
Parry Sound	2.49	1.99	2.19	5.98	3.09
Sundridge	8.10	3.34	3.00	2.19	1.87
Total	2.06	2.37	2.16	2.87	2.26

b) With respect to Table 24 (Exhibit 1), please provide the annual (2019-2023) values for LPDL's average number of times that power to a customer is interrupted separately for: i) the former Parry Sound service area and ii) the balance of LPDL's service area.

With MED & LoS - Number of customer interruptions - SAIFI					
	2019 SAIFI	2020 SAIFI	2021 SAIFI	2022 SAIFI	2023 SAIFI
Bracebridge	5.729	7.458	6.018	6.633	1.133
Huntsville	1.347	2.067	1.998	4.105	1.150
Burks Falls	1.544	3.566	11.75	6.899	3.395
Sundridge	5.457	1.144	1.977	4.256	1.047
Magnetawan	3.483	3.098	4.888	3.146	2.380
Parry Sound	0.134	0.909	0.137	0.349	0.270

c) With respect to Table 5.2-7 (DSP), please provide the 2023 emergency response performance percentages separately for: i) the former Parry Sound service area and ii) the balance of LPDL's service area.

2023 Emergency Response Performance %		
	% - Balance of LPDL's Service Area	Parry Sound Portion of LPDL's Service Area
January		
February		
March		
April	100%	
May	100%	
June	83%	
July	100%	100%
August	100%	
September	100%	100%
October	100%	100%
November	100%	
December	100%	100%

1.0-VECC-3

Reference: Exhibit 1, page 68 & Appendix G

"*For more than ten years now, LPDL has engaged a third party to conduct biennial customer satisfaction surveys*."

a) Has LPDL employed the same party to conduct the last 10 years surveys?

No, LPDL has used three different companies; RedHead Media, Advanis, and in 2025 Oraclepoll.

b) What was the cost of the last (2023?) biennial customer survey?

The cost of the last 2023 biennial customer survey was $9,917.

1.0-VECC-4

Reference: Exhibit 1, pages 75 – 82

a) Please update Tables 27 through 36 to include 2023 and 2024 results.

LPDL has updated the APB tables for 2023 results. LPDL will provide data required for the 2024 APB results to the OEB by the OEB's Apr 30/25 due date.

Billing O&M

	Cost ($1,000)							Scale (1,000 Customers)							Unit Cost ($/Customer)						
	2018	2019	2020	2021	2022	2023	Avg	2018	2019	2020	2021	2022	2023	Avg	2018	2019	2020	2021	2022	2023	Avg
LPDL	475.6	487.1	486.9	467.3	508.9	551.8	**496.3**	13.6	13.8	13.9	14.2	14.4	14.6	**14.1**	34.86	35.39	34.94	32.95	35.46	37.81	**35.24**
Chg by Year $		11.49	(0.11)	(19.69)	41.60	42.99			0.12	0.17	0.24	0.17	0.24			0.54	(0.45)	(1.99)	2.51	2.36	
Chg by Year %		2.4%	0.0%	-4.0%	8.9%	8.4%			0.9%	1.3%	1.8%	1.2%	1.7%			1.5%	-1.3%	-5.7%	7.6%	6.6%	

Metering O&M

	Cost ($1,000)							Scale (1,000 Customers)							Unit Cost ($/Customer)						
	2018	2019	2020	2021	2022	2023	Avg	2018	2019	2020	2021	2022	2023	Avg	2018	2019	2020	2021	2022	2023	Avg
LPDL	176.6	168.8	220.3	153.9	172.1	180.3	**178.7**	13.6	13.8	13.9	14.2	14.4	14.6	**14.1**	12.94	12.26	15.81	10.85	12.00	12.35	**12.70**
Chg by Year $		(7.80)	51.50	(66.39)	18.26	8.14			0.12	0.17	0.24	0.17	0.24			(0.68)	3.54	(4.95)	1.14	0.36	
Chg by Year %		-4.4%	30.5%	-30.1%	11.9%	4.7%			0.9%	1.3%	1.8%	1.2%	1.7%			-5.2%	28.9%	-31.3%	10.5%	3.0%	

Vegetation Management O&M

	Cost ($1,000)							Scale (1,000 Poles)							Unit Cost ($/Pole)						
	2018	2019	2020	2021	2022	2023	Avg	2018	2019	2020	2021	2022	2023	Avg	2018	2019	2020	2021	2022	2023	Avg
LPDL	193.6	180.4	208.1	203.8	160.2	167.4	**185.6**	6.3	6.3	6.4	6.4	6.4	6.4	**6.4**	30.51	28.47	32.71	31.95	25.21	26.29	**29.19**
Chg by Year $		(13.22)	27.63	(4.24)	(43.61)	7.15			(0.01)	0.02	0.02	(0.02)	0.01			(2.04)	4.24	(0.77)	(6.74)	1.08	
Chg by Year %		-6.8%	15.3%	-2.0%	-21.4%	4.5%			-0.2%	0.4%	0.3%	-0.4%	0.2%			-6.7%	14.9%	-2.3%	-21.1%	4.3%	

Lines O&M

	Cost ($1,000)							Scale (Circuit km of Primary Line)							Unit Cost ($/Circuit km Primary Line)						
	2018	2019	2020	2021	2022	2023	Avg	2018	2019	2020	2021	2022	2023	Avg	2018	2019	2020	2021	2022	2023	Avg
LPDL		763.5	1,007.9	1,001.6	1,256.3	996.9	**1,005.2**		358.0	353.0	364.0	385.0	385.0	**369.0**		2,132.72	2,855.34	2,751.57	3,263.17	2,589.34	**2,718.43**
Chg by Year $			244.42	(6.36)	254.75	(259.43)				(5.00)	11.00	21.00	-				722.63	(103.77)	511.60	(673.83)	
Chg by Year %			32.0%	-0.6%	25.4%	-20.6%				-1.4%	3.1%	5.8%	0.0%				33.9%	-3.6%	18.6%	-20.6%	

Stations O&M

	Cost ($1,000)							Scale (Total MVA)							Unit Cost ($/MVA)						
	2018	2019	2020	2021	2022	2023	Avg	2018	2019	2020	2021	2022	2023	Avg	2018	2019	2020	2021	2022	2023	Avg
LPDL	55.3	67.3	74.6	73.5	80.1	276.4	**104.5**	80.5	75.5	76.0	75.5	75.0	75.5	**76.3**	686.61	891.72	981.56	972.95	1,068.38	3,660.31	**1,376.92**
Chg by Year $			7.27	(1.14)	6.67	196.22				0.50	(0.50)	(0.50)	0.50			205.11	89.85	(8.61)	95.43	2,591.93	
Chg by Year %			10.8%	-1.5%	9.1%	244.9%				0.7%	-0.7%	-0.7%	0.7%			29.9%	10.1%	-0.9%	9.8%	242.6%	

Poles, Towers & Fixtures O&M

	Cost ($1,000)							Scale (1,000 Poles)							Unit Cost ($/Pole)						
	2018	2019	2020	2021	2022	2023	Avg	2018	2019	2020	2021	2022	2023	Avg	2018	2019	2020	2021	2022	2023	Avg
LPDL	3.6	27.1	50.5	32.9	92.0	93.0	**49.8**	6.3	6.3	6.4	6.4	6.4	6.4	**6.4**	0.57	4.27	7.93	5.16	14.48	14.61	**7.84**
Chg by Year $			23.41	(17.52)	59.08	1.01				0.02	0.02	(0.02)	0.01			3.70	3.67	(2.77)	9.32	0.13	
Chg by Year %			86.5%	-34.7%	179.4%	1.1%				0.4%	0.3%	-0.4%	0.2%			653.5%	85.9%	-34.9%	180.5%	0.9%	

Stations CAPEX

	Cost ($1,000)							Scale (Total MVA)							Unit Cost ($/MVA)						
	2018	2019	2020	2021	2022	2023	Avg	2018	2019	2020	2021	2022	2023	Avg	2018	2019	2020	2021	2022	2023	Avg
LPDL	-	-	8.1	95.1	-	272.4	**125.2**	80.5	75.5	76.0	75.5	75.0	75.5	**76.3**	-	-	106.25	1,259.51	-	3,607.50	**1,657.75**
Chg by Year $			8.08	87.02	(95.09)	272.37				0.50	(0.50)	(0.50)	0.50					1,153.26	(1,259.51)	3,607.50	
Chg by Year %			#DIV/0!	1077.6%	-100.0%	#DIV/0!				0.7%	-0.7%	-0.7%	0.7%					1085.4%	-100.0%	#DIV/0!	

Poles, Towers and Fixtures CAPEX

	Cost ($1,000)							Scale (Pole Additions)							Unit Cost ($/Pole Addition)						
	2018	2019	2020	2021	2022	2023	Avg	2018	2019	2020	2021	2022	2023	Avg	2018	2019	2020	2021	2022	2023	Avg
LPDL	756.5	989.5	733.4	1,556.5	2,215.2	1,677.6	**1,321.4**	94.0	95.0	95.0	128.0	142.0	130.0	**114.0**	8,047.37	10,415.62	7,719.77	12,159.97	15,600.06	12,904.45	**11,141.21**
Chg by Year $			(256.11)	823.10	658.73	(537.63)				-	33.00	14.00	(12.00)			2,368.25	(2,695.85)	4,440.20	3,440.09	(2,695.61)	
Chg by Year %			-25.9%	112.2%	42.3%	-24.3%				0.0%	34.7%	10.9%	-8.5%			29.4%	-25.9%	57.5%	28.3%	-17.3%	

Lines Transformer CAPEX

	Cost ($1,000)							Scale (Lines Transformer Additions)							Unit Cost ($/Lines Transformer Addition)						
	2018	2019	2020	2021	2022	2023	Avg	2018	2019	2020	2021	2022	2023	Avg	2018	2019	2020	2021	2022	2023	Avg
LPDL	454.8	482.0	294.2	762.4	590.8	604.3	**531.4**	50.0	62.0	60.0	91.0	80.0	81.0	**70.7**	9,096.02	7,774.42	4,902.88	8,377.70	7,384.95	7,460.62	**7,499.43**
Chg by Year $			(187.84)	468.20	(171.57)	13.51				(2.00)	31.00	(11.00)	1.00			(1,321.60)	(2,871.54)	3,474.82	(992.75)	75.67	
Chg by Year %			-39.0%	159.2%	-22.5%	2.3%				-3.2%	51.7%	-12.1%	1.3%			-14.5%	-36.9%	70.9%	-11.8%	1.0%	

Meters CAPEX

	Cost ($1,000)							Scale (1,000 Customers)							Unit Cost ($/Customer)						
	2018	2019	2020	2021	2022	2023	Avg	2018	2019	2020	2021	2022	2023	Avg	2018	2019	2020	2021	2022	2023	Avg
LPDL	260.2	355.9	133.5	151.0	159.8	232.3	**215.4**	13.6	13.8	13.9	14.2	14.4	14.6	**14.1**	19.07	25.86	9.58	10.65	11.14	15.92	**15.37**
Chg by Year $			(222.35)	17.45	8.85	72.47				0.17	0.24	0.17	0.24			6.79	(16.28)	1.07	0.49	4.78	
Chg by Year %			-62.5%	13.1%	5.9%	45.3%				1.3%	1.8%	1.2%	1.7%			35.6%	-63.0%	11.1%	4.6%	42.9%	

b) Please update Table 26 to show the 2018 to 2024 average unit costs

LPDL has updated the APB average unit costs with 2023 results. The average unit cost is for 2019-2023 per the most recent OEB APB unit calculation report. LPDL will provide data required for the 2024 APB results to the OEB by the OEB's Apr 30/25 due date.

Activity	Measure	LPDL Average Unit Cost (2019-2023) $	Industry Average Unit Cost (2019-2023) $	Variance $	Variance %
Billing O&M	$/customer	35.31	27.32	7.99	29%
Metering O&M	$/customer	12.65	13.16	(0.51)	-4%
Vegetation O&M	$/pole	28.93	68.08	(39.15)	-58%
Lines O&M	$/primary circuit km	2,718.43	1,098.90	1,619.53	147%
Stations O&M	$/MVA	1,372.90	1,375.00	(2.10)	0%
Poles & Towers O&M	$/pole	9.82	12.65	(2.83)	-22%
Stations CAPEX	$/MVA	1,649.80	3,222.32	(1,572.52)	-49%
Poles & Towers CAPEX	$/poles installed	11,760.00	13,039.03	(1,279.03)	-10%
Lines Transformers CAPEX	$/lines transformers installed	7,669.30	9,960.42	(2,291.12)	-23%
Meters CAPEX	$/customer	14.63	29.83	(15.20)	-51%

c) Please add a column to Table 26 which shows LPDL's average unit costs for the 2018-2025 (forecast) period.

As noted in parts a) and b), LPDL does not have 2024 results nor 2025 forecast data to prepare this request.

1.0-VECC-5
Reference: Exhibit 1, page 65

b) Please update the OEB Scorecard to include 2024 results.

LPDL will provide data required for the 2024 OEB Scorecard to the OEB by the OEB's Apr 30/25 due date.

1.0-VECC-6
Reference: Exhibit 1, pages 65-

a) What are the ten most frequent reasons for live agent phone interactions/transactions? Please provide a list, in the order of frequency and, if available, the number of such transactions in each of the years 2024 through 2024.

The reason and frequency for live agent phone interactions is not tracked, therefore LPDL cannot provide a definitive list in order of frequency. However, in discussion with phone staff, LDPL feels the following ten reasons are common live agent phone interactions. The order is not reflective of frequency.

- Moving in/moving out requests
- Billed amount inquiries
- Usage inquiries
- Outage inquiries
- Current balance inquiries
- Making/reporting a payment
- Collections/payment arrangements
- Online portal inquiries
- RPP rate plan inquiries
- Rates inquiries

b) What are the most common complaints of customers registered either through on-line or agent calls?

The most common complaints received are due to high bills and outages.

c) Based on 2024, what are the most common residential customer payment methods?

The most common residential customer payment methods are pre-authorized and online banking payments.

Exhibit 2 – Rate Base and Capital

OEB Staff

2-Staff-6
2024 Bridge Year
Ref: Chapter 2 Appendices

Question:

(a) Please update the Chapter 2 Appendices, Tabs 2-AA, 2-AB, 2-BA, and other affected models to reflect updates to 2024 estimates, if any.

The Chapter 2 Appendices, Tabs 2-AA, 2-AB, 2-BA, 2C have been updated with preliminary 2024 actuals.

2-Staff-7
Asset Retirement
Ref 1: Chapter 2 Appendices, Tab 2-BA
Ref 2: Chapter 2 Appendices, Tab 2-H
Ref 3: Exhibit 2, Part 1 of 4, Section 2.3.3, p. 27

Preamble:
Lakeland Power states that it plans to dispose and sell an existing double bucket truck in the 2025 test year.

There are disposals in Appendix 2-BA for 2025 in the amount of ($314k) relating to transportation equipment. There are no gains or losses on asset disposition/retirement in Tab 2-H for the 2025 test year.

Question:
(a) Please confirm that Tab 2-H is accurate with respect to gains or losses on asset disposition/retirement for the 2025 test year. If not confirmed, please revise the evidence as necessary.

LPDL confirms that Tab 2-H is accurate. LPDL doesn’t expect to have any gains or losses from the disposition of the double bucket truck in 2025. The 2006 bucket truck has significant wear and tear and its potential gain is not determinable.

2-Staff-8
Cost of Power
Ref 1: Exhibit 2, Part 1 of 4, Section 2.5.2, p. 54
Ref 2: Regulated Price Plan Price Report, November 1, 2024 to October 31, 2025, issued October 18, 2024
Ref 3: Chapter 2 Appendices, Tabs 2-ZA – Commodity Exp. Forecast and 2-ZB – Cost of Power
Ref 4: Revenue Requirement Workform, Tab 3 – Data Input Sheet

Preamble:

On October 18, 2024, the OEB announced electricity prices under the Regulated Price Plan (RPP) effective November 1, 2024. Also, effective November 1, 2024, the Ontario government's Ontario Electricity Rebate (OER) will be 13.1%.

Questions:

(a) Please update Tabs 2-ZA and 2-ZB of the Chapter 2 Appendices to reflect the latest RPP Report.

The Chapter 2 Appendices, Tabs 2-ZA and 2-ZB have been updated to reflect the latest RPP report.

(b) Please update the Revenue Requirement Workform to reflect the updated Cost of Power where required. Please also ensure the updated Cost of Power reflects any updates to RTSRs, regulatory charges etc. made as part of Lakeland Power's interrogatory responses.

LPDL has updated the Revenue Requirement Workform to reflect the updated rates.

2-Staff-9
Ref 1: Non-Wires Solutions Guidelines for Electricity Distributors/Conservation Demand Management in Distribution System Planning EB-2024-0118, Non-Wires Solutions Guidelines for Electricity Distributors, March 28, 2024
Ref 2: Exhibit 2, Rate Base and Capital, Table 32-Summary of Capital Projects

Preamble:
The OEB recently released its Non-Wires Solutions Guidelines for Electricity Distributors (NWS Guidelines) and the Benefit-Cost Analysis Framework for Addressing Electricity System Needs (BCA Framework). These aim to help distributors assess the economic feasibility of using non-wires solutions (NWS) to address defined electricity system needs. Electricity distributors must incorporate consideration of NWS into their distribution system planning process by evaluating whether a distribution rate-funded NWS may be a preferred approach to meeting a system need, thus avoiding or deferring spending on traditional infrastructure.

The NSW Guidelines state that:

Distributors are required to document their consideration of NWSs when making investment decisions on electricity system needs with an expected capital cost of $2 million or more as part of distribution system planning, excluding general plant investments.

Question:

(a) Lakeland Power is proposing capital spending of $1M in 2026 and $2M in 2027 for the Bracebridge MS3-New 27.6kV Substation (Bracebridge Substation). Please provide documentation/evidence of the screening and/or consideration of non-wires solutions related to the Bracebridge Substation.

The final phase of the conversions involves the decommissioning of an aging 5MVA, 4.16kV substation. Given that 27.6kV conversions and system planning were in progress prior to the release of the framework, and in accordance with OEB guidance indicating that the BCA framework is not mandatory for 2024 and 2025 rate applications, a formal BCA was not conducted. However, LPDL undertook a study at the expense of its affiliate Bracebridge Generation and Natural Resources Canada. LPDL was compensated for its expenses and was provided a detailed report at no cost.

The $12M project provided some great insights:

- The use of demand response was tested using hot water tank controllers, in home battery energy storage systems, and EV charger controls. These projects proved effective and could be used to reduce costs on distribution and transmission systems as they can regulate peaks on the distribution system or take signals from the transmission system. The provincial regulators have made it difficult to make any progress using these assets. In Muskoka, electric hot water tanks are common as propane is more expensive and natural gas is limited to urban cores. LPDL's affiliate, Lakeland Energy, rents 5.5MW of hot water tanks, but controlling them to any benefit to the customer and system is not a program allowed under the IESO.
- Control logic and algorithms take time to develop. During the course of LPDL's testing, it saw steady improvements that allowed LPDL to match peaks and improve performance.
- Solar, Battery and other DERS can play a vital role of reducing peak demand and constraints on the system. The Use of a BESS can have great affects when controlled efficiently. Currently there are some IESO programs that allow bidding on a market. The programs are designed to get the lowest possible price, at the risk to the asset owner. As participating in the market is becoming a gamble, it is not a great place for a regulated LDC to be playing in. This market is more well suited to private industry investors.

- The OEB has stated it may take many years to come up with new regulations. New regulations are required as there are many layered rules that prevent many opportunities that have potential to reduce costs to consumers. Carolyn Calwell, Chief Corporate Services Officer & General Counsel reiterated this fact at the Smart Grid City Conference in November of 2024.
- Hydro One complemented us on the project. Lakeland was told however that it will not be successful because the way regulated utilities get compensated on their rates is off Capital Spend, therefore until the OEB reevaluates it, the only way to continue operating as a utility is by building more capital assets.

Lakeland learned a great deal on this project and has determined that DER and DERMS have a great potential for electricity generation, transmission and distribution, the regulations lack behind and may take many years to catch up with other jurisdictions.

With regard to the Bracebridge MS3 project, LPDL considered the aforementioned demand response options and maintaining its existing 4.16kV substation. LPDL found that a NWS will not achieve the main drivers:

- Reliability improvements by connecting additional customers to Hydro One's Bracebridge TS.
- Capacity expansion for future load growth and system stability.
- Replacement of aging 4.16kV assets.

In addition, it is not considered an acceptable risk to LPDL to maintain one 4.16kV substation that does not have a reliable backup source.

2-Staff-10
Historical Capital Expenditures
Ref 1: Exhibit 2, part 2, Table 5.4-34, p. 101
Ref 2: Exhibit 2, part 2, pp. 103-108

Preamble:
During the historical period, there was a significant net underspend compared to plan in several categories and years, for example:

- Net System Renewal spending was 70% below plan in 2020 and 34% below plan in 2021.
- Net System Service spending was 73% below plan in 2020, 54% below plan in 2021, and 67% below plan in 2022.
- Net General Plant spending was 45% below plan in 2019.

This underspend is primarily attributed to reallocation of funds to meet unexpectedly high System Access requirements, as well as delays due to the Covid-19 pandemic.

Questions:

(a) What impacts has this underspend had on system performance, and what actions are planned to address these?

In 2020, multiple projects were not completed due to the pandemic. The Rene Caisse project was originally planned for 2020 and was a key strategic location to convert prior to beginning other conversion projects. The project was not completed until 2023. While the pandemic did play a part, overall delay of conversion work was partially due to distribution transformer supply chain issues. In response, since 2023 LPDL has been completing conversion projects as quickly and efficiently as possible to meet its goals. In 2021, LPDL did not invest in any distribution automation or SCADA upgrades. The plan was to install trip-saver reclosers on single-phase run-offs to mitigate tripping on the main line, and remote fault indicators to increase visibility and improve outage investigation times. The impact of not completing this is not seeing the planned project's benefits.
In 2022, LPDL reduced spending in System Service, mainly Distribution Automation, in favour of system renewal projects that were deemed higher priority, such as the replacement of a highly deteriorated 44kV pole line on Muskoka Beach Rd.
In response, LPDL aims to steadily invest in distribution automation in all years.

(b) For any deferred projects that are yet to be completed, how has this backlog been accounted for in the planned expenditures during the forecast period?

The Westvale 27.6kV conversion project was originally budgeted in 2020 but has been deferred to 2025. A small portion was completed in 2020 to bring 27.6kV to a new subdivision development on Quinn Forest Dr. The King William St – Huntsville project was originally budgeted for 2023. It was deferred to 2024 and is now planned in the 2025 test year. The project has seen delays due to ongoing easement negotiations with the adjacent property owner.

(c) What actions are planned to improve overall budget forecasting to ensure that necessary investments are not unduly deferred or abandoned?

The DSP is a plan and being a smaller utility, unplanned projects can cause significant changes and shifts to the original plan. The years of 2020 and 2021 were during the pandemic and not representative of typical years. LPDL was not able to predict or forecast during this time, given the disruption to supply chain and workforce.

LPDL is of the view that its budget process is robust in normal circumstances.

2-Staff-11
Capital Meters
Ref: Exhibit 2, part 3, Material Investment Narrative, Meters, pp. 64-65 of PDF

Preamble:
Lakeland Power has forecasted a capital meter budget of $380k in 2024, $50k in 2025 and $150k from 2026 to 2029. Lakeland Power notes that it proactively ordered a larger than typical number of meters that arrived in Spring 2024. Lakeland Power also notes that it plans to replace 265 meters in 2024 when on average it has replaced 242 meters on average from 2020 to 2023.

Questions:

(a) Please note how much of the $380k budget is for the capital expenditure of meters and how much is for the replacement of meters. If this is the case, what are the in-service additions of meters in 2024?

Meter Replacements: 47.4% = $180,131.
New Installations: 52.6% = $199,869.
In-service additions of meters in 2024 = 229.

(b) How many meters has Lakeland Power replaced or is forecasted to replace from 2019-2029?

LPDL replaced a range of 182-251 meters per year due to failure from 2019 to 2024. The average replaced per year is 218. There are no clear upward or downward trends in failures, therefore we forecasted roughly the same for 2025-2029. In 2027 and 2029, a large portion of LPDL's meters will be due for reverification and/or sampling. LPDL took the position doing a methodical and scheduled meter replacement over time to ease the burden both financially and on human resources.

2-Staff-12
Trouble Call Capital
Ref: Exhibit 2, part 3, Material Investment Narrative, Trouble Call Capital, p. 21 of PDF

Preamble:
Lakeland Power has forecasted a trouble call budget of $250k in 2024 to 2029. On average, the budget for trouble call capital has been $167k from 2019 to 2023.

Questions:
(a) Please detail how Lakeland Power estimated the trouble call budget for 2024 and the forecast period (2025-2029) and why it is higher than historical years.

LPDL has considered the rising costs of materials and labour, along with experienced increased storm frequency and intensity due to climate change. For example, LPDL experienced a major storm in December 2024 that shut down the Muskoka area, along with major highways in the area, for multiple days making access near impossible. To align with calls for grid resiliency, LPDL will strongly consider capital investments that offer greater reliability, such as underground conversions, when making significant repairs during storm events. Please also refer to 2-VECC-9.

2-Staff-13
Cybersecurity
Ref: Exhibit 2, part 3, Material Investment Narrative, Cybersecurity, p.3 of PDF

Preamble:
Lakeland Power has forecasted a cybersecurity budget of $200k in 2024.

Question:
(a) Please explain the increased cybersecurity budget in 2024 and what constitutes the budget.

LPDL's long-term plan to upgrade its software against cyberattacks involves:
- New Identity and Access Management software to enable two factor authentication on remote connection.
- New data encryption software to protect data-at-rest.
- New backup software to provide greater protection and immutability.
- Vulnerability Management software to provide greater control and visibility into LPDL's operational technology.
- New firewall software to improve security.

LPDL will continue to re-assess annually and make any necessary adjustments to address changes in the technology landscape.

Lakeland Power - CyberSecurity - Capital Budget	Quantity/Notes	2024 Forecast
Identity and Access Management	IAM- Two-factor - $50K/yr	25,000
Penetration Test	Expanded scope	25,000
Redundant Corporate Firewall		75,000
Privilege Access Management System (PAM)	Insurance requriement for max cybersecurity coverage	25,000
Vulnerability Assessment Management System	OEB recommendation	50,000
		200,000

2-Staff-14
Underground Renewal
Ref 1: Exhibit 2, part 3, Material Investment Narrative, Underground Renewal, pp. 26-27 of PDF
Ref 2: Exhibit 2, part 2, Table 5.4-51: Project Prioritization Matrix, p. 132
Preamble:
According to reference 1, Lakeland Power has forecasted an underground renewal budget of $290k in 2025 to replace aging underground infrastructure. The existing 12.47kV radial feed at the Westvale Dr. subdivision will be replaced with a 27.6kV loop feed system.

According to reference 2, the project has a low priority rating compared to all other projects, including other voltage conversion and other general asset replacement projects.

Questions:

(a) Please explain why the underground renewal project has a low priority rating compared to other voltage conversion and asset replacement projects.

Based on Exhibit 2, part 2, Table 5.4-51 on page 132 (Project Prioritization Matrix), the categorization and associated rankings effectively reflect the urgency and potential impact of each asset. The lower values for “Public & Worker Safety”, "environmental concern", and "innovation" assign a lower priority to the underground cable replacement project compared to other initiatives. Additionally, the radial feed system or distribution cable serves a smaller service area and fewer customers than the main feed or cable, further justifying its lower priority in relation to other projects.

(b) Please explain the fallbacks of deferring the underground renewal project one or two years due to its low priority rating.

There are several potential risks and consequences associated with deferring the project to other years, i.e.,

1. Increased risk of failure
2. Increased risk of service disruptions
3. Higher maintenance cost in case of failure
4. Customer expectations in terms of reliability

This project has already been delayed five years and an additional one to two years could solidify one or more of the above risks.

2-Staff-15
Transportation Equipment/Fleet
Ref 1: Exhibit 2, part 3, Material Investment Narrative, Transportation Equipment/Fleet, pp. 9-11 of PDF
Ref 2: Exhibit 2, part 1, p. 38
Ref 3: Exhibit 2, part 1, p. 40

Preamble:
Lakeland Power has a transportation equipment/fleet budget of $470k in 2024 and $730k in 2025 according to reference 1. Lakeland Power notes that in 2024 it has replaced a single bucket truck (reference 2) and in 2025 it has purchased a new double bucket truck to replace an aging truck from Parry Sound (reference 3). The double bucket truck was pre-ordered with a portion of the truck's cost being already paid (reference 1).

Questions:

(a) Please provide a breakdown of the 2025 Transportation Equipment/Fleet budget by vehicle. Has Lakeland Power explored any opportunities to defer some of the 2025 expenditures in this category to the year 2026?

The 2025 budget for Transportation Equipment/Fleet budget consists solely of the double bucket truck. Deferral is no longer an option as the truck was ordered in 2022.

(b) Please confirm if the pre-paid portion of the double bucket truck is included in the 2025 opening rate base and if so, why is that the case?

No, the pre-paid portion of the double bucket truck is in Account 2055 - Construction Work in Progress and is not included in the 2025 opening rate base.

(c) Please confirm if the single bucket truck was received in 2024.

Yes, the single bucket truck was received in the Spring of 2024.

(d) Please provide the factor point score of the single bucket truck and the double bucket truck broken down by each factor at the time of replacement using the investment priority criteria in reference 1 (i.e., age, kilometers/hours, type of service, reliability, maintenance and repair costs, and condition).

Vehicle ratings for the single bucket and double bucket trucks are shown below.

Primary Criteria

LIGHT VEHICLE	Truck #	Total Mileage (KM)	Annual Average Mileage (KM)	AGE	Total Hours Average	Cumulative Maintenance Cost	Average Maintenance Cost/Year
POSI-PLUS 500-55 (Double Bucket)	**V28**	**117910**	6935.88235	17		**$122,071**	$7,181
2014 Freightliner M2 (Single Bucket)	**V77**	**184281**	18428	10		**$62,497**	$6,250

Secondary Criteria Replacement Score

Age	Mileage 25000	Type of service	Reliability	Maintenance Cost %	Maintenance & Repair Cost	Body Condition	Total Points	Points-Based Recommendation
17	5	5	1	58%	7	4	39	Needs Immediate Consideration
10	7	5	1	20%	1	3	27	Qualifies for Replacement

(e) Lakeland Power notes it has scheduled the replacement of a small bucket truck at 5 years of age. What is the reason for replacing the truck at this stage, given Lakeland Power's general guidelines in the Material Investment Narrative consider a minimum age threshold of 10 years for vehicle replacement?

LPDL acknowledges the discrepancy in the Material Investment Narrative. LPDL starts the evaluation at 5 years but historically replaces in the 8-15 year range. The small bucket truck in question, purchased in 2019, will be 6 years old in 2025. The vehicle will be evaluated for potential replacement in 2027 or 2028, based on its condition and maintenance history at that time. By 2028, the truck is projected to have accumulated approximately 245,000 kilometers. The small bucket truck is heavily utilized, responding to most of the service and trouble calls within LPDL's extensive service territory. In addition, this truck can reach many destinations on rural roads that our larger fleet vehicles are incapable of.

2-Staff-16
Capacity Upgrades
Ref: Exhibit 2, part 3, Material Investment Narrative, Capacity Upgrades, pp. 41-42 of PDF

Preamble:
Lakeland Power has a capacity upgrade budget of $440k in 2025, $190k in 2026, and $145k in 2027. In 2025, Lakeland Power has budgeted for the installation of new conductors to address the growing energy demands in the Isabella St., Parry Sound area. Lakeland Power notes that it has conducted feeder-modelling and consultations with developers and Electric Vehicle Supply Equipment (EVSE) installers in preparing the estimate.

Questions:
(a) Is Lakeland Power anticipating capital contributions from developers for the capacity upgrade projects? If not, why not?

The Isabella St. project is considered an enhancement under Section 3.3 of the DSC; as such, LPDL shall not charge a customer capital contribution.

(b) When performing feeder-modelling, does Lakeland Power take into account residential electric vehicle charging, or only charging at the EVSE locations identified? Has Lakeland Power considered other electrification measures in its feeder-modelling such as the adoption of heat pumps? If not, why not?

To date, LPDL has considered residential EV charging and heat pumps at a high level. Installations are indirectly modelled in CYME through available revenue meter data. While we are aware additional future installations will have impacts in the future, not enough information is known about the locations of these installations as customers do not notify LDC's unless a service upgrade is required.

(c) Please provide a cost breakdown of the Isabella St., Parry Sound project in 2025.

In 2025, the project consists of 28 pole replacements and re-stringing of two circuits – one 44kV circuit and one 12.5kV circuit. Costs per pole are expected to be slightly above average because the poles must be set and worked on near a live 44kV radial line that cannot be isolated.

Labour	$166,292
Equipment	$ 61,892
Material	$145,637
Contracts	$ 50,400
~4% Contingency	$ 16,969
Total	$441,190

(d) When are the new loads expected?

In 2025, LPDL expects the Tesla EV Charging Site to be in service.
In 2026, LPDL expects the expanded High School and Recreational Centre to be in service.
The date of commissioning for the EV sites at the car dealership is not currently known.
The in-service date for the new Winnifred Phase 2 subdivision is not currently known.

2-Staff-17
Distribution Automation/SCADA
Ref: Exhibit 2, part 3, Material Investment Narrative, Distribution Automation/SCADA, p. 48 of PDF

Preamble:
Lakeland Power has an Automation/SCADA budget of $140k in 2024 and $266k in 2025. Lakeland Power notes that the 2025 budget is for three advanced smart-switch installations.

Questions:

(a) Please describe what the $140k budget is for in 2024 in this category.

The $140K budget in 2024 for Automation/SCADA was for two smart-switches in Bracebridge. However, the spending has been deferred to 2026 and 2027.

(b) Please describe the risks of deferring one or all of the switch installations in 2025 to a future year.

The key risks of deferring the smart-switch installations to a future year include:

- Budgeting issues, due to the new substation in 2026 and other smart switches deferred for 2026-2027
- Increased system vulnerability and longer outage times
- Operational inefficiencies in grid management
- Higher future costs due to inflation or regulatory changes
- Customer dissatisfaction from poorer reliability

Having a robust SCADA and outage management system is a benefit to the customer in getting service restored faster and operational efficiencies to pinpoint trouble areas quickly.

2-Staff-18
Voltage Conversion Projects
Ref: Exhibit 2, part 3, Material Investment Narrative, Voltage Conversions, p. 35 of PDF

Preamble:
According to reference 1, Lakeland Power has forecasted voltage conversion projects of $610k in 2024 and $445k in 2025. The projects involve the replacement and upgrading of existing pole lines that have reached end of life or require replacement.

Questions:

(a) Please provide a table listing how many poles have been replaced (or are planned for replacement) as part of this program from 2019-2029 along with the cost of replacement.

Year	Project Poles Replaced	Project Pole Replacement Cost
2019	24	115,723
2020	5	93,171
2021	20	112,809
2022	10	59,955
2023	12	142,370
2024	6	59,898
2025	33	350,586
2026	27	295,438
2027	27	307,255
2028	29	346,647
2029	32	386,039

(b) Please provide a similar table outlining the total number of poles replaced in all programs with associated costs from 2019-2029.

Year	Total Poles Replaced	Total Pole Replacement Cost $	Cost $/Pole
2019	95	989,484	10,416
2020	95	733,378	7,720
2021	128	1,556,476	12,160
2022	142	2,215,208	15,600
2023	130	1,677,578	12,904
2024	178	1,762,469	9,902
2025	99	1,049,400	10,600
2026	108	1,182,600	10,950
2027	97	1,093,190	11,270
2028	58	673,380	11,610
2029	67	801,320	11,960

(c) Please describe what techniques are used to estimate costs for projects within the Voltage Conversions program and how voltage conversion projects are prioritized amongst each other, especially for the projects within the 2025 test year.

Projects are estimated by engineering technologists using available field data and considering all standard construction that will occur. Estimates are input into LPDL's work management system, Worktech, in full detail including labour, vehicles and equipment, and material needed.

Example criteria include:

- Number of poles replaced
- Height and class of poles
- Framing and attachments of each pole, including down guying, underground risers, etc.
- Terrain of installation (e.g. earth, rock, swamp)
- Number and type of transformer replacements (overhead, large three-phase padmounted transformers, etc.).
- Scope of work to string new conductor including size, number of circuits, requirement for vehicle flagging or road closures, and equipment available for the project.

Voltage conversions are prioritized systematically by:

1) Typically, the first consideration when prioritizing which projects to complete is maintaining redundancy in the event of emergencies or outages.

2) Location of the existing 27.6kV feeders. The location of the existing infrastructure plays a large role in determining the next best project to undertake. For example, LPDL needed to complete the Rene Caisse Ln. project before proceeding with the Mary & James St. project due to the location of existing infrastructure.
3) Load growth is sometimes considered on an as-needed basis. For example, a portion of Glendale Rd and Catherine Cres. was completed in 2020 to accommodate a new subdivision on Quinn Forest Dr.
4) Efficiency is also considered. LPDL will prioritize projects that will generate larger impact for lesser effort.
5) Supply chain may be considered. In 2020-2022, the supply chain was widely disrupted, in particular the availability of distribution transformers, which are crucial for conversions.
6) Reliability is considered. If an area will see a particular improvement as a result of conversion, it may be given higher priority.

(d) What impacts are these projects anticipated to have on system performance and losses? How does this compare to the alternative of maintaining existing infrastructure?

The benefits of converting to 27.6kV include:

- Increased system flexibility, redundancy and reduced outage times, particularly outages due to loss of supply.
- Increased capacity to meet new growth demand.
- Facilitate connection of DERs.
- Line losses will be reduced however this is not the primary driver.

The risks of maintaining the existing infrastructure include:

- No backup substation – Bracebridge MS3 is the last remaining.
- Inability to connect new customers, particularly large industrial customers or large DER projects.
- Not meeting industry goals to account for future growth demand.

2-Staff-19
New 27.6kV Substation
Ref: Exhibit 2, part 3, Material Investment Narrative, New 27.6kV Substation, pp. 74-76 of PDF

Preamble:
Lakeland Power has budgeted $1M in 2026 and $2M in 2027 to construct a new 27.6kV substation in Bracebridge to replace Bracebridge MS3. Bracebridge MS3 is the last remaining 4.16kV substation in Bracebridge.

Lakeland Power notes that beyond voltage conversion, the project aligns with its asset management process as typically the oldest and most at-risk infrastructure is on the 4.16kV system.

Questions:
(a) Please provide the cost breakdown for the 27.6kV substation project.

LPDL is currently in the midst of formal engineering. A class D estimate should be available in early to mid February.

2-Staff-20
Asset Condition Assessment
Ref: Exhibit 2, part 2, pp. 68-69

Preamble:
Lakeland Power notes that it employed Barkley Technology Inc. to carry out an asset condition assessment (ACA). Lakeland Power notes that the ACA plays a critical role in informing Lakeland Power's maintenance and capital investment decisions.

Questions:
(a) Please provide a breakdown of all Lakeland Power-owned substation equipment by age, asset condition, and overall condition based on Lakeland Power's Asset Condition Assessment results.

While LPDL is aware of the condition of its substations through regular inspections and maintenance, substation assets are not yet implemented in LPDL's formal ACA. Substation assets will be included in the ACA in the near future as LPDL strives for continuous improvement.

(b) Please describe the general methodology employed by Barkley Technology to assess and determine the Overall Risk Rating and Asset Risk Rating for each asset assessed as part of the ACA. What factors contribute to the ratings assigned to an asset?

The following table describes the general methodology used:

CATEGORY	% WEIGHTING	SUB-CATEGORY	POLES	TRANSFORMERS	SWITCHES	CONDUCTORS
ASSET	50%	AGE	Y	Y	Y	Y
		CONDITION	Y	Y	Y	Y
SYSTEM	15%	SYSTEM IMPACT	Y		Y	Y
BUSINESS	10%	CONNECTED CUSTOMERS	Y	Y	Y	Y
		CRITICAL CUSTOMERS	Y	Y	Y	Y
HEALTH/SAFETY	10%	PUBLIC	Y	Y	Y	Y
		WORKER	Y	Y	Y	Y
PHYSICAL	10%	ACCESSIBILITY	Y	Y	Y	
		POTENTIAL FOR DAMAGE	Y	Y	Y	Y
CONSTRUCTION	5%	Availability	Y	Y	Y	Y
		Equipment	Y	Y	Y	Y
		Attachments - JU	Y			

For each asset, the risk rating is calculated using the following formula and each category is scaled from 1 to 5, where 5 is the worst:

(AMP_ASSETRISK * 0.50) + (AMP_SYSTEMRISK *0.15) + (AMP_BUSINESSRISK * 0.1) + (AMP_SAFETYRISK * 0.1) +(AMP_PHYSICALRISK * 0.1) + (AMP_CONSTRUCTIONRISK * 0.05)

(c) Please provide an example of how Lakeland Power weighs age versus condition when calculating the asset risk of a wood pole. How is the asset condition determined and weighed?

For the 50% Asset Category, Age is weighted at 60%:

Pole Material Type: - All Other Wood Types - Age Risk	
Risk Rating Category	Year Grouping
1	< 10 yrs (>2014)
2	10-19 yrs (=<2014 and > 2004)
3	20-29 yrs (=<2004 and > 1994
4	30-39 yrs (=<1994 and >1984)
5	> 40 yrs (=<1984)

For the 50% Asset Category, Condition is weighted at 40%:

Pole Condition: - All Wood Types - Condition Risk	
Risk Rating Category	Scientific Test - Remaining Strength
1	100-91%
2	90-81%
3	80-71%
4	70-61%
5	< 60 %

Using the site testing with the industrially proven test equipment (scientific method), remaining strength is calculated. This result calculates the actual condition of a pole which is then accordingly assigned with risk rating category as indicated above.

(d) Please provide an example of how Lakeland Power weighs all factors when calculating the overall risk of a wood pole. How would an asset in 'very good' asset condition result in an overall risk condition of 'good' or 'fair'?

This example will assume a pole of 15 years old and based on condition assessment/risk it has a remaining strength of 75%. The downstream side connected customers are 80 and all are residential. The pole is not accessible to the public but easily accessible to staff/bucket trucks. A pole for replacement is available in store. No communication cable is installed.

Based on the ACA:

1.Risk rating category for age = 2

2.Risk rating category for condition = 3

3. Risk rating category for Business Risk - Connected Customers = 1

4. Risk rating category for Physical – Accessibility and Potential for Damage = 1

5. Risk rating category for construction = 1

Risk = (AMP_ASSETRISK * 0.50) + (AMP_SYSTEMRISK *0.15) + (AMP_BUSINESSRISK * 0.10) + (AMP_SAFETYRISK * 0.10) (AMP_PHYSICALRISK * 0.10) + (AMP_CONSTRUCTIONRISK * 0.05)

= (2*0.50) + (3*0.15) + (1*0.10) + (1*0.10) + (1*0.10) + (1*0.05) = 1.8

(e) Please describe if and how Lakeland Power extrapolated data to form the risk rating or overall rating for wood poles to account for missing data.

LPDL would use data from other similar poles (in terms of age, condition, or environmental factors) to predict values for the poles with missing data. Normally, the assumption is if the age is unknown then that wood pole would be >40 years, however, the condition is dependent on visual inspection and expert judgement.

(f) Please note what role Barkley Technologies had in carrying out the ACA given that Lakeland Power does not have a third-party ACA report.

Barkley Technologies carried out the assessment themselves based on the database provided by LPDL. They also provided the graphical representation of data, and asset and overall risk ratings in Arc GIS Pro.

(g) Did Barkley Technologies provide any recommendations based on the ACA results, such as a recommended flagged for action plan or ways to improve the asset data registry?

Barkley Technologies did not recommend it, but LPDL is committed to a continuous improvement philosophy, and the results from the ACA, conducted by Barkley Technology Inc., are certainly a key part of that effort. LPDL reviews the model while assessing the assets and identifies recommendations for flagged action plans or enhancements to its asset data registry. For example, if there is missing or outdated information for certain assets, a flagged action plan could involve updating those asset details in the registry to ensure all data is current and accurate. LPDL also remains attentive to any regulatory changes that may impact its operations, ensuring its practices evolve in alignment with both industry standards and compliance requirements.

2-Staff-21
Asset Condition Summary
Ref 1: Exhibit 2, part 2, pp. 76 & 88
Ref 2: Exhibit 2, part 2, Figure 5.3-20, p. 79
Ref 3: Exhibit 2, part 2, Figure 5.3-21, p. 80
Ref 3: Exhibit 2, part 3, Material Investment Narrative, System Renewal: General Asset Replacement, p. 14 of PDF

Preamble:
The 2024 ACA resulted in many of Lakeland Power's assets being assigned health ratings of Poor or Very Poor. For example, according to Figure 5.3-21, at least 60% of all underground secondary conductors, overhead secondary conductors, overhead primary conductors, switches, and wood poles are rated Poor or Very Poor. However, as many of

these assets result in minimal customer impact upon failure, Lakeland Power's system has been deemed to exhibit relatively low overall risk.

Questions:

(a) Lakeland Power states that availability of condition data is limited for underground primary conductors, underground secondary conductors, and overhead secondary conductors. What is the process undertaken for assessing the condition of these assets and determining replacement needs? What plans are in place to improve the availability of condition data?

For underground primary and secondary conductors, due to the limited availability of condition data, LPDL will rely on a combination of indirect assessment methods and targeted inspections to evaluate the health of these assets. These methods may include routine inspections, monitoring and cable testing (e.g. Meggering)/partial discharge testing).

For overhead secondary conductor, the overhead system is normally assessed through routine inspections as the system is generally more accessible. These include visual inspection, Infrared scanning and load testing.

LPDL has identified most of the inspection/ testing in the annual maintenance plan, such as visual inspections, Infrared scanning and load testing. However, LPDL has also considered underground cable testing in the next years.

2-Staff-22
Reliability
Ref 1: Exhibit 2, part 2, p. 55
Ref 2: Exhibit 2, part 2, p. 58
Ref 3: Exhibit 2, part 2, p. 59
Ref 4: Exhibit 2, part 2, p. 26

Preamble:
In reference 1, Lakeland Power notes that 24% of outage numbers derive from defective equipment, and in reference 2 and reference 3, Lakeland Power notes that 2% of customer interruptions and 2% of customer hours of interruption are derived from defective equipment.

In reference 2 and reference 3, Lakeland Power notes that loss of supply makes up 73% of all customers interrupted and 69% of customer hours of interruption from 2019-2023.

In reference 4, Lakeland Power notes that the new 27.6kV substation scheduled to be in service in 2027 will greatly decrease the duration of loss of supply outages and reduce the risk of widespread outages.

Questions:

(a) Please provide a breakdown of outages by defective equipment type and how the capital plan addresses outages for equipment that has experienced high outages.

LPDL does not currently track these outages by specific device, however LPDL is aware based on experience that the leading cause of equipment failure is porcelain switch failure.

(b) Has Lakeland Power conducted a detailed assessment of the types of adverse weather and foreign interference incidents that occurred over the historical period? If so, what specific capital measures seek to improve outage causes due to these interferences and adverse weather events?

LPDL experienced 85 outages from 2019-2024 that were due to squirrels coming into contact with transformer bushings or switches. Other leading causes of foreign interference incidents include contactors hitting lines and vehicles hitting poles and padmounted transformers.

In response to outages caused by squirrels, LPDL installs squirrel-guards on all new transformer installations. This helps prevent the squirrel from contacting energized parts and grounded parts simultaneously.

In response to vehicles hitting padmounted transformers, LPDL has purchased, and is in the midst of installing, tall high-visibility markers on all padmounted equipment. LPDL's region receives several feet of snow per year, which often buries padmounted equipment. In addition, LPDL requires bollards around all new padmounted equipment that is susceptible to vehicle damage.

(c) What does Lakeland Power attribute to its lowered SAIDI and SAIFI (without loss of supply and major event days) in 2023 and has Lakeland Power seen a similar trend in 2024?

The largest major contributor to a lowered SAIDI calculation for 2023 is a reduction in Adverse Weather outages. Customer hours interrupted in 2023 was 4,850 versus 44,877 in 2022 and 16,703 in 2021. The same can be said for the lowered SAIFI calculation in 2023. The number of Customers Interrupted due to Adverse Weather in 2023 was 2,746 versus 10,797 in 2022 and 10,114 in 2021. LPDL has not seen the same trend in 2024 as outages due to Adverse Weather are higher and more in line with historical averages.

(d) Please explain in further detail how the 27.6kV station will reduce loss of supply outages specifically as well as reduce the risk of widespread outages.

Currently, LPDL's 27.6kV system is solely serviced from Hydro One's Muskoka TS M7 feeder. This feeder is one of the worst performing feeders in the province. The M7 44kV line extends from Utterson, ON to Bracebridge, ON through approximately 20km of densely forested terrain. The Bracebridge TS M21 feeder, which currently services the 4.16kV Bracebridge MS3, is less than 2km from the substation and is located along a major road with significantly less reliability and accessibility challenges. With the new 27.6kV substation on the Bracebridge TS M21, LPDL would have the capability to immediately restore power to other parts of the 27.6kV system during a loss of supply. This would be accomplished using a viper recloser in the substation in conjunction with viper reclosers at key feeder tie points.

(e) Besides the new substation, what has Lakeland Power done to improve reliability concerning loss of supply outages in collaboration with Hydro One? Please provide plans that Hydro One has to improve reliability, if any, and the timeline for its expected in-service dates.

LPDL has participated in meetings with the municipality and Hydro One, in an attempt to build a 44kV and 27.6kV tie-line that would greatly empower both utilities to restore power more quickly in emergency situations. The project was met with disapproval from the municipality due to its impact on the forestry in the area. In late 2024, LPDL brought this issue forward to the municipality once more, for further discussion, in hopes that the project will proceed.

In 2019/2020, LPDL worked closely with Hydro One for the installation of telemetered motorized switches on the 44kV around LPDL's service territory. The goal was to provide a means for the Ontario Grid Control Centre to quickly restore power depending on the location of faults. LPDL currently does not have good visibility to the operation of those switches, however, has requested of Hydro One to allow us to view the status using our existing SCADA connection.

2-Staff-23
Performance Metrics Overview
Ref 1: Exhibit 2, part 2, p. 29
Ref 2: Exhibit 2, part 2, p. 50

Preamble:
Lakeland Power states that improvements have been made to its Outage Management System (OMS) during the historical period to improve communication with customers during outages and enhance its ability to respond to disruptions. Nevertheless, Customer Satisfaction Survey results show a declining trend in customer satisfaction with respect to system reliability.

Question(s):

(a) What specific system improvements has Lakeland Power made or planned to make to improve response times to outages and overall outage management?

LPDL has implemented smart-switches in Bracebridge at key 27.6kV tie points. This has allowed for faster restoration times in scenarios where a section of line can be transferred to a different substation. Battery backup systems have been installed in substations, allowing LPDL to monitor the station and provide faster, more accurate outage information to customers during loss of supply events. LPDL plans to continue to invest in advancement of its distribution automation systems.

(b) What measures have been implemented or are included in the system plan to enhance customer satisfaction with system reliability?

LPDL has included the following initiatives to enhance customer satisfaction with system reliability:

- Continue 27.6kV conversions and replace Bracebridge MS3 with a new 27.6kV substation. This project will greatly assist with restoration efforts during loss of supply events.
- Install smart-switches in Magnetawan. This will significantly improve LPDL's visibility and enhance its outage communications in that area.
- Install smart-switches at Parry Sound MS5. Currently, LPDL does not have visibility in the station when a recloser trips. The new switches will give LPDL SCADA connectivity, thereby reducing investigation time, restoration time, and

allowing LPDL to communicate to the customers via the outage management system in real time.

2-Staff-24
Outage Times
Ref 1: Trestle Brewing Company_IntervenorRQST_20241209
Ref 2: Dave B_LOC_Lakeland Power_rate increase_20241216

Preamble:
In reference 1, Trestle Brewing Company notes having an issue with service. Reference 1 states that there is one Lakeland Power employee present in the Parry Sound catchment area with equipment assets being dispatched from Bracebridge which extends outage times. In reference 2, a letter of comment was received noting a similar concern.

Questions:

(a) Please explain what measures have been taken or contemplated by Lakeland Power in the historical period to address the customer concerns.

The main options LPDL has considered in response to complaints from the Town of Parry Sound are:

- Always having two lines staff and one truck available in the town. This option would pose a significant financial burden on LPDL's customer base. The additional challenge is that both staff would need to be on-call 365 days per year in order to ensure the desired outcome. Currently, all operations staff report to the Bracebridge office.
- LPDL has had discussions with Hydro One in Parry Sound about mutual assistance. For example, Hydro One may respond to LPDL outages when they have crews close by, and LPDL may respond if LPDL crews are closer. Hydro One was not interested in this possibility at the time. There are also easily foreseeable challenges with the Power Workers Union for this type of arrangement.

As discussed in part b) of the question above, LPDL plans to install smart-switches at Parry Sound MS5 which will enhance LPDL's SCADA connectivity in Parry Sound. This increased visibility to the system will reduce investigation time and restoration time, allowing LPDL to communicate to the customers via the outage management system in real time and reduce the duration of outages.

(b) How will the 2025-2029 capital or OM&A plan address these customer comments? If these comments are not being directly addressed over the forecast period, please explain why.

LPDL is attempting to address these customer comments through SCADA enhancements and any system improvements performed in Parry Sound which should eliminate/minimize the trouble calls and improve system reliability. While LPDL's response time is within the acceptable parameters/standards, LPDL is constantly looking for opportunities to upgrade the system to eliminate outages.

(c) Does Lakeland Power have separate reliability figures per area or town? If so, please provide SAIDI and SAIFI figures from 2019-2024 with and without loss of supply and major event days per area.

LPDL tracks outages at the feeder level, so is able to deduce metrics by town. The following tables provide a summary of SAIDI and SAIFI by town, with and without loss of supply (LoS) and Major Event Days (MED):

With MED & LoS - Number of Customer Hours Interrupted - SAIDI					
	2019 SAIDI	2020 SAIDI	2021 SAIDI	2022 SAIDI	2023 SAIDI
Bracebridge	0.042	0.185	0.042	0.125	0.028
Huntsville	0.022	0.020	0.015	0.037	0.008
Burks Falls	0.034	0.107	0.098	0.040	0.036
Sundridge	0.057	0.092	0.040	0.042	0.025
Magnetawan	0.173	0.073	0.419	0.071	0.054
Parry Sound	0.021	0.033	0.011	0.028	0.016

With MED & LoS - Number of customer interruptions - SAIFI					
	2019 SAIFI	2020 SAIFI	2021 SAIFI	2022 SAIFI	2023 SAIFI
Bracebridge	5.729	7.458	6.018	6.633	1.133
Huntsville	1.347	2.067	1.998	4.105	1.150
Burks Falls	1.544	3.566	11.75	6.899	3.395
Sundridge	5.457	1.144	1.977	4.256	1.047
Magnetawan	3.483	3.098	4.888	3.146	2.380
Parry Sound	0.134	0.909	0.137	0.349	0.270

Without MED & LoS - Number of Customer Hours Interrupted - SAIDI					
	2019 SAIDI	2020 SAIDI	2021 SAIDI	2022 SAIDI	2023 SAIDI
Bracebridge	0.037	0.043	0.023	0.058	0.026
Huntsville	0.022	0.019	0.009	0.033	0.007
Burks Falls	0.025	0.099	0.028	0.029	0.009
Sundridge	0.024	0.087	0.026	0.028	0.025
Magnetawan	0.035	0.069	0.000	0.020	0.051
Parry Sound	0.021	0.033	0.009	0.028	0.016

Without MED & LoS - Number of customer interruptions - SAIFI					
	2019 SAIFI	2020 SAIFI	2021 SAIFI	2022 SAIFI	2023 SAIFI
Bracebridge	0.770	0.708	2.161	1.310	0.932
Huntsville	0.405	0.452	0.089	0.292	0.199
Burks Falls	1.003	2.367	1.051	0.262	0.329
Sundridge	2.264	0.168	0.018	0.047	1.047
Magnetawan	0.015	0.176	0.000	0.083	1.400
Parry Sound	0.134	0.734	0.056	0.297	0.270

(d) Are there particular areas within Lakeland Power's service territory that are experiencing more significant reliability issues compared to others? If so, how has this factored into the regional distribution of Lakeland Power's planned investments over the forecast period?

The portion of Bracebridge that is fed from Hydro One's Muskoka TS M7 has been a significant challenge for many years, generally resulting in numerous outages per year for over 6,000 customers. Please see 2-Staff-1 for further details on LPDL's collaboration with Hydro One to reduce outages.

The Bracebridge territory also has significantly more rural, densely treed pole lines than the other municipalities. A notable area of concern is the Beaumont Dr, Stephens Bay, and Ennis Bay area which significantly contributed to outages during the last major event and will be thoroughly investigated.

While LPDL has a 7 year tree trimming program in place, it also plans to conduct a vegetation risk assessment in 2025.

2-Staff-25
System Demand and Efficiency
Ref 1: Exhibit 2, part 2, Table 5.3-26, p. 73
Ref 2: Exhibit 2, part 2, Table 5.3-27, p. 73

Preamble:
Per Tables 5.3-26 and 5.3-27, losses have generally trended upwards over the historical period. Approximately one third of these losses are attributed to Hydro One transmission losses. Losses were highest in 2023, at 6.93% when including Hydro One transmission losses or 4.53% when excluding Hydro One transmission losses.

Questions:
(a) What is the expected impact that planned investments, such as voltage conversion, will have in reducing losses?

The primary driver for conversion projects is the increase in feeder capacity and system renewal. However, one of the secondary drivers is loss reduction. The shift to higher voltage systems will lower resistive losses, reduce the amount of energy lost in the converted/upgraded distribution system, and improve overall load management. The impact of the conversion project is not visible in terms of losses at this point in time. However, once all the conversion is completed, there will be an impact on line losses, particularly in areas where older, lower-voltage infrastructure has been replaced.

2-Staff-26
Other Fixed Assets
Ref 1: Exhibit 1 (1 of 2), p. 175 of 230
Ref 2: Chapter 2 Appendices, Tab 2-BA_Fixed Asset Cont

Preamble:
OEB staff has compiled the following table outlining the other fixed assets reflected in reference 1 versus reference 2.

	Other Fixed Assets as per Notes to Financial Statements 2023	Other Fixed Assets as per Appendix 2-BA 2023	Difference
Starting balance 2023	$5,518,518	$5,356,053	$162,465
Additions	$650,166	$650,166	$0
Disposals	($239,907)	($239,907)	$0
Ending Balance 2023	$5,928,777	$5,766,312	$162,465

Questions:

(a) Please explain the difference between other fixed assets amount between reference 1 and reference 2 in the chart above.

Reference 1 (Financial Statements) includes $162,465 for Account 2075 - Non Rate-Regulated Utility Property Owned – Renewable Generation and Reference 2 (Appendix 2-BA) does not include account 2075 as its a non-distribution asset and therefore, not included in the rate base calculation.

(b) Please update the evidence as needed.

No updates are required.

2-Staff-27
Depreciation – Land Rights
Ref 1: Exhibit 2 (1 of 4), p. 47
Ref 2: LPDL_2025_Filing_Requirements_Chapter2_Appendices_1.0_ 20241216
Ref 3: Exhibit 1, p. 38

Preamble:
In reference 1, Lakeland Power states “The depreciation expenses in OEB Appendix 2-C for each year reconciles with the accumulated depreciation balances in the fixed asset continuity schedule from 2019 through the 2025 Test Year found in Appendix 2-BA. The discrepancy for account 1612 Land Rights is related to the approved former PSP accounting treatment that LPDL had adopted. LPDL will deem this account as indefinite with no depreciation starting in 2027.”

OEB staff compiled the following table using values from the Chapter 2 Appendices.

	Depreciation as per		
Year	Appendix 2-C Depreciation Expense	Appendix 2-BA Fixed Asset Continuity	Difference
2019	$1,453,821	$1,396,295	($57,526)
2020	$1,531,972	$1,467,255	($64,717)
2021	$1,614,229	$1,540,266	($73,962)
2022	$1,718,620	$1,632,331	($86,289)
2023	$1,839,255	$1,735,707	($103,547)
2024	$1,967,837	$1,838,418	($129,419)
2025	$2,102,952	$1,930,373	($172,579)

In reference 3, Lakeland Power states that it has applied a materiality of $50,000 throughout this application.

Questions:

(a) OEB staff noticed differences between Appendix 2-C and Appendix 2-BA are above the materiality threshold. Please explain further the approved former PSP accounting treatment that Lakeland Power had adopted.

This difference is due to Account 1612 - Land Rights (formerly known as Account 1906), which is an intangible asset with an indefinite useful life.

School Energy Coalition (SEC)

SEC-13

[Ex. 2, p. 38] Please provide the original plan to “upgrade the service to 27.6kV”, any current modified version of that plan, and a summary by year of progress to date.

LPDL inherited one 27.6kV substation (Golden Beach MS) from Hydro One upon annexation in 2000. Prior to this, LPDL’s territory was comprised of only 4.16kV. Since then, various residential and commercial developments have necessitated converting to 27.6kV. LPDL has had to choose whether to invest expanding 4.16kV systems to feed new growth or convert to 27.6kV to meet new growth. Given only one 27.6kV substation was available, at a minimum, expanding to create redundancy was prudent.

Since at least 2012, LPDL has been working to convert all remaining 4.16kV to 27.6kV. Conversion to 27.6kV has been instrumental to facilitate connection of large DERs, namely over 8MW of hydroelectric generation within the Town of Bracebridge, that is serviced by our 27.6kV distribution system. Conversions such as this are normal within this industry.

2012-2018:

- Dill St, Holditch St, Smith St area
- Monck Rd, McDonald St, Hiram St area
- Ecclestone Dr, Southbank Dr area
- Dawsonwood Dr area
- Shoreline Dr
- North Manitoba St area
- South Manitoba St rear-lot
- Robert Dollar Dr area
- Sander Dr, Sadler Dr,
- Pine St, Wilshier Blvd area
- Maple St, Sherwood Dr, Dudley Dr area
- Woodward St, Front St
- River Rd, Wilsons Falls Rd area
- Liddard St, Aubrey St, Woodland Dr, Ann St area (this location includes the Bracebridge Hospital, a 3MVA customer)
- Wellington St, Armstrong St, Valley Dr area
- Quebec St, Victoria St, Ontario St area

2019:

- Catherine Cres area, Toronto St, Richard St area
- South Wellington St area

2020:

- None

2021:

- Alice St, York St area

2022:

- Bird Ln, Richard St area

2023:

- Woodchester Ave, Park Ln area

2024:

- Rene Caisse Ln area
- Mary St, James St, Robert St area

- McMurray St, John St, Buller St area
- Young St, Milton St area

Planned 2025:

- Entrance Dr, Alexandra Dr area
- Manitoba St backlot
- Ontario, Kimberley, Mahaffey area
- Anglo St, Shaw St area
- Muskoka Rd area

SEC-14
[Ex. 2, p. 38] Please provide the most current version of the “long-term plan to upgrade its software against cyberattacks”.

Please see response to 2-Staff-13.

Vulnerable Energy Consumers Coalition (VECC)

2.0-VECC -7
Reference: Exhibit 2, pages 14- Appendix 2-BA

a) LPDL did not record any amounts under construction work in progress (CWIP) prior to 2024. For 2024 and 2025 and amount $158,698 is shown for both years. Please explain this change.

In 2024, the CWIP of $158,698 relates to the partial payment of a bucket truck that will not be ready for delivery until 2025. LPDL is required to make payments on the truck at different stages of the truck build. In 2025, the CWIP of $(158,698) is a negative amount as its transferred from CWIP to Account 1930 – Transportation Equipment and included in the 2025 capital additions of $730K. Of note, LPDL capital projects are usually completed by the end of the year due to inclement weather and frozen ground.

2.0-VECC -8
Reference: Exhibit 2, Distribution System Plan

a) Please explain the derivation of the capital contribution forecasts for each year 2024 through 2029.

Capital contribution forecasts for 2024-2029 are based on historical costs, fibre-to-the-home projects and customer-driven projects which require capital contribution. LPDL receives early consultation requests from its municipal partners. However, many projects may not proceed and thus cannot be fully relied upon to create an accurate forecast. As such, capital contributions are difficult to predict.

FIbre-to-the-home projects through the UBF program in LPDL's territory were expected to end in late 2024 early 2025, therefore no expenditures have been forecast beyond 2025.

LPDL has amended its 2025-2029 forecast capital contributions to account for the December 23, 2024 Distribution System Code amendments. These amendments are intended to facilitate the connection of housing developments by extending the connection horizon to a maximum of 15 years for qualifying housing developments and extending the revenue horizon to 40 years for all residential customers.

LPDL has limited visibility on planning applications beyond 2026, so has forecasted similarly to the historical years while accounting for regulatory changes.

b) What were the actual contributions in 2024?

The actual contributions in 2024 were $2,399,386.

2.0-VECC -9
Reference: Exhibit 2, Distribution System Plan, Appendix 2-AA

a) Please explain the derivation of the $250k for “All Capital Storm Damage/Trouble Call Capital for each year 2024 through 2029.

Please see OEB Question 2-Staff-12.

b) What is the actual amount expended in this category in 2024?

The actual amount expended in this category in 2024 was $81,550. However, the extreme storms occurring in late 2024 involved a state of emergency in the Muskoka area for several days and caused O&M costs of more than $130K. LPDL expects damage from this storm may lead to incremental capital in 2025 for items found during the major incident, as the priority at the time was to restore power as quickly as possible.

2.0-VECC -10
Reference: Exhibit 2, Appendix 2-AA

a) Please confirm (or correct) that the following 27.6kV conversion projects have been completed and are in service:

i. McMurray St.;

Completed and in service September 2024.

ii. John, Buller, Willis; and,

Completed and in service September 2024

iii. Mary & St. James St.

Completed and in service August 2024.

2.0-VECC -11

Reference: Exhibit 2, Distribution System Plan

a) Please update Tables 5.2-11, 5.2-12, 5.2-16, 5.2-18, 5.2-19, and 5.2-20 for 2024 results.

Table 5.2-11 Historical Reliability Performance Metrics - All Cause Codes

Metric	2019	2020	2021	2022	2023	2024 Prelim	Average
SAIDI	7.66	11.39	8.99	13.35	2.34	11.59	9.22
SAIFI	3.71	4.81	4.16	4.65	1.04	3.10	3.58
CAIDI	2.06	2.37	2.16	2.07	2.25	3.74	2.44

Table 5.2-12 Historical Reliability Performance Metrics -LOS and MED Adjusted							
	Loss of Supply Adjusted (including MEDs, Exclusing LOS)						
Metric	**2019**	**2020**	**2021**	**2022**	**2023**	**2024 Prelim**	**Average**
SAIDI	1.29	5.78	2.62	4.24	1.30	2.93	3.03
SAIFI	0.66	1.40	1.48	1.30	0.66	0.74	1.04
CAIDI	1.95	4.13	1.77	3.26	1.97	3.96	2.84
	Major Event Days Adjusted (including LOS, Excluding MEDs)						
Metric	**2019**	**2020**	**2021**	**2022**	**2023**	**2024 Prelim**	**Average**
SAIDI	7.67	10.42	7.00	6.18	2.34	3.84	6.24
SAIFI	3.72	4.35	3.93	3.23	1.04	1.34	2.94
CAIDI	2.06	2.40	1.78	1.91	2.25	2.87	2.21
	Loss of Supply and Major Event Days Adjusted (Excluding LOS and MEDs)						
Metric	**2019**	**2020**	**2021**	**2022**	**2023**	**2024 Prelim**	**Average**
SAIDI	1.29	5.79	2.62	3.84	1.30	1.56	2.73
SAIFI	0.66	1.40	1.48	1.30	0.66	0.62	1.02
CAIDI	1.95	4.14	1.77	2.95	1.97	2.52	2.55

Table 5.2-16 Outage Numbers by Cause Codes - Excluding MEDs								
Cause Code	**2019**	**2020**	**2021**	**2022**	**2023**	**2024 Prelim**	**Total Outages**	**%**
0-Unknown/Other	10	17	8	11	8	15	69	8.02%
1-Scheduled Outage	31	13	1	1	32	8	86	10.00%
2-Loss of Supply	24	22	20	17	10	8	101	11.74%
3-Tree Contacts	20	14	16	16	22	28	116	13.49%
4-Lightning	1	2	3	0	3	4	13	1.51%
5-Defective Equipment	55	46	28	30	20	19	198	23.02%
6-Adverse Weather	15	16	15	19	13	8	86	10.00%
7-Adverse Environment	0	0	0	0	0	0	0	0.00%
8-Human Element	3	3	0	0	2	2	10	1.16%
9-Foreign Interference	37	44	30	28	22	20	181	21.05%
Total Number of Outages	**196**	**177**	**121**	**122**	**132**	**112**	**860**	**100.00%**

5.2-18: Customers Interrupted Numbers by Cause Code - Excluding MEDs

Cause Code	2019	2020	2021	2022	2023	2024 Prelim	Total CI	%
0-Unknown/Other	1,507	1,513	295	3,348	1,548	1,550	9,761	3.49%
1-Scheduled Outage	1,015	333	2	9	546	323	2,228	0.80%
2-Loss of Supply	42,095	55,005	37,936	48,239	5,493	9,359	198,127	70.85%
3-Tree Contacts	1,927	802	5,001	1,423	3,368	1,871	14,392	5.15%
4-Lightning	1	405	26	-	369	30	831	0.30%
5-Defective Equipment	720	964	2,153	1,119	270	4,290	9,516	3.40%
6-Adverse Weather	3,306	7,372	10,114	10,797	2,746	2,896	37,231	13.31%
7-Adverse Environment	-	-	-	-	-	-	-	0.00%
8-Human Element	169	533	-	-	181	6	889	0.32%
9-Foreign Interference	469	215	3,408	1,948	537	81	6,658	2.38%
Total Number of CI	**51,209**	**67,142**	**58,935**	**66,883**	**15,058**	**20,406**	**279,633**	100.00%

5.2-19: Customer Hours Interrupted Numbers (rounded) by Cause Code - Excluding MEDs

Cause Code	2019	2020	2021	2022	2023	2024 Prelim	Total CHI	%
0-Unknown/Other	1,882	2,055	499	2,208	1,419	2,048	10,111	1.63%
1-Scheduled Outage	3,571	739	2	4	961	1,952	7,229	1.16%
2-Loss of Supply	87,915	100,038	90,395	131,151	15,160	29,179	424,659	68.37%
3-Tree Contacts	3,205	2,374	6,914	2,583	7,911	6,918	22,987	3.70%
4-Lightning	3	1,044	56	-	1,683	72	2,786	0.45%
5-Defective Equipment	2,105	1,402	3,863	3,076	799	5,948	11,245	1.81%
6-Adverse Weather	6,046	49,073	16,703	44,876	4,850	4,197	121,548	19.57%
7-Adverse Environment	-	-	-	-	-	-	-	0.00%
8-Human Element	143	798	-	-	121	23	1,062	0.17%
9-Foreign Interference	819	309	9,143	8,072	1,109	120	19,452	3.13%
Total Number of CHI	**105,689**	**157,832**	**127,575**	**191,970**	**34,013**	**50,457**	**621,079**	100.00%

Table 5.2-20: Historical Power Quality Issues (2019-2024)

Power Issues	2019	2020	2021	2022	2023	2024 Prelim
Blown Fuse	0	0	0	0	0	0
Brown Out	1	0	0	0	0	2
Flickering Lights	1	2	1	2	0	2
Fluctuation Power	1	0	0	1	0	0
Part Power	1	0	0	0	0	0
Power Surges	5	0	0	0	0	0
Voltage Issue	5	5	2	8	4	8
Total	**14**	**7**	**3**	**11**	**4**	**12**

b) Does LPDL maintain its reliability data separately for each of its six non-contiguous service territories? If not, please explain why this is not possible.

Please see response to 2-Staff-24.

c) If LPDL does collect data for each of the six service areas separately then please provide the updated tables requested in a), for each of the six service areas.

Please see response to 2-Staff-24.

2.0-VECC -12

Reference: Exhibit 2, pg.57, App A – Material Investments PDF pg. 74

"*LPDL has a discrete capital project within the five-year horizon that would potentially be eligible 2 for this policy option; however, it is too early in the investment planning process to make an 3 adequate business case to meet all of the criteria of an ACM. LPDL is not requesting approval 4 for an ACM mechanism in this rate application.*"

a) Is it LPDL's intention to seek an ICM for the Bracebridge MS3 project? If so when is that application expected?

LPDL will evaluate whether or not it will pursue ICM funding for this project once it has more information on the scope, need and prudence for the work. LPDL has not yet determined whether it will seek ICM funding, and if so when such an application would be expected.

b) The DSP anticipates this project to start in 2026, is less than a year from the present. Please explain what in the planning process needs to be done in order to prepare an application for incremental funding for this project (if the Utility will be seeking funding).

This project is anticipated to start in late 2026, with the majority of work occurring in 2027. At the time of this application, LPDL was in the process of a transformer RFQ, and are now currently weighing options with the vendors. Supply chain for power transformers has been extremely volatile in recent years, which added a lot of uncertainty during the time of application. In addition, a shortage of internal human resources has had a negative impact on project progress overall. Formal engineering is ongoing, which will need to be completed before an accurate cost can be determined. A class D estimate is expected to be received in mid-February.

Exhibit 3 – Customer and Load Forecast

OEB Staff

3-Staff-28
Customer Forecast
Ref: Exhibit 3, p. 14

Preamble:
Lakeland Power has used a geometric mean analysis from 2014 to 2023 applied to 2024 customer numbers to determine the 2024 and 2025 customer forecast.

Questions:
(a) Please provide the customer numbers for the most recent historical months for 2024.
(b) Please update the customer forecast using 2024 actuals for the months available.

The 2025 load forecast has been updated to include 2024 monthly actual data such as power purchases, customers, consumption and demand by rate class where applicable. All 12 months have been provided. The updated load forecast is provided in Excel format with file name LPDL_2025_CoS_Load Forecast Model_Updated for 2024_20250206. The updated monthly data is provided in tab Inputs rows 144 to 155.

3-Staff-29
Load Forecast
Ref: Exhibit 3, Attachment 3-A, pp. 39-41

Preamble:
Lakeland Power has developed a consumption forecast based on 2014 to 2023 actual data.

Question:
(a) Please provide the consumption numbers for the most recent historical months for 2024.
(b) Please provide an updated load forecast based on 2024 data for the months available.

Please see response to 3-Staff-28.

3-Staff-30
COVID-19
Ref: Exhibit 3, p. 22

Preamble:
Lakeland Power notes a 7.8% decrease in consumption in 2020 due to businesses closing down during COVID-19 for the GS<50 kW rate class.
Question:
(a) Did Lakeland Power test for COVID-19 as an explanatory variable in its regression analysis? If so, please provide the results. If not, please explain why.

LPDL did not test for COVID-19 as an explanatory variable in its regression analysis. It was not tested since the statistical and forecast results were reasonable with the explanatory variables used in the load forecast and no other variables were needed.

3-Staff-31
Electric Vehicles and Heat Pumps
Ref 1: Exhibit 3
Ref 2: Exhibit 2, part 3, p. 41

Preamble:
The load forecast make no reference to electrification through electric vehicles, heat pumps, or other emerging technologies.

In reference 2, Lakeland Power states,

> *“Through feeder-modelling and consultation with developers and Electric Vehicle Supply Equipment (EVSE) installers, LPDL has identified critical areas in the north end of Parry Sound that require new conductors to meet the increasing demand. This includes a new subdivision, a high school, a recreation centre, two level-three EVSE charger locations, and several vehicle dealerships installing EVSEs. LPDL plans to commence this essential work in 2025.”*

Questions:

(a) Has Lakeland Power considered how EVs and Heat Pumps will affect load growth over the forecast period?

At the time the load forecast was prepared LPDL did not anticipate there would be a noticeable impact on the load forecast from EVs and heat pumps in the 2025 test year. Information on the installation of EVs and heat pumps is highly limited. Customers are not required to consult with LDCs unless a service upgrade is required, at which time capacity is considered.

(b) How has Lakeland Power accounted for the additional load in reference 2?

Please response to part a).

School Energy Coalition (SEC)

SEC-15

[Ex. 3, p. 8 & 20] Please explain why the GS>50 kW forecast for the Test Year is lower than all of the six preceding years’ actuals, while the kWh forecast for the Test Year is higher than four of the six preceding years’ actuals.

The following outlines the GS>50 kW forecast for the Test Year and the six preceding years’ actuals. It does not appear that the 2025 kWh are higher than the preceding years’ actuals; it appears that both the 2025 kW and kWh forecast are lower than any of the six preceding years. The decline in consumption and demand shown is driven by the forecast decline in customers in the GS>50kW rate class in the Test Year. Customer declines are forecast on the basis of a 10 year customer count average, during which actual customer count declined in all but one year.

	2014 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge Weather Normal	2025 Test Weather Normal
General Service > 50 to 4999 kW									
Customers	172	138	137	136	131	129	130	126	122
kWh	121,885,729	119,092,479	118,495,415	117,859,877	119,633,612	125,207,062	122,653,645	119,652,398	116,858,492
kW	288,261	288,024	289,524	290,763	285,432	308,241	316,961	291,506	284,699

Vulnerable Energy Consumers Coalition (VECC)

3.0-VECC -13

Reference: Exhibit 3, page 6
Exhibit 8, Appendix B

Preamble: The Application (Exhibit 3) states:

"*Customer/Connection values are presented on an average basis throughout this evidence for the purpose of rate design, and the Unmetered Scattered Load (USL), Sentinel Lighting and Street Lighting rate classes are measured as connections*".

a) The proposed tariff 2025 tariff sheet does not indicate the billing determinants used for the Sentinel Lighting, Street Lighting and USL monthly service charges. Please confirm that, in each case, the billing determinant is the number of connections.

LPDL confirms the billing determinant for Sentinel Lighting, Street Lighting and USL monthly service charges is the number of connections.

3.0-VECC -14

Reference: Exhibit 3, page 10

Preamble: The. Application states:

"*The multivariate regression model has determined the drivers of year-over-year changes in LPDL's load growth are: weather (heating degree days), days in month, a spring/fall flag, a summer flag, and a Trend variable*."

a) What other independent variables were tested and why were they not used?

The following variables were tested and not used for the reasons provided:

- Cooling Degree Days was tested and not used since it produced a non-intuitive negative coefficient along with a T-stat of -0.1976.

- Monthly Customer Count (Residential, GS<50 and GS>50) along with Work Days in the Month were tested with and without the trend variable. In the case with the trend variable, the trend variable coefficient was a non-intuitive negative coefficient. In the case without the trend variable the resulting power purchased forecast for the 2025 test year was unreasonable compared to the 10 actual years of power purchases from 2014 to 2023.
- A Covid flag variable was considered but not tested as per the response to 3-Staff-30.

b) It is noted that cooling degree days was one of the explanatory variables used in LPDL's last cost of service application (EB-2018-0050). If not addressed in part (a), please provide a version of the proposed load forecast model (and resulting 2025 forecast) that also includes cooling degree days as an explanatory variable.

The cooling degree days variable is addressed in part a).

c) If not addressed in part (a), please provide a version of the proposed load forecast model (and resulting 2025 forecast) that uses monthly customer count (Residential, GS<50 and GS>50) as an explanatory variable instead of a trend variable.

The monthly customer count (Residential, GS<50 and GS>50) variable is addressed in part a).

d) If not addressed in part (a), please provide a version of the proposed load forecast model (and resulting 2025 forecast) that also includes a COVID flag for those months when there was a provincial shut-down.

The COVID flag variable is addressed in part a).

3.0-VECC -15

Reference: Exhibit 3, page 9

Preamble: The Application states:

"*The dependent variable in the multivariate regression analysis is*

Power Purchases by month, and the regression model uses monthly values of independent variables from January 2014 to December 2023 to determine the monthly regression coefficients."

a) Please update the regression model to include 2024 customer counts, power purchases and customer class usage for those months where actual values are available.

Please see response to 3-Staff-28

3.0-VECC -16

Reference: Exhibit 3, pages 15 and 16

Preamble: The Application states:

"*The 2024 and 2025 forecast of usage per customer/connection have been held constant at the 2023 level since the usage per customer/connection has generally been declining in most rate classes, which may reflect conservation programs over these years. Since incremental conservation programs have not been assumed in 2024 and 2025, additional usage decline has not been incorporated into the forecast*." (page 15)

And

"*The difference between the non-normalized and normalized forecast is assumed to be the adjustment to move the forecast to a weather normal basis, and this amount will be assigned to those rate classes that are weather sensitive*" (page 16)

a) Please provide a schedule that sets out: i) the actual annual HDD value for 2023 and ii) the weather normal annual HDD value used by LPDL in its load forecast?

The requested schedule is provided below.

	Heating Degree Days	
	Actual	Weather Normal
Jan-23	712	845
Feb-23	707	776
Mar-23	629	676
Apr-23	381	428
May-23	237	218
Jun-23	69	80
Jul-23	27	28
Aug-23	56	41
Sep-23	116	129
Oct-23	268	312
Nov-23	536	501
Dec-23	590	678
Total	4,328	4,713

b) If the 2023 actual annual HDD value is greater than the weather normal HDD value, please reconcile this with the fact that the adjustment described on page 16 is positive and increases the billed energy for the weather sensitive classes.

The 2023 actual annual HDD value is less than the weather normal HDD value which means no reconciliation is needed.

Exhibit 4 – Operations, Maintenance & Administration

OEB Staff

4-Staff-32
General
Ref: Chapter 2 Appendices, Tabs 2-JA, 2-JB and 2-JD

Question:

(a) Please update the Chapter 2 Appendices, Tabs 2-JA, 2-JB and 2-JD, to reflect 2024 actuals.

Appendix 2-JA

Summary of Recoverable OM&A Expenses

	2019 Last Rebasing Year OEB Approved	2019 Last Rebasing Year Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year
Reporting Basis								
Operations	$ 360,081	$ 370,938	$ 489,384	$ 424,454	$ 375,552	$ 436,101	$ 547,849	$ 535,935
Maintenance	$ 1,473,726	$ 1,339,716	$ 1,642,609	$ 1,619,030	$ 2,062,665	$ 2,016,403	$ 2,322,113	$ 2,310,892
SubTotal	**$ 1,833,808**	**$ 1,710,655**	**$ 2,131,993**	**$ 2,043,484**	**$ 2,438,217**	**$ 2,452,503**	**$ 2,869,962**	**$ 2,846,827**
%Change (year over year)		-6.7%	24.6%	-4.2%	19.3%	0.6%	17.0%	-0.8%
%Change (Test Year vs Last Rebasing Year - Actual)								66.4%
Billing and Collecting	$ 971,160	$ 936,607	$ 1,346,742	$ 871,019	$ 979,184	$ 1,037,652	$ 1,093,112	$ 1,136,558
Community Relations	$ 75,000	$ 38,436	$ 7,183	$ 17,638	$ 6,639	$ 14,519	$ 34,862	$ 36,225
Administrative and General	$ 2,133,000	$ 2,083,437	$ 1,883,032	$ 1,869,254	$ 2,021,057	$ 2,299,743	$ 2,551,573	$ 2,561,246
SubTotal	**$ 3,179,160**	**$ 3,058,480**	**$ 3,236,957**	**$ 2,757,911**	**$ 3,006,881**	**$ 3,351,913**	**$ 3,679,547**	**$ 3,734,029**
%Change (year over year)		-3.8%	5.8%	-14.8%	9.0%	11.5%	9.8%	1.5%
%Change (Test Year vs Last Rebasing Year - Actual)								22.1%
Total	**$ 5,012,968**	**$ 4,769,134**	**$ 5,368,950**	**$ 4,801,396**	**$ 5,445,098**	**$ 5,804,416**	**$ 6,549,509**	**$ 6,580,856**
%Change (year over year)		-4.9%	12.6%	-10.6%	13.4%	6.6%	12.8%	0.5%

	2019 Last Rebasing Year OEB Approved	2019 Last Rebasing Year Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year
Operations[4]	$ 360,081	$ 370,938	$ 489,384	$ 424,454	$ 375,552	$ 436,101	$ 547,849	$ 535,935
Maintenance[5]	$ 1,473,726	$ 1,339,716	$ 1,642,609	$ 1,619,030	$ 2,062,665	$ 2,016,403	$ 2,322,113	$ 2,310,892
Billing and Collecting[6]	$ 971,160	$ 936,607	$ 1,346,742	$ 871,019	$ 979,184	$ 1,037,652	$ 1,093,112	$ 1,136,558
Community Relations[7]	$ 75,000	$ 38,436	$ 7,183	$ 17,638	$ 6,639	$ 14,519	$ 34,862	$ 36,225
Administrative and General[8]	$ 2,133,000	$ 2,083,437	$ 1,883,032	$ 1,869,254	$ 2,021,057	$ 2,299,743	$ 2,551,573	$ 2,561,246
Total	**$ 5,012,968**	**$ 4,769,134**	**$ 5,368,950**	**$ 4,801,396**	**$ 5,445,098**	**$ 5,804,416**	**$ 6,549,509**	**$ 6,580,856**
%Change (year over year)		-4.9%		-10.6%	13.4%	6.6%	12.8%	0.5%

Appendix 2-JB

Recoverable OM&A Cost Driver Table[1,3]

OM&A	Last Rebasing Year (2019 Actuals)	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Opening Balance[2]	$ 5,012,968	$ 4,769,134	$ 5,368,950	$ 4,801,395	$ 5,445,098	$ 5,804,417	$ 6,549,509
Wages/Merit increase & FTE changes	-$ 240,580	$ 251,830	-$ 217,540	$ 261,613	$ 13,479	$ 175,806	$ 200,716
Vacant positions - Offset Corp Allocation	-$ 27,922	-$ 174,898	$ 41,191	$ 108,324	$ 149,843	$ 67,707	-$ 5,467
Bad Debt	-$ 17,325	$ 402,105	-$ 458,246	$ 63,523	-$ 7,415	$ 45,543	-$ 36,433
OH/UG Maintenance and Storm Trouble Calls	-$ 17,926	$ 165,079	$ 75,330	$ 178,198	$ 55,171	$ 245,588	-$ 164,195
General Plant Expenses, Information System Technology	$ 69,696	-$ 47,106	-$ 6,974	$ 53,546	$ 55,599	$ 131,968	-$ 77,906
Tree trimming better contract pricing	-$ 20,145	$ 27,631	-$ 4,237	-$ 43,611	$ 7,145	$ 54,296	-$ 11,648
Joint Use Pole rental charge	$ 34,045	-$ 15,111	$ 5,019	-$ 10,708	$ 3,635	$ 466	$ 6,004
Regulatory charges - intervenor charges/rate applications/OEB assessment	-$ 19,875	$ 2,132	$ 5,017	$ 11,578	-$ 11,366	$ 8,101	$ 78,113
U/G Locates	-$ 3,802	-$ 11,846	-$ 7,113	$ 21,239	$ 93,227	$ 15,618	$ 42,162
Closing Balance[2]	$ 4,769,134	$ 5,368,950	$ 4,801,395	$ 5,445,098	$ 5,804,417	$ 6,549,509	$ 6,580,856

Appendix 2-JD
OM&A Programs Table

USoA Account	USoA Account Name	Last Rebasing Year (2019 OEB-Approved)	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year	Variance (Test Year vs. 2023 Actuals)	Variance (Test Year vs. Last Rebasing Year (2019 OEB-Approved)
	Reporting Basis										
5,005	Operation Supervision and Engineering	0	0	0	0	0	0	0	0	0	0
5,010	Load Dispatching	9,299	40,455	65,173	39,823	36,909	38,658	40,516	47,250	8,592	37,951
5,012	Station Buildings and Fixtures Expense	0	0	0	0	0	0	0	0	0	0
5,014	Transformer Station Equipment - Operation Labour	0	0	0	0	0	0	0	0	0	0
5,015	Transformer Station Equipment - Operation Supplies and Expenses	0	0	0	0	0	0	0	0	0	0
5,016	Distribution Station Equipment - Operation Labour	0	11,780	14,656	8,584	11,737	12,005	10,157	10,500	-1,505	10,500
5,017	Distribution Station Equipment - Operation Supplies and Expenses	0	0	0	0	0	0	0	0	0	0
5,020	Overhead Distribution Lines and Feeders - Operation Labour	0	6,524	9,645	10,495	15,532	31,729	61,952	0	-31,729	0
5,025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	18,444	6,264	2,768	1,331	0	0	0	31,500	31,500	13,056
5,030	Overhead Subtransmission Feeders - Operation	0	0	0	0	0	0	0	0	0	0
5,035	Overhead Distribution Transformers - Operation	0	841	4,760	2,273	6,974	5,928	909	10,500	4,572	10,500
5,040	Underground Distribution Lines and Feeders - Operation Labour	0	422	4,067	3,856	2,287	0	11,691	2,100	2,100	2,100
5,045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	0	0	0	0	0	0	0	0	0	0
5,050	Underground Subtransmission Feeders - Operation	0	0	0	0	0	0	0	0	0	0
5,055	Underground Distribution Transformers - Operation	0	1,303	2,106	3,248	17,197	10,252	21,483	29,663	19,411	29,663
5,060	Street Lighting and Signal System Expense	0	0	0	0	0	0	0	0	0	0
5,065	Meter Expense	98,099	67,370	148,044	89,331	97,780	112,474	106,357	120,173	7,699	22,074
5,070	Customer Premises - Operation Labour	0	0	0	0	0	0	0	0	0	0
5,075	Customer Premises - Materials and Expenses	0	0	0	0	0	0	0	0	0	0
5,085	Miscellaneous Distribution Expense	166,240	133,933	151,232	173,559	105,891	140,175	209,438	192,900	52,725	26,660
5,090	Underground Distribution Lines and Feeders - Rental Paid	0	0	0	0	0	0	0	0	0	0
5,095	Overhead Distribution Lines and Feeders - Rental Paid	68,000	102,045	86,934	91,953	81,245	84,880	85,346	91,350	6,470	23,350
5,096	Other Rent	0	0	0	0	0	0	0	0	0	0
	Distribution Expenses - Operations	360,081	370,938	489,384	424,454	375,552	436,101	547,849	535,935	99,835	175,854
5,105	Maintenance Supervision and Engineering	357,550	341,766	344,000	392,376	505,030	529,562	527,723	563,273	33,711	205,722
5,110	Maintenance of Structures	0	0	0	0	0	0	0	0	0	0
5,112	Maintenance of Transformer Station Equipment	0	0	0	0	0	0	0	0	0	0
5,114	Mtaint Dist Stn Equip	80,830	55,545	59,943	64,874	68,391	264,348	391,335	92,400	-171,948	11,570
5,120	Maintenance of Poles, Towers and Fixtures	0	27,054	50,463	32,938	92,015	109,938	93,028	99,225	-10,713	99,225
5,125	Maintenance of Overhead Conductors and Devices	0	81,983	119,073	137,849	170,802	48,226	21,609	139,587	91,361	139,587
5,130	Maintenance of Overhead Services	562,477	407,662	643,754	572,117	810,238	589,630	776,969	813,750	224,120	251,273
5,135	Overhead Distribution Lines and Feeders - Right of Way	200,569	180,424	208,055	203,818	160,207	167,352	221,648	210,000	42,648	9,431
5,145	Maintenance of Underground Conduit	0	0	0	0	689	903	0	0	-903	0
5,150	Maintenance of Underground Conductors and Devices	52,400	39,099	34,028	83,416	53,737	26,507	22,511	40,058	13,551	-12,343
5,155	Maintenance of Underground Services	123,315	119,513	107,667	100,554	121,793	215,020	230,638	272,800	57,780	149,485
5,160	Maintenance of Line Transformers	85,070	29,725	50,049	16,468	63,536	50,364	20,162	57,225	6,861	-27,845
5,165	Maintenance of Street Lighting and Signal Systems	0	0	0	0	0	0	0	0	0	0
5,170	Sentinel Lights - Labour	0	0	0	0	0	0	0	0	0	0
5,172	Sentinel Lights - Materials and Expenses	0	0	0	0	0	0	0	0	0	0
5,175	Maintenance of Meters	11,515	56,945	25,576	14,620	16,229	14,552	16,491	22,575	8,023	11,060
5,178	Customer Installations Expenses - Leased Property	0	0	0	0	0	0	0	0	0	0
5,195	Maintenance of Other Installations on Customer Premises	0	0	0	0	0	0	0	0	0	0
	Distribution Expenses - Maintenance	1,473,726	1,339,716	1,642,609	1,619,030	2,062,665	2,016,403	2,322,113	2,310,892	294,489	837,166
5,305	Supervision	158,875	145,764	149,444	150,349	154,780	175,525	174,838	188,265	12,740	29,390
5,310	Meter Reading Expense	64,380	44,464	46,664	49,937	58,140	53,259	107,026	89,723	36,464	25,342
5,315	Customer Billing	454,485	487,053	486,947	467,261	508,864	551,850	497,912	575,070	23,220	120,585
5,320	Collecting	118,212	109,835	108,929	109,563	100,290	106,170	115,283	115,500	9,330	-2,712
5,325	Collecting - Cash Over and Short	0	0	0	0	0	0	0	0	0	0
5,330	Collection Charges	0	-7,800	0	0	0	0	0	0	0	0
5,335	Bad Debt Expense	45,000	27,675	429,779	-28,467	35,056	27,640	73,183	36,750	9,110	-8,250
5,340	Miscellaneous Customer Accounts Expenses	130,208	129,618	124,979	122,376	122,055	123,208	124,870	131,250	8,042	1,042
	Billing & Collecting	971,160	936,607	1,346,742	871,019	979,184	1,037,652	1,093,112	1,136,558	98,906	165,397
5,405	Supervision	0	0	0	0	0	0	0	0	0	0
5,410	Community Relations - Sundry	65,000	28,571	2,034	4,224	4,639	4,602	10,286	10,500	5,898	-54,500
5,415	Energy Conservation	0	0	0	0	0	0	0	0	0	0
5,420	Community Safety Program	0	0	0	0	0	0	0	0	0	0
5,425	Miscellaneous Customer Service and Informational Expenses	10,000	9,866	5,150	13,414	2,000	9,917	24,576	25,725	15,808	15,725
	Community Relations	75,000	38,436	7,183	17,638	6,639	14,519	34,862	36,225	21,706	-38,775
5,605	Executive Salaries and Expenses	18,000	43,997	69,988	70,488	75,426	86,638	80,816	95,550	8,912	77,550
5,610	Management Salaries and Expenses	0	0	0	0	0	0	0	0	0	0
5,615	General Administrative Salaries and Expenses	80,000	55,002	47,078	0	0	0	0	0	0	-80,000
5,620	Office Supplies and Expenses	156,781	143,590	113,745	108,463	125,570	135,341	145,721	173,542	38,200	16,761
5,625	Administrative Expense Transferred-Credit	0	0	0	0	0	0	0	0	0	0
5,630	Outside Services Employed	85,000	85,781	88,408	89,702	57,268	79,616	98,488	105,000	25,384	20,000
5,635	Property Insurance	103,525	56,316	51,539	47,176	52,820	55,393	73,225	81,270	25,877	-22,255
5,640	Injuries and Damages	0	1,000	2,672	88	0	0	0	0	0	0
5,645	Employee Pensions and Benefits	0	9,969	42,554	9,922	8,493	50,816	11,145	12,600	-38,216	12,600
5,646	OPEB	0	-3,227	-8,587	-5,891	-1,706	-7,926	-6,495	0	7,926	0
5,650	Franchise Requirements	0	0	0	0	0	0	0	0	0	0
5,655	Regulatory Expenses	99,900	80,025	82,157	87,174	98,752	87,386	95,487	173,600	86,214	73,700
5,660	General Advertising Expenses	0	0	0	0	0	0	0	0	0	0
5,665	Miscellaneous Expenses	1,090,557	1,062,635	887,737	928,928	1,037,253	1,187,096	1,319,803	1,314,335	127,240	223,778
5,670	Rent	0	0	0	0	0	0	0	0	0	0
5,675	Maintenance of General Plant	468,237	519,968	477,989	501,647	541,001	585,079	704,809	592,349	7,270	124,112
5,680	Electrical Safety Authority Fees	18,000	15,381	14,752	18,558	13,180	20,472	15,574	0	-20,472	-18,000
5,685	Independent Market Operator Fees and Penalties	0	0	0	0	0	0	0	0	0	0
5,695	OM&A Contra Account	0	0	0	0	0	0	0	0	0	0
6,205	Donations - LEAP	13,000	13,000	13,000	13,000	13,000	19,832	13,000	13,000	-6,832	0
	Administrative and General	2,133,000	2,083,437	1,883,032	1,869,254	2,021,057	2,299,743	2,551,573	2,561,246	261,504	428,246
	Miscellaneous									0	0
	Total	**5,012,968**	**4,769,134**	**5,368,950**	**4,801,396**	**5,445,098**	**5,804,416**	**6,549,509**	**6,580,856**	**776,439**	**1,567,888**

4-Staff-33

OM&A Expenses

Ref 1: Exhibit 1, Section 1.1.3.1, p. 14

Ref 2: Exhibit 4

In reference 1, Lakeland Power states that one of the contributing factors for its proposed 2025 service revenue requirement compared to its 2019 OEB-approved service revenue requirement is the increase in its OM&A costs "due to increased staffing for succession planning, cloud computing costs, and improved maintenance practices".

With respect to the driver "increased staffing for succession planning", OEB staff observes that Lakeland Power's forecast 2025 FTE count of 23 represents an increase of only 1 FTE relative to the OEB-approved number in 2019.

With respect to the driver "cloud computing costs", OEB staff is unable to locate discussions in the evidence on specific drivers and associated costs in Exhibit 4.

Questions:

(a) Please further elaborate on the statement that "increased staffing for succession planning" is one of the OM&A drivers for the increase in Lakeland Power's revenue requirement.

Increased staffing and succession planning should have been phrased as 'Wages/Merit increase and FTE changes', accompanied with 'Corporate Allocation', as OM&A drivers. LPDL has experienced a compound annual growth rate of 4.57% in overall wages and benefits between 2019 and 2025 Test Year and with the addition of 1 FTE overall, that accounts for the bulk of the Wages/Merit increase driver. The Corporate Allocation as discussed in several other IRR's, represents LPDL's direct portion of the parent company's executive, finance and human resources staff. The portion of their actual time attributable to LPDL tasks is tracked through weekly timesheets and these direct costs are cross charged to LPDL through the management fee. With increasing time spent on regulatory requirements and rate applications, LPDL's portion of corporate costs has increased, with a spike seen in 2019 and 2024 due to the Cost of Service applications.

(b) Please provide a breakdown of increased OM&A costs associated with cloud computing for 2019-2024 and those included in the 2025 test year.

    i. Please indicate which cost drivers in (b) is a result of shifting from on premise solutions to cloud-based solutions.

The cost driver between switching from on-premise to cloud-based solutions is the elimination of large up-front software purchase costs replaced with monthly system access, maintenance and support subscription fees. The new Bamboo HR system, which is cloud based, was implemented and fully launched in 2024. It will eliminate the need for the existing health and safety training software that LPDL has been using for several years. The new Netsuite ERP system, is also cloud based and will be implemented in

2025. It will replace the existing GP financial software and Worktech operations software, that are both on-premise.

ii. Please describe any cost savings as a result of moving to cloud-based solutions which Lakeland Power would otherwise being incurring with on-premise solutions.

LPDL does not anticipate any cost savings at this time. The Bamboo HR cloud-based solution replaces the existing health and safety training software. This new solution costs a bit more but offers much more in terms of automating, streamlining and digitizing personnel records and HR functionality creating efficiencies for personnel and access to better data. The NetSuite cloud-based solution replaces the existing financial and operations software. This new solution is needed as the current systems are now obsolete and no longer supported by the vendor. This will also offer efficiencies for personnel and improved data, analytical and reporting functionality.

iii. Please complete the following table on spending between on premise and cloud-based solutions.

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
On Premise												
	Capex	$										
	OM&A	$										
Cloud												
	Capex	$										
	OM&A	$										

LPDL has completed the following table on spending between on premise and cloud-based solutions:

	2019	2020	2021	2022	2023	2024	2025
On Premise							
Capex	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OM&A	$15,163	$12,269	$14,026	$14,593	$15,987	$16,942	$ 18,092
Cloud							
Capex	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OM&A	$ -	$ -	$ -	$ -	$ -	$ 2,896	$ 90,955
						Difference in OM&A	$ 72,862

4-Staff-34
OM&A Expenses
Ref 1: Responses to OEB staff Error Checking Questions, Item 1, December 16, 2024
Ref 2: RRWF, Tab 3

Preamble:
In reference 1, Lakeland Power notes that truck depreciation of $303,799 is allocated to and included in the proposed total 2025 OM&A expenses of $6,580,856.

Questions:

(a) Please explain why this specific truck-related depreciation is allocated to OM&A expenses as opposed to the "Depreciation/Amortization" line in reference 2.

All truck-related depreciation is either expensed in OM&A or capitalized, based on where the trucks were used. The truck usage is tracked on daily timesheets and recorded to the expense or capital account it was used for. This methodology has been consistently applied since 2000.

(b) Please confirm if Lakeland Power included any other depreciation amounts in its OM&A expenses for each of the following: 2019-OEB approved, 2019 actuals, 2020-2024.

   i. If the answer to (b) is yes, please confirm the respective amounts, what the depreciation was related to, and explain why it was included in OM&A as opposed to depreciation/amortization.

LPDL confirms that no other deprecation amounts were included in OM&A expenses for 2019-OEB approved, 2019 actuals and 2020-2024.

4-Staff-35
OM&A Expenses
Ref 1: Exhibit 4, Section 4.1.4, p. 12
Ref 2: Chapter 2 Appendices, Tab 2-JD

Preamble:
Lakeland Power states that the 2025 test year expenditures were budgeted based on the actual expected costs, and not specifically based on an overall inflation rate.

Based on Tab 2-JD of the Chapter 2 Appendices, OEB staff calculates that, apart from Accounts 5155 and 5655, the 2025 test year costs reflect an increase of 5% for all accounts from the 2024 bridge year forecasted costs.

Question:

(a) Please explain how the 5% increase was derived, and why it was applied uniformly to all accounts (apart from Accounts 5155 and 5655).

Due to staffing changes and time constraints, a general inflationary factor was applied. This inflationary factor was based on historical trending. LPDL's average change in OM&A from 2019 actuals to 2024 actuals is 5.2%.

4-Staff-36
Cost Drivers – U/G Locates
Ref 1: Chapter 2, Appendices, Tab 2-JB – OM&A Cost Drivers
Ref 2: Exhibit 4, Section 4.2, p. 22

Preamble:
OEB staff notes that the overall increase for underground locates from the 2019 actuals to OEB-approved to 2025 proposed is $149k, with increases beginning in 2021.

Lakeland Power states that labour shortages negatively impacted its compliance metrics. To address these challenges, Lakeland Power's locate provider "implemented a mass hiring campaign and significantly increased wages to attract and retain employees, subsequently raising the costs for utilities."

Lakeland Power conducted an analysis of the benefits, risks, and costs associated with bringing underground locate services in-house. It was concluded that continuing to contract out these services was the most financially viable option.

Questions:

(a) Please confirm which USoA account(s) Lakeland Power records locate expenses.

LPDL records locate expenses in account 5155 - Maintenance of Underground Services.

(b) Please provide total annual locate expenses incurred during the historic period (i.e., for each of 2019-2024)

Account 5155	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Prelim Actual
Locate Expenses	119,513	107,667	100,554	121,793	215,020	230,638

i. What amount is forecasted for locate expenses in 2025 and how was the amount determined?

LPDL forecasted $273K for 2025. This forecast was based on the recent historical trend of rising labour rates for locate services due to the scarcity of available labour. LPDL is experiencing an increasing number of locate requests, historically and with future customer growth.

(c) Please provide the analysis used to conclude that continuing to contract out locate services was the most financially viable option.

In 2023, LPDL conducted an internal analysis on the financial viability of bringing locates in-house or continuing to contract them out. Based on the analysis below, continuing to outsource the locates is much more favourable as it would cost approximately $150K more to LPDL customers if in-house labour was used instead. Due to the seasonality of this area, it would be burdensome and ineffective to have a full-time person while the locate window is less than a year.

Estimated Locate Costs to Lakeland Power	Hourly Rate	Annual Cost
Locate Tech x 2	$ 70	$ 136,500
Locate Tech x 2 Burden @ 45%	$ 32	$ 61,425
Admin	$ 30	$ 58,500
Admin Burden @ 45%	$ 14	$ 26,325
Pick up Truck x 2	$ 50	$ 102,000
Total In-House Locate Costs		**$ 384,750**
Total Outsourced Located Costs		**$ 230,638**
Cost Difference		**$ 154,112**

4-Staff-37
OM&A Programs: Distribution Expenses – Maintenance and Cost Drivers – OH/UG Maintenance and Storm Trouble Calls
Ref 1: Chapter 2 Appendices, Tabs 2-JA, 2-JB and 2-JD
Ref 2: Exhibit 1, Section 1.1.3.1, p. 14
Ref 3: Exhibit 4, Section 4.3, pp. 27-34

Preamble:

The total 2019 OEB-approved amount for OM&A Expenses – Maintenance was $1.47M. Lakeland Power is proposing a 2025 test year amount of $2.31M, an increase of about $837k or 57%.

In reference 2, Lakeland Power states that one of the contributing factors for its proposed 2025 service revenue requirement compared to its 2019 OEB-approved service revenue requirement is the increase in its OM&A costs due to improved maintenance practices.

In reference 3, Lakeland Power provides a year-over-year variance analysis for its Maintenance costs, among other matters. OEB staff observes that except for certain references to overhead scanning and infrared scanning for preventative maintenance, the changes in expenses seem to be associated with storm damage/storm burden and locate expenses.

Questions:

(a) Please summarize the improvements made to Lakeland Power's maintenance practices compared to the historical period which contribute to and support the proposed increase in Maintenance costs in the 2025 test year.

LPDL has made the following improvements to its maintenance practices:

- LPDL will have hired two additional staff – one Power Line Technician vacancy from 2023, and one Engineering Technologist, to support business operations and meet the high workload demand. A portion of their wages will be allocated to OM&A.
- Infrared scanning and partial discharge scanning will be completed, and all immediate risks will be mitigated.
- LPDL will ramp up its porcelain switch change program. LPDL forecasts to change at least 100 in 2025.
- LPDL will continue to invest in ACA improvement. This includes bringing the database and associated maintenance in-house to our experienced staff.
- LPDL will continue to advance pole and attachment inspections in order to meet goals of the ACA including reduce data gaps and gather detailed condition information.
- LPDL wishes to improve its maintenance & inspection program, particularly with regard to substations as it has experienced an unprecedented catastrophic failure.
- LPDL will continue to invest in CYME modelling in 2025. This is necessary for various reasons, including Arc-Flash studies internally and for customers and Connection Impact Assessments for projects such as DERs.

- LPDL will increase the frequency of substation oil analysis at some sites as recommended by AVO Diagnostics.

(b) Please explain the main cost drivers and associated amount ($) for each driver that contributes to the increases in the following accounts in the 2025 test year amounts compared to the 2019 OEB-approved amounts.

LPDL has listed the main cost drivers and associated amounts for each of the accounts below:

i. Account 5105 - Maintenance Supervision and Engineering. As part of this response, please also specifically explain the increase in costs beginning in 2022.

- LPDL created and filled a new Assets & Engineering Supervisory position in 2022.

ii. Account 5120 - Maintenance of Poles, Towers and Fixtures. As part of this response, please also explain why the 2019 OEB-approved amount is shown as $0.

- Joint Use Attachments - This includes reviewing new permits, providing approvals, signoffs, site visits during and after construction. LPDL forecasts to spend $30,000 in 2025 in this category.
- Pole and attachment inspections - LPDL must increase its expenditures in order to meet goals of the ACA including reduce data gaps and gather detailed condition information. LPDL forecasts to spend $65,000 in 2025 in this category.

In 2019, expenses that are now recorded in account 5120 were previously recorded in Account 5130.

iii. Account 5125 - Maintenance of Overhead Conductors and Devices. As part of this response, please also explain why the 2019 OEB-approved amount is shown as $0.

- Infrared scanning and associated repairs. LPDL forecasts to spend $45,000 in 2025 in this category.
- Switch maintenance, including the porcelain switch program. LPDL forecasts to spend $49,000 in 2025 in this category.

In 2019, expenses that are now recorded in account 5125 were previously recorded in Account 5130.

iv. Account 5130 - Maintenance of Overhead Services. As part of this response, please also explain the causes for the fluctuations in this account.

- Customer-requested disconnects and reconnects. LPDL forecasts to spend $198,000 in 2025 in this category.
- Trouble/Storm OM&A. LPDL forecasts to spend $340,000 in 2025 in this category.

The main drivers for the above items are reactive-based. Trouble OM&A fluctuates based on weather (frequency, severity, season) and disconnect/reconnects fluctuate based on how many service requests are received by LPDL.

v. Account 5155 - Maintenance of Underground Services

- Underground Locates. Please see the response to 4-Staff-36 above.

(c) Please explain how:

i. Increases in voltage conversion projects over the historical period influenced the 2025 test year maintenance amounts.

Voltage conversion projects reduce the risk of infrastructure failure in specific areas by replacing outdated or undersized conductors and insulators, replacing aged poles and upgrading distribution transformers. The implementation of modern protections, construction materials and design standards reduce the costs associated with emergency repairs when necessary. LPDL's real-time SCADA visibility and switching capabilities are far superior on its 27.6kV system when compared to its 4.16kV counterpart, which has led to reduced response times. For example, in the event of a recloser trip at the station recloser caused by a temporary fault on the line, LPDL will attempt to re-energize the feeder remotely, which avoids a truck roll-out, which provides some savings to the customer, albeit minimal. The driver is reliability, capacity and replacing aging infrastructure.

ii. The asset risk and overall risk of overhead and underground assets influenced the 2025 test year maintenance amounts.

LPDL's increasingly aging pole infrastructure has resulted in a projected increase to OM&A costs. LPDL believes it is prudent to continue with its ACA improvement to fully utilize its purpose, which is to assist LPDL in maintaining its distribution system as safely and financially efficient as possible. To achieve this goal, a significant increase in detailed pole inspections and testing are required to enhance the quality of LPDL's data registry. This should allow more robust information to plan capital projects more effectively and enhance or replace aging infrastructure.

(d) Please provide actual OM&A costs relating to Storm Trouble Calls for each year between 2019 and 2024, and the amount forecasted for 2025. As part of the response, please explain how the 2025 test year amount was forecasted.

Account 5130	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Prelim Actual
Storm/Trouble Costs	229,082	391,992	298,349	475,736	283,448	448,928

LPDL has taken into account the rising costs of materials and labour, along with experienced increased storm frequency and intensity due to climate change. For example, LPDL experienced a major storm in December 2024 that shut down the Muskoka area, along with major highways in the area, for multiple days making access near impossible.

4-Staff-38
Cost Drivers – OH/UG Maintenance and Storm Trouble Calls
Ref: Exhibit 4, Section 4.2, p. 19

Preamble:
Lakeland Power "initiated a porcelain switch replacement program in 2020. Over the past few years, approximately 700 porcelain switches have been proactively replaced with more resilient polymer switches."

Questions:

(a) For each year between 2020 and 2024, please provide the number of porcelain switches replaced and the total OM&A related costs/year.

LPDL has spent $235K in porcelain switch changes between 2020-2024. On average, the cost per switch change has been $372/unit. The following table provides a summary of the number of switches and related costs per year:

Year	# of Changes	Cost Per Unit	Total Cost
2020	182	$440	$80,117
2021	179	$299	$53,624
2022	208	$292	$60,823
2023	46	$524	$23,820
2024	17	$991	$16,741
2025	100	$490	$49,000

(b) How many porcelain switches does Lakeland Power intend to replace in the 2025 test year? Please also provide the total OM&A related costs included in the 2025 test year related to this initiative.

LPDL plans to replace roughly 100 porcelain switches in 2025. The cost per switch has fluctuated significantly year over year due to various individual circumstances. For instance, some switches may require outages affecting multiple customers or may be situated in difficult to access locations. The number of switches changed out in 2023 and 2024 were lower due to limited resources available to complete the work which is being addressed through new hires to fill existing vacancies. LPDL expects through planning and execution, these costs can be reduced to $490 per switch, resulting in a total forecasted expenditure of $49K in account 5125 for 2025.

4-Staff-39
OM&A Programs: Billing and Collecting, CIS
Ref 1: Chapter 2 Appendices, Tabs 2-JA and 2-JD
Ref 2: Exhibit 4, Section 4.3, pp. 33-34

Preamble:
When comparing the 2024 bridge year to the 2025 test year, total Billing and Collecting costs are increasing by about $56k. In reference 2, Lakeland Power states that “In addition to regular wage increases, LPDL is planning to implement a new version of its CIS, Northstar, along with continued work with PowerAssist to send customers notifications.”

Questions:

(a) Please provide the OM&A costs ($) included in 2025 test year specifically associated with the new version of Lakeland Power’s CIS.
   i. What is the basis for this cost estimate?

LPDL removed the estimated OM&A costs associated with the new version of LPDL's CIS before final submission of this application as it came to understand that the release of the new version is still in development and will not be ready for upgrade until after 2025. LPDL missed removing the verbiage from the exhibit.

ii. What are the ongoing costs related to this product?

The annual support and maintenance costs for the current version of NorthStar in use by LPDL is approximately $140K.

(b) Please explain why there does not seem to be costs associated with the CIS included in Lakeland Power's proposed capital expenditures for 2025 or previous years.

There were no costs associated with the CIS included in LPDL's proposed capital expenditures for 2025 as the year LPDL will do the upgrade is still uncertain and is dependant on when the new release will be available. The release is still currently in development, so the upgrade is expected to take place beyond 2025. There were no costs in previous years as the last large CIS upgrade was prior to 2019.

(c) What are the reasons behind the decision for a new version of the CIS?

LPDL's current NorthStar version 6 is becoming obsolete.

i. What are the expected benefits and/or cost savings, both to Lakeland Power and its customers, of this new version of the CIS.

LPDL is moving off of the existing Northstar platform due to it becoming obsolete. Cost savings at this point are unknown and no additional costs have been included in this application.

a. Please confirm if any associated savings have been factored into the 2025 test year forecast.

No, there have been no associated savings factored into the 2025 test year. See response to part i) above.

4-Staff-40
OM&A Programs: Administrative and General
Ref 1: Chapter 2 Appendices, Tabs 2-JA and 2-JD
Ref 2: Exhibit 4, Section 4.3, p. 33
Ref 3: Exhibit 4, Section 4.2, pp. 19-21

Preamble:
When comparing the 2025 test year to the 2024 bridge year, Administrative and General costs are increasing by about $155k in 2025.

In reference 2, Lakeland Power states that this increase is largely due to the new ERP, HR and Asset Management software **being implemented** to replace end of life products. **(OEB staff emphasis added)**

In reference 3, Lakeland Power states that it "has **fully implemented** its Asset Condition Assessment software to assist with planned capital upgrades and "has **recently launched** a new HR software system provided by Bamboo HR to replace Compliance Science." **(OEB staff emphasis added)** Lakeland Power plans to implement a new ERP in 2025.

Questions:

(a) With respect to the Asset Management and HR software, respectively, please reconcile the evidence in reference 2 which states that part of the increase in 2025 compared to 2024 is a result of these systems "being implemented" with the evidence in reference 3 that states that the Asset Condition Assessment software has been "fully implemented" and the new HR software has been "fully launched".

The new Bamboo HR system, which is cloud based, was implemented and fully launched in 2024. The new Netsuite ERP system, which includes financial Asset Management (not ACA), is also cloud based and will be implemented in 2025. Both of these cloud based programs incur a monthly subscription.

i. Please confirm the year that the Asset Condition Assessment software was implemented/will be implemented.

The Asset Condition Assessment software, ArcGIS Pro, was originally implemented in 2020 and updated in 2024. The updates included bringing the database in house, updating it with LPDL's newest data registry which will be managed by existing inhouse LPDL staff.

ii. Please confirm the year that the HR software was implemented/will be implemented.

The new Bamboo HR system was implemented and fully launched in 2024.

iii. If one or both programs have already been implemented (i.e., prior to the 2025 test year), please explain how/what aspects of the Asset Management software and the HR software drive the $155k increase between 2024 and 2025.

Of the $155K increase in total Administrative and General Expenses, the new Bamboo HR system is $5K/year and the new NetSuite ERP system, which includes financial Asset Management, is $68K.

(b) Please confirm the OM&A costs ($) specifically associated with each product listed above (i.e., Asset Condition Assessment software, HR software, new ERP) and the line item(s) these costs have been incorporated into the evidence in each of Tabs 2-JA, 2-JB, 2-JD.

The Asset Management/Condition Assessment software costs are included in Distribution Expenses, account 5085: $48K in 2024 and $0 in 2025.
The Bamboo HR software costs are included in Administrative and General Expenses, account 5665: $3K in 2024 and $5K in 2025.
The NetSuite ERP software costs are included in Administrative and General Expenses, account 5665, included with the corporate cost allocation from LHL: $68K in 2025.

i. Please confirm the basis of the respective project cost estimates.

The costs for each of the respective projects above are based on actual invoices and contracts.

ii. What are the ongoing costs related to each new software included in OM&A (e.g., licensing, as applicable)?

For the Bamboo HR software, the ongoing costs will be $5K/year, as stated above in part b).
For the NetSuite ERP software, the ongoing costs will be a net change of $68K in 2025, as stated above in part b).

(b) Please explain why costs associated with these three software programs do not seem to be included in Lakeland Power's proposed capital expenditures for 2025 or previous years.

The costs associated with these three software programs were not included in LPDL's proposed capital expenditures for 2025 as the ACA was a database move rather than a software implementation in 2024 and the other two are cloud based programs with monthly service fees allocated direct to OM&A.

(c) What are the expected benefits and/or cost savings, both to Lakeland Power and its customers, of each new software.

The expected benefits from the Asset Management/Condition Assessment software include the ability to better prioritize asset replacements before failure, by identifying various risk factors and higher risk assets in an effort to minimize outages, emergency damagers/repairs and improved service to the customer.

The expected benefits from the Bamboo HR software include enhanced reporting, integration capabilities with the new ERP system to eliminate duplication of some HR and payroll/benefits tasks and efficiencies in having all personnel data, files, training and performance evaluation data in one secure, paperless online location for ease of access and updating.

The expected benefits from the new NetSuite ERP are unknown at this point. The driver for implementing was that the existing financial software in place since 2010, will no longer be supported by Microsoft in the next few years.

i. Please confirm if any associated savings have been factored into the 2025 test year forecast.

LPDL has not quantified any associated savings into the 2025 test year forecast as HR Bamboo is a new program and NetSuite ERP is being implemented due to end of life of the existing system. LPDL currently uses separate systems for operations and finance. The efficiencies from having these functionalities in one fully integrated system are expected to allow staff access to more robust reporting and analytical data outputs easily generated by the system for enhanced decision making.

4-Staff-41
OM&A Programs: Administrative and General
Ref: Chapter 2 Appendices, Tab 2-JD

Preamble:
Account 5665 – Miscellaneous Expenses has increased from approximately $1.1M (2019 OEB-approved) to a proposed amount of about $1.3M (2025 test year). The 2025 test year amount proposed is an increase of about $62.5k over the 2024 bridge year. Further, OEB staff notes that this line item makes up about 51% of total Administrative and General Expenses.

Questions:

(a) What items are captured in Miscellaneous Expenses in Account 5665.

In Miscellaneous Expenses in Account 5665, LPDL captures membership dues (CHEC, EDA, Trade Associations), training and meeting costs and corporate management fees based on LPDL's direct portion of corporate costs.

(b) What are the main cost drivers for increases in this account when compared to the 2019 OEB-approved amount, and when compared to the 2024 bridge year.

When comparing 2019 OEB-approved to 2024 bridge year, the main cost drivers for increases in this account 5665 are $45K for trainings and meetings and $110K for corporate management fees based on LPDL's direct portion of corporate costs. This represents a 3% average increase per year which would include annual wage increases in LPDL and LHL.

(c) Please provide an explanation for material year over year variances in this account.

The material year over year variances are highlighted in yellow below and are due to corporate management fees, based on LPDL's direct portion of corporate costs. 2020 vs 2019 shows a decrease as 2019 included higher direct corporate costs reflecting the time and cost for LHL staff to do the 2019 rate application. The increases for 2022 vs 2021, 2023 vs 2022 and 2024 vs 2023 are due to increasing direct corporate costs reflecting the time and cost for LHL staff to assist with increasing regulatory functions as LPDL has been unable to fill a full-time regulatory person and in preparation for this rate application in addition to average wage increases in LHL.

USoA Account	Miscellaneous Expenses Detail Breakdown	Last Rebasing Year (2019 OEB-Approved)	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year
5665	Membership Dues - CHEC, EDA, OACETT, Mearie HR	83,078	80,951	81,359	78,630	83,832	86,589	87,881	92,275
5665	Internal Meetings and Training - Labour and Expense	85,420	83,233	40,670	76,849	91,087	140,901	130,197	139,287
5665	Management Fee - Corporate Allocation	921,317	897,728	765,057	772,827	859,778	949,333	1,031,748	1,080,755
5665	Misc and Employee Expense	742	723	651	623	2,556	10,273	1,922	2,018
	Total 5665 Miscellaneous Expenses	**1,090,557**	**1,062,635**	**887,737**	**928,928**	**1,037,253**	**1,187,096**	**1,251,748**	**1,314,335**

USoA Account	Miscellaneous Expenses Detail Breakdown	2019 Actual to Board Approved	2020 vs PYR Actuals	2021 vs PYR Actuals	2022 vs PYR Actuals	2023 vs PYR Actuals	2024 vs PYR Actuals	2025 Test Year
5665	Membership Dues - CHEC, EDA, OACETT, Mearie HR	-2,127	408	-2,729	5,202	2,757	1,292	4,394
5665	Internal Meetings and Training - Labour and Expense	-2,187	-42,563	36,179	14,238	49,814	-10,704	9,090
5665	Management Fee - Corporate Allocation	-23,589	-132,671	7,770	86,951	89,555	82,415	49,007
5665	Misc and Employee Expense	-19	-72	-29	1,933	7,717	-8,351	96
	Total 5665 Miscellaneous Expenses - Variance Yr over Yr	**-27,922**	**-174,898**	**41,191**	**108,324**	**149,843**	**64,652**	**62,587**

4-Staff-42
OM&A Programs: Administrative and General
Ref: Exhibit 4, Section 4.3, p. 32

Preamble:
In explaining the variance between 2023 actual and 2024 bridge year costs, Lakeland Power states that “Administrative and General is increasing by $106,825 due to increases in office expenses, software costs, estimated regulatory expenses and shared services.”

Questions:

(a) Please explain the nature of the increase in office expenses in 2024. Are these expenses one-time costs or expected to continue.

The increase in office expenses in 2024 over 2023 include job recruiting costs, incremental fibre internet fees for SCADA capabilities, new AED’s for office/shop/vehicles and increased bank fees. The AED’s are the only one-time costs from above.

(b) Please explain the nature of the increase in software costs in 2024. Are these expenses one-time costs or expected to continue.

The increase in software costs in 2024 over 2023 include the new Bamboo HR costs that started mid year 2024 and the NetSuite ERP costs that started late in 2024. These are cloud based software expenses and are expected to continue.

4-Staff-43
Regulatory Charges
Ref: Chapter 2 Appendices, Tab 2-M – Regulatory Costs

Preamble:

OEB staff has reproduced Tab 2-M of the Chapter 2 Appendices below.

	Regulatory Costs (One-Time)	Last Rebasing (2019 OEB Approved)	Last Rebasing (2019 Actual)	Sum Of Historical Years (2020-2023)	2024 Bridge Year	2025 Test Year
		(A)	(B)	(C)	(D)	(E)
1	Expert Witness costs	0				
2	Legal costs	34,450	38,980	4,486	45,000	45,000
3	Consultants' costs	87,050			55,000	55,000
4	Intervenor costs	50,000	24,033		30,000	30,000
5	OEB Section 30 Costs (application-related)	0	27,067		15,000	15,000
6	Include other items in green cells, as applicable[1]					
7	Incremental operating expenses associated with ot	16,500	4,043			
8	Difference in OEB Assessment from Board Approved		-3,453			
	Sub-total - One-time Costs	$ 188,000	$ 90,670	$ 4,486	$ 145,000	$ 145,000

Application-Related One-Time Costs	Total (F =C+D+E)
Total One-Time Costs Related to Application to be Amortized over IRM Period	$ 294,486
1/5 of Total One-Time Costs	$ 58,897

Questions:

(a) Please provide 2024 actual regulatory one-time application-related costs for each line item populated in Appendix 2-M.

	Regulatory Costs (One-Time)	Last Rebasing (2019 OEB Approved)	Last Rebasing (2019 Actual)	Sum Of Historical Years (2020-2023)	2024 Bridge Year	2024 Actuals	2025 Test Year
		(A)	(B)	(C)	(D)		(E)
1	Expert Witness costs	0					
2	Legal costs	34,450	38,980	4,486	45,000	39,331	45,000
3	Consultants' costs	87,050			55,000	152,760	55,000
4	Intervenor costs	50,000	24,033		30,000	0	30,000
5	OEB Section 30 Costs (application-related)	0	27,067		15,000	0	15,000
6	Include other items in green cells, as applicable[1]						
7	Incremental operating expenses associated with other resources allocated to this application. 1	16,500	4,043				
8	Difference in OEB Assessment from Board Approved		-3,453				
9							
10							
	Sub-total - One-time Costs	$ 188,000	$ 90,670	$ 4,486	$ 145,000	$ 192,091	$ 145,000

i. If necessary, please shift forecasted 2024 expenses to the 2025 test year, as applicable.

	Regulatory Costs (One-Time)	Last Rebasing (2019 OEB Approved)	Last Rebasing (2019 Actual)	Sum Of Historical Years (2020-2023)	2024 Bridge Year	2024 Actuals	2025 Test Year with 2024 shifted
		(A)	(B)	(C)	(D)		(E)
1	Expert Witness costs	0					
2	Legal costs	34,450	38,980	4,486	45,000	39,331	50,670
3	Consultants' costs	87,050			55,000	152,760	-22,760
4	Intervenor costs	50,000	24,033		30,000	0	40,000
5	OEB Section 30 Costs (application-related)	0	27,067		15,000	0	30,000
6	Include other items in green cells, as applicable[1]						
7	Incremental operating expenses associated with other resources allocated to this application. 1	16,500	4,043				
8	Difference in OEB Assessment from Board Approved		-3,453				
9							
10							
	Sub-total - One-time Costs	$ 188,000	$ 90,670	$ 4,486	$ 145,000	$ 192,091	$ 97,910

Application-Related One-Time Costs	Total (F =C+D+E)	
Total One-Time Costs Related to Application to be Amortized over IRM Period	$ 294,486	$ -
1/5 of Total One-Time Costs	$ 58,897	

(b) With respect to legal costs:

i. Please explain the proposed increase from 2019 actuals ($39k) to the amount forecasted for Lakeland Power's current application ($90k).

The proposed increase in legal costs from 2019 actuals to the amount forecasted for LPDL's current application is due to increase in legal rates, regulatory requirements and assistance with the rate application due to staff changeover and new, less experienced staff preparing the rate application.

ii. Please provide the assumptions used to forecast $90k in legal costs for the current application.

LPDL assumed the legal costs would include assistance and review during the application submission, the interrogatory responses and for the settlement conference.

(c) With respect to consultant costs:

i. Please confirm if 2019 actuals were $0 when the OEB-approved amount was about $87k

LPDL confirms the 2019 actual consultant costs were $0. This was offset by corporate management fee direct costs, recorded in account 5665 in 2019, that were higher in 2019 due to corporate staff performing the regulatory function and submitting the 2019 rate application for LPDL, due to lack of LPDL regulatory staff resources. These do not include any unpaid overtime.

ii. Please break down the total of $110k in consulting costs into its components for the current application and if all consulting costs have already been accrued for this application.

The consulting costs were made up of: $55K in 2024 for assistance with and review of load forecast, load profile, PILS, cost allocation and Chapter 2 appendices models as well as review of the exhibit write ups and DSP. $55K was forecasted in 2025 for assistance with interrogatory responses, model updates and settlement. Due to newer staff that are less experienced in regulatory and the rate application process, consultants were more heavily involved with this rate application than in past years.

(d) With respect to intervenor costs:

i. Please provide the assumptions used to forecast $60k in intervenor costs for the current application.

LPDL assumed $20K for each of the 3 intervenors including Board Staff, SEC & VECC.

4-Staff-44
FTEs - Recruiting
Ref: Exhibit 4, Section 4.4.5, p. 50

Question:

(a) Lakeland Power planned to add one junior linesman in 2024. Please provide an update on the status of the hiring for the junior linesman position.

i. Why was an additional linesman required?

The linesman was not an addition but was required in 2024 to fill the position that has been vacant since late 2023. A successful candidate has been selected, and the position will be filled in February 2025.

(b) Lakeland Power plans to add an Engineering Technologist in January 2025. Please provide an update on the status of the hiring for this individual.

The position was posted in mid 2024 and an offer will be going out in February 2025.

i. What is the role and responsibilities of the Engineering Technologist and why was the position required?

The rationale for hiring an Engineering Technologist is to manage the increased workload and support the business in addressing evolving industry challenges related to technology, codes, and regulatory issues. This role's responsibilities are closely aligned with key functions such as handling customer service requests, ensuring regulatory compliance, conducting data analysis, and fostering technological innovation. These functions are critical for maintaining the utility's operations and effectively serving its customers. By focusing on these areas, the position supports the utility's long-term objectives of reliability, efficiency, and growth.

The roles and responsibilities of and Engineering Technologist include:

- Design and manage projects including capital, maintenance and customer driven.
- Prepare cost estimates, scope of work, and bills of materials.
- Work closely with customers and their consultants in a professional manner.
- Develop, maintain, and implement data models for the distribution system.

- Collect field information for all phases of a project including surveying and as-built data for GIS.
- Work with LPDL's accounting department on economic evaluations and budgeting.
- Complete single-phase meter changes from time to time and/or assist meter technicians with three-phase metering.
- Installation and analysis of voltage and power quality equipment and associated troubleshooting and reporting.
- Review of third-party attachment applications, including as-built inspections.
- Provide specification data and equipment technical support as requested by other departments.
- Review and validate equipment certified test reports to ensure compliance with current equipment specifications and Government regulations. (Ontario Reg. 22/04).
- Maintain Ontario Reg. 22/04 documentation and assist with the yearly audits.
- Assist in the technological growth of LPDL with associated systems, implementations and improvements.

4-Staff-45
FTEs
Ref 1: Exhibit 4, Section 4.1.5, pp. 13-14
Ref 2: Chapter 2 Appendices, Tab 2-K

Preamble:
At reference 1, Lakeland Power states that it has faced turnover in its engineering and operations roles. Further, **while some positions remain unfilled** due to challenges in finding qualified candidates, others have been filled but are currently undergoing training to address the learning curve typical in the industry. **(OEB staff emphasis added)**

Questions:

(a) Please confirm if Tab 2-K of the Chapter 2 Appendices reflects Lakeland Power's actual FTE count per year for 2019-2024.

  i. If not confirmed, please provide Lakeland Power's current actual FTEs and provide a list of the current vacancies and how long those positions have been unfilled for.

LPDL confirms that Tab 2-K does reflect actual FTE count per year for 2019-2024.

(b) Please update Tab 2-K for 2024 actuals, if required.

No updates are required as the actual FTE count for 2024 remains at 22.

4-Staff-46
Compensation
Ref: Exhibit 4, Section 4.4.5, p. 43

Lakeland Power states that management increases are based on recognition for individual performance against pre-determined KPI's that are formally reviewed annually. Further, "the incentive plan is based on mutually agreed upon goals and objectives that recognize performance that exceeds normal job requirements."

Questions:

(a) Please provide the KPIs used to assess recognition for individual management performance.

LPDL uses the following KPIs to assess recognition for individual management performance for LPDL's 4 managers:

- Zero Loss Time Accidents
- EBITDA
- Training Compliance > 95%
- 0 Staff Resignations
- Controllable Cost Per Customer
- SAIDI and CAIDI
- Text Power Implementation
- Increased E-billing
- Customer Satisfaction Score Improvement
- Cost of Service Application to OEB
- Improve Leadership Organization

(b) What is the percentage incentive compared to total compensation for each of 2019-2024.

	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year
Incentive as a % Total of Compensation	1.0%	1.0%	0.9%	1.0%	0.9%	0.9%

There are only 4 management staff that are eligible for incentives and the achievement of their KPI's noted above align with LPDL's company scorecard targets.

(c) Is the reasonability of the incentive plan and resulting incentives paid benchmarked. If so, how? If not, why not?

Yes, incentives are benchmarked against Audited Financial Statements, Customer Satisfaction survey, OEB acceptance of Cost-of-Service rate application and internal scorecards. LPDL also participates in the annual Mearie Management Salary and compensation is benchmarked to the survey results each year.

4-Staff-47
Compensation
Ref 1: Chapter 2 Appendices, Tab 2-K
Ref 2: Exhibit 4, Section 4.4.5, p. 49
Ref 3: Exhibit 4, Section 4.4.4, p. 42

Preamble:
Based on reference 1, OEB staff calculates an increase of 10.06% on a unitized basis (i.e., per FTE) for non-management (union and non-union) when comparing 2024 to 2023 with respect to total salary and wages including overtime and incentive pay.

In reference 2, Lakeland Power states that a driver for the 2024 increase is the new Collective Labour Agreement effective January 1, 2024, with 5% wage increase. In reference 3, Lakeland Power states that "In preparation for the 2024 negotiations, LPDL reviewed the Collective Labour Agreements of other LDC's in its geographic service area. This allowed LPDL to ensure that the amount being requested was reasonable and just for the industry, and did not exceed the going rate of other Agreements, but allowed LPDL to remain competitive, assist with employee retention and strive to ensure succession planning was not jeopardized."

Question:

(a) Please provide the results of Lakeland Power's review of Collective Labour Agreements of other LDC's in its geographic service area and where Lakeland Power's negotiated 2024 increase falls in comparison.

Of the five LDC's shown for 2024 below, LPDL linesman's hourly wage is lower than three LDC's and higher than only one. The only LDC that is within LDPL's geographic service area is Hydro One. Hydro One linesman's wage is $8.72/hr higher than LPDL's and in

2025, this increases to a gap of $9.53/hr. The next two closest LDC's in geographical proximity to LPDL would be Elexicon, in Gravenhurst, and Innisfil Hydro and the hourly linesman wage for each of them are higher than LPDL's hourly wage as well. LPDL also reviewed the annual Mearie Labour Relations Report. The 2023 report validated there is upward pressure on wages in the utility industry, given housing and fuel costs are important drivers for negotiating wage increases as well as labour scarcity. The report presented the expectation that in 2023 and onward, wage increases may exceed CPI and near 4-5% per year.

LDC Name	Collective Agreement Period	Linesman Hourly Wage 2022	Linesman Hourly Wage 2023	Linesman Hourly Wage 2024	Linesman Hourly Wage 2025
Sudbury Hydro	2019-2022	$ 45.39			
PUC	2021-2024	$ 44.56	$ 45.45		
Elexicon	2022-2025		$ 49.27	$ 50.41	
Innisfil Hydro	2022-2026	$ 46.90	$ 48.12	$ 49.27	$ 50.45
North Bay Hydro	2023-2026		$ 45.49	$ 46.85	$ 48.02
Hydro One	**2023-2025**		**$ 54.84**	**$ 57.33**	**$ 59.60**
Lakeland Power	**2024-2027**	**$ 44.91**	**$ 46.26**	**$ 48.61**	**$ 50.07**
HONI vs LPDL			**$ 8.58**	**$ 8.72**	**$ 9.53**

i. Please confirm if Lakeland Power's review of other Collective Labour Agreements also included similarly sized LDCs in addition to those in its geographic service area.

Please see response to part a).

(b) Please explain the drivers for the difference between the 5% negotiated increase and the unitized 10% increase when comparing 2024 to 2023 as calculated by OEB staff.

LPDL has tried to replicate the same unitized calculation as OEB staff, by comparing non-management (union and non-union) total salary and wages including overtime and incentive pay for 2024 to 2023 divided by the FTE counts, and it results in a unitized of 7.6% rather than 10.06%. The drivers for the difference between the 5% negotiated increase and the unitized 7.6% increase when comparing 2024 to 2023 is the promotion of a second lead hand journeyman, the progression of an apprentice from 2nd to 3rd year rate as well as the progression of an engineering technician from Start to 1st year rate and an increase in overtime.

Non-Management (union and Non-union)	2023 Actuals	2024 Bridge Year
Number of Employees	18	18
Total Salary and Wages including overtime and incentive	$ 1,573,694	$ 1,693,823
Total Salary and Wages per FTE	$ 87,427	$ 94,101
Difference %		7.6%

4-Staff-48
Compensation
Ref: Exhibit 4, Section 4.4.5, p. 43

Preamble:
Lakeland Power uses the Mearie Management Salary Survey for the annual review and benchmarking of non-union positions. Lakeland Power states that it generally pays at or below the average base salary when compared to equivalent positions at similar sized LDC's in the industry.

Question:
(a) Please provide copies, or a summary document, of the compensation review for base salaries of non-union staff.

LPDL's compensation review for base salaries of non-union staff is primarily based on the annual Mearie Management Salary Survey report for management and average CPI and union rate increases for non-management. For management, LPDL considers the P50 base salary, job rate and minimum and maximum salary ranges for each applicable position and ensures LPDL's salaries are in the range and scaled to the level of experience of the person in the position.

Non-Union Staff	2023 Mearie Survey P50 Minimum Salary	2023 Mearie Survey P50 Base Salary	2023 Mearie Survey P50 Maximum Salary
Operations Manager	$ 115,200	$ 137,900	$ 151,500
Engineering Supervisor	$ 98,300	$ 120,900	$ 139,400
Lines Supervisor	$ 98,400	$ 122,600	$ 127,300
Customer Service Manager	$ 98,400	$ 119,400	$ 132,500

4-Staff-49
Benefits Costs
Ref: Exhibit 4, Section 4.4.5, p. 50

Preamble:

Lakeland Power notes that in the 2025 test year, there is an estimated 20% increase to Health, Dental, LTD and Life Insurance premiums due to the expiration of 3-year rate guarantee and increase in claims.

Question:

(a) Did Lakeland Power contemplate or search for a new benefits provider? If yes, what were the outcomes of such?

At this point, LPDL has not searched for a new benefits provider however LPDL's benefits advisor will be going to market on LPDL's behalf this year.

4-Staff-50
Cost Drivers – Wages/Merit Increases & FTE Changes
Ref: Chapter 2 Appendices, Tab 2-JB

Preamble:
In reference 1, two of the OM&A cost drivers listed include 1) "Wages/Merit increase & FTE changes" and 2) "Vacant positions - Offset Corp Allocation".

Question:

(a) Please confirm if the first driver specifically relates to wages/merit increases and FTE changes within Lakeland Power, while the second driver relates to FTE employee costs allocated to Lakeland Power by Lakeland Holding.

Correct. LPDL confirms the first driver specifically relates to wages/merit increases and FTE changes within LPDL staff, while the second driver relates to FTE employee costs allocated to LPDL by LHL. The employee costs allocated to LPDL by LHL are a function of the amount of staff hours spent in each affiliate company based on weekly timesheets at their actual wage. This allocation is thus variable, not fixed. This direct cost allocation does not include any overtime costs as LHL staff are not compensated for overtime worked. For 2024 and January 2025, that equated to approximately $122K that was not cross charged to LPDL, which is ultimately a savings to the rate payer that can not be sustained.

4-Staff-51
Vacant Positions – Offset Corp. Cost Allocation
Ref 1: Chapter 2 Appendices, Tab 2-JB
Ref 2: Exhibit 4, Section 4.2, p. 18
Ref 3: Chapter 2 Appendices, Tab 2-K

Preamble:
In reference 1, Lakeland Power shows that one of the cost drivers leading to increased OM&A expenses is “Vacant positions - Offset Corp Allocation”. The total increase attributable to the OM&A cost driver “Vacant Positions – Offset Corp. Cost Allocation” from 2019 actuals is about $224k. In reference 2, Lakeland Power states that during the 2019 to 2025 period, it lost key employees to Hydro One and retirements, leaving FTE vacancies. One strategy to fill resource gaps was to offset staff losses with additional support from affiliates where possible and appropriate.
Questions:

(a) Please provide a breakdown of the $224k increase between 2019 and 2025 for the cost driver “Vacant Positions – Offset Corp. Cost Allocation” into its major components.

This cost driver is primarily due to one vacant position, the regulatory position. This position’s roles and responsibilities continue to be backfilled by LHL employees, predominantly the CFO and other senior finance staff. This equates to wage rates that are higher than would be paid to a full time regulatory person. As discussed elsewhere in this application and in LPDL’s last application, this position had been posted various times without being successfully filled. It has proven very difficult to recruit a qualified person who possesses the specialized skillset and expertise in our area. Over the past ten years, the regulatory accounting and reporting role has grown significantly, now warranting not only a regulatory accountant but also an additional support position. This is warranted in order to maintain the data required for RRR filing and keeping LPDL informed and up to date with all regulations that are being reviewed and updated regularly.

i. Please provide a list of the vacant positions at Lakeland Power that were being offset by additional support from affiliates. As part of the response, please provide the job titles of the individuals from the affiliates that were used to help offset the associated staff losses/vacancies at Lakeland Power.

Please see the response to part a).

ii. What specific roles and needs were the additional resources from affiliates filling within Lakeland Power?

Please see the response to part a).

(b) Based on Tab 2-K, in 2022 Lakeland Power added two FTEs when compared to 2021. Please explain why the "Vacant Positions – Offset Corp. Cost Allocation" cost driver increased in the context of Lakeland Power's statement in reference 1 that "One strategy to fill resource gaps was to offset staff losses with additional support from affiliates".

The two 2 FTEs added in 2022 were operations staff, not regulatory/finance positions.

(c) Are there benefits to Lakeland Power's customers for Lakeland Power relying on corporate cost allocations vs. adding additional FTEs instead? If so, please explain.

The benefits to LPDL's customers are the senior executive and support roles are shared amongst the affiliates rather than having an individual person for each role in each company (i.e. one payroll staff performing payroll and benefits administration for all companies, rather than having four payroll staff doing the same function for each company). However, the vacant regulatory role would be better served by a full time position in LPDL rather than utilizing multiple resources in LHL. To date, being able to hire for this position has been futile due to salary expectations and location.

4-Staff-52
Corporate Cost Allocation
Ref 1: Exhibit 4, Section 4.5
Ref 2: Chapter 2 Appendices, Tab 2-N

OEB staff has summarized the % of costs for the various items allocated to Lakeland Power from Lakeland Holding between 2019 and 2025 (see table below). OEB staff observes that except for decreases in the % allocations in 2020 from 2019 in line items "Telephone/Internet/IT support/Office expenses" and "Training services", the % allocations are relatively consistent across all years.

	% of Corp. Costs						
	2019	2020	2021	2022	2023	2024	2025
Executive & Mgmt services	100	100	100	100	100	100	100
Board of Directors	100	100	100	100	100	100	100
Financial/HR/Payroll	100	100	100	100	100	100	100
Telephone/Internet/IT support/Office expenses	40	28	27	28	27	27	27
Audit fees/IFRS conversion	33	31	29	29	29	29	29
Legal services	100	100	100	100	100	100	100
Training services	37	28	27	28	27	27	27
Building rent	41	41	41	41	41	41	41

Based on the references, OEB staff calculates the following. Significant drivers that make-up total 2025 allocated costs include Executive & Management Services and Finance, HR, Payroll.

	2025 Allocated Costs	% of Total 2025 Corporate Cost Allocation
Exec. & Management Services	$650,780	60%
Board of Directors	$75,000	7%
Finance, HR, Payroll	$187,700	17%
Telephone, internet, IT support, office exp.	$74,047	7%
Audit fees, IFRS conversion	$18,862	2%
Legal services	$0	0%
Training services	$24,599	2%
Building rent	$49,767	5%
Total	**$1,080,755**	**100%**

Questions:

(a) Please explain why there are four items listed in the first table above which are allocated 100% to Lakeland Power in 2025 and have been since 2019.

LPDL misrepresented the 100% allocation above due to a misunderstanding of the chart requirements. LPDL has recreated the OEB's "% of Corp Cost" table presented above, updated with the appropriate corporate allocations:

	% of Corp. Costs						
	2019	2020	2021	2022	2023	2024	2025
Executive & Mgmt services	37	30	26	28	29	33	30
Board of Directors	37	30	26	28	29	33	30
Financial/HR/Payroll	37	30	26	28	29	33	30
Telephone/Internet/IT support/Office expenses	40	28	27	28	27	27	27
Audit fees/IFRS conversion	33	31	29	29	29	29	29
Legal services	-	-	-	-	-	-	-
Training services	37	28	27	28	27	27	27
Building rent	33	31	29	29	29	29	29

i. Does Lakeland Holding not provide Lakeland Power's affiliates these services?

Yes, LHL does provide all these services to LPDL and its affiliates. Please see the updated tables provided in part a).

(b) With respect to the "Exec. & Management Services" and "Finance, HR, Payroll" line items in the second table, please provide the number of FTEs from Lakeland Holding allocated to each line item which contribute to the total 2025 costs.

	# of FTEs Allocated from LHL						
	2019	2020	2021	2022	2023	2024	2025
Executive & Mgmt services	2.8	2.4	2.1	2.1	2.1	2.6	2.1
Financial/HR/Payroll	3.8	3.3	2.9	2.9	2.9	3.5	2.9
	6.6	5.7	5.0	5.0	5.0	6.1	5.0

(c) Please populate Tab 2-N of the Chapter 2 Appendices for 2025 for the Corporate Cost Allocation table. While the information is provided in Exhibit 4 (section 4.5.1), the Excel version does not seem to be populated.

The rows containing 2025 data in the original excel file were populated however they were hidden. Whenever the model is reopened, rows 244-344 seem to be hidden. LPDL has updated Tab 2-N of the Chapter 2 Appendices, including 2025 below:

Year: 2019

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Lakeland Power	Lakeland Energy	Rent	sq. ft. market	$42,000	
Lakeland Power	Bracebridge Generation	Rent	sq. ft. market	$6,000	
Lakeland Power	Bracebridge Generation/	Trouble assistance-project assistance	market	$49,529	$47,493
Lakeland Power	Lakeland Energy	Trouble assistance-project assistance	market	$7,202	$6,467
Lakeland Energy	Lakeland Power	GIS	market based service agreement	$112,020	
Lakeland Energy	Lakeland Power	ISP/Telephone system	market based service agreement	$76,200	
Lakeland Energy	Lakeland Power	IT Support & Cybersecurity	market based service agreement	$302,322	
Lakeland Energy	Lakeland Power	Building mtce	cost	$6,568	
Lakeland Energy/BGL	Lakeland Power	Building mtce	cost	$553	
Lakeland Energy	Lakeland Power	Hot water tank rental	market	$768	
Lakeland Holding	Lakeland Power	Project Mgmt - IESO AP Study	market	$14,706	

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs	Amount Allocated
From	To			%	$
Lakeland Holding	*Lakeland Power*	Executive & Mgmt services	Direct Cost - based on timesheets	37%	$586,083
Lakeland Holding	Lakeland Power	Board of Directors	Cost	37%	$42,250
Lakeland Holding	Lakeland Power	Financial/HR/Payroll	Direct Cost - based on timesheets	37%	$153,642
Lakeland Holding	Lakeland Power	Telephone/Internet/IT support/Office expenses	Cost - number of employees	40%	$48,843
Lakeland Holding	Lakeland Power	Audit fees/IFRS conversion	Cost - asset percentage	33%	$9,959
Lakeland Holding	Lakeland Power	Legal services	Cost - direct disbursement	0%	
Lakeland Holding	Lakeland Power	Training services	Cost - number of employees	37%	$9,391
Lakeland Holding	Lakeland Power	Building rent	Cost - asset percentage	33%	$47,560

Year: 2020

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Lakeland Power	Lakeland Energy	Rent	sq. ft. market	$42,000	
Lakeland Power	Bracebridge Generation	Rent	sq. ft. market	$6,000	
Lakeland Power	Bracebridge Generation/	Trouble assistance-project assistance	market	$175,915	$174,704
Lakeland Power	Lakeland Energy	Trouble assistance-project assistance	market	$48,612	$44,188
Lakeland Energy	Lakeland Power	GIS	market based service agreement	$112,020	
Lakeland Energy	Lakeland Power	ISP/Telephone system	market based service agreement	$51,400	
Lakeland Energy	Lakeland Power	IT Support & Cybersecurity	market based service agreement	$292,410	
Lakeland Energy	Lakeland Power	Building mtce	cost	$2,909	
Lakeland Energy/BGL	Lakeland Power	Building mtce	cost	$2,770	
Lakeland Energy	Lakeland Power	Hot water tank rental	market	$768	
Lakeland Holding	Lakeland Power	Project Mgmt - IESO AP Study	market	$17,973	

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	Corporate Costs Allocated	Amount Allocated
From	To			%	$
Lakeland Holding	*Lakeland Power*	Executive & Mgmt services	Direct Cost - based on timesheets	30%	$455,325
Lakeland Holding	Lakeland Power	Board of Directors	Cost	30%	$66,667
Lakeland Holding	Lakeland Power	Financial/HR/Payroll	Direct Cost - based on timesheets	30%	$161,837
Lakeland Holding	Lakeland Power	Telephone/Internet/IT support/Office expenses	Cost - number of employees	28%	$37,957
Lakeland Holding	Lakeland Power	Audit fees/IFRS conversion	Cost - asset percentage	31%	$9,921
Lakeland Holding	Lakeland Power	Legal services	Cost - direct disbursement	0%	
Lakeland Holding	Lakeland Power	Training services	Cost - number of employees	28%	$2,002
Lakeland Holding	Lakeland Power	Building rent	Cost - asset percentage	31%	$44,349

Year: 2021

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Lakeland Power	Lakeland Energy	Rent	sq. ft. market	$42,000	
Lakeland Power	Bracebridge Generation	Rent	sq. ft. market	$6,000	
Lakeland Power	Bracebridge Generation/	Trouble assistance-project assistance	market	$202,571	$202,240
Lakeland Power	Lakeland Energy	Trouble assistance-project assistance	market	$5,195	$1,778
Lakeland Energy	Lakeland Power	GIS	market based service agreement	$112,020	
Lakeland Energy	Lakeland Power	ISP/Telephone system	market based service agreement	$51,000	
Lakeland Energy	Lakeland Power	IT Support & Cybersecurity	market based service agreement	$303,672	
Lakeland Energy	Lakeland Power	Building mtce	cost	$1,645	
Lakeland Energy/BGL	Lakeland Power	Building mtce	cost	$2,696	
Lakeland Energy	Lakeland Power	Hot water tank rental	market	$768	

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	Corporate Costs Allocated	Amount Allocated
From	To			%	$
Lakeland Holding	*Lakeland Power*	Executive & Mgmt services	Direct Cost - based on timesheets	26%	$409,850
Lakeland Holding	Lakeland Power	Board of Directors	Cost	26%	$66,667
Lakeland Holding	Lakeland Power	Financial/HR/Payroll	Direct Cost - based on timesheets	26%	$158,697
Lakeland Holding	Lakeland Power	Telephone/Internet/IT support/Office expenses	Cost - number of employees	27%	$46,118
Lakeland Holding	Lakeland Power	Audit fees/IFRS conversion	Cost - asset percentage	29%	$31,948
Lakeland Holding	Lakeland Power	Legal services	Cost - direct disbursement	0%	
Lakeland Holding	Lakeland Power	Training services	Cost - number of employees	27%	$5,160
Lakeland Holding	Lakeland Power	Building rent	Cost - asset percentage	29%	$41,386

Year: 2022

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Lakeland Power	Lakeland Energy	Rent	sq. ft. market	$42,000	
Lakeland Power	Bracebridge Generation	Rent	sq. ft. market	$6,000	
Lakeland Power	Bracebridge Generation/	Trouble assistance-project assistance	market	$5,052	$3,639
Lakeland Power	Lakeland Energy	Trouble assistance-project assistance	market	$10,398	$6,547
Lakeland Energy	Lakeland Power	GIS	market based service agreement	$73,458	
Lakeland Energy	Lakeland Power	ISP/Telephone system	market based service agreement	$51,000	
Lakeland Energy	Lakeland Power	IT Support & Cybersecurity	market based service agreement	$308,097	
Lakeland Energy	Lakeland Power	Building mtce	cost	$5,154	
Lakeland Energy/BGL	Lakeland Power	Building mtce	cost	$595	
Lakeland Energy	Lakeland Power	Hot water tank rental	market	$768	

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	Corporate Costs Allocated	Amount Allocated
From	To			%	$
Lakeland Holding	*Lakeland Power*	Executive & Mgmt services	Direct Cost - based on timesheets	28%	$495,923
Lakeland Holding	Lakeland Power	Board of Directors	Cost	28%	$71,875
Lakeland Holding	Lakeland Power	Financial/HR/Payroll	Direct Cost - based on timesheets	28%	$165,763
Lakeland Holding	Lakeland Power	Telephone/Internet/IT support/Office expenses	Cost - number of employees	28%	$45,549
Lakeland Holding	Lakeland Power	Audit fees/IFRS conversion	Cost - asset percentage	29%	$28,275
Lakeland Holding	Lakeland Power	Legal services	Cost - direct disbursement	0%	
Lakeland Holding	Lakeland Power	Training services	Cost - number of employees	28%	$9,947
Lakeland Holding	Lakeland Power	Building rent	Cost - asset percentage	29%	$42,446

Year: 2023

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Lakeland Power	Lakeland Energy	Rent	sq. ft. market	$42,000	
Lakeland Power	Bracebridge Generation	Rent	sq. ft. market	$6,000	
Lakeland Power	Bracebridge Generation/	Trouble assistance-project assistance	market	$5,934	$5,453
Lakeland Power	Lakeland Energy	Trouble assistance-project assistance	market	$4,778	$4,612
Lakeland Energy	Lakeland Power	GIS	market based service agreement	$55,900	
Lakeland Energy	Lakeland Power	ISP/Telephone system	market based service agreement	$52,665	
Lakeland Energy	Lakeland Power	IT Support & Cybersecurity	market based service agreement	$301,872	
Lakeland Energy	Lakeland Power	Building mtce	cost	$1,591	
Lakeland Energy/BGL	Lakeland Power	Building mtce	cost	$0	
Lakeland Energy	Lakeland Power	Hot water tank rental	market	$768	

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs	Amount Allocated
From	To			%	$
Lakeland Holding	*Lakeland Power*	Executive & Mgmt services	Direct Cost - based on timesheets	29%	$557,184
Lakeland Holding	Lakeland Power	Board of Directors	Cost	29%	$81,250
Lakeland Holding	Lakeland Power	Financial/HR/Payroll	Direct Cost - based on timesheets	29%	$164,393
Lakeland Holding	Lakeland Power	Telephone/Internet/IT support/Office expenses	Cost - number of employees	27%	$64,853
Lakeland Holding	Lakeland Power	Audit fees/IFRS conversion	Cost - asset percentage	29%	$16,520
Lakeland Holding	Lakeland Power	Legal services	Cost - direct disbursement	0%	
Lakeland Holding	Lakeland Power	Training services	Cost - number of employees	27%	$21,544
Lakeland Holding	Lakeland Power	Building rent	Cost - asset percentage	29%	$43,588

Year: 2024

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Lakeland Power	Lakeland Energy	Rent	sq. ft. market	$42,000	
Lakeland Power	Bracebridge Generation	Rent	sq. ft. market	$6,000	
Lakeland Power	Bracebridge Generation/	Trouble assistance-project assistance	market	$0	$0
Lakeland Power	Lakeland Energy	Trouble assistance-project assistance	market	$0	$0
Lakeland Energy	Lakeland Power	GIS	market based service agreement	$58,695	
Lakeland Energy	Lakeland Power	ISP/Telephone system	market based service agreement	$60,600	
Lakeland Energy	Lakeland Power	IT Support & Cybersecurity	market based service agreement	$311,226	
Lakeland Energy	Lakeland Power	Building mtce	cost	$2,483	
Lakeland Energy/BGL	Lakeland Power	Building mtce	cost	$0	
Lakeland Energy	Lakeland Power	Hot water tank rental	market	$768	

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Lakeland Holding	*Lakeland Power*	Executive & Mgmt services	Direct Cost - based on timesheets	33%	$617,869
Lakeland Holding	Lakeland Power	Board of Directors	Cost	33%	$75,000
Lakeland Holding	Lakeland Power	Financial/HR/Payroll	Direct Cost - based on timesheets	33%	$179,189
Lakeland Holding	Lakeland Power	Telephone/Internet/IT support/Office expenses	Cost - number of employees	27%	$70,690
Lakeland Holding	Lakeland Power	Audit fees/IFRS conversion	Cost - asset percentage	29%	$18,007
Lakeland Holding	Lakeland Power	Legal services	Cost - direct disbursement	0%	$0
Lakeland Holding	Lakeland Power	Training services	Cost - number of employees	27%	$23,483
Lakeland Holding	Lakeland Power	Building rent	Cost - asset percentage	29%	$47,511

Year: 2025

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Lakeland Power	Lakeland Energy	Rent	sq. ft. market	$42,000	
Lakeland Power	Bracebridge Generation	Rent	sq. ft. market	$6,000	
Lakeland Power	Bracebridge Generation/	Trouble assistance-project assistance	market	$0	$0
Lakeland Power	Lakeland Energy	Trouble assistance-project assistance	market	$0	$0
Lakeland Energy	Lakeland Power	GIS	market based service agreement	$58,695	
Lakeland Energy	Lakeland Power	ISP/Telephone system	market based service agreement	$60,600	
Lakeland Energy	Lakeland Power	IT Support & Cybersecurity	market based service agreement	$330,622	
Lakeland Energy	Lakeland Power	Building mtce	cost	$2,483	
Lakeland Energy/BGL	Lakeland Power	Building mtce	cost	$0	
Lakeland Energy	Lakeland Power	Hot water tank rental	market	$768	

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Lakeland Holding	*Lakeland Power*	Executive & Mgmt services	Direct Cost - based on timesheets	30%	$650,780
Lakeland Holding	Lakeland Power	Board of Directors	Cost	30%	$75,000
Lakeland Holding	Lakeland Power	Financial/HR/Payroll	Direct Cost - based on timesheets	30%	$187,700
Lakeland Holding	Lakeland Power	Telephone/Internet/IT support/Office expenses	Cost - number of employees	27%	$74,047
Lakeland Holding	Lakeland Power	Audit fees/IFRS conversion	Cost - asset percentage	29%	$18,862
Lakeland Holding	Lakeland Power	Legal services	Cost - direct disbursement	0%	$0
Lakeland Holding	Lakeland Power	Training services	Cost - number of employees	27%	$24,599
Lakeland Holding	Lakeland Power	Building rent	Cost - asset percentage	29%	$49,767

4-Staff-53
Shared Services and Corporate Cost Allocation - Rent
Ref: Exhibit 4, Section 4.5.1, Table 24

Preamble:
The table below summarizes information gathered by OEB staff. It is based on the evidence provided in the reference with respect to **rent charged** by Lakeland Power, and **rent paid** by Lakeland Power.

Shared Services								
From	**To**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Lakeland Power	Lakeland Energy	$42k	$42k	$42k	$42k	$42k	$42k	$42k
Lakeland Power	Bracebridge Generation	$6k	$6k	$6k	$6k	$6k	$6k	$6k
	Total	**$48k**	**$48k**	**$48k**	**$48k**	**$48k**	**$48k**	**$48k**
Corporate Cost Allocation								
From	**To**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Lakeland Holding	Lakeland Power	$47,560	$44,349	$41,386	$42,446	$43,588	$47,511	$49,767
	% Allocation	41%	41%	41%	41%	41%	41%	41%

Questions:

(a) Please confirm which company owns the building utilized by Lakeland Power.

LPDL owns the operations building, located in Bracebridge, where the majority of LPDL and affiliate employees work. LHL rents an office in Huntsville, where LPDL billing and customer service as well as LHL finance employees work.

(b) Please explain why Lakeland Power is both charged rent by its holding company, Lakeland Holding Ltd., and charges rent to its affiliates.

LPDL charges rent to its affiliates, LEL and BGL, for their space occupied at the operations centre located in Bracebridge. This rent was based on the percentage of sq. ft. occupied in the building for shop and office space. In turn, the building rent allocated from LHL to LPDL is LPDL's percentage of LHL's rent expense based on a percentage of each company's net assets of the total net assets.

i. Please confirm if the rent charged by Lakeland Power (i.e., proposed $48k) is included in Other Revenue, while the rent paid by Lakeland Power (i.e., proposed $49.7k) is included in OM&A expenses.

LPDL confirms the rent charged by LPDL is included in Other Revenue account 4210, while the rent paid by LPDL is included in OM&A expense account 5665.

(c) Please explain why the rent charged by Lakeland Power to its affiliates has remained and is proposed to remain constant ($48k) from 2019 to the 2025 test year, while the rent charged to Lakeland Power by Lakeland Holding has changed year-over-year from 2019-2025 and specifically increased since 2022.

While LPDL's rent charged to its affiliates is constant in this period, BGL has since purchased their own building and vacated the operations centre owned by LPDL. Over the past few years, LEL has also reduced their occupancy in the operations centre now that several of their employees work remotely from home. Both of these reductions would be a loss of revenue for LPDL.

LPDL did a benchmarking assessment in 2019 to review market rates in Muskoka, for locations that offer comparable features. LPDL has rented space at a fair market value to is affiliates. Average property values were assessed to come up with a reasonable rate for a long term agreement.

2019	Location	sq ft	rent/mth	$/sq ft/mth	$/sq ft/yr
1	Gravenhurst	3,250	$3,500	$1.08	$12.92
2	Bracebridge Large	10,092	$7,500	$0.74	$8.92
3	Bracebridge	1,500	$1,500	$1.00	$12.00
	2019 Rental Rate to Affiliates			$0.94	$11.28

The reasons for selecting an affiliate:

- Consistent Income: A tenant with a stable and reliable income source will pay rent on time.
- Good Credit History: A positive credit report indicates financial responsibility and a history of meeting financial obligations.
- Affordability: Ensure the rent is attractive enough to not make the tenant look for more affordable alternatives. Managers are tasked with looking for the most cost effective solutions for their business:
- Respect for Property: Our affiliate will comply and demonstrate a willingness to treat the property with care and respect.

- Length of Tenancy: Consider the tenant's desired length of stay, as longer tenancies can reduce turnover costs. This reduces the cost for LPDL as vacancy, lack of payment, listing and finding new tenants all have a cost.

In Muskoka, during the period of March 2020 until late 2022, there was a mass instability in the commercial rental space. Prices dropped as there was an abundance of rental space available. LPDL was isolated from this as their long-term tenant kept this stable and the income consistent. The market is now stabilized, and new rates will be compared in 2026. LPDL will update the rental lease agreement in with LEL to reflect their reduced occupancy and adjust the rental invoice accordingly.

The driver of the change in rent charged to LPDL from LHL is the lease agreement increase for the administration building in Huntsville as the allocation percentage between affiliates has not changed materially.

i. Please provide evidence to support that maintaining the rent charged by Lakeland Power to its affiliates should not increase in the context of section 2.3.3.6 of the Affiliate Relationships Code.

Please see response to part c) above.

4-Staff-54
Shared Services
Ref 1: Exhibit 4, Section 4.5.2, p. 61
Ref 2: Chapter 2 Appendices, Tab 2-N

Preamble:
At reference 1, Lakeland Power states that for Shared Services, the primary pricing methodology is market-based. This applies to transactions provided by Lakeland Power to its affiliates and by the affiliates to Lakeland Power.

OEB staff has reproduced a portion of reference 2 below with respect to shared services forecasted for the 2025 test year.

Year: 2025

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Lakeland Power	Lakeland Energy	Rent	sq. ft. market	$42,000	
Lakeland Power	Bracebridge Generation	Rent	sq. ft. market	$6,000	
Lakeland Power	Bracebridge Generation/L	Trouble assistance-project assistance	market	$0	$0
Lakeland Power	Lakeland Energy	Trouble assistance-project assistance	market	$0	$0
Lakeland Energy	Lakeland Power	GIS	market based service agreement	$58,695	
Lakeland Energy	Lakeland Power	ISP/Telephone system	market based service agreement	$60,600	
Lakeland Energy	Lakeland Power	IT Support & Cybersecurity	market based service agreement	$330,622	

Questions:

(a) For each applicable market-based service listed in the table above, how does Lakeland Power ensure that it is paying no more than the market price when acquiring that service, product, resource or use of asset from an affiliate?

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.

LPDL has recently inquired about GIS services with another local provider and the hourly rate proposed by the third party is the same as LPDL currently pays LEL. LEL also covers the cost of GIS software licensing which is a savings to LPDL.

There is no revenue forecasted for trouble assistance/project assistance in 2025.

(b) For the line items noted above provided by Lakeland Energy to Lakeland Power through a market-based service agreement, has Lakeland Power ever undertaken a bidding process for these services? If yes, what were the results of such tendering? If not, why not?

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. However, LPDL has just recently sent out an RFQ for IT Outsourcing, for comparison sake, and will evaluate any bids in February. LPDL has also recently inquired about GIS services with another local provider and the hourly rate proposed by the third party is the same as LPDL currently pays LEL.

(c) Please explain why Lakeland Power has not included any forecasted amounts (both price and cost) for 2024 and 2025 for “Trouble assistance-project assistance” when historically, in each year from 2019 to 2023, a price and cost for the service have both been itemized.

LPDL does not forecast accounts 4375 and 4380 as they are unplanned and offset each other to a minimal amount. The costs associated with non-rate regulated activities are not included in OM&A or anywhere else for the Bridge and Test Years. LPDL confirms the actual amounts in accounts 4375 and 4380 for 2024 are $235,819 and $(191,345) respectively.

4-Staff-55
Shared Services and Corporate Cost Allocation

Questions:

(a) Has Lakeland Power ever undertaken an independent third-party review of its corporate cost allocation and/or shared services arrangements and related cost allocation methodology? If yes, please provide the results of such review.

No, LPDL has not undertaken an independent third-party review.

(b) How is the allocation methodology designed to avoid the improper shifting of costs between regulated and non-regulated affiliates?

The methodology prevents improper shifting of costs and cross subsidy as its based on actual time spent reflecting on cost causality.

(c) Is there a clear and consistent method to ensure that each affiliate pays its fair share of costs?

This method has been consistently applied since 2006, with the largest cost portion being payroll which is allocated by direct time spent on LPDL tasks.

(d) Are there safeguards in place to prevent cross-subsidization or preferential treatment of non-regulated affiliates?

The methodology itself includes the safeguards to prevent cross-subsidization as the allocation is based on actual timesheets, actual number of employees per company per payroll records and audited financial statements for the asset base for each company.

4-Staff-56
OMERs and OPEB
Ref: Exhibit 4, p. 56, Table 23

Preamble:
Table 23 in the reference reflects the OMERS and OPEB breakdown between capital and OM&A. There is no amount for OPEB reflected for 2024 Bridge and 2025 Test Year.

Questions:

(a) Please confirm there is no OPEB expense in OM&A for the 2024 bridge year and 2025 test year.

LPDL confirms there is no OPEB expense forecasted in OM&A for 2024 bridge and 2025 test years.

i. If there should be amount for OPEB expense for 2024 and 2025, please confirm the forecast OPEB does not include actuarial gain/loss. Please explain and provide the necessary details.

As per LPDL's actuarial valuation, LPDL should have forecasted a negative expense of $(6,495) in 2024 and a negative expense of $(3,124) in 2025 to account 5645. LPDL confirms there are no actuarial gains/losses included.

Items	2022 Actual		2023 Actual		2024 Bridge		2025 Test	
Opening Balance - Post Retirement Benefits	$	80,532	$	49,492	$	39,891	$	33,396
Actuarial Expense								
Post-Retirements Benefits	$	6,627	$	4,619	$	4,646	$	4,651
Actuarial (Gains)/Losses	-$	29,334	$	-	$	-	$	-
Premium Paids	-$	8,333	-$	14,220	-$	11,141	-$	7,775
Net OPEB Expense in Account 5645	-$	31,040	-$	9,601	-$	6,495	-$	3,124
Closing Balance - Post Retirement Benefits	**$**	**49,492**	**$**	**39,891**	**$**	**33,396**	**$**	**30,272**
	per 2022 Val		*per 2022 Val*		*per 2022 Val*		*per 2022 Val*	

(b) Please update the evidence as needed.

LPDL will update the evidence as needed.

School Energy Coalition (SEC)

SEC-16
[Ex. 4,p. 6] Please provide a list of the “peer” utilities referred to. Please provide the most recent internal comparison of costs as against those peers.

The most recent comparison to “peer utilities” was utilizing the 2023 PEG benchmarking report. In order to determine peers, LPDL compared customer count, pole O&M, pole capex, vegetation O&M and meter capex.

The total cost per customer of the peer utilities referred to include:

- InnPower Corporation $1,122
- Lakeland Power $ 893
- Festival Hydro Inc $ 760

SEC-17
[Ex. 4, p. 7-8] Please provide a copy of Table 2 with the names of all individuals listed that are directly employed by the utility (as opposed to affiliates) highlighted.

LPDL has highlighted, in blue, all Lakeland Power employees included on the Lakeland Power scorecard. Taylor (CPO) and Darren (CFO) are the only parent company employees included on this scorecard.

2024, 2025, 2026 BALANCED SCORECARD

1 Environmental Health & Safety

	Key Performance Indicator	Timeline	Improvement Same/Yes/No	Responsibility	Update
a	Zero Loss Time Accidents Annually	2024-2027		Brian/Andrew/ Jordan/Sharon	
b	Cyber attack - no loss of customer information and/or money	2024-2027		Brian/Andrew/ Jordan/Sharon	
c	Waste reduction committee membership	2024-2027		Brian/Andrew/ Jordan/Sharon	
d	Compliance Science at least 95%	2024-2027		Brian/Andrew/ Jordan/Sharon / Taylor	

2 Team

	Key Performance Indicator	Timeline	Improvement Same/Yes/No	Responsibility	Update
a	1 Vacant linesperson?	2024		Brian/Andrew	
b	New Meter Technician Apprenticeship?	2024		Brian/Jordan / Taylor	
c	2 Retiring CSRs?	2025&2026		Sharon/Taylor	

3 Customer Service & Investments

	Key Performance Indicator	Timeline	Improvement Same/Yes/No	Responsibility	Update
a	Ensure in top 10% of most reliable distribution companies in Ontario. Annual average number of times that power to a customer is interrupted = <0.77	2024-2027		Brian/Andrew/ Jordan	
b	Ensure in top 10% of most reliable distribution companies in Ontario. Annual average number of hours that power to a customer is interrupted = <1 hour34 minutes	2024-2027		Brian/Andrew/ Jordan	
c	Improve PowerAssist 24-hour outage assistance - TextPower	2024		Sharon/Brian / Andrew	
d	Implement Customer Education Plan to improve satisfaction	2024-2025		Sharon/Brian	
e	Customer Satisfaction Survey OEB requirement minimal score	2025 = 79%		Sharon/Brian	
f	Install at least 2 new Smart Switches annually to increase smart grid operations	2024-2027		Jordan/Andrew/ Brian	
g	Annual operations: continue porcelain switch replacements, IR scanning, implement asset management plan, tree trimming	2024-2027		Andrew/Brian / Jordan	
h	Northstar Billing Upgrade	2024/2025		Sharon	
i	New M3 Substation replacement to connect more customers to local Bracebridge TS improving reliability vs Utterson	2024 = engineering 2025 = material order 2026 = installation		Jordan/Brian/ Andrew	

4 Financial

	Key Performance Indicator	Timeline	Improvement Same/Yes/No	Responsibility	Update
a	Complete Cost of Service Application to Ontario Energy Board	2024		Darren/Brian/ Sharon / Jordan / Andrew	
b	Defend Cost of Service Application and implement new rates	2025		Darren/Brian/ Sharon / Jordan	
c	Annually ensure are in 10% lowest controllable cost per customer distribution companies in Ontario	2024 = <$339 2025 = <$346 2026 = <$353		Brian/Andrew/ Jordan/Sharon	
d	Annually increase Ebilling - reducing costs by proactively engaging customers to enroll	2024 = 44% 2025 = 47% 2026 = 51%		Sharon	
e	Annual Days Sales Outstanding = <30	2023-2025		Sharon	
f	Annual Deemed Return on Equity = >8%	2024-2027		Brian/Darren	

SEC-18

[Ex. 4, p. 8] Please reconcile the 2024 and 2025 controllable costs per customer of $339 and $346 with the information filed on Appendix 2-L (i.e. $355 and $372 respectively).

The 2024 and 2025 controllable costs reported on LPDL's internal scorecard include only controllable costs that are within the control of the department managers and do not include the corporate costs allocated through the management fee from LHL.

SEC-19

[Ex. 4, p. 9] Please provide the most recent "monthly Actual to Budget Review".

LPDL has attached LPDL_Appendix I - 4-SEC-19 - LPDL Financial Commentary 2024-11.

SEC-20

[Ex. 4, p. 11] Please restate Table 3 as a comparison of 2025 to 2019 Actuals. Please confirm that the CAGR from actuals is 5.5%. Please calculate the CAGR for each of the five categories from 2019 actuals to 2025 Test Year.

LPDL has restated Exhibit 4 – Table 3 below and confirms the CAGR from 2019 Actual to 2025 Test Year is 5.5%.

	2019 Actual	2025 Test	CAGR %
Operations	370,938	500,535	5.1%
Maintenance	1,339,716	2,310,892	9.5%
Billing and Collecting	936,607	1,171,958	3.8%
Community Relations	38,436	36,225	-1.0%
Administrative and General	2,083,437	2,561,246	3.5%
TOTAL	**4,769,134**	**6,580,856**	**5.5%**

SEC-21

[Ex. 4, p. 18] Please explain why costs allocated by affiliates to "fill resource gaps" produced an overall increase in OM&A as compared to Board-approved costs.

The Regulatory functions in accounting, reporting and compliance still continue to be completed by a variety of LHL corporate staff. LPDL tried several times over the years to fill the Regulatory Analyst/Accountant position to take on the combined tasks that are currently being completed piecemeal by a number of executives and senior staff. In the 2019 COS application, it was expected that the corporate allocation would be reduced once the position was 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. This position was never filled due to lack of qualified candidates. LHL continues to provide the finance, accounting and regulatory functions for LPDL and faces the same resource burden again in 2024/25 as experienced in 2018/19 during the rate application process. Overtime has not been included in the costs as management staff are not compensated. For 2024 to January 2025, the corporate management fee allocation is higher than 2020-2023 due to the LHL staff regular hours spent on LPDL tasks and rate application. This same increase was seen in 2019. Again, the unpaid and unallocated overtime worked by LHL staff on the rate application equates to approximately $122 K that was not cross charged to LPDL – ultimately a savings to the rate payer that can not be sustained.

SEC-22

[Ex. 4, p. 20] Please provide details of any "data analytics and reporting capabilities" that have been implemented to date relative to the SCADA system.

LPDL's SCADA system employs mainly Schweitzer 651R relays and General Electric F35 Relays. The data from the devices communicate directly to LPDL SCADA servers. Survalent is the main software vendor of LPDL's SCADA system.

All data points are available both in real-time and historically. Historical databases are customizable and is the basis for LPDL's historical feeder data. Historical reports can be exported based on date, time, and selectable datapoints.

Datapoints include, but are not limited to:

Analog:

- Voltage
- Amperage
- True Power (Watts)
- Apparent Power (Volt-Amps)
- Reactive Power (Volt-Amps Reactive)
- Power Factor

Status:

- Open/Close signals from reclosers
- Communication line (on/off)

- Holdoff
- Fast Curve

In addition to receiving data from its own devices, LPDL has an Inter-Control Center Communications Protocol (ICCP) link with Hydro One, which allows the sharing of data between each others control centers. LPDL also sends and receives real-time data from some customers who own DERs in its territory, including hydro-electric plants, solar and battery sites, and one manufacturing facility which owns a natural gas generator.

SEC-23

[Ex. 4, p. 23] Please explain why the Applicant was able to absorb increases in locates costs since 2021 while still earning well in excess of the Board-approved ROE each year, but is now unable to do so without a rate increase in 2025.

As seen in Exhibit 4 – Table 4 (Appendix 2-JB), LPDL's contracted locate costs have increased each year since 2022, with the largest one-year increase of $93K in 2023. This was due to G-Tel increasing their locate rates significantly following their mass hiring campaign in 2023, with significant wage increases to attract and retain employees, to address their labour shortage, as discussed in Exhibit 4.2. LPDL has faced price increases in several expense and capital items (i.e. fuel, wages, transformers, etc.). Over the past few years, it is not just locates that have increased. Everything has gone up and LPDL is trying to mitigate as much as possible.

SEC-24

[Ex. 4, p. 24] Please confirm that OM&A per customer has increased 30.5% from 2019 actuals, a CAGR of 4.54%.

LPDL confirms that OM&A per customer has increased 30.3% from 2019 Actual to 2025 Test, with a CAGR of 4.5%.

Per Appendix 2-L	2019 Actual	2025 Test
O&M	$ 1,710,655	$ 2,811,427
Admin Expenses	$ 3,058,480	$ 3,769,429
Total Recoverable OM&A	**$ 4,769,134**	**$ 6,580,856**
Number of Customers	16,707	17,698
Total OM&A per customer	**$ 285**	**$ 372**
% Change		**30.3%**
CAGR		**4.50%**

SEC-25

[Ex. 4, p. 27] Please provide a detailed breakdown of "Miscellaneous Expenses", which are more than half of A&G expenses, for the Test Year and each of the prior years being reported.

Please see response to 4-Staff-41.

SEC-26

[Ex. 4, p. 31-35] An increase in shared services costs appears to be a driver of cost variances for each of the years 2022-2025. Please provide a comprehensive table of costs for each of those years that shows

a. The full amount of each cost incurred by an affiliate any part of which was allocated to the utility;

b. The allocation of that cost between affiliates, showing both the amount allocated to the utility and the amount allocated to each other company within the corporate group,

c. The basis for the allocation, including any allocation formula or algorithm, and detailed calculations of the amount allocated to the affiliate,

d. Any market value comparisons or other documentation showing the value of the services to the utility, and

e. A cross-reference to the dollar figure in Appendix 2-N that includes the allocation to or from the utility.

If the Applicant has received any independent third party review of its allocations and/or allocation methodology, please also provide a copy of that review.

Please see responses to 4-Staff-51, 4-Staff-52 and 4-Staff-55.

SEC-27

[Ex. 4, p. 46-7] Please restate Tables 16 and 17 to include partial FTEs for all employees of affiliates that provide services to the utility for which the utility receives a cost allocation, and the cost of those partial FTEs to the utility.

Please see Appendix 2K Employee Costs and Appendix 2K Employee Cost and Variance Analysis restated below:

Appendix 2-K - Employee Costs

	Last Rebasing Year 2019 - OEB Approved	Last Rebasing Year (2019 Actuals)	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year
Number of Employees (FTEs including Part-Time)[1]								
Management (including executive)	3	6	5	5	6	6	7	6
Non-Management (union and non-union)	19	22	20	19	20	21	22	22
Total	22	28	25	25	27	27	28	28
Total Salary and Wages including ovetime and incentive pay								
Management (including executive)	$ 358,394	$ 868,964	$ 795,995	$ 793,397	$ 972,852	$ 1,031,314	$ 1,105,532	$ 1,131,971
Non-Management (union and non-union)	$ 1,502,549	$ 1,534,344	$ 1,574,168	$ 1,538,058	$ 1,656,352	$ 1,700,150	$ 1,831,661	$ 2,021,221
Total	$ 1,860,943	$ 2,403,308	$ 2,370,164	$ 2,331,455	$ 2,629,205	$ 2,731,464	$ 2,937,193	$ 3,153,192
Total Benefits (Current + Accrued)								
Management (including executive)	$ 89,599	$ 234,139	$ 204,778	$ 201,924	$ 246,675	$ 266,020	$ 287,186	$ 296,916
Non-Management (union and non-union)	$ 387,055	$ 408,548	$ 400,170	$ 406,532	$ 427,737	$ 453,005	$ 478,050	$ 542,741
Total	$ 476,654	$ 642,686	$ 604,947	$ 608,456	$ 674,413	$ 719,025	$ 765,236	$ 839,656
Total Compensation (Salary, Wages, & Benefits)								
Management (including executive)	$ 447,993	$ 1,103,102	$ 1,000,773	$ 995,321	$ 1,219,528	$ 1,297,334	$ 1,392,718	$ 1,428,887
Non-Management (union and non-union)	$ 1,889,604	$ 1,942,892	$ 1,974,338	$ 1,944,590	$ 2,084,090	$ 2,153,155	$ 2,309,711	$ 2,563,961
Total	$ 2,337,597	$ 3,045,994	$ 2,975,111	$ 2,939,912	$ 3,303,617	$ 3,450,489	$ 3,702,429	$ 3,992,848
Total Compensation Breakdown (Capital, OM&A)								

Appendix 2-K - Employee Cost and FTE Variance Analysis

	2019 Actual vs 2019 Board Approved	2020 vs 2019	2021 vs 2020	2022 vs 2021	2023 vs 2022	2024 vs 2023	2025 vs 2024
Number of Employees (FTEs including Part-Time)[1]							
Management (including executive)	2.8	- 0.4	- 0.1	0.8	- 0.0	0.5	- 0.5
Non-Management (union and non-union)	2.8	- 2.3	- 0.2	1.1	0.8	0.7	0.1
Total	5.6	- 2.7	- 0.3	1.9	0.7	1.1	- 0.4
Total Salary and Wages including ovetime and incentive pay							
Management (including executive)	$510,570	-$72,968	-$2,598	$179,455	$58,461	$74,218	$26,439
Non-Management (union and non-union)	$31,795	$39,824	-$36,110	$118,294	$43,798	$131,510	$189,560
Total	$542,365	-$33,144	-$38,708	$297,749	$102,260	$205,728	$215,999
Total Benefits (Current + Accrued)							
Management (including executive)	$144,540	-$29,361	-$2,853	$44,751	$19,344	$21,167	$9,729
Non-Management (union and non-union)	$21,493	-$8,378	$6,362	$21,206	$25,268	$25,045	$64,691
Total	$166,032	-$37,739	$3,509	$65,956	$44,612	$46,212	$74,420
Total Compensation (Salary, Wages, & Benefits)							
Management (including executive)	$655,109	-$102,329	-$5,452	$224,206	$77,806	$95,385	$36,168
Non-Management (union and non-union)	$53,288	$31,446	-$29,748	$139,499	$69,066	$156,556	$254,251
Total	$708,397	-$70,883	-$35,200	$363,706	$146,872	$251,940	$290,419

Vulnerable Energy Consumers Coalition (VECC)

4.0 -VECC -17
Reference: Exhibit 4, Appendix 2-JA & 2-JC

a) Please update Appendices 2-JA and 2-JD (programs) for 2024 actual results.

Please see response to 4-Staff-32.

4.0 -VECC -18
Reference: Exhibit 4, Appendix 2-JA

a) Please clarify as to whether there are any costs of this application shown in the OM&A reported for the year 2024 in Appendix 2-JA.

LPDL confirms there are no costs of this application included in OM&A for 2024.

LPDL's rate application was deferred in 2023 to 2024 so no rate application costs were recorded in 2024. The one-time rate application costs from 2019 were expensed from 2019-2023. All 2024 one-time costs associated with this application have been recorded in prepaids to be expensed over 2025-2029.

b) What were the annual amortized one-time costs of the prior application in each year from 2019 onward?

	2019	2020	2021	2022	2023	2024	TOTAL
2019 Rate Application one-time costs amortized - account 5655	$ 20,170	$ 23,500	$ 23,500	$ 23,500	$ -	$ -	$ 90,670

4.0 -VECC -19

Reference: Exhibit 4, Appendix 2-JD

a) Please provide the annual cybersecurity related costs in each year from 2019 to 2025 forecast. Please show the costs paid to affiliates separately.

Cybersecurity:	2019	2020	2021	2022	2023	2024	2025
Third Party	$ 2,267	$ 552	$ 780	$ 15,407	$ 13,752	$ 46,228	$ 41,616
Lakeland Energy	$ 22,050	$ 12,138	$ 9,000	$ 13,425	$ 7,200	$ 7,200	$ 7,200
	$ 24,317	$ 12,689	$ 9,780	$ 28,832	$ 20,952	$ 53,428	$ 48,816

4.0 -VECC -20

Reference: Exhibit 4, Appendix 2-JD

a) Please describe the elements of "miscellaneous expenses" (line 86) and explain why these costs have increase from $887,737 in 2020 to $1.3 million in 2025.

Please see response to SEC-25.

4.0 -VECC -21

Reference: Exhibit 4, Appendix 2-JD

b) Please explain how the bad debt expense for 2025 was estimated.

LPDL's bad debt expense for 2025 was estimated based on budget which accounts for historical trends, current markets and affects from disconnection moratoriums.

4.0 -VECC 22
Reference: Exhibit 4,

a) Under what category of costs in Appendix 2-JD (OM&A programs table) are memberships costs found?

Membership costs are included in Account 5665 – Miscellaneous General Expenses and Account 5085 – Miscellaneous Distribution Expenses.

b) Please provide a list of the memberships (e.g. EDA, CHEC, USF etc.) and provide a breakdown for each for each of the years 2020 through 2025 (forecast).

Memberships	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year
5665 - CHEC	42,662	38,881	44,160	44,711	46,023	48,324
5665 - EDA	34,900	35,200	35,200	37,000	37,900	39,795
5665 - MEARIE HR	3,020	3,655	3,591	3,669	3,958	4,156
5665 - GEORGIAN BAY DISTRICT EDA/TRADES ASSOC	777	894	881	1,209	-	-
5085 - USF	7,950	8,750	8,750	8,750	9,144	9,556

4.0 -VECC -23
Reference: Exhibit 4, Tab 1, Schedule 1, Table 3

a) Under what category of costs in Appendix 2-JD (OM&A programs table) are Insurance costs found?

Credit risk, property and liability insurance are recorded in Account 5635 – Property Insurance. Vehicle insurance is recorded in various OM&A and capital accounts where the trucks were used, based on actual hours tracked to jobs worked on.

b) Please provide a breakdown of Insurance costs for each year 2019 through 2025 (forecast) showing those costs paid to MEARIE separately from other insurance costs.

Property Insurance:	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year
Mearie - Liability	22,636	21,730	5,754	10,196	8,979	23,412	24,583
Mearie - Property	12,941	13,556	20,968	22,794	30,825	35,311	37,077
Euler credit risk Insurance	20,738	16,254	20,453	19,830	15,589	18,676	19,610
Total Property Insurance	56,316	51,539	47,176	52,820	55,393	77,400	81,270
Mearie - Vehicle Insurance	10,311	10,496	12,313	10,267	24,755	26,082	27,386
Total Insurance	66,626	62,035	59,489	63,087	80,148	103,482	108,656

Mearie Insurance:	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year
Mearie - Liability	22,636	21,730	5,754	10,196	8,979	23,412	24,583
Mearie - Property	12,941	13,556	20,968	22,794	30,825	35,311	37,077
Mearie - Vehicle	10,311	10,496	12,313	10,267	24,755	26,082	27,386
Total Mearie Insurance Costs	45,888	45,782	39,035	43,256	64,559	84,805	89,045

c) Does LPDL or any of its affiliates receive any dividends or financial payments related to their membership in MEARIE? If yes are these reported as income or revenue?

No, LPDL nor any of its affiliates receive any dividends or financial payments from Mearie.

4.0 -VECC -24

Reference: Exhibit 4, -

a) Please provide the labour costs and FTEs attributable to the Customer Billing Costs (Appendix 2-JD line 60) for each year 2019 through 2025 (forecast).

USoA Account	Customer Billing Expenses Detail Breakdown	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year
5315	Labour & Burdens (100% LPDL staff)	183,194	185,143	160,370	172,644	202,907	183,056	188,547
5315	FTE Count (100% LPDL staff)	3.50	3.50	2.55	2.80	2.96	2.57	2.00

b) Please provide the number of FTEs in this category that are currently vacant.

There are currently no vacant positions in this category.

4.0 -VECC -25

Reference: Exhibit 4, Tab 4, Schedule 5

a) Please provide the OEB annual Assessment costs for each year 2019 through 2025 (forecast).

USoA Account	Regulatory Expenses	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year
5655	OEB Annual Assesment Costs	57,372	57,179	55,310	61,428	69,087	79,645	90,126

4.0 -VECC -26

Reference: Exhibit 4, Tab 4, Schedule 5

a) Please provide the spent-do-date actual one-time cost of this application as per the categories in Appendix 2-M.

Please see response to 4-Staff-43a).

b) Please explain how the incremental operating costs of staff associated with this application were calculated.

The incremental operating costs of staff associated with this application are included in the corporate management fees, based on LPDL's direct portion of corporate costs. The portion of their actual time and wage attributable to LPDL tasks is cross charged to LPDL through the management fee. LHL continues to provide the finance, accounting and regulatory functions for LPDL and faces the same resource burden again in 2024/25 as experienced in 2018/19 during the rate application process. Overtime has not been included in the costs as management staff are not compensated. For 2024 to January 2025, the corporate management fee allocation is higher than 2020-2023 due to the LHL staff regular hours spent on LPDL tasks and rate application. This same increase was seen in 2019. Again, the unpaid and unallocated overtime worked by LHL staff on the rate application equates to approximately $122 K that was not cross charged to LPDL – ultimately a savings to the rate payer that can not be sustained. LPDL does not incur any incremental operating costs from internal LPDL staff as only managers have been involved in this application and no overtime is compensated to managers.

4.0 -VECC -27

Reference: Exhibit 4, page 64

a) Please provide the most recent third-party review/audit of LPDL's affiliate corporate cost allocation methodology.

Please see response to 4-Staff-55 a).

Exhibit 5 – Cost of Capital

OEB Staff

5-Staff-57
Debt Instruments
Ref 1: Exhibit 5, Section 5.3, p. 10
Ref 2: Chapter 2 Appendices, Tab 2-OB

Preamble:
All of Lakeland Power's long-term debt instruments are with TD Bank. All debt instruments have medium length terms, ranging from two to five years.

Questions:
(a) Please explain why all of Lakeland Power's debt is with one banking institution. As part of the response, please explain if there are cost savings for Lakeland Power and/or its customers by having all its debt at one banking institution.

LPDL has historically borrowed from TD Bank as they offered competitive rates. Borrowing arrangements are reviewed annually. TD Bank loans represent an arm's length transaction and are deemed to be competitive.

5-Staff-58
2025 Cost of Capital Parameters
Ref: EB-2024-0063, OEB Letter, October 31, 2024

Preamble:
On October 31, 2024, the OEB issued a letter updating 2025 Cost of Capital parameters.

Question:
(a) Please update the evidence where applicable to reflect the 2025 Cost of Capital parameters.

LPDL has updated the evidence to reflect the 2025 Cost of Capital parameters.

5-Staff-59
Cost of Capital
Ref 1: EB-2024-0063, Notice, March 6, 2024
Ref 2: EB-2024-0063, OEB Letter, April 22, 2024

Preamble:
On March 6, 2024, the OEB commenced a hearing (EB-2024-0063) on its own motion to consider the methodology for determining the values of the cost of capital parameters and deemed capital structure to be used to set rates for electricity transmitters, electricity distributors, natural gas utilities, and Ontario Power Generation Inc. The methodology for determining the OEB's prescribed interest rates and matters related to the OEB's Cloud Computing Deferral Account will also be considered, including what type of interest rate, if any, should apply to this deferral account.

On April 22, 2024, the OEB approved the final Issues List for this proceeding, including the following two issues, amongst other issues:

18. How should any changes in the cost of capital parameters and/or capital structure of a utility be implemented (e.g., on a one-time basis upon rebasing or gradually over a rate term)?

19. Should changes in the cost of capital parameters and/or capital structure arising out of this proceeding (if any) be implemented for utilities that are in the middle of an approved rate term, and if so, how?

Question:
(a) Please confirm that the applicant proposes to implement the outcomes from the OEB's generic cost of capital proceeding, including what the OEB decides with respect to implementation. If this is not the case, please explain.

LPDL will comply with the content of any applicable order of the OEB from the generic cost of capital proceeding. LPDL cannot commit to the outcome(s) of a proceeding that has not yet been decided and for which LPDL has not had an opportunity to review and consider.

5-Staff-60
Ref: EB-2024-0063, OEB Letter, July 26, 2024

Preamble:
On July 26, 2024, the OEB issued a Letter and Accounting Order regarding prescribed interest rates and the deemed short-term debt rate (DSTDR).

Questions:

(a) Please confirm that the applicant will use the 2025 DSTDR, as set on October 31, 2024 on an interim basis.

LPDL confirms it will use the 2025 DSTDR, as set on October 31, 2024 on an interim basis.

(b) Please confirm that the applicant will follow all other direction included in the OEB's Letter and Accounting Order issued on July 26, 2024, including the establishment of a new variance account for the DSTDR.

LPDL confirms it will follow all other direction included in the OEB's Letter and Accounting Order issued on July 26, 2024, including the establishment of a new variance account for the DSTDR.

5-Staff-61
Ref: EB-2024-0063, OEB Letter, October 31, 2024

Preamble:
On October 31, 2024, the OEB issued a Letter and Accounting Orders regarding the return on equity (ROE) and deemed long-term debt rate (DLTDR).

Questions:

(a) Please confirm that the applicant will use the 2025 ROE, as set on October 31, 2024 on an interim basis.

LPDL confirms it will use the 2025 ROE, as set on October 31, 2024 on an interim basis.

(b) Please confirm that the applicant will follow all other direction included in the OEB's Letter and Accounting Orders issued on October 31, 2024, including the establishment of new variance accounts for the ROE and DLTDR, as applicable.

LPDL confirms it will follow all other direction included in the OEB's Letter and Accounting Orders issued on October 31, 2024, including the establishment of new variance accounts for the ROE and DLTDR, as applicable.

School Energy Coalition (SEC)

SEC-28

[Ex. 5, p. 12] Please confirm that the overearning in Table 5 is primarily the result of billing determinants and therefore revenues being higher than 2019 Board approved.

LPDL confirms that the overearning in Table 5 is primarily the result of billing determinants and therefore revenues being higher than 2019 Board approved.

The table below shows the recalculated ROE overearnings averaged 0.53% over 2019 to 2023.

	2019	2020	2021	2022	2023	
Deemed ROE	8.98%	8.98%	8.98%	8.98%	8.98%	
Achieved ROE	11.51%	6.07%	12.06%	11.82%	11.02%	
Over/(Under) Earn	2.53%	-2.91%	3.08%	2.84%	2.04%	
	2019	**2020**	**2021**	**2022**	**2023**	
Deemed ROE	8.98%	8.98%	8.98%	8.98%	8.98%	
Recalculated ROE AFTER PILS Impact	10.66%	5.72%	10.19%	10.38%	10.58%	
Recalculated Over/(Under) Earn	**1.68%**	**-3.26%**	**1.21%**	**1.40%**	**1.60%**	**0.53%**
						Average ROE Chg

The next table below shows a CAGR for total billed kWh of 1.3% over 2019 to 2024.

	2019 Board Approved	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge Weather Normal	2025 Test Weather Normal		
Purchases										
Actual kWh Purchases		309,952,095	304,387,702	309,941,422	322,673,989	315,137,434				
Predicted kWh Purchases	302,020,231	315,495,988	311,243,705	309,366,915	314,197,405	310,731,968	317,256,029	317,983,860		
% Difference between actual and predicted purchases		1.8%	2.3%	(0.2%)	(2.6%)	(1.4%)				
Chg to 2019 Board Appr		4.5%	3.1%	2.4%	4.0%	2.9%	5.0%		CAGR	1.0%
Loss Factor							1.0678	1.0678		
Total Billed	278,140,292	289,860,629	286,230,671	290,240,292	303,102,277	296,977,680	297,109,186	297,790,797		
Chg to 2019 Board Appr		4.2%	2.9%	4.4%	9.0%	6.8%	6.8%		CAGR	1.3%
Billing Determinants										
Residential										
Customers	11,368	11,430	11,566	11,726	11,912	12,125	12,262	12,400		
kWh	104,102,897	110,765,686	112,437,412	112,958,103	116,633,398	113,498,414	115,790,918	118,317,067		
Chg to 2019 Board Appr		6.4%	8.0%	8.5%	12.0%	9.0%	11.2%		CAGR	2.2%
General Service < 50 kW										
Customers	2,165	2,154	2,155	2,191	2,205	2,206	2,218	2,229		
kWh	58,088,237	59,276,659	54,635,310	56,374,252	59,995,612	59,565,733	60,404,777	61,352,783		
Chg to 2019 Board Appr		2.0%	-5.9%	-3.0%	3.3%	2.5%	4.0%		CAGR	0.8%
General Service > 50 to 4999 kW										
Customers	138	137	136	131	129	130	126	122		
kWh	114,585,590	118,495,415	117,859,877	119,633,612	125,207,062	122,653,645	119,652,398	116,858,492		
kW	278,531	289,524	290,763	285,432	308,241	316,961	291,506	284,699		
Chg to 2019 Board Appr		3.9%	4.4%	2.5%	10.7%	13.8%	4.7%		CAGR	0.9%
Unmetered Scattered Load										
Connections	51	55	56	65	64	63	64	65		
kWh	166,068	172,797	173,568	178,362	172,344	169,785	172,555	175,370		
Chg to 2019 Board Appr		4.1%	4.5%	7.4%	3.8%	2.2%	3.9%		CAGR	0.8%
Sentinel Lighting										
Connections	44	41	40	40	38	33	31	29		
kWh	42,775	39,114	37,289	37,046	34,937	31,176	29,308	27,553		
kW	119	109	104	103	97	87	81	77		
Chg to 2019 Board Appr		-9.1%	-13.3%	-13.9%	-18.8%	-27.5%	-31.9%		CAGR	-7.4%
Street Lighting										
Connections	2,849	2,849	2,851	2,851	2,851	2,851	2,852	2,853		
kWh	1,154,724	1,110,958	1,087,215	1,058,917	1,058,924	1,058,927	1,059,230	1,059,533		
kW	3,183	3,074	3,080	3,082	3,082	3,083	2,994	2,994		
Chg to 2019 Board Appr		-3.4%	-3.2%	-3.2%	-3.2%	-3.1%	-5.9%		CAGR	-1.2%
Total										
Customer/Connections	16,615	16,666	16,804	17,003	17,199	17,409	17,552	17,698		
Chg to 2019 Board Appr		**0.3%**	**1.1%**	**2.3%**	**3.5%**	**4.8%**	**5.6%**		CAGR	1.1%
kWh	278,140,292	289,860,629	286,230,671	290,240,292	303,102,277	296,977,680	297,109,186	297,790,797		
Chg to 2019 Board Appr		**4.2%**	**2.9%**	**4.4%**	**9.0%**	**6.8%**	**6.8%**		CAGR	1.3%
kW	281,833	292,707	293,947	288,617	311,420	320,130	294,581	287,770		
Chg to 2019 Board Appr		**3.9%**	**4.3%**	**2.4%**	**10.5%**	**13.6%**	**4.5%**		CAGR	0.9%

SEC-29

[Ex. 5, App. A] Please confirm that none of the facilities are for use by the holding company, and all of the facilities are solely for use by the utility.

LPDL confirms that all facilities are solely for use by the utility and not the holding company.

SEC-30

[Ex. 5, App. A, p. 10, 11] Please provide the most recent reports to the lender under "Reporting Covenants" for each of 1), 2) and 3), and under "Financial Covenants" for each of 1) and 2).

For "Reporting Covenants" items, TD receives the same reports that are provided to the shareholders for items 1) and 2):

1) see Exhibit 1 Appendix C.
2) see LPDL's response to SEC-1.
3) see LPDL_Appendix J - 5-SEC-30 - LPDL ICR Calculation for TD - 2024-09

For "Financial Covenants" items:

1) see page 2 of item 3) above.
2) see page 1 of item 3) above.

Vulnerable Energy Consumers Coalition (VECC)

5.0-VECC-28

Reference: Exhibit 5,

a) Please Appendix 2-OA using the OEB's updated 2025 Cost of Capital Parameters issued on October 3, 2024.

Please see response to 5-Staff-58.

b) Please provide the adjustment to revenue requirement resulting from this change.

Please see response to 5-Staff-58.

5.0-VECC-29

Reference: Exhibit 5, page 11

a) Please update Table 4 to include 2024 ROE results.

LPDL will report the 2024 ROE results to the OEB by the OEB's Apr 30/25 due date.

5.0-VECC-30

Reference: Exhibit 5, page 11

a) Please explain what due diligence LPDL undertakes to ensure that the loans offered by TD Bank are at a competitive rate.

Please see response to 5-Staff-57.

b) Please explain why LPDL has no debt with a term over 5 years.

LPDL has no debt with a term over 5 years in anticipation of potential rate volatility.

c) Please explain how the short-term debt which LPDL has acquired since 2022 is competitive with longer-term debt that might have been acquired.

LPDL's shorter-term debt acquired since 2022, with terms of 1-2 years, were selected as the longer term rates were substantially higher and LPDL felt it would benefit from picking shorter terms at lower rates. Upon maturity, LPDL will review the long term and short term options available and select the most appropriate that will be beneficial to its customers.

5.0-VECC-31

Reference: Exhibit 5, Appendix 2-OB

a) Appendix 2-OB (Debt Instruments) shows that in 2022 LPDL had a total of $13,494,435 (5 x $2,698,887) in loans with a 10-year term that were issue in July of 2022. Yet for 2025 no such loans are shown. Please explain this discrepancy.

The $2,698,887 loan was a 5-year fixed rate loan that matured in July 2022 and was renewed as a 2-year variable rate loan. In Appendix 2-OB, LPDL had shown this July 7, 2022 loan renewed as a 10-year term in error where it should reflect instead a 2-year term, as shown correctly in 2023 onward. The interest rate calculations remain the same as the error was in the Term column only and had no impact to the 2022 interest cost calculation. This same 2-year $2,698,887 variable rate loan is listed 5 times in 2022 in order to calculate the actual interest cost impacted by five prime rate changes that occurred from June 2022 to December 2022. This same 2-year

$2,698,887 variable rate loan then matured in July 2024 and was renewed as a 2-year fixed rate loan in August 2024, shown as Term Loan – 07 in 2024 and 2025.

b) Please explain why the loan shown in Row 1 in 2022 with a Start Date of 1-Feb-22 (principal $4,000,000) has a rate of 2.167% in that year and, what appears to be the same loan, has in 2025 a rate of 2.98% notwithstanding it is described as a “fixed” rate loan.

See updated Appendix 2-OB provided below. LPDL has updated the ‘Rate %’ column to reflect the actual rate and moved the proration calculation into the ‘Interest $’ column however the interest expense remains unchanged.

c) Similarly, please explain why the “fixed” 2023 5-year term loan of 24-Mar-23 (principal $1,162,500) is shown in 2023 with a rate of 3.736% whereas in 2025 this loan now has a rate of 5.0%.

Please see response to part b).

d) There are similar discrepancies in the “fixed” loans of 5-Jul-23, 28-Oct-22 and 1-Aug-24 where the loans are described in the year of acquisition as fixed and yet the rates in 2025 exceed those at the time of acquisition. Please explain these discrepancies.

Please see response to part b).

Appendix 2-OB
Debt Instruments

Notes

1 If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.
2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009, or with any subsequent update issued by the OEB.
3 Add more lines above row 12 if necessary.

Year 2019

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Term Loan - 03	TD Bank	Third-Party	Fixed	15-Mar-18	5	$ 1,162,500	3.62%	$ 42,082.50	
2	Term Loan - 05	TD Bank	Third-Party	Fixed	3-Feb-17	2	$ 4,000,000	2.17%	$ 7,372.05	
3	Term Loan - 05	TD Bank	Third-Party	Fixed	3-Feb-19	3	$ 4,000,000	3.38%	$ 121,865.21	
4	Term Loan - 09	TD Bank	Third-Party	Fixed	24-Oct-17	5	$ 2,325,000	3.21%	$ 74,632.50	
5	Term Loan - 10	TD Bank	Third-Party	Fixed	14-Jul-17	5	$ 2,698,887	3.04%	$ 82,046.15	
6	Term Loan - 13	TD Bank	Third-Party	Fixed	22-Aug-19	5	$ 8,000,000	2.94%	$ 78,614.79	
7	Term Loan - 12	TD Bank	Third-Party	Fixed	18-Jul-16	3	$ 7,403,025	2.18%	$ 13,706.75	
8	Term Loan - 12	TD Bank	Third-Party	Fixed	18-Jul-16	3	$ 7,382,117	2.18%	$ 13,668.04	
9	Term Loan - 12	TD Bank	Third-Party	Fixed	18-Jul-16	3	$ 7,361,170	2.18%	$ 12,310.30	
10	Term Loan - 12	TD Bank	Third-Party	Fixed	18-Jul-16	3	$ 7,338,867	2.18%	$ 13,587.96	
11	Term Loan - 12	TD Bank	Third-Party	Fixed	18-Jul-16	3	$ 7,317,838	2.18%	$ 13,111.96	
12	Term Loan - 12	TD Bank	Third-Party	Fixed	18-Jul-16	3	$ 7,296,335	2.18%	$ 13,509.22	
13	Term Loan - 12	TD Bank	Third-Party	Fixed	18-Jul-16	3	$ 7,275,230	2.18%	$ 13,035.62	
14	Term Loan - 12	TD Bank	Third-Party	Fixed	18-Jul-16	3	$ 7,253,650	2.18%	$ 13,863.41	
15	Term Loan - 12	TD Bank	Third-Party	Fixed	18-Jul-16	3	$ 7,253,650	2.18%	$ 1,299.70	
16									$ -	
Total							$ 18,186,387	2.83%	$ 514,706.16	

Year 2020

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Term Loan - 03	TD Bank	Third-Party	Fixed	15-Mar-18	5	$ 1,162,500	3.62%	$ 42,197.79	
2	Term Loan - 05	TD Bank	Third-Party	Fixed	3-Feb-19	3	$ 4,000,000	3.38%	$ 135,570.41	
3	Term Loan - 09	TD Bank	Third-Party	Fixed	24-Oct-17	5	$ 2,325,000	3.21%	$ 74,836.97	
4	Term Loan - 10	TD Bank	Third-Party	Fixed	14-Jul-17	5	$ 2,698,887	3.04%	$ 82,270.94	
5	Term Loan - 13	TD Bank	Third-Party	Fixed	22-Aug-19	5	$ 8,000,000	2.94%	$ 235,844.38	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 18,186,387	3.14%	$ 570,720.50	

Year 2021

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Term Loan - 03	TD Bank	Third-Party	Fixed	15-Mar-18	5	$ 1,162,500	3.62%	$ 42,082.50	
2	Term Loan - 05	TD Bank	Third-Party	Fixed	3-Feb-19	3	$ 4,000,000	3.38%	$ 135,200.00	
3	Term Loan - 09	TD Bank	Third-Party	Fixed	16-Oct-17	5	$ 2,325,000	3.21%	$ 74,632.50	
4	Term Loan - 10	TD Bank	Third-Party	Fixed	14-Jul-17	5	$ 2,698,887	3.04%	$ 82,046.15	
5	Term Loan - 13	TD Bank	Third-Party	Fixed	22-Aug-19	5	$ 8,000,000	2.94%	$ 235,200.00	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 18,186,387	3.13%	$ 569,161.15	

Year 2022

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Term Loan - 02	TD Bank	Third-Party	Fixed	1-Feb-22	4	$ 4,000,000	2.98%	$ 96,666.30	
2	Term Loan - 05	TD Bank	Third-Party	Fixed	3-Feb-19	3	$ 4,000,000	3.38%	$ 25,558.36	
3	Term Loan - 03	TD Bank	Third-Party	Fixed	15-Mar-18	5	$ 1,162,500	3.62%	$ 42,082.50	
4	Term Loan - 09	TD Bank	Third-Party	Fixed	16-Oct-17	5	$ 2,325,000	3.21%	$ 63,590.98	
5	Term Loan - 16	TD Bank	Third-Party	Fixed	28-Oct-22	4	$ 2,325,000	5.77%	$ 22,412.24	
6	Term Loan - 10	TD Bank	Third-Party	Fixed	14-Jul-17	5	$ 2,698,887	3.04%	$ 40,910.68	
7	Term Loan - 11	TD Bank	Third-Party	Variable	7-Jul-22	2	$ 2,698,887	4.45%	$ 6,909.89	
8	Term Loan - 11	TD Bank	Third-Party	Variable	7-Jul-22	2	$ 2,698,887	5.45%	$ 22,164.14	
9	Term Loan - 11	TD Bank	Third-Party	Variable	7-Jul-22	2	$ 2,698,887	6.20%	$ 22,248.14	
10	Term Loan - 11	TD Bank	Third-Party	Variable	7-Jul-22	2	$ 2,698,887	6.70%	$ 20,311.89	
11	Term Loan - 11	TD Bank	Third-Party	Variable	7-Jul-22	2	$ 2,698,887	7.20%	$ 6,920.98	
12	Term Loan - 13	TD Bank	Third-Party	Fixed	22-Aug-19	5	$ 8,000,000	2.94%	$ 235,200.00	
Total							$ 18,186,387	3.33%	$ 604,976.11	

Year 2023

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Term Loan - 02	TD Bank	Third-Party	Fixed	1-Feb-22	4	$ 4,000,000	2.98%	$ 119,200.00	
2	Term Loan - 03	TD Bank	Third-Party	Fixed	15-Mar-18	5	$ 1,162,500	3.62%	$ 10,837.68	
3	Term Loan - 14	TD Bank	Third-Party	Fixed	24-Mar-23	5	$ 1,162,500	5.00%	$ 43,315.07	
4	Term Loan - 05	TD Bank	Third-Party	Fixed	5-Jul-23	4	$ 3,000,000	5.95%	$ 82,647.95	
5	Term Loan - 13	TD Bank	Third-Party	Fixed	22-Aug-19	4	$ 8,000,000	2.94%	$ 156,585.21	
6	Term Loan - 13	TD Bank	Third-Party	Fixed	22-Aug-23	1	$ 8,000,000	6.57%	$ 175,680.00	
7	Term Loan - 16	TD Bank	Third-Party	Fixed	28-Oct-22	4	$ 2,325,000	5.77%	$ 134,106.00	
8	Term Loan - 11	TD Bank	Third-Party	Variable	7-Jul-22	2	$ 2,698,887	7.20%	$ 16,503.88	
9	Term Loan - 11	TD Bank	Third-Party	Variable	7-Jul-22	2	$ 2,698,887	7.45%	$ 66,104.24	
10	Term Loan - 11	TD Bank	Third-Party	Variable	7-Jul-22	2	$ 2,698,887	7.70%	$ 17,080.62	
11	Term Loan - 11	TD Bank	Third-Party	Variable	7-Jul-22	2	$ 2,698,887	7.95%	$ 107,312.19	
12									$ -	
Total							$ 21,186,387	4.39%	$ 929,372.83	

Year 2024

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Term Loan - 02	TD Bank	Third-Party	Fixed	1-Feb-22	4	$ 4,000,000	2.98%	$ 119,526.58	
2	Term Loan - 14	TD Bank	Third-Party	Fixed	24-Mar-23	5	$ 1,162,500	5.00%	$ 58,284.25	
3	Term Loan - 05	TD Bank	Third-Party	Fixed	5-Jul-23	4	$ 3,000,000	5.95%	$ 178,989.04	
4	Term Loan - 13	TD Bank	Third-Party	Fixed	22-Aug-23	1	$ 8,000,000	6.57%	$ 357,120.00	
5	Term Loan - 03	TD Bank	Third-Party	Fixed	5-Sep-24	2	$ 8,000,000	4.75%	$ 122,849.32	
6	Term Loan - 16	TD Bank	Third-Party	Fixed	28-Oct-22	4	$ 2,325,000	5.77%	$ 134,473.41	
7	Term Loan - 11	TD Bank	Third-Party	Variable	7-Jul-22	2	$ 2,698,887	7.95%	$ 92,878.67	
8	Term Loan - 11	TD Bank	Third-Party	Variable	7-Jul-22	2	$ 2,698,887	7.70%	$ 28,083.39	
9	Term Loan - 11	TD Bank	Third-Party	Variable	7-Jul-22	2	$ 2,698,887	7.45%	$ 3,416.49	
10	Term Loan - 07	TD Bank	Third-Party	Fixed	1-Aug-24	2	$ 2,698,887	5.15%	$ 58,262.68	
11									$ -	
12									$ -	
Total							$ 21,186,387	5.45%	$ 1,153,883.82	

Year 2025

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Term Loan - 02	TD Bank	Third-Party	Fixed	1-Feb-22	4	$ 4,000,000	2.98%	$ 119,200.00	
2	Term Loan - 14	TD Bank	Third-Party	Fixed	24-Mar-23	5	$ 1,162,500	5.00%	$ 58,125.00	
3	Term Loan - 05	TD Bank	Third-Party	Fixed	5-Jul-23	4	$ 3,000,000	5.95%	$ 178,500.00	
4	Term Loan - 03	TD Bank	Third-Party	Fixed	5-Sep-24	2	$ 8,000,000	4.75%	$ 380,000.00	
5	Term Loan - 16	TD Bank	Third-Party	Fixed	28-Oct-22	4	$ 2,325,000	5.77%	$ 134,106.00	
6	Term Loan - 07	TD Bank	Third-Party	Fixed	1-Aug-24	2	$ 2,698,887	5.15%	$ 138,992.66	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 21,186,387	4.76%	$ 1,008,923.66	

5.0-VECC-32

Reference: Exhibit 5,

a) LPDL's 2025 long-term debt for the purpose of rate setting is $20,014,990 as shown in Appendix 2-OB. For 2025 the amount of embedded debt shown for the derivation of the weighted interest rate to be used is $21,186,387. Since LPDL is "overleveraged" as compared to its allowed regulator long-term debt amount how did the utility adjust the calculation of the weighted cost of embedded long-term debt?

LPDL did not adjust the calculation of the weighted cost of embedded long-term debt.

b) If the Utility did not make any adjustment, then please recalculate the embedded long-term weighted cost of debt by removing the "overage" of $1,171,397 from the most expensive issuance debt (i.e. 5-Jul-23 @ 5.95%) from the calculation. Please provide the revenue requirement adjustment of this change.

By removing the "overage" of $1,171,397 from the $3,000,000 term loan at 5.95%, LPDL's embedded long-term weighted cost of debt would be 4.69%, a reduction of 0.07% from the submitted rate of 4.76%. The resulting adjustment from this change would be a decrease in deemed interest expense, thus a decrease in revenue requirement of $13,915.

	Long-Term Debt	Cost Rate	Return
Per Original Submission	$ 20,014,990	4.76%	$ 953,140
Per 5-VECC-32 request for 'overage'	$ 20,014,990	4.69%	$ 939,226
Change in Revenue Requirement for 5-VECC-32			$ (13,915)

Exhibit 6 – Revenue Requirement

OEB Staff

6-Staff-62
Other Revenues – 2024 and 2025
Ref: Chapter 2 Appendices, Tab 2-H

Questions:

(a) Please update Tab 2-H of the Chapter 2 Appendices for 2024 actuals.

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2019 Actual²	2020 Actual²	2021 Actual²	2022 Actual²	2023 Actual	Bridge Year	Test Year
		2019	2020	2021	2022	2023	2024	2025
	Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
4082	Retail Services Revenues	-$ 13,252	-$ 12,382	-$ 9,221	-$ 3,512	-$ 3,696	-$ 3,746	-$ 3,963
4084	Service Transaction Requests (STR) Revenues	$ -	$ -	$ -	$ -	$ -	-$ 208	$ -
4086	SSS Administration Revenue	-$ 47,509	-$ 48,083	-$ 48,881	-$ 49,606	-$ 47,430	-$ 50,885	-$ 50,854
4090	Electric Services Incidental to Energy Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4205	Interdepartmental Rents	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4210	Rent from Electric Property	-$ 341,634	-$ 398,956	-$ 425,879	-$ 433,461	-$ 456,681	-$ 461,139	-$ 418,390
4215	Other Utility Operating Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4220	Other Electric Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4225	Late Payment Charges	-$ 76,717	-$ 122,604	-$ 65,346	-$ 76,229	-$ 78,834	-$ 89,316	-$ 77,000
4230	Sales of Water and Water Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4235	Miscellaneous Service Revenues	-$ 72,304	-$ 65,493	-$ 72,525	-$ 68,021	-$ 57,344	-$ 68,605	-$ 66,438
4240	Provision for Rate Refunds	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4245	Government and Other Assistance Directly Credited to Income	-$ 208,154	-$ 227,815	-$ 262,024	-$ 308,119	-$ 352,329	-$ 403,836	-$ 439,197
4305	Regulatory Debits	$ 262,293	$ 131,146	$ -	$ -	$ -	$ -	$ -
4310	Regulatory Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4315	Revenues from Electric Plant Leased to Others	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4320	Expenses of Electric Plant Leased to Others	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4325	Revenues from Merchandise	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4330	Costs and Expenses of Merchandising	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4335	Profits and Losses from Financial Instrument Hedges	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4340	Profits and Losses from Financial Instrument Investments	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4345	Gains from Disposition of Future Use Utility Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4350	Losses from Disposition of Future Use Utility Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4355	Gain on Disposition of Utility and Other Property	-$ 807	-$ 29,551	-$ 26,637	$ -	-$ 35,000	-$ 45,101	$ -
4357	Gain from Retirement of Utility and Other Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4360	Loss on Disposition of Utility and Other Property	$ -	$ -	$ 6,497	$ -	$ -	$ -	$ -
4362	Loss from Retirement of Utility and Other Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4365	Gains from Disposition of Allowances for Emission	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4370	Losses from Disposition of Allowances for Emission	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4375	Revenues from Non Rate-Regulated Utility Operations	-$ 107,291	-$ 301,457	-$ 248,679	-$ 96,845	-$ 375,658	-$ 235,819	$ -
4380	Expenses of Non Rate-Regulated Utility Operations	$ 104,606	$ 294,498	$ 390,481	$ 89,377	$ 401,656	$ 191,345	$ -
4385	Non Rate-Regulated Utility Rental Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4390	Miscellaneous Non-Operating Income	-$ 107,585	-$ 122,519	-$ 136,267	-$ 114,898	-$ 100,987	-$ 126,058	-$ 103,038
4395	Rate-Payer Benefit Including Interest	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4398	Foreign Exchange Gains and Losses, Including Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4405	Interest and Dividend Income	-$ 125,961	-$ 39,309	-$ 25,578	-$ 76,055	-$ 236,784	-$ 257,850	-$ 15,000
4410	Lessor's Net Investment in Finance Lease	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4415	Equity in Earnings of Subsidiary Companies	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4420	Share of Profit or Loss of Joint Venture	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Miscellaneous Service Revenues		-$ 72,304	-$ 65,493	-$ 72,525	-$ 68,021	-$ 57,344	-$ 68,605	-$ 66,438
Late Payment Charges		-$ 76,717	-$ 122,604	-$ 65,346	-$ 76,229	-$ 78,834	-$ 89,316	-$ 77,000
Other Operating Revenues		-$ 610,547	-$ 687,236	-$ 746,004	-$ 794,697	-$ 860,137	-$ 919,814	-$ 912,404
Other Income or Deductions		$ 25,254	-$ 67,191	-$ 40,183	-$ 198,421	-$ 346,772	-$ 473,483	-$ 118,038
Total		-$ 734,314	-$ 942,524	-$ 924,058	-$ 1,137,369	-$ 1,343,087	-$ 1,551,218	-$ 1,173,880

4235 - Miscellaneous Service Revenues	2019 Actual²	2020 Actual²	2021 Actual²	2022 Actual²	2023 Actual	Bridge Year	Test Year
	2019	2020	2021	2022	2023	2024	2025
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Change of Occupancy Charges	-$ 52,620	-$ 50,340	-$ 57,210	-$ 51,961	-$ 50,970	-$ 52,560	-$ 50,970
Reconnection Charges	-$ 7,305	-$ 3,825	-$ 4,140	-$ 4,420	$ 5,720	-$ 3,770	-$ 4,002
NSF Returned Cheque Charges	-$ 6,674	-$ 4,374	-$ 3,945	-$ 4,695	-$ 5,205	-$ 5,505	-$ 4,695
MicroFIT Service Charges	-$ 5,600	-$ 6,954	-$ 7,020	-$ 6,931	-$ 6,771	-$ 6,659	-$ 6,771
Miscellaneous Charges (Historical Usage/Arrears/Credit Reference)	-$ 105	$ -	-$ 210	-$ 15	-$ 118	-$ 111	$ -
Total	-$ 72,304	-$ 65,493	-$ 72,525	-$ 68,021	-$ 57,344	-$ 68,605	-$ 66,438

4210 - Rent from Electric Property	2019 Actual²	2020 Actual²	2021 Actual²	2022 Actual²	2023 Actual	Bridge Year	Test Year
	2019	2020	2021	2022	2023	2024	2025
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Pole Rental	-$ 287,502	-$ 344,667	-$ 347,834	-$ 354,981	-$ 377,711	-$ 381,670	-$ 338,921
Building Rental	-$ 6,000	-$ 6,173	-$ 30,000	-$ 30,480	-$ 30,970	-$ 31,469	-$ 31,469
Building Rental - Intercompany	-$ 48,000	-$ 48,000	-$ 48,000	-$ 48,000	-$ 48,000	-$ 48,000	-$ 48,000
Sentinel Rental	-$ 132	-$ 117	-$ 45	$ -	$ -	$ -	$ -
Total	-$ 341,634	-$ 398,956	-$ 425,879	-$ 433,461	-$ 456,681	-$ 461,139	-$ 418,390

4375 - Revenues from Non Rate-Regulated Utility Operations	2019 Actual²	2020 Actual²	2021 Actual²	2022 Actual²	2023 Actual	Bridge Year	Test Year
	2019	2020	2021	2022	2023	2024	2025
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Intercompany Wages (On-Call & Trouble Call Assistance)	-$ 56,731	-$ 224,527	-$ 207,767	-$ 15,450	-$ 10,712	-$ 160,761	$ -
Mutual Assistance with other LDC's	-$ 5,798	-$ 5,559	-$ 35,545	-$ 73,125	-$ 95,223	-$ 16,773	$ -
Billable Union Work (Power Workers Union)	-$ 5,616	$ -	-$ 4,160	-$ 2,080	-$ 4,160	-$ 2,080	$ -
IESO Grid Innovation - AP Study	-$ 29,520	-$ 70,460	$ -	$ -	$ -	$ -	$ -
Billable Customer Work	-$ 9,625	-$ 910	-$ 1,208	-$ 6,190	-$ 265,562	-$ 56,205	$ -
Net Metering/Load Displacement Connection Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	-$ 107,291	-$ 301,457	-$ 248,679	-$ 96,845	-$ 375,658	-$ 235,819	$ -

4380 - Expenses of Non Rate-Regulated Utility Operations	2019 Actual²	2020 Actual²	2021 Actual²	2022 Actual²	2023 Actual	Bridge Year	Test Year
	2019	2020	2021	2022	2023	2024	2025
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Intercompany Wages (On-Call & Trouble Call Assistance)	$ 53,960	$ 218,892	$ 204,018	$ 10,187	$ 10,066	$ 162,206	$ -
Mutual Assistance with other LDC's	$ 5,155	$ 4,267	$ 33,411	$ 59,985	$ 73,888	$ 16,683	$ -
Billable Union Work (Power Workers Union)	$ 5,539	$ -	$ 4,457	$ 2,431	$ 5,339	$ 3,173	$ -
IESO Grid Innovation - AP Study	$ 30,326	$ 69,430	$ -	$ -	$ -	$ -	$ -
Billable Customer Work	$ 9,626	$ 1,909	$ 1,271	$ 1,630	$ 310,191	$ 9,282	$ -
Amortization on Approved REG Rate Protection Amount			$ 147,324	$ 15,144		$ -	$ -
CDM Program Final Expense					$ 2,172	$ -	$ -
Total	$ 104,606	$ 294,498	$ 390,481	$ 89,377	$ 401,656	$ 191,345	$ -

4390 - Miscellaneous Non-Operating Income	2019 Actual²	2020 Actual²	2021 Actual²	2022 Actual²	2023 Actual	Bridge Year	Test Year
	2019	2020	2021	2022	2023	2024	2025
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Charge for Interval Data Access	-$ 16,800	-$ 16,800	-$ 16,803	-$ 16,845	-$ 16,800	-$ 4,040	-$ 16,800
FIT Admin Service Charges	-$ 9,000	-$ 9,000	-$ 9,000	-$ 9,000	-$ 9,000	-$ 9,000	-$ 9,000
Admin Charge for Service Layouts, New Connections, etc	-$ 67,364	-$ 91,275	-$ 88,887	-$ 68,068	-$ 63,568	-$ 101,805	-$ 65,000
Sale of Scrap Metal	-$ 14,420	-$ 5,444	-$ 21,577	-$ 20,986	-$ 11,619	-$ 11,213	-$ 12,238
Total	-$ 107,585	-$ 122,519	-$ 136,267	-$ 114,898	-$ 100,987	-$ 126,058	-$ 103,038

4405 - Interest and Dividend Income	2019 Actual²	2020 Actual²	2021 Actual²	2022 Actual²	2023 Actual	Bridge Year	Test Year
	2019	2020	2021	2022	2023	2024	2025
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Bank Deposit Interest	-$ 79,886	-$ 24,339	-$ 21,147	-$ 56,357	-$ 159,014	-$ 184,107	-$ 15,000
OEB Carrying Charges	-$ 46,075	-$ 14,971	-$ 4,431	-$ 19,698	-$ 77,770	-$ 73,744	$ -
Total	-$ 125,961	-$ 39,309	-$ 25,578	-$ 76,055	-$ 236,784	-$ 257,850	-$ 15,000

(b) Please explain the method Lakeland Power used to forecast its Other Revenues for 2025 for each applicable account noted in Tab 2-H.

For accounts 4235 and 4390, LPDL forecasted 2025 to be the same as 2024 forecast as the amounts are fairly consistent year over year. For account 4210, LPDL also forecasted 2025 to be the same as 2024 forecast as the amounts are consistent year over year. The exception in 4210 is Pole Rental for which LPDL based the 2025 forecast on a calculation using expected pole count at the 2024 pole rental rate. For accounts 4375 and 4380, LPDL forecasted $0 as the jobs are unplanned and the balances offset each other to a minimal amount. For account 4405-Bank Deposit Interest, LPDL did not forecast a significant amount as the bank balance was forecasted to be minimal due to capital spending. For account 4405-OEB Carrying Charges, LPDL forecasted $0 due to the uncertainty of the deferred variance balances in 2025. Likewise, LPDL also forecasted $0 for carrying charge expenses in account 6035.

6-Staff-63
Other Revenues – Account 4210
Ref: Chapter 2 Appendices, Tab 2-H

Preamble:
The 2025 test year amount in Account 4210 is made up of three items: Pole Rental, Building Rental, and Building Rental – intercompany.

Questions:

(a) Please explain the driver for the forecasted decrease in the Pole Rental line item compared to each historical year from 2020-2024.

The driver for the forecasted decrease in the Pole Rental line in 2025 is the rate differential between the current joint use pole rate for 2024 and 2025 that is lower than the joint use pole rate approved in LPDL's 2019 COS rates. The current approved joint use pole rental rate for 2024 was $37.78/pole whereas LPDL had an approved rate of $44.50/pole which would remain in LPDL rates until Apr 30/25. The rate variance has been reflected in the forecasted 1508 account balance in this application. However, this rate differential disappears effective May 1/2025, with the approval of LPDL's approved 2025 rate application, as the pole rental used in the application is the lower rate of $37.78.

Wireline Pole Attachment Revenue	USoA	Number of Poles	Approved COS Rate $/pole	Approved Annual Rate $/pole	Revenue at Approved COS Rate	4210 Pole Rental
2024 Estimate	4210	8,398	44.50	37.78	377,448	377,448
2025 Estimate January to April	4210	8,398	44.50	37.78	125,515	
2025 Estimate May to December	4210	8,398	37.78	37.78	213,406	338,921

(b) Please explain the building rental amount of $(31,469) – is this rent paid to Lakeland Power by a third party (i.e., not an affiliate)?

   i. Please explain why the rental amount is not forecasted to increase in 2025 when compared to 2024.

The building rent of $31,469 is rent charged to two third party tenants. LPDL assumed 2025 building rent would be the same as 2024 but has since confirmed the building rental rate, on one of the properties, did increase by 2% effective January 1, 2025.

6-Staff-64
Other Revenues – Accounts 4375 and 4380
Ref 1: Chapter 2 Appendices, Tab 2-H
Ref 2: Chapter 2 Filing Requirements for Electricity Distribution Rate Applications – 2023 Edition for 2024 Rate Applications, December 15, 2022, p. 43

Preamble:
Reference 2 states that revenue from affiliate transactions should be recorded in Account 4375, Revenues from Non Rate-Regulated Utility Operations, and expenses from affiliate transactions should be recorded in Account 4380, Expenses of Non Rate-Regulated Utility Operations. Further, the balances recorded in Account 4375 and Account 4380 must reconcile to the balances recorded in Appendix 2-N – Shared Services and Corporate Cost Allocation for the three historical years, the bridge year and the test year. Any differences must be reconciled.

Questions:
(a) Please explain why no amounts have been entered in 2024 and 2025 for Accounts 4375 and 4380.

LPDL does not forecast accounts 4375 and 4380 as they are unplanned and offset each other to a minimal amount. The costs associated with non-rate regulated activities are not included in OM&A or anywhere else for the Bridge and Test Years. LPDL confirms the actual amounts in accounts 4375 and 4380 for 2024 are $235,819 and $(191,345) respectively. Account 4375 includes a prior year billing adjustment for 2023 caught up in 2024.

(b) If updates are required to the evidence, please ensure Lakeland Power does so in accordance with reference 2.

LPDL will update the models and evidence with 2024 preliminary actuals.

6-Staff-65
Other Revenues – Account 4405
Ref: Chapter 2 Appendices, Tab 2-H

Preamble:
In each of 2019-2023 an amount has been recorded in Account 4405 for the line item "OEB Carrying Charges".

Questions:
(a) Please explain what constitutes the balance for this line item and why no amount is forecasted for 2025, if appropriate.

LPDL records the carrying charges earned on deferred variance debit balances to account 4405 interest income. LPDL did not forecast these carrying charges for 2025 due to the uncertainty of the deferred variance balances in 2025. Likewise, LPDL also forecasted $0 in account 6035 interest expense, for carrying charges incurred on deferred variance credit balances.

6-Staff-66
Property Taxes
Ref: Exhibit 6, Section 6.3.3

Preamble:
Lakeland Power states that it pays property taxes to the Town of Bracebridge, the Town of Huntsville and the Town of Parry Sound for their Operations Centres and distribution stations.

Questions:
(a) Please provide the last 5 years of property taxes paid by Lakeland Power and the amounts for bridge year and test year.

Account #	Account Name	2019	2020	2021	2022	2023	2024	2025
6106	Property Tax - Town of BB	28,212	28,795	29,443	29,853	31,492	32,768	34,406
6106	Property Tax - Town of HV	10,843	11,247	11,535	11,653	12,342	12,918	13,564
6106	Property Tax - Town of PS	18,732	19,399	18,507	18,920	18,983	19,714	20,700
6106	Total Property Tax	57,787	59,441	59,485	60,426	62,817	65,400	68,670
	Variance - Yr over Yr $		1,654	44	941	2,391	2,583	3,270
	Variance - Yr over Yr %		2.9%	0.1%	1.6%	4.0%	4.1%	5.0%

(b) Please provide a variance analysis for the property tax for the last 5 years.

Please see response to a) above.

School Energy Coalition (SEC)

SEC-31

[Ex. 6, p. 19] Please recalculate the taxable capital excluding the building that is shared between the Applicant and its affiliates.

LPDL does not feel a recalculation of taxable capital excluding the building that is shared is relevant. The building rental revenue that LPDL has forecasted should actually be than lower forecasted as one of the affiliates has purchased and now occupies their own building. LPDL has charged rent in their building based on sq. ft. occupied by the affiliates and their sq. ft. relative to the entire building sq. ft. is fairly small.

SEC-32

[Ex. 6, p. 23 and Ex. 9, p. 32] Please calculate the amount of Accelerated CCA expected to be foregone in each of 2024, 2025 and 2026.

Year	CCA with Accelerated CCA	CCA - No Accelerated CCA	Difference is Foregone CCA
2024	$2,475,210	$2,177,949	-$297,261
2025	$2,639,300	$2,472,723	-$166,577
2026	$2,571,904	$2,534,387	-$37,517
		Total	-$501,355

SEC-33

[Ex. 6, App. 2-H] Please explain why accounts 4375 and 4380 are zero for 2024 and 2025. Please advise where the costs associated with those non-rate-regulated activities are included in the OM&A for those years. Please advise the actual amounts in 4375 and 4380 for 2024.

Please see response to 6-Staff-64.

Vulnerable Energy Consumers Coalition (VECC)

6.0-VECC-33
**Reference: Chapter 2 Appendices, Appendix 2-H
Exhibit 6, page 26**

a) Please provide a revised version of Appendix 2-H that includes the 2024 actual values.

Please see response to 6-Staff-62.

b) With respect to Account #4210, please provide the details supporting the 2023, 2024 and 2025 Joint Pole Use revenues (i.e. number of poles and annual rate used).

Wireline Pole Attachment Revenue	USoA	Number of Poles	Approved COS Rate $/pole	Approved Annual Rate $/pole	Revenue at Approved COS Rate	4210 Pole Rental
2023	4210	8,398	44.50	36.05	377,711	377,711
2024 Estimate	4210	8,398	44.50	37.78	377,448	377,448
2025 Estimate January to April	4210	8,398	44.50	37.78	125,515	
2025 Estimate May to December	4210	8,398	37.78	37.78	213,406	338,921

c) With respect to Accounts #4375 and #4389, please explain why, for 2023, the expenses exceed the revenues for: i) Billable Customer Work and ii) Billable Union Work,

During this application process, LPDL identified a third party vendor invoice that was expensed to account 4380 in 2023 but missed being invoiced to the customer. LPDL has since rectified this and recorded the offsetting revenue to account 4375 in 2024. This adjustment makes the revenue exceed the expenses in 2024 and offsets where expenses exceed revenue in 2023. As well, LPDL identified in the last quarter, that the agreed upon intercompany billable rate is slightly lower than actual costs and will be rectified in 2025.

The billable expenses exceed the revenues for Billable Union Work, due to payroll labour and benefit rates that are higher than the rate the Power Workers Union agrees to pay for. The amount in 4380 is the actual labour including benefits, whereas the revenue in 4375 is the actual labour plus some, but not all, benefits that the union agrees to cover.

Exhibit 7 – Cost Allocation

OEB Staff

7-Staff-67
Weighting Factors
Ref: Exhibit 7, p. 5

Preamble:
Explanations are provided to support the relative the approximate weighting factors but are not at a level of detail sufficient to determine the appropriate weightings. OEB staff also notes that the weighting factors have changed since the last cost of service application in 2019.

Questions:

(a) Please provide a detailed derivation of the Billing and Collecting weighting factors used.

Account #	Account Name	2023	Allocated to Res & GS<50	Allocated to All Accounts	Allocated to All Meters	Total Allocated	
5315	Customer Billing	$ 551,850	$ 56,654	$ 495,195	$ -	$ 551,850	
5320	Collecting	$ 106,170	$ -	$ 106,170	$ -	$ 106,170	
5340	Miscellaneous Customer Accounts Expenses	$ 123,208	$ 3,448	$ -	$ 119,760	$ 123,208	
	Total Billing and Collecting Expenses	$ 781,228	$ 60,102	$ 601,366	$ 119,760	$ 781,228	
	# of Accounts Billed in a month	14,565	14,331	14,565	14,469		
	Total Billing and Collecting Per Account/Mth		**$ 4.19**	**$ 41.29**	**$ 8.28**	**$ 53.76**	
			Cost/Meter to Res & GS<50	**Cost/Meter to All Accounts**	**Cost/Meter to All Meters**	**Total Cost/Meter**	**Weighting Factor**
	Total Billing and Collecting Per Account/Mth - Residential		$ 4.19	$ 41.29	$ 8.28	**$ 53.76**	**1.0**
	Total Billing and Collecting Per Account/Mth - GS<50		$ 4.19	$ 41.29	$ 8.28	**$ 53.76**	**1.0**
	Total Billing and Collecting Per Account/Mth - GS>50		$ -	$ 41.29	$ 8.28	**$ 49.57**	**0.9**
	Total Billing and Collecting Per Account/Mth - Street Light		$ -	$ 41.29	$ 8.28	**$ 49.57**	**0.9**
	Total Billing and Collecting Per Account/Mth - Sentinel		$ -	$ 41.29	$ -	**$ 41.29**	**0.8**
	Total Billing and Collecting Per Account/Mth - USL		$ -	$ 41.29	$ -	**$ 41.29**	**0.8**

(b) Please explain why the weighting factors have changed since 2019.

The weighting factors have changed due to aligning the weights to current cost contributors. The 2019 weighting factors were the same as LPDL's 2013 Cost Allocation model. LPDL updated the factors based on 2023 actual billing and collecting costs allocated to the customer classes that contribute to each. Smart meter costs only apply to Residential and GS<50 customers classes and costs that are applicable to accounts with meters do not apply to Sentinel or Unmetered Scattered Load customer classes.

School Energy Coalition (SEC)

SEC-34

[Ex. 7, p. 23] Please provide details of the primary reasons why, with a decreasing number of customers, the costs allocated to GS>50 increased by 67.9%, while the overall costs to be allocated increased by 36.8%.

The updated load profile information has shifted costs to the GS > 50 from the GS < 50 class which has caused the GS>50 to increase 67.9% compared to the 2019 cost allocation model. The costs allocated to GS < 50 indicates an increase of 20.3% from the 2019 cost allocation model. The load profile information used in the 2019 cost allocation model was based on 2004 data. The load profile information used in 2025 was based on average data from 2021 to 2023. Since 2004 the GS < 50 class has become much more efficient and the GS >50 slightly less efficient. The efficiency is measured by a load factor which is a measure of usage over demand. The load factor for the GS < 50 has increased from 45% in 2004 to 63% in the average 2021 to 2023 data which means less demand is used per kWh and less costs are allocated to this class on a demand basis. The load factor for the GS > 50 has decreased from 73% in 2004 to 69% in the average 2021 to 2023 data which means more demand is used per kWh and more cost are allocated to this class on a demand basis.

Vulnerable Energy Consumers Coalition (VECC)

7.0-VECC-34

Reference: **Cost Allocation Model, Tab I8 (Demand Data)**
Load Profile Model
Exhibit 7, page 4

Preamble: The Application states:

"*LPDL's load profile calculation utilized three years of actual hourly data by rate class for 2021-2023 to determine the Coincident Peak (CP) and Non-Coincident Peak (NCP) contributions to the system to prepare inputs into tab "I8 Demand Data" of the OEB's Cost Allocation Model*."

a) Please confirm that the CP and NCP values used in Tab I8 were based on the average of the values CP and NCP calculated using the actual 2021-2023 data.

LPDL confirms that the CP and NCP values used in Tab I8 were based on the average of the values CP and NCP calculated using the actual 2021-2023 data.

b) If confirmed, please explain why the actual CP and NCP values in each year for each customer class were not adjusted to account for the difference between the class's total annual usage in that year and the class's forecast 2025 energy use.

The actual CP and NCP values in each year for each customer class were not adjusted to account for the difference between the class's total annual usage in that year and the class's forecast 2025 energy use. This step was not conducted since the Historical Average method, outlined in the Chapter 2 filing requirements, section 2.7.1.1 Load Profiles and Demand Allocators, does not have this step included in the explanation of the method.

c) Please provide a schedule setting out, for each customer class: i) the actual 2021-2023 CP and NCP values as calculated by LPDL, ii) the actual customer class use for each of 2021-2023 as a ratio of the forecast 2025 customer class use, iii) the adjusted CP and NCP values for each years based on these ratios and iv) the resulting average CP and NCP values.

The following provides the requested schedules:

Actual 2021-2023 CP values

2021	Residential	GS<50	GS>50	Street Lighting	Sentinel Lighting	USL
1CP	21,787	10,737	18,840	-	-	18
4CP	97,696	39,039	64,250	433	14	91
12CP	231,188	103,117	192,036	560	20	240
2022						
1CP	28,241	10,671	15,840	43	1	26
4CP	97,696	39,039	64,250	433	14	91
12CP	222,647	112,299	206,043	519	17	233
2023						
1CP	27,561	10,992	15,625	-	-	22
4CP	81,362	43,138	70,046	43	1	81
12CP	211,791	120,909	206,259	216	6	227

Actual 2021-2023 NCP values

2021	Residential	GS<50	GS>50	Street Lighting	Sentinel Lighting	USL
1NCP	29,720	11,097	19,939	257	9	27
4NCP	103,105	42,565	74,900	1,027	36	98
12NCP	252,271	116,459	210,136	3,082	108	253
2022						
1NCP	28,241	11,912	20,879	257	8	26
4NCP	102,504	45,082	79,469	1,027	34	96
12NCP	248,372	124,031	221,601	3,082	102	250
2023						
1NCP	27,728	12,015	20,086	257	8	25
4NCP	94,397	45,790	77,511	1,027	30	91
12NCP	240,918	127,402	219,448	3,082	91	239

The actual customer class use for each of 2021-2023 as a ratio of the forecast 2025 customer class use:

TOTAL CONSUMPTION	Residential	GS<50	GS>50	Street Lighting	Sentinel Lighting	USL	Total Sales
2021	113,140,344	55,908,965	119,799,580	1,058,951	37,046	177,963	**290,122,850**
2022	116,691,873	59,411,500	125,262,869	1,058,951	34,937	171,955	**302,632,086**
2023	113,549,693	59,244,744	122,283,098	1,058,951	31,176	169,404	**296,337,066**
2025	118,317,067	61,352,783	116,858,492	1,059,533	27,553	175,370	**297,790,797**
Ratio							
2021	1.05	1.10	0.98	1.00	0.74	0.99	
2022	1.01	1.03	0.93	1.00	0.79	1.02	
2023	1.04	1.04	0.96	1.00	0.88	1.04	

The adjusted CP values for each year based on the above ratios:

2021	Residential	GS<50	GS>50	Street Lighting	Sentinel Lighting	USL
1CP	22,784	11,782	18,378	-	-	17
4CP	99,056	40,315	59,940	433	11	93
12CP	242,838	112,678	186,738	560	15	237
2022						
1CP	28,634	11,020	14,777	43	1	26
4CP	99,056	40,315	59,940	433	11	93
12CP	231,203	114,735	188,179	520	14	238
2023						
1CP	28,718	11,383	14,932	-	-	22
4CP	84,778	44,673	66,938	43	1	84
12CP	221,574	124,469	196,885	303	8	236

The adjusted NCP values for each year based on the above ratios:

2021	Residential	GS<50	GS>50	Street Lighting	Sentinel Lighting	USL
1NCP	31,079	12,177	19,450	257	7	26
4NCP	107,822	46,709	73,061	1,028	27	97
12NCP	263,814	127,799	204,977	3,084	80	250
2022						
1NCP	28,634	12,301	19,478	257	7	26
4NCP	103,931	46,555	74,137	1,028	27	98
12NCP	251,831	128,084	206,733	3,084	80	255
2023						
1NCP	28,893	12,443	19,195	257	7	26
4NCP	98,360	47,419	74,072	1,028	27	95
12NCP	251,033	131,935	209,713	3,084	80	248

The resulting average CP values:

Average	Residential	GS<50	GS>50	Street Lighting	Sentinel Lighting	USL
1CP	26,712	11,395	16,029	14	0	22
4CP	93,238	42,564	63,398	231	6	89
12CP	231,872	117,294	190,601	461	12	237

The resulting average NCP values:

Average	Residential	GS<50	GS>50	Street Lighting	Street Lighting	USL
1NCP	29,536	12,307	19,374	257	7	26
4NCP	103,371	46,895	73,757	1,028	27	96
12NCP	255,559	129,273	207,141	3,084	80	251

7.0-VECC-35

Reference: Exhibit 7, pages 12-13

Preamble: The Application states:

"*The proposed Billing and Collecting weighting factor for both classes (i.e. GS>50 and Street Lighting) is 0.9. All customers within this classification have interval meters that are read and verified by a third-party vendor with a retail meter account. The retail settlement provider costs attributed to these customer classes are less than the overall smart meter network costs required for residential and GS < 50 kW customers.*"

a) The statement copied in the Preamble suggests that Street Lighting customers have interval meters. Please clarify whether this is the case.

Street Lighting customers do not have interval meters, however their usage and pricing are provided for by the same third-party vendor that reads the GS>50 customer interval meters.

b) What are the costs that LPDL considers to be “smart meter network costs” for purposes of determining the Billing and Collection weighting factors? (Note: The question is not asking for the dollar value but rather the types of activities and costs included).

The costs that LPDL considers to be ‘smart meter network costs’ include smart meter service maintenance contract costs with Elster for firmware upgrades and connection issues, retailer hub services for business transactions between LPDL and retailers and hosted AMI software services that read all the smart meters.

c) For the GS>50 and Street Lighting classes is the third-party vendor responsible all costs comparable to those identified in response to part (b)?

The third-party vendor costs mentioned for GS>50 and Street Lighting are also applicable to all customer classes with meters as it provides settlement pricing for all metered accounts.

7.0-VECC-36

Reference: Exhibit 7, page 14
Cost Allocation Model, Tab 6.2

a) In Tab 6.2, for the GS>50 class the customer count for use of LPDL transformers (103) is less than the customer count for LPDL secondary assets. This would suggest that there are some GS>50 customers that own their transformer but LPDL owns the secondary assets on the low voltage side of the transformer. Please confirm that this is the case.

LPDL confirms there are some GS>50 customers that own their transformer but LPDL owns the secondary assets on the low voltage side of the transformer.

7.0-VECC-37

Reference: Exhibit 7, page 15
Cost Allocation Model, Tabs 7.1 and 7.2

a) Please explain why the cost of meter reading for interval meter is less than the cost of meter reading for smart meters.

The cost of meter reading for interval meters is less than the cost of meter reading for smart meters as the smart meter and gatekeeper fibre network costs and ODS meter data services, both provided by third parties, are attributable to residential and GS<50 smart meters only, not the GS>50 interval meters.

b) Do any of LPDL's GS customers have more than one meter that is owned and/or read by LPDL? If yes, how many such customers are there in each GS class and how many additional meters are owned and/or read by LPDL?

No, LPDL does not have any GS customers that have more than one meter that is owned and/or read by LPDL.

7.0-VECC-38
Reference: Exhibit 7, page 15
EB-2018-0050, Exhibit 3, page 63

Preamble: In EB-2018-0050 LPDL's evidence stated: "*LPDL incurs a $10.00 monthly fee per microFIT meter point from LPDL's vendor, Utilismart, and would like to pass this charge onto its microFIT customers*."

a) Has Utilismart's fee increased since EB-2018-0050? If yes, what is its current monthly fee per microFIT delivery point?

Yes, Utilismart's fee has increased since EB-2018-0050. It's current monthly fee per microFIT delivery point is $29.35/mth.

Exhibit 8 – Rate Design

OEB Staff

8-Staff-68
microFIT
Ref 1: Exhibit 8, Section 8.1.11, p. 23
Ref 2: EB-2018-0050, Exhibit 3, September 27, 2018, p. 63

Preamble:
Lakeland Power is requesting to retain the current microFIT rate class fixed charge of $10 per month per customer.

In reference 2, in its 2019 rebasing application, Lakeland Power stated that it incurs a $10 monthly fee per microFIT meter point from its vendor and would like to pass this charge onto its microFIT customers.
Question:

(a) Please confirm that Lakeland Power continues to incur a $10 monthly fee per microFIT meter point from its vendor**.**

Yes, LPDL continues to incur a monthly fee per microFIT meter point. Currently the monthly fee is approximately $30/meter point. A $10 monthly fee is consistent with the approved May 1st, 2024 rates for Wasaga Beach EB-2023-0055.

8-Staff-69
Regulatory Charges
Ref 1: EB-2024-0282, Decision and Order, December 10, 2024
Ref 2: Exhibit 8, Sections 8.1.7 and 8.1.8, Pages 17-19

Preamble:
On December 10, 2024, the OEB issued its decision and order in the matter of regulatory charges effective January 1, 2025, for the Wholesale Market Services rate and the Rural or Remote Electricity Rate Protection charge.

Question:

(a) Please update the affected portions of the application to reflect the OEB's generic decision (e.g., Cost of Power calculation, Tariff and Bill Impact Model)

LPDL has updated the models to reflects these new rates.

8-Staff-70
Bill Impact Model
Ref 1: Exhibit 8, Section 8.1.15, p. 30
Ref 2: Tariff Schedule and Bill Impact Model, Tab 3 – Regulatory Charges and Tab 6 – Bill Impacts
Ref 3: Regulated Price Plan Price Report, November 1, 2024 to October 31, 2025, issued October 18, 2024

Preamble:

The Tariff Schedule and Bill Impact Model requires updating for the following items. Please make the necessary changes. If Lakeland Power requires any assistance, please contact ratemodels@oeb.ca.

Questions:

(a) Please update Tab 3 of the Tariff Schedule and Bill Impact Model to reflect the following:
   i. Time-of-Use RPP Prices to reflect latest RPP Report as noted in reference 3
   ii. Latest OER of 13.1%
   iii. The OEB's Distribution Rate Protection decision, issued May 30, 2024. The maximum monthly base distribution charge increased from $39.49 per month in 2023 to $41.39 effective July 1, 2024
   iv. The OEB's Decision and Order on the Distribution Pole Attachment Charge for 2025 (EB-2024-0227). The distribution pole attachment charge for 2025 is $39.14 per attacher, per year, per pole. Cell E39 should note the OEB's 2025 approved inflation factor of 3.6%.
   v. The OEB's decision for the Wholesale Market Services rate and the Rural or Remote Electricity Rate Protection charge for 2025.

(b) Please ensure that the applicable updates flow-through to Tab 6 of the Tariff Schedule and Bill Impact Model.

LPDL has updated the model to reflects these new rates.

8-Staff-71
Bill Impacts
Ref 1: Tariff Schedule and Bill Impact Model
Ref 2: Exhibit 8, Section 8.1.15, p. 30
Ref 3: Exhibit 8, Section 8.1.9, p. 20

Preamble:
The Distribution Rate Protection (DRP) program includes eligible residential customers of Lakeland Power Distribution Ltd. in the former Parry Sound Power service area.

The most recent decision issued by the OEB in the matter of Distribution Rate Protection (DRP) can be found here.

Question:

(a) Please provide a separate version of the Tariff and Bill Impact Model which shows the current DRP adjustment that would be applicable to eligible residential customers in the former Parry Sound Power service area. If Lakeland Power requires any assistance, please contact ratemodels@oeb.ca.

The DRP adjustment that would be applicable to eligible residential customers in the former Parry Sound Power service area is an additional credit of $1.53 off their monthly bill.

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION	
RPP / Non-RPP:	RPP	
Consumption	750	kWh
Demand	-	kW
Current Loss Factor	1.0723	
Proposed/Approved Loss Factor	1.0652	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 39.61	1	$ 39.61	$ 42.92	1	$ 42.92	$ 3.31	8.36%
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -	
RRRP Credit		750	$ -		750	$ -		
DRP Adjustment	$ 41.39	1	$ -	$ 41.39	1	$ (1.53)	$ (1.53)	
Fixed Rate Riders	$ (0.13)	1	$ (0.13)	$ (1.45)	1	$ (1.45)	$ (1.32)	1015.38%
Volumetric Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 39.48**			**$ 39.94**	**$ 0.46**	**1.17%**
Line Losses on Cost of Power	$ 0.0990	54	$ 5.37	$ 0.0990	49	$ 4.84	$ (0.53)	-9.82%
Total Deferral/Variance Account Rate Riders	$ 0.0013	750	$ 0.98	$ (0.0020)	750	$ (1.50)	$ (2.48)	-253.85%
CBR Class B Rate Riders	$ (0.0001)	750	$ (0.08)	$ -	750	$ -	$ 0.08	-100.00%
GA Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Low Voltage Service Charge	$ 0.0047	750	$ 3.53	$ 0.0043	750	$ 3.23	$ (0.30)	-8.51%
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		750	$ -	$ -	750	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 49.70**			**$ 46.93**	**$ (2.77)**	**-5.57%**
RTSR - Network	$ 0.0085	804	$ 6.84	$ 0.0089	799	$ 7.11	$ 0.27	4.01%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0071	804	$ 5.71	$ 0.0072	799	$ 5.75	$ 0.04	0.74%
Sub-Total C - Delivery (including Sub-Total B)			**$ 62.24**			**$ 59.79**	**$ (2.45)**	**-3.94%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	804	$ 3.62	$ 0.0045	799	$ 3.60	$ (0.02)	-0.66%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	804	$ 1.21	$ 0.0015	799	$ 1.20	$ (0.01)	-0.66%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0760	480	$ 36.48	$ 0.0760	480	$ 36.48	$ -	0.00%
TOU - Mid Peak	$ 0.1220	135	$ 16.47	$ 0.1220	135	$ 16.47	$ -	0.00%
TOU - On Peak	$ 0.1580	135	$ 21.33	$ 0.1580	135	$ 21.33	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 141.60**			**$ 139.11**	**$ (2.48)**	**-1.75%**
HST	13%		$ 18.41	13%		$ 18.08	$ (0.32)	-1.75%
Ontario Electricity Rebate	13.1%		$ (18.55)	13.1%		$ (18.22)	$ 0.33	
Total Bill on TOU			**$ 141.46**			**$ 138.97**	**$ (2.48)**	**-1.75%**

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION	
RPP / Non-RPP:	RPP	
Consumption	750	kWh
Demand	-	kW
Current Loss Factor	1.0723	
Proposed/Approved Loss Factor	1.0652	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 39.61	1	$ 39.61	$ 42.92	1	$ 42.92	$ 3.31	8.36%
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -	
Fixed Rate Riders	$ (0.13)	1	$ (0.13)	$ (1.45)	1	$ (1.45)	$ (1.32)	1015.38%
Volumetric Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 39.48**			**$ 41.47**	**$ 1.99**	**5.04%**
Line Losses on Cost of Power	$ 0.0990	54	$ 5.37	$ 0.0990	49	$ 4.84	$ (0.53)	-9.82%
Total Deferral/Variance Account Rate Riders	$ 0.0013	750	$ 0.98	$ (0.0020)	750	$ (1.50)	$ (2.48)	-253.85%
CBR Class B Rate Riders	$ (0.0001)	750	$ (0.08)	$ -	750	$ -	$ 0.08	-100.00%
GA Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Low Voltage Service Charge	$ 0.0047	750	$ 3.53	$ 0.0043	750	$ 3.23	$ (0.30)	-8.51%
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		750	$ -	$ -	750	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 49.70**			**$ 48.46**	**$ (1.24)**	**-2.49%**
RTSR - Network	$ 0.0085	804	$ 6.84	$ 0.0089	799	$ 7.11	$ 0.27	4.01%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0071	804	$ 5.71	$ 0.0072	799	$ 5.75	$ 0.04	0.74%
Sub-Total C - Delivery (including Sub-Total B)			**$ 62.24**			**$ 61.32**	**$ (0.92)**	**-1.48%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	804	$ 3.62	$ 0.0045	799	$ 3.60	$ (0.02)	-0.66%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	804	$ 1.21	$ 0.0015	799	$ 1.20	$ (0.01)	-0.66%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0760	480	$ 36.48	$ 0.0760	480	$ 36.48	$ -	0.00%
TOU - Mid Peak	$ 0.1220	135	$ 16.47	$ 0.1220	135	$ 16.47	$ -	0.00%
TOU - On Peak	$ 0.1580	135	$ 21.33	$ 0.1580	135	$ 21.33	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 141.60**			**$ 140.64**	**$ (0.95)**	**-0.67%**
HST	13%		$ 18.41	13%		$ 18.28	$ (0.12)	-0.67%
Ontario Electricity Rebate	13.1%		$ (18.55)	13.1%		$ (18.42)	$ 0.12	
Total Bill on TOU			**$ 141.46**			**$ 140.50**	**$ (0.95)**	**-0.67%**

8-Staff-72
RTSRs
Ref: RTSR Workform

Questions:

(a) Please confirm which historic year of RRR data has been used.

LPDL confirms 2023 RRR data has been used.

(b) Please confirm which year of wholesale purchase volumes have been used.

LPDL confirms 2023 wholesale purchase volumes have been used.

(c) Please update RTSRs with the 2025 final HONI rates issued on December 19, 2024, in EB-2024-0032.

LPDL has updated the RTSRs with the new rates.

8-Staff-73
Low Voltage Charges
Ref 1: Exhibit 8, p. 24
Ref 2: RTSR Workform, Tab 9 - LV Rates

Preamble:
The evidence in Exhibit 8 details that Lakeland Power is projecting 2025 LV costs based on 2023 volumes at current 2024 Hydro One Sub-Transmission rates.

Question:
(a) As a scenario, please calculate, and provide the derivation of the LV charge that would result if the 2025 host rates were used.

Using 2023 volumes at 2025 host rates, LV charges would increase by $53,349 to $1,265,629 for 2025.

Low Voltage Charges						
Host I:						
	2020	**2021**	**2022**	**2023**	**2024 Forecast**	**2025 Forecast**
Host Volume	483820.2	497279.96	536957.95	519936.87	519936.87	519936.87
Host Charges - Recalculated per 8-Staff-73	1,139,114	1,284,410	1,348,363	1,183,242	1,212,279	1,265,629
Host Charges - per Original Submission	1,139,114	1,284,410	1,348,363	1,183,242	1,212,279	1,212,279
Change in LV Charges	**0**	**0**	**0**	**0**	**0**	**53,349**

School Energy Coalition (SEC)

SEC-35

[Ex. 8, p. 27] Please confirm that one of the reasons for the plan to upgrade feeders to 27.6kV was to reduce loss factors. Please provide the original forecast or forecasts of loss factor improvements as a result of that upgrade program, and compare that forecast to actuals for each year in which data is available.

Loss factor improvements are a benefit of 4.16kV to 27.6kV conversions, however system renewal and capacity are the main drivers. Loss factor forecasts are not available.

Vulnerable Energy Consumers Coalition (VECC)

8.0-VECC-39
Reference: Exhibit 8, page 13-15
RTSR Workform

a) Please confirm that the RRR data used in Tab 3 and the billing data used in Tab 5 are both based on the same year.

LPDL confirms the RRR data used in Tab 3 and the billing data used in Tab 5 are both based on the same year 2023.

b) Do any of LPDL's customers have embedded generation that is subject to gross load billing for purposes of applying HON's ST rate? If yes, has the RRR data used in Tab 3 been adjusted to reflect the gross loads for these customers?

No, LPDL does not have any customers with embedded generation that is subject to gross load billing.

c) The historic RRR usage values in Tab 3 of the RTSR Workform by customer class differ from the actual class usage values set out in the Load Forecast Model (Load Forecast Summary Tab). Please reconcile.

The difference in the 2023 RRR usage values in Tab 3 of the RTSR Workform and the kWh usage values set out in the Load Forecast Model is reconciled below. The reconciled difference is minimal, when compared to the total usage for the year (0.02% difference), and is due to the methodology used for each source. The RRR data includes actual billed kWh in the calendar year adjusted for the change in year end accruals (actual 12 mths – prior year end accrual + current year end accrual). Whereas, the load forecast data includes all actual billed kWh shifted back one calendar month, to reflect all actual usage in the proper months.

Rate Class	Non-Loss Adjusted Metered kWh per RTSR WF per RRR data 2023	Non-Loss Adjusted Metered kWh per Load Forecast Summary 2023	Difference kWh
RESIDENTIAL SERVICE CLASSIFICATION	113,529,467	113,498,414	31,053
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	59,668,770	59,565,733	103,037
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	122,452,018	122,653,645	-201,627
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	169,785	169,785	0
SENTINEL LIGHTING SERVICE CLASSIFICATION	31,173	31,176	-3
STREET LIGHTING SERVICE CLASSIFICATION	1,058,922	1,058,927	-5
TOTALS	296,910,135	296,977,680	-67,545

d) Please update the RTSR Workform to reflect: i) the preliminary 2025 UTRs issued by the OEB on November 1, 2024 and ii) HON's 2025 ST RTSRs (EB-2024-0032) approved on December 19, 2024.

Please see response to 8-Staff-72c).

8.0-VECC-40

Reference: **Exhibit 8, page 20**
Tariff Schedule and Bill Impact Model
EB-2024-0133, Decision and Rate Order re Distribution Rate Protection effective July 1, 2024

Preamble: The Application states:

"*The DRP Regulation still includes Lakeland Power Distribution Ltd (former Parry Sound Power service area) customers as eligible for the DRP. LPDL's current distribution rate of $39.61 effective May 1, 2024, is below this DRP cap so no DRP claim is currently required. As of May 1, 2025, the proposed rate for residential customers of $43.03 will be higher than the current DRP cap of $41.39 and the monthly claim for the rate differential will once again be claimed by LPDL.*"

a) Based on the most recent actual data, how many of LPDL's Residential customers are in the former Parry Sound Power service area and how many are not?

Based on the most recent actual data, LPDL has 3,268 Residential customers in the former Parry Sound Power service area and just under 9,000 that are not.

b) Please confirm that only Residential customers in the former Parry Sound Power Service are eligible for the DRP. If not confirmed, please explain why.

LPDL confirms that only Residential customers in the former Parry Sound service area are eligible for the DRP.

c) Does LPDL plan to undertake any customer communications in order to explain to its Residential customers why they are not all paying the same rates as of May 1, 2025?

LPDL will assess customer communication requirements once the rate application is settled as the rate differential is small and may change.

d) Please revise the Bill Impact calculations to show separately the bill impacts for Residential customers eligible for DRP and those not eligible for DRP.

Please see response to 8-Staff-71.

e) Assuming the OEB updates the maximum monthly base distribution charge that utilities subject to the DRP program can charge an eligible residential customer for consumption on or after July 1, 2025, will LPDL adjust the DRP discount applicable to Residential customers in the former Parry Sound Power Service area accordingly as of the same date?

Yes, LPDL will adjust the DRP discount applicable to Residential customers in the former Parry Sound Power service area accordingly as of the same date.

8.0-VECC-41
Reference: Exhibit 8, page 23

a) Please update the pole attachment rate to reflect the approved rate for 2025 of $39.14. What impact, if any, does this update have on LPDL's Other Revenue forecast?

With the pole attachment rate updated from $37.78 to $39.14 for 2025, the 2025 forecasted pole rental revenue included in Other Revenue would increase by $7,614.

Wireline Pole Attachment Revenue	USoA	Number of Poles	Approved COS Rate $/pole	Approved Annual Rate $/pole	Revenue at Approved COS Rate	4210 Pole Rental
At 2024 Pole Rental Rate						
2025 Estimate January to April	4210	8,398	**44.50**	37.78	125,515	
2025 Estimate May to December	4210	8,398	**37.78**	37.78	213,406	**338,921**
At 2025 Pole Rental Rate						
2025 Estimate January to April	4210	8,398	**44.50**	39.14	125,515	
2025 Estimate May to December	4210	8,398	**39.14**	39.14	221,020	**346,535**
			Change in Pole Rental Revenue			**7,614**

8.0-VECC-42
Reference: Exhibit 8, page 24
Preamble: The Application states:

> "*LPDL is projecting 2025 LV costs based on 2023 volumes at current 2024 Hydro One Sub-Transmission rates.*"

a) Please update the forecast 2025 LV costs based on Hydro One's approved 2025 ST Rates (EB-2024-0032) and actual 2024 volumes.

Please see response to 8-Staff-73.

8.0-VECC-43
Reference: Exhibit 8, page 26

a) With respect to Table 21, for each year please break down both the A(1) and A(2) values as between IESO purchases, HON purchases and embedded generation.

Appendix 2-R
Loss Factors

		Historical Years					5-Year Average
		2019	2020	2021	2022	2023	
	Losses Within Distributor's System						
A(1)	Wholesale kWh delivered by IESO	80,776,363	83,637,637	85,858,894	92,333,895	85,690,598	85,659,477
A(1)	Wholesale kWh delivered by HONI	168,891,659	151,767,500	158,746,071	180,080,968	165,340,167	164,965,273
A(1)	Wholesale kWh delivered by Embedded Generation	60,284,073	68,982,565	65,336,458	50,259,126	64,106,669	61,793,778
A(1)	"Wholesale" kWh delivered to distributor (higher value)	309,952,095	304,387,702	309,941,422	322,673,989	315,137,434	312,418,529
A(2)	Wholesale kWh delivered by IESO	78,116,036	80,858,441	82,997,164	89,251,692	82,837,252	82,812,117
A(2)	Wholesale kWh delivered by HONI	164,595,431	148,551,699	154,954,240	175,730,454	161,486,957	161,063,756
A(2)	Wholesale kWh delivered by Embedded Generation	60,284,073	68,982,565	65,336,458	50,259,126	64,106,669	61,793,778
A(2)	"Wholesale" kWh delivered to distributor (lower value)	302,995,540	298,392,705	303,287,862	315,241,272	308,430,877	305,669,651
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	-	-	-	-	-	-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	302,995,540	298,392,705	303,287,862	315,241,272	308,430,877	305,669,651
D	"Retail" kWh delivered by distributor	289,860,629	286,230,671	290,240,292	303,102,277	296,977,680	293,282,310
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	-	-	-	-	-	-
F	Net "Retail" kWh delivered by distributor = **D - E**	289,860,629	286,230,671	290,240,292	303,102,277	296,977,680	293,282,310
G	Loss Factor in Distributor's system = **C / F**	1.0453	1.0425	1.0450	1.0400	1.0386	1.0422
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0230	1.0201	1.0219	1.0236	1.0217	1.0221
	Total Losses						
I	Total Loss Factor = **G x H**	1.0693	1.0634	1.0679	1.0646	1.0611	1.0652

Exhibit 9 – Deferral & Variance Accounts

OEB Staff

9-Staff-74
OEB Prescribed Interest Rates
Ref 1: LPDL 2025 1592 Accelerated CCA
Ref 2: LPDL 2025 DVA Continuity Schedule
Ref 3: OEB Prescribed Interest Rates

On December 11, 2024, the OEB published the 2025 Quarter 1 prescribed accounting interest rates applicable to the carrying charges of deferral, variance and construction work in progress (CWIP) accounts of natural gas utilities, electricity distributors and other rate-regulated entities.

Questions:

(a) Please update Tab OEB Prescribed Int Rates and Tab 1592 Balance Calculation in reference 1 as necessary to reflect the Q1 2025 OEB-prescribed interest rate of 3.64%.

LPDL has updated the Q1 2025 interest rate to reflect the updated OEB-prescribed rate of 3.64%. The difference is $1,577.

Year	CCA with Accelerated CCA	CCA - No Accerlated CCA	Difference	PILs Impact	PILs Gross Up	Credit Entry to 1592	Account 1592 Balance (Principal)	Carrying Charges	Cumulative Carrying Charges	Total Balance
2019	$2,207,862	$1,924,312	-$283,550	-$75,141	-$102,232	-$102,232	-$102,232	$0	$0	**-$102,232**
2020	$2,119,796	$1,998,371	-$121,425	-$32,178	-$43,779	-$43,779	-$146,011	-$1,406	-$1,406	**-$147,417**
2021	$2,697,101	$2,050,965	-$646,136	-$171,226	-$232,961	-$232,961	-$378,972	-$832	-$2,238	**-$381,210**
2022	$2,693,769	$2,181,474	-$512,295	-$135,758	-$184,705	-$184,705	-$563,677	-$7,257	-$9,495	**-$573,172**
2023	$2,543,831	$2,380,319	-$163,512	-$43,331	-$58,953	-$58,953	-$622,630	-$28,438	-$37,933	**-$660,563**
2024	N/A	N/A	N/A	N/A	N/A	N/A	-$622,630	-$32,034	-$69,967	**-$692,597**
2025 (Jan-Apr)	N/A	N/A	N/A	N/A	N/A	N/A	-$622,630	-$7,555	-$77,522	**-$700,152**
		Total	**-$1,726,918**	**-$457,633**	**-$622,630**					

(b) Please update column BR in Tab 2a and Tab 2b in reference 2 to reflect the Q1 2025 OEB-prescribed interest rate of 3.64%.

LPDL has updated column BR in Tab 2a and Tab 2b, to reflect the updated Q1 2025 OEB-prescribed interest rate of 3.64%. The updated DVA Continuity schedule is provided in Excel format with file name LPDL_2025_DVA_Continuity_Schedule_CoS_1.0_20250206.

9-Staff-75
Green Button Variance Account
Ref 1: Green Button Implementation – OEB Staff Guidance OEB File No. EB-2021-0183, page 6
Ref 2: Exhibit 9, Table 2

Preamble:
In reference 1, the letter states “The OEB has confirmed that this account is to record the incremental costs directly attributable to the implementation of the Green Button initiative but is not intended to record ongoing costs related to Green Button beyond the initial implementation of the program. As with any other deferral account, disposition of any amounts recorded will be subject to OEB review and established materiality thresholds.”

Reference 2 reflects Lakeland power is requesting disposition of 1508 – Green Button Initiative Costs for $37,220.

Questions:

(a) Please provide the associated periods when these costs were incurred.

LPDL's Green Button principal costs included in $37,220 were incurred in 2023.

(b) Please explain how Lakeland Power determined that the costs recorded in the account are incremental costs.

The costs are incremental as they are direct invoices from third party vendors that provided the customer interface upgrades.

(c) Please explain why Lakeland Power has not proposed to close this account after disposition or update the evidence accordingly.

LPDL has since confirmed that all incremental costs have been incurred and LPDL will propose to close this account after disposition accordingly.

9-Staff-76
GOCA Variance Account
Ref: The OEB's Decision and Order for Getting Ontario Connected Act Variance Account, October 31, 2023

Preamble:
On October 31, 2023, the OEB issued a decision and order EB-2023-0143 for Getting Ontario Connected Act Variance Account (GOCA variance account). The decision states that:

> The OEB notes that the GOCA variance account will only be available to a utility until the end of its current IRM period. The account is not available for utilities that have reflected Bill 93 in their most recent rebasing applications.
>
> The disposition of any balance in this account will be subject to a prudence review and a requirement to establish that any cost incurred over and above what is provided for in initial and IRM adjusted base rates is an incremental cost resulting from Bill 93.

Questions:

(a) Please confirm that the OM&A cost in the test year reflects the Bill 93 impact for the utility's locate cost.

LPDL confirms it has included additional locate costs in its 2025 test year, however the amount specific to Bill 93 is indeterminable.

i. If so, please confirm that the Account 1508 sub-account GOCA variance account is to be discontinued after this rebasing application and update the evidence accordingly.

LPDL confirms that Account 1508-GOCA will be discontinued after this application.

ii. If not, please provide the rationale why the Bill 93 impact is not reflected in the test year's OM&A cost.

LPDL does not expect Bill 93 to cause a major increase in locate costs in its service territory.

9-Staff-77
Generic Cloud DVA
Ref 1: EB-003-2023, Accounting Order, November 2, 2023
Ref 2: Cloud Computing Implementation Q&A Document, PDF, February 20242
Ref 3: EB-2024-0063, Notice, March 6, 2024

Preamble:
On November 2, 2023, the OEB issued the Accounting Order (003-2023) for the Establishment of a Deferral Account to Record Incremental Cloud Computing Arrangement Implementation Costs (Cloud Computing Implementation Report). The Cloud Computing Implementation Report noted that the Cloud Computing Implementation Account is generally intended to record cloud computing implementation costs when utilities first transition from on-premise solutions to cloud computing. In February 2024, the OEB hosted a webinar and Q&A session related to the Accounting Order for the establishment of a deferral account to record cloud computing arrangement implementation costs and issued a Q&A document.

On March 6, 2024, the OEB commenced a generic hearing (EB-2024-0063) on its own motion to consider cost of capital and other matters, including those related to the OEB's

Cloud Computing Deferral Account (e.g., what type of interest rate, if any, should apply to this deferral account).

Questions:

(a) Please confirm whether Lakeland Power has considered cloud computing solutions in its rebasing term and whether any amounts have been included in its forecast.

LPDL confirms it has considered cloud computing solutions in its rebasing term and has included associated monthly costs in 2025 Test Year. LPDL's CIS system is scheduled for replacement to cloud-base in 2026/27 at an estimated one-time implementation cost of $75K. This has not been considered in the application as LPDL would consider using this DVA for this amount. There are no one-time implementation costs included in 2025 Test Year. For further details, please see response to 4-Staff-33 b) and 4-Staff-40.

(b) If not confirmed, please explain why and Lakeland Power's proposal to address its cloud solution implementation needs during its rebasing term.

N/A

9-Staff-78
Deferral Variance Accounts
Ref: Exhibit 9, Table 1

Preamble:
In reference 1, Table 1 shows selected Group 1 and Group 2 accounts that are being sought for disposition, with proposal to either leave them open or close them.

Questions:

(a) Please update Table 1 in Exhibit 9 to reflect all accounts reflected in the DVA continuity schedule, even if there is no balance.

Account Description	USoA	Principal Dec 31/23	Carrying Charges Dec 31/23	Total Dec 31/23	Balance per 2023 RRR 2.1.7 and F/S	Variance	UPDATED Seeking Disposition	UPDATED Account Status
Group 1 Accounts								
LV Variance Account	1550	113,023	8,907	121,929	121,929	(0)	Yes	Continue
Smart Metering Entity Charge Variance Account	1551	(71,663)	(3,330)	(74,993)	(74,994)	(0)	Yes	Continue
RSVA - Wholesale Market Service Charge	1580	(245,319)	(4,566)	(249,885)	(249,886)	(2)	Yes	Continue
Variance WMS – Sub-account CBR Class A	1580	-	-	-	-	-	No	Continue
Variance WMS – Sub-account CBR Class B	1580	(12,397)	(1,575)	(13,972)	(13,972)	0	Yes	Continue
RSVA - Retail Transmission Network Charge	1584	334,220	22,054	356,274	356,275	1	Yes	Continue
RSVA - Retail Transmission Connection Charge	1586	200,440	11,696	212,137	212,138	1	Yes	Continue
RSVA - Power (excluding Global Adjustment)	1588	(397,813)	(10,244)	(408,057)	(408,057)	0	Yes	Continue
RSVA - Global Adjustment	1589	26,584	1,987	28,572	28,572	0	Yes	Continue
Disposition and Recovery/Refund of Regulatory Balances (2018 and pre-2018)	1595	(17)	(1)	(18)	(18)	(0)	Yes	Already final
Disposition and Recovery/Refund of Regulatory Balances (2019)	1595	(471,939)	433,334	(38,605)	(180,750)	(142,145)	Yes	Discontinue
Disposition and Recovery/Refund of Regulatory Balances (2020)	1595	(104,249)	116,689	12,440	29,185	16,745	No	Continue
Disposition and Recovery/Refund of Regulatory Balances (2021)	1595	490,876	(68,718)	422,158	668,626	246,468	No	Continue
Disposition and Recovery/Refund of Regulatory Balances (2022)	1595	(45,653)	3,417	(42,236)	(42,236)	(0)	No	Continue
Disposition and Recovery/Refund of Regulatory Balances (2023)	1595	(113,460)	(17,546)	(131,006)	(131,006)	(0)	No	Continue
Disposition and Recovery/Refund of Regulatory Balances (2024)	1595	-	-	-	-	-	No	Continue
Subtotal Group 1 Accounts		**(297,368)**	**492,106**	**194,738**	**315,805**	**121,067**		
Group 2 Accounts								
Deferred IFRS Transition Costs	1508	-	-	-	-	-	No	Discontinue
Pole Attachment Revenue Variance	1508	-	-	-	-	-	No	Discontinue
Retail Service Charge Incremental Revenue	1508	-	-	-	-	-	No	Discontinue
Customer Choice Initiative Costs	1508	-	-	-	-	-	No	Discontinue
Local Initiatives Program Costs	1508	-	-	-	-	-	No	Discontinue
Green Button Initiative Costs	1508	33,943	1,033	34,976	34,976	-	Yes	Discontinue
Other Regulatory Assets, Sub-account Designated Broadband Project Impacts	1508	-	-	-	-	-	No	Discontinue
Other Regulatory Assets, Sub-account ULO Implementation Cost	1508	3,613	140	3,752	-	(3,752)	Yes	Discontinue
Other Regulatory Assets, Sub-Account GOCA Variance Account	1508	-	-	-	-	-	No	Discontinue
Other Regulatory Assets, sub-account LEAP EFA Funding Deferal Account	1508	-	-	-	-	-	No	Discontinue
Other Regulatory Assets - Sub-Account - Other - Incremental Capital Charges	1508	-	-	-	-	-	No	Discontinue
Other Regulatory Assets - Sub-Account - Other - Late Payment Penalty Litigation	1508	-	-	-	-	-	No	Discontinue
Other Regulatory Assets - Sub-Account - Other - OEB Assessment	1508	15,011	2,465	17,476	17,476	0	Yes	Discontinue
Other Regulatory Assets - Sub-Account - Other - TransCanada	1508	-	-	-	-	-	No	Discontinue
Other Regulatory Assets - Sub-Account - Other - Customer Choice Initiative	1508	14,548	878	15,426	19,178	3,752	Yes	Continue
Other Regulatory Assets - Sub-Account - Other - Pole Attachment Revenue Var	1508	80,244	(802)	79,442	79,442	-	Yes	Discontinue
Retail Cost Variance Account - Retail	1518	(38,596)	(1,806)	(40,402)	(40,402)	-	Yes	Discontinue
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying	1522	-	-	-	-	-	No	Discontinue
Misc. Deferred Debits	1525	-	-	-	-	-	No	Discontinue
Retail Cost Variance Account - STR	1548	(948)	(85)	(1,033)	(1,033)	0	Yes	Discontinue
Extra-Ordinary Event Costs	1572	-	-	-	-	-	No	Continue
Deferred Rate Impact Amounts	1574	-	119	119	119	-	Yes	Discontinue
RSVA - One-time	1582	-	(48)	(48)	(48)	(0)	Yes	Discontinue
Other Deferred Credits	2425	-	-	-	-	-	No	Discontinue
PILs and Tax Variance for 2006 and Subsequent Years	1592	-	(21)	(21)	(21)	(0)	Yes	Continue
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account - CCA Chang	1592	(622,630)	(37,933)	(660,563)	-	660,563	Yes	Discontinue
Subtotal Group 2 Accounts		**(514,817)**	**(36,061)**	**(550,878)**	**109,686**	**660,563**		
Other Accounts								
LRAM Variance Account	1568	-	-	-	-	-	No	Discontinue
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential	1522	-	-	-	-	-	No	Discontinue
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Contra A	1522	-	-	-	-	-	No	Discontinue
Renewable Generation Connection Capital Deferral Account	1531	-	-	-	-	-	No	Discontinue
Renewable Generation Connection OM&A Deferral Account	1532	-	-	-	-	-	No	Discontinue
Renewable Generation Connection Funding Adder Deferral Account	1533	-	-	-	-	-	No	Discontinue
Smart Grid Capital Deferral Account	1534	-	-	-	-	-	No	Discontinue
Smart Grid OM&A Deferral Account	1535	-	-	-	-	-	No	Discontinue
Smart Grid Funding Adder Deferral Account	1536	-	-	-	-	-	No	Discontinue
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter C	1555	-	-	-	-	-	No	Discontinue
Meter Cost Deferral Account (MIST Meters)	1557	-	-	-	-	-	No	Discontinue
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	-	-	-	-	-	No	Discontinue
Accounting Changes Under CGAAP Balance + Return Component	1576	-	-	-	-	-	No	Discontinue
Accounting Changes Under CGAAP Balance + Return Component	1576	(6,793)	-	(6,793)	(6,793)	-	Yes	Discontinue
Impacts Arising from the COVID-19 Emergency	1509	421,631	33,548	455,179	455,179	-	No	Discontinue
Subtotal Other Accounts		**414,838**	**33,548**	**448,386**	**448,386**	**-**		

(b) For all the accounts, please clarify if Lakeland Power is planning to keep them open or close them in this application.

Please see response to part a).

(c) For the accounts not being proposed to close, please provide an explanation.

Account Description	USoA	Seeking Disposition	UPDATED Account Status	Reason to Continue
Group 1 Accounts				
LV Variance Account	1550	Yes	Continue	Ongoing
Smart Metering Entity Charge Variance Account	1551	Yes	Continue	Ongoing
RSVA - Wholesale Market Service Charge	1580	Yes	Continue	Ongoing
Variance WMS – Sub-account CBR Class A	1580	No	Continue	Ongoing
Variance WMS – Sub-account CBR Class B	1580	Yes	Continue	Ongoing
RSVA - Retail Transmission Network Charge	1584	Yes	Continue	Ongoing
RSVA - Retail Transmission Connection Charge	1586	Yes	Continue	Ongoing
RSVA - Power (excluding Global Adjustment)	1588	Yes	Continue	Ongoing
RSVA - Global Adjustment	1589	Yes	Continue	Ongoing
Disposition and Recovery/Refund of Regulatory Balances (2020)	1595	No	Continue	Not yet eligible to dispose
Disposition and Recovery/Refund of Regulatory Balances (2021)	1595	No	Continue	Not yet eligible to dispose
Disposition and Recovery/Refund of Regulatory Balances (2022)	1595	No	Continue	Not yet eligible to dispose
Disposition and Recovery/Refund of Regulatory Balances (2023)	1595	No	Continue	Not yet eligible to dispose
Disposition and Recovery/Refund of Regulatory Balances (2024)	1595	No	Continue	Not yet eligible to dispose
Subtotal Group 1 Accounts				
Group 2 Accounts				
Other Regulatory Assets - Sub-Account - Other - Customer Choice Initiative	1508	Yes	Continue	Ongoing regulation
Extra-Ordinary Event Costs	1572	No	Continue	Potential Storm Z-Factor
PILs and Tax Variance for 2006 and Subsequent Years	1592	Yes	Continue	Future tax changes
Subtotal Group 2 Accounts				

9-Staff-79
Account 1595 – 2019, 2020 and 2021
Ref 1: Exhibit 9
Ref 2: OEB letter "Adjustments to Correct for Errors in Electricity Distributor "Pass-Through" Variance Accounts After Disposition" October 31, 2019

Preamble:
In reference 1, page 11, Lakeland Power states:

> Account 1595 Account Disposition and Recovery/Refund of Regulatory Balances (2019), Account 1595 Account Disposition and Recovery/Refund of Regulatory Balances (2020) and Account 1595 Account Disposition and Recovery/Refund of Regulatory Balances (2021) variances reflect amounts that Class A customers were charged for Rate Riders for Disposition of Global Adjustment – Applicable only for Non-RPP customers for May 2019 through to January 2022 in error. Table 4 shows the breakdown of these billing errors.

In reference 1, Table 4 has provided a breakdown of costs by customer numbers per year.

Table 4 - Class A Customers Deferred Variance Non-RPP GA Billing Error 2019-2021

Class A Customer	Rate Year	Billed kWh	Approved Rate $/kWh	Billing Error $
Class A Customer #1	May19-Apr20	4,854,092	$ 0.0046	22,329
Class A Customer #2	May19-Apr20	7,363,656	$ 0.0046	33,873
Class A Customer #3	May19-Apr20	10,255,397	$ 0.0046	47,175
Class A Customer #4	May19-Apr20	11,273,166	$ 0.0046	51,857
Class A Customer #5	May19-Apr20	7,271,323	$ (0.0018)	(13,088)
2019 Rate Year		**41,017,633**		**142,145**
Class A Customer	**Rate Year**	**Billed kWh**	**Approved Rate $/kWh**	**Billing Error $**
Class A Customer #1	May20-Apr21	2,780,007	$ (0.0004)	(1,112)
Class A Customer #2	May20-Apr21	9,516,496	$ (0.0004)	(3,807)
Class A Customer #3	May20-Apr21	11,696,457	$ (0.0004)	(4,679)
Class A Customer #4	May20-Apr21	14,614,120	$ (0.0004)	(5,846)
Class A Customer #5	May20-Apr21	7,272,003	$ 0.0002	1,454
Class A Customer #6	May20-Apr21	6,889,352	$ (0.0004)	(2,756)
2020 Rate Year		**52,768,434**		**(16,744)**
Class A Customer	**Rate Year**	**Billed kWh**	**Approved Rate $/kWh**	**Billing Error $**
Class A Customer #1	May21-Jan22	2,587,418	$ (0.0060)	(15,525)
Class A Customer #2	May21-Jan22	7,590,330	$ (0.0060)	(45,542)
Class A Customer #3	May21-Jan22	8,963,364	$ (0.0060)	(53,780)
Class A Customer #4	May21-Jan22	11,012,647	$ (0.0060)	(66,076)
Class A Customer #5	May21-Jan22	5,687,129	$ (0.0060)	(34,123)
Class A Customer #6	May21-Jan22	5,237,157	$ (0.0060)	(31,423)
2021 Rate Year		**41,078,044**		**(246,468)**
		Total Class A Billing Error		**(121,068)**

In reference 2, The OEB's retroactivity letter states that "Where an accounting or other error is discovered after the balance in one of the above-listed variance accounts has been cleared by a final order of the OEB, the OEB will determine on a case-by-case basis whether to make a retroactive adjustment based on the particular circumstances of each case, including factors such as:

- whether the error was within the control of the distributor
- the frequency with which the distributor has made the same error
- failure to follow guidance provided by the OEB
- the degree to which other distributors are making similar errors

Questions:

(a) Please clarify how this error occurred and explain the details of the error.

This error occurred in May 2019 upon the harmonization of LPDL's rates. Prior to the 2019 rate order, LPDL did not have a Non-RPP Class B GA Rate Rider approved on its

2017 or 2018 rate orders, due to the Group 1 DVA balances being under the threshold. When the May 1, 2019 rates came into effect, LPDL had 5 Class A customers (since July 2017) and missed inactivating the Non-RPP Class B GA Rate Rider for these 5 Class A customers at that time. This error was realized in February 2022 upon LPDL conducting an analysis of account 1595 balances.

(b) For the Class A customers listed in Table 4, please explain how they were charged in the respective years. Did they get charged of the Class B GA rate riders on top of the Installment payment/collections?

Yes, LPDL had charged the 5 Class A customers both the Non-RPP Class B GA Rate Rider as well as their correct Class A GA portion of LPDL's IESO Class A charges

(c) Please provide journal entries of $142K, $16K, and $246K with the associated date of these entries booked in the general ledger.

At this point, no journal entries have been recorded. LPDL put in a place holder in 2023 in the DVA continuity schedule to identify the issue.

LPDL requests approval to record journal entries in 2025, to reclass the 2020 $16K and 2021 $246K Class A error, to separate 1595 sub-accounts, to be approved for disposition on future IRM applications. These 1595 sub-accounts would be applicable to Class A customers only. The residual 1595 (2020) and 1595 (2021) balances can then be requested for disposition in future IRM applications in the year they are eligible.

In this application, LPDL requests approval for the following one-year rate rider, applicable to Class A customers only. This rate rider would return the 2019 Non-RPP GA Rate Rider, applied to Class A Customers in 2019 in error, of $142,145 (per Table 4 above).

Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj.) - Class A Customers Only

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Account 1595 (2019) CLASS A Adjustment	Rate Rider for Deferral/Variance Account Class A only
RESIDENTIAL		-	$ -	-
GS <50 KW		-	$ -	-
GS 50 TO 4,999 KW - Class A Only	kWh	52,663,689	-$ 142,145	-$ 0.0027
UNMETERED SCATTERED LOAD		-	$ -	-
SENTINEL LIGHTING		-	$ -	-
STREET LIGHTING		-	$ -	-
Total			**-$ 142,145**	

(d) Please provide Lakeland Power's thought of whether this error is a rates retroactivity issue, if so, please provide comments on the four factors.

From an accounting point of view, we have treated this as a 1595 issue and as a consequence the treatment of the error only gives rise to retroactivity issues for the years where this account has been disposed on a final basis. Account 1595 was last disposed of on a final basis for 2018 balances in 2022 (EB-2021-0040). Since the error relates to the period 2019-2022 and Account 1595 has not been disposed of on a final basis for this period, the applicant's view is there is no retroactivity issues arising from this correction. If the OEB approves the corrections, the requisite accounting entries would be made at that time and would seek disposition of those corrections in the appropriate IRM proceeding for 2025 balances.

While LPDL does not agree that the retroactivity letter applies, this was a one-time error that occurred upon rate harmonization in 2019 which was new to LPDL and complex at the time. This affected only 6 customers out of more than 14,000. As soon as LPDL had realized the error upon analyzing the 1595 balance in February 2022, the Non-RPP Class B GA Rate Rider was removed from all 6 Class A customers. The rate rider was debit rate on 2019's rate order offset by credit rates on 2020 and 2021 rate orders, which resulted in LPDL over-crediting the 6 Class A customers, resulting in the net credit balance in account 1595.

In the year each Class A customer switched from Class B to Class A, they had each received their portion of non-RPP Class B GA charges, from while they were a class B customer, correctly. LPDL had followed OEB guidance in applying Class A charges to Class A customers and Non-RPP Class B customers to all Class B customers and the resulting error is due to a software setup issue. LPDL is unaware of the degree to which other distributors are making similar errors

(e) Please describe Lakeland Power's procedures that have been implemented to prevent mistakes like this.

LPDL has implemented a more robust process for validating rate changes, new rate setups and customer class changes to ensure accuracy of the rates applied to each customer class and that all rates applied to a customer class are valid. LPDL has updated process notes for the above and has another staff member review all rate and class changes to ensure everything has been updated and applied correctly.

9-Staff-80
1595-2021
Ref 1: Chapter 2 Filing Requirements For Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, December 15, 2022, p. 67
Ref 2: Exhibit 9, pp. 7, 21 and 22
Ref 3: OEB letter "Adjustments to Correct for Errors in Electricity Distributor "Pass-Through" Variance Accounts After Disposition" October 31, 2019
Ref 4: EB-2020-0037 2021 IRM Decision and Order

Preamble:
OEB staff compiled the following table outlining all the dates for 1595 sub-accounts disposition for Lakeland Power.

Account	Final Balances December 31	Application Number	Application filed in Rate Year	Rate Rider Expires	Audited Sub account balance eligible for dispostion	Disposition Rate Year
Disposition and Recovery/Refund of Regulatory Balances (2019)[3]	2019	EB-2020-0037	2021	30-Apr-20	31-Dec-22	2024
Disposition and Recovery/Refund of Regulatory Balances (2020)[3]	2020	EB-2021-0040	2022	30-Apr-21	31-Dec-23	2025
Disposition and Recovery/Refund of Regulatory Balances (2021)[3]	2021	EB-2022-0047	2023	30-Apr-22	31-Dec-24	2026
Disposition and Recovery/Refund of Regulatory Balances (2022)[3]	2022	EB-2023-0036	2024	30-Apr-23	31-Dec-25	2027
Disposition and Recovery/Refund of Regulatory Balances (2023)[3]	2023	EB-2024-0039	2025	30-Apr-24	31-Dec-26	2028

According to reference 1, Section 2.9.1.3 of the Filing Requirements states that distributors are expected to request disposition of residual balances in Account 1595 Sub-accounts for each vintage year once and on a final basis. Distributors become eligible to seek disposition of these residual balances two years after the expiry of the rate rider. During the two years after the expiry of the rate rider, distributors may still make billing corrections as per the Retail Settlement Code and should record the related transactions in the associated Account 1595 sub-account. The eligibility criteria for disposition of Account 1595 sub-accounts depends on the distributor's rate year. For example:

- May 1 rate year – If 2019 rate riders expire on April 30, 2020, the balance of subaccount 1595 (2019) is eligible to be disposed after the account balance as at December 31, 2022 has been audited. Therefore, sub-account 1595 (2019) would be eligible for disposition in the 2024 rate year.

No further transactions are expected to be recorded in the Account 1595 sub-account once the residual balance in the sub-account has been disposed of. Generally, after the rate riders associated with balances transferred to an Account 1595 sub-account have expired, the residual balance is expected to be relatively small, represented by the difference between the forecast billing determinants upon which the riders were derived and the actual billing determinants over that period. If there are material residual balances being proposed for disposition, distributors are expected to provide a detailed explanation, including quantifying any significant drivers of the residual balance

As per Table 1 in reference 2, page 7, Lakeland Power is requesting disposition of 1595(2019), 1595(2020) and 1595(2021).

In reference 2, page 22, Lakeland Power states, “In 2022 LPDL realized the 2021 IRM model Tab ‘6.1 GA’ did not include the correct pre populated RRR stats. GS>50 Non-RPP & Street Light kWh were missing thus the total kWh were understated. In Table 15, LPDL has replicated the 2021 IRM rate calculator for the Account 1595 (2021) Non-RPP GA Class B only rate and calculated what the rate should have been if the proper kWh had been included.”

In reference 2, page 21, for Account 1595 (2021), Lakeland states that:

> The adjusted balance requested for disposal, including carrying charges to April 30, 2025, is a debit of $454,613. This adjusted balance reflects the 2021 Class A Customer Billing Error of $(246,468) backed out of the audited balance as shown in Table 13.

OEB staff notes from Lakeland’s 2021 IRM decision and order, the following dispositions of DVAs were approved by the OEB:

- Group 1 DVAs of a credit balance of $639,991, on an interim basis
- Group 2 DVAs of a credit balance of $3,956 for Parry Sound rate zone
- Group 2 DVAs of a debit balance of $7,849 for former Lakeland Power rate zone.

OEB staff notes that the adjusted residual balance of $454,613 represents a significant portion of the original approved total balance that was transferred to Account 1595 sub-account 2021.

In reference 3, the OEB’s 2019 retroactivity letter provides the four factors (see 9-Staff-79 for the details).

Questions:

(a) As per reference 1 and the chart above, Disposition and Recovery/Refund of Regulatory Balances (2021) is not eligible for disposition until rate year 2026. Please explain why Lakeland Power is requesting disposition in this application. If the intention of the disposition is to fix the GA billing error to Class A customers, please confirm that the early disposition would not impact the residual balance in sub-account 2021 under Account 1595 after fixing the error.

LPDL has replicated the OEB's chart and updated the cells highlighted in blue below. With the periods laid out in the OEB's clear format, LPDL now understands that the balance in sub-account 2021 was requested for disposition in error. In this application, LPDL is requesting approval to fix the 2019-2021 GA error to Class A customers, thus leaving the residual balance in sub-account 2021 under Account 1595 for future disposition. Once the correction is made and audited in 2025, the residual balance can then be requested for disposition in the 2026 IRM application.

Account	Final Balances December 31	Application Number	Application filed in Rate Year	Rate Rider Expires	Audited Sub account balance eligible for disposition	Disposition Rate Year
Disposition and Recovery/Refund of Regulatory Balances (2019)	2017	EB-2018-0050	2019	30-Apr-20	31-Dec-22	2024
Disposition and Recovery/Refund of Regulatory Balances (2020)	2018	EB-2019-0051	2020	30-Apr-21	31-Dec-23	2025
Disposition and Recovery/Refund of Regulatory Balances (2021)	2019	EB-2020-0037	2021	30-Apr-22	31-Dec-24	2026
Disposition and Recovery/Refund of Regulatory Balances (2022)	2020	EB-2021-0040	2022	30-Apr-23	31-Dec-25	2027
Disposition and Recovery/Refund of Regulatory Balances (2023)	2021	EB-2022-0047	2023	30-Apr-24	31-Dec-26	2028

(b) As per Chapter 2 filing requirements, Account 1595 representing the residual balance of the DVA and GA rate riders is expected to be relatively small. Lakeland Power is asking to dispose debit amount of $454,613 through 1595-2021 rate rider. Please fill out the attached 1595 analysis workform and provide explanations as required.

Ontario Energy Board

1595 Analysis Workform

Year in which this worksheet relates to 2021

Step 1

Components of the 1595 Account Balances:		Principal Balance Approved for Disposition	Carrying Charges Balance Approved for Disposition	Total Balances Approved for Disposition	Rate Rider Amounts Collected/(Returned)	Residual Balances Pertaining to Principal and Carrying Charges Approved for Disposition	Carrying Charges Recorded on Net Principal Account Balances	Total Residual Balances	Collections/Returns Variance (%)
Total Group 1 and Group 2 Balances excluding Account 1589 - Global Adjustment		-$545,959	-$16,004	-$561,963	-$644,281	$82,318	$6,734	**$89,052**	**-14.6%**
Account 1589 - Global Adjustment		$132,217	-$103,249	$28,968	-$506,779	$535,747	$43,829	**$579,575**	**1849.5%**
Total Group 1 and Group 2 Balances		-$413,743	-$119,253	-$532,996	-$1,151,060	$618,064	$50,563	$668,627	**-116.0%**
							Shared Tax Savings (Approved by the OEB in Prior Decision(s) and Order(s) and Transferred to Account 1595), if any:		
							Total Balances:	$668,627	
							Total residual balance per continuity schedule:	$668,626	
							Difference (any variance should be explained):	-$1	

*Unresolved differences of +/- 10% require further analysis and explanation. Amounts originally approved for disposition based on forecasted consumption or number of customers must be compared to actual figures.

Step 2 Select Rate Rider(s) Applicable for 1595 Recovery Period by indicating "Yes" in column G

Rate Rider- Group 1 DVA Accounts (Excluding Global Adjustment)	No
Rate Rider- Group 1 DVA Accounts (Excluding Global Adjustment) - Non-WMP	No
Rate Rider - RSVA - Global Adjustment	No
Rate Rider - RSVA - Group 2 Accounts (If a separate Group 2 rate rider was created)	No
Other 1	No
Other 2	No
Other 3	No

As per the 1595 analysis workform completed for 2021, the residual balance is $668,626. As identified in Exhibit 9 Table 14, this residual balance includes an error for Class A customers in 2021 of $246,468.

Table 14 - Class A Customers Non-RPP GA Billing Error 2021

Class A Customer	Rate Year	Billed kWh	Approved Rate $/kWh	Billing Error $
Class A Customer #1	May21-Jan22	2,587,418	$ (0.0060)	(15,525)
Class A Customer #2	May21-Jan22	7,590,330	$ (0.0060)	(45,542)
Class A Customer #3	May21-Jan22	8,963,364	$ (0.0060)	(53,780)
Class A Customer #4	May21-Jan22	11,012,647	$ (0.0060)	(66,076)
Class A Customer #5	May21-Jan22	5,687,129	$ (0.0060)	(34,123)
Class A Customer #6	May21-Jan22	5,237,157	$ (0.0060)	(31,423)
2021 Rate Year		**41,078,044**		**(246,468)**

As identified in Exhibit 9 Tables 15 and 16, this residual balance also includes an IRM model rate calculation issue that affected Non-RPP Class B customers in 2021 of $345,659.

Table 15 - Rate Error on 2021 IRM - Rate Rider for Disposition of Global Adjustment Account (2021) - Applicable only for Non-RPP Class B GA Customers only

2021 IRM Per Submitted Model

Customer Class	Total Non-RPP Meter kWh (no loss)	Less Class A kWh	Class B non-RPP	Balanced Approved for Disposition	kWh basis	Rate per Approved 2021 Rate Order
RESIDENTIAL SERVICE CLASSIFICATION	2,366,774	-	2,366,774	$ (14,192)	2,366,774	$ (0.0060)
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	10,436,363	-	10,436,363	$ (62,582)	10,436,363	$ (0.0060)
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	22,852,990	40,625,026	(17,772,036)	$ 106,571	(17,772,036)	$ (0.0060)
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	600	-	600	$ (4)	600	$ (0.0060)
SENTINEL LIGHTING SERVICE CLASSIFICATION	-	-	-	$ -	-	$ -
STREET LIGHTING SERVICE CLASSIFICATION	137,517	-	137,517	$ (825)	137,517	$ (0.0060)
	35,794,244		(4,830,782)	$ 28,968	(4,830,782)	

2021 IRM Model Adjusted

Customer Class	Total Non-RPP Meter kWh (no loss)	Less Class A kWh	Class B non-RPP	Balanced Approved for Disposition	kWh basis	ADJUSTED Rate should be
RESIDENTIAL SERVICE CLASSIFICATION	2,366,774	-	2,366,774	$ 786	2,366,774	$ 0.0003
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	10,436,363	-	10,436,363	$ 3,468	10,436,363	$ 0.0003
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	114,513,035	40,625,026	73,888,009	$ 24,553	73,888,009	$ 0.0003
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	600	-	600	$ 0	600	$ 0.0003
SENTINEL LIGHTING SERVICE CLASSIFICATION	-	-	-	$ -	-	
STREET LIGHTING SERVICE CLASSIFICATION	482,837	-	482,837	$ 160	482,837	$ 0.0003
	127,799,609		87,174,583	$ 28,968	87,174,583	

Difference

Customer Class	Total Non-RPP Meter kWh (no loss)	Less Class A kWh	Class B non-RPP
RESIDENTIAL SERVICE CLASSIFICATION	-	-	-
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	-	-	-
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	91,660,045	-	91,660,045
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	-	-	-
SENTINEL LIGHTING SERVICE CLASSIFICATION	-	-	-
STREET LIGHTING SERVICE CLASSIFICATION	345,320	-	345,320
	92,005,365		92,005,365

Table 16 - ERROR Impact to Non-RPP Class B Customers Only based on May 2021 to April 2022 Actual Usage kWh

Customer Class	ACTUAL Metered Non-RPP kWh (no loss)	Rate per Approved 2021 Rate Order	1595 Non-RPP GA Billed to Class B only	ADJUSTED Rate should be	1595 Non-RPP GA Should Have Been Billed to Class B only	Balance due to Rate Error to be Recovered from Non-RPP Class B Customers
RESIDENTIAL SERVICE CLASSIFICATION	929,193	$ (0.0060)	$ (5,575)	$ 0.0003	$ 279	$ (5,854)
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	6,951,627	$ (0.0060)	$ (41,710)	$ 0.0003	$ 2,085	$ (43,795)
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	46,662,696	$ (0.0060)	$ (279,976)	$ 0.0003	$ 13,999	$ (293,975)
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	600	$ (0.0060)	$ (4)	$ 0.0003	$ 0	$ (4)
SENTINEL LIGHTING SERVICE CLASSIFICATION	-	$ -	$ -	$ -	$ -	$ -
STREET LIGHTING SERVICE CLASSIFICATION	322,422	$ (0.0060)	$ (1,935)	$ 0.0003	$ 97	$ (2,031)
	54,866,539		$ (329,199)		$ 16,460	$ (345,659)

The impact to Account 1595 (2021) balance, after reflecting the above two noted issues, results in a final residual balance of $76,500.

Account 1595 (2021) Balance - Breakdown	Account Balance 1595 (2021)
Residual Balance per 1595 workform	$668,627
Less: 2021 Class A Error - Request for Adjustment to Class A Customers only	-$246,468
Residual Balance	$422,159
Less: Impact of 2021 IRM model error for 1595 Non-RPP Class B GA rate	-$345,659
Final Residual Balance	$76,500

As stated above in LPDL's response to 9-Staff-79 c), LPDL requests approval to record journal entries in 2025, to reclass the 2020 $16K and 2021 $246K Class A error, to separate 1595 sub-accounts, to be approved for disposition on future IRM applications. These 1595 sub-accounts would be applicable to Class A customers only. The residual 1595 (2020) and 1595 (2021) balances can then be requested for disposition in future IRM applications in the year they are eligible.

LPDL is not requesting disposition of Account 1595 (2021) at this time pending OEB decisions on the Class A adjustments.

(c) As per reference 2, the 2021 IRM model Tab '6.1 GA' did not include the correct pre-populated RRR stats, hence the application being approved on wrong data provided which resulted in incorrect rate riders on the Tariff of Rates and Charges. Please provide Lakeland Power's thought of whether this error is a rates retroactivity issue, if so, please provide comments on the four factors.

Account 1595 was last disposed of on a final basis for 2018 balances in 2022 (EB-2021-0040). Since the error relates to the period 2021-2022 and Account 1595 has not been disposed of on a final basis for this period, the applicant's view is there is no retroactivity issues arising from this correction. If the OEB approves the corrections, the requisite accounting entries would be made at that time and would seek disposition of those corrections in the appropriate IRM proceeding for 2025 balances.

The 2021 IRM model was the first harmonized rate model for LPDL. Prior to that, LPDL had been filing two separate IRM models, one for Lakeland Power and one for Parry Sound. In this first harmonized rate model, the model formulas were protected, and the consumption kWh were auto populated. There had been several reiterations of the model as it was sent back to OEB IT support staff for different updates and modifications due to issues with the harmonization of RRR data. After the model updates, the kWh and kW billing determinants in 'Tab 4. Billing Det. For Def-Var' were reported correctly. LPDL staff thought they had identified and corrected all the issues found with the harmonized data in the model but missed the incorrect data that auto populated on 'Tab 6.1 GA'. Through this application process, LPDL identified that 'Tab 6.1 GA' brought over only some of the RRR data. For 2021, the SSS Metered Consumption for customers Not on RPP was not included in the auto population for the GS>50 and Street Light rate classes. In the 2022 IRM model, none of the PS kWh were included in the auto population. In previous years, LDCs input these volumes but since the models were locked down and auto populated at the same time as harmonization, it added another layer of complexity.

(d) Please describe Lakeland Power's procedures that have been implemented to prevent mistakes like this.

LPDL should no longer have this issue as all RRR data and rates are now fully harmonized. However, LPDL has implemented a more robust process for validating that the auto populated data in all tabs in the IRM model tie to the RRR data.

9-Staff-81
1595 – 2022
Ref 1: Exhibit 9, p. 24 of 91
Ref 2: OEB letter "Adjustments to Correct for Errors in Electricity Distributor "Pass-Through" Variance Accounts After Disposition" October 31, 2019

Preamble:
In reference 1 Lakeland Power states, "In 2023 LPDL realized the 2022 IRM model Tab '6.1 GA' did not include the correct pre-populated RRR stats. The non-RPP kWh for all

Former Parry Sound rate classes were missing thus the total kWh were understated. In Table 17, LPDL has replicated the 2022 IRM rate calculator for the Account 1595 (2022) Non-RPP GA Class B only rate and calculated what the12 rate should have been if the proper kWh had been included."

In reference 2, the OEB's 2019 retroactivity letter provides the four factors (see 9-Staff-79 for the details).

Questions:

(a) As per reference 1, 2023 IRM model Tab '6.1 GA' did not include the correct pre-populated RRR stats, hence the application being approved on wrong data provided which resulted in incorrect rate riders on Tariff and Rates. Please provide Lakeland Power's thought of whether this error is a rates retroactivity issue, if so, please provide comments on the four factors.

Account 1595 was last disposed of on a final basis for 2018 balances in 2022 (EB-2021-0040). Since the error relates to the period 2021-2022 and Account 1595 has not been disposed of on a final basis for this period, the applicant's view is there is no retroactivity issues arising from this correction. If the OEB approves the corrections, the requisite accounting entries would be made at that time and would seek disposition of those corrections in the appropriate IRM proceeding for 2025 balances.

The 2022 IRM model was the second year a harmonized rate model was prepared by LPDL. As discussed above in the response to 9-Staff-80 part c), there had been issues with the auto-populated data that were missed on 'Tab 6.1 GA in the 2021 IRM model. At the time of the 2022 IRM rate application, LPDL was not aware of the issue with the 2021 IRM model with the auto populated data on 'Tab 6.1 GA'. Again, the kWh and kW billing determinants in 'Tab 4. Billing Det. For Def-Var' were reported correctly and LPDL staff did not recognize the incorrect data that auto populated on 'Tab 6.1 GA' again. Through this application process, LPDL identified that 'Tab 6.1 GA' brought over only some of the RRR data again. For 2021, the SSS Metered Consumption for customers Not on RPP was missing for the GS>50 and Street Light rate classes. In the 2022 IRM model, all PS kWh were missed during the auto population.

(b) Please describe Lakeland Power's procedures that have been implemented to prevent mistakes like this.

Please see response to 9-Staff-80 part d).

9-Staff-82
GA Analysis Workform
Ref 1: Exhibit 9, p. 47 of 91
Ref 2: LPDL 2025 GA Analysis Workform
Ref 4: Instructions for Completing GA Analysis Workform – 2025 Rates

Preamble:
In reference 1, Lakeland Power states "LPDL has performed the Account 1588 Reasonability Test included in the 2023_GA_Analysis_Workform. As shown in Table 31 below, the calculation indicates that Account 1588 RSVA – Power is -1.1% of Account 4705 Cost of Power. LPDL confirms that 0.98% of this difference is due to unaccounted for system losses included in Account 1588 due to 2023 actual system losses being less than the approved loss factor."

As per reference 3, any annual Account 1588 variance greater than +/- 1% of that year's cost of power purchased must be explained.

In reference 2, the GA Analysis Workform Tab GA 2023 reflects Lakeland Power's records unbilled revenue using the GA 1st estimate price.

Questions:

(a) Please fill out the attached revised 1588 analysis workform and provide explanations as required.

LPDL has submitted the attached 1588 analysis workform, with file name LPDL_2025_1588_Analysis_Workform_1.0_20250206. LPDL has also filed an updated GA Analysis Workform, with the only update being to the variance explanation on the 'Account 1588' tab.

Account 1588 Reasonability Test

Year	Account 1588 - RSVA Power Transactions[1]	Principal Adjustments[1]	Total Activity in Calendar Year	Account 4705 - Power Purchased	Account 1588 as % of Account 4705
2023	- 230,338		- 230,338	21,594,273	-1.1%
Cumulative	**- 230,338**	**-**	**- 230,338**	**-**	**0.0%**

Note 8 **Reconciling Items and Principal Adjustments - complete for each year where Account 1588 as a % of Account 4705 is greater than + / - 1% of that year's c**

	Item	Amount	Explanation	Principal Adjustment on DVA Continuity	If "no", please provide an explanation[3]
1a	CT 148 True-up of GA Charges based on Actual RPP Volumes - prior year				
1b	CT 148 True-up of GA Charges based on Actual RPP Volumes - current year				
2a	CT 1142/142 true-up adjustment based on actual price and volume - prior year				
2b	CT 1142/142 true-up adjustment based on actual price and volume - current year				
3a	Remove prior year end unbilled to actual revenue differences				
3b	Add current year end unbilled to actual revenue differences				
4a	Significant prior period billing adjustments recorded in current year				
4b	Significant current period billing adjustments recorded in other year(s)				
5	Unaccounted for Energy Variance (eg. Variance due to significant understated/overstated line loss factor)	$ (254,466)	2023 actual system losses were less than the approved loss factor. Unaccounted for Losses were (3,092,909)kWh for an over-recovery of $(254,466) in Account 1588. RPP wholesale purchases kWh - RPP Billed kWh = Unaccounted Losses due to RPP (2,176,734) kWh at COP + GA $0.1046 = $(227,679). Non-RPP wholesale purchases kWh - Non-RPP Class B Billed kWh = Unaccounted Losses due to Non-RPP Class B (916,175) kWh at COP $0.0292 = $(26,787).	No	Reconciling item only
6					
7					
8					
	Total Reconciling Items	**$ (254,466)**			

LPDL's account 1588 variance is attributable to the following unaccounted for losses that were over-recovered due to system losses being less than the approved loss factor in 2023.

Account 1588 - Unaccounted for System Losses Breakdown	**RPP/TOU/ULO**	**Non-RPP**	**Total RPP & Non-RPP**
Unaccounted for Losses kWh	- 2,176,734	- 916,175	- 3,092,909
Cost of Power $/kWh	$ 0.0298	$ 0.0292	
Actual Calculated GA Rate per Class B GA Paid $/kWh	$ 0.0748		
	$ 0.1046	$ 0.0292	
Unaccounted for Losses $	-$ 227,679	-$ 26,787	**-$ 254,466**

(b) Please explain in detail where there is no amount reflected in Note 5 2a and 2b to reflect the current and prior year unbilled differences.

As part of LPDL's year-end process, it reviews account 1589 and records a journal entry each December to true up the account to reflect an accurate balance. The offset to this entry is account 1588. The GA Analysis Workform methodology is used to reconcile this account and determine the adjustment. This true-up adjustment eliminates any reconciling items on the GA Analysis Workform.

(c) If done in error, please update the evidence accordingly.

Please see response to part a). No updates to the evidence are required.

9-Staff-83
DVA Disposition
Ref 1: Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, December 15, 2022, pages 6-7
Ref 2: Exhibit 1, p. 38
Ref 3: Exhibit 9, p. 9

Preamble:
As noted in section 2.0.8 in reference 1:

> The distributor provide justification for material amounts and material annual variances described in its application… An explanation and/or supporting evidence (e.g., calculations, supporting rationale, etc.) is required for amounts exceeding the materiality threshold, and the threshold should be applied in the following ways:
>
> Deferral and Variance Accounts (DVAs): For each Group 2 DVA, the account balance, unless there is other specific guidance.

In reference 2, Lakeland Power states that it has applied a materiality of $50,000 throughout this application.

As shown in reference 3, the following group 2 accounts reflected in Table 2 are included in this application for disposition.

Group 2 Accounts						
Green Button Initiative Costs	1508	33,943		3,277	37,220	37,220
Other Regulatory Assets, Sub-account ULO Implementation Cost	1508	3,613		378	3,991	3,991
Other Regulatory Assets - Sub-Account - Other - OEB Assessment	1508	15,011		3,458	18,468	18,468
Other Regulatory Assets - Sub-Account - Other - Customer Choice Initiative	1508	14,548		1,840	16,388	16,388
Other Regulatory Assets - Sub-Account - Other - Pole Attachment Revenue Var	1508	80,244	76,227	9,543	166,014	166,014
Retail Cost Variance Account - Retail	1518	(38,596)		(4,358)	(42,954)	(42,954)
Retail Cost Variance Account - STR	1548	(948)		(148)	(1,096)	(1,096)
Deferred Rate Impact Amounts	1574	-		119	119	119
RSVA - One-time	1582	-		(48)	(48)	(48)
PILs and Tax Variance for 2006 and Subsequent Years	1592	-		(21)	(21)	(21)
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account - CCA Changes	1592	(622,630)		(79,099)	(701,729)	(701,729)
Subtotal Group 2 Accounts		**(514,817)**	**76,227**	**(65,059)**	**(503,649)**	**(503,649)**
Other Accounts						
Accounting Changes Under CGAAP Balance + Return Component	1576	(6,793)		-	(6,793)	(6,793)
Impacts Arising from the COVID-19 Emergency	1509	421,009	621	33,548	455,179	-
Subtotal Other Accounts		**414,216**	**621**	**33,548**	**448,386**	**(6,793)**

Questions:

(a) Please explain why the following accounts are being requested for disposition despite being under the materiality threshold:

- Account 1508 Subaccount – Green Button Initiative Costs
- Account 1508 Subaccount – ULO Implementation Cost
- Account 1508 Subaccount – OEB Assessment
- Account 1508 Subaccount – Customer Choice Initiative
- Account 1518 Retail Cost Variance – Retail
- Account 1548 Retail Cost Variance – STR
- Account 1574 Deferred Rate Impact Amounts
- Account 1582 RSVA – One time
- Account 1592 PILs and Tax Variance for 2006 and Subsequent Years.

Group 2 accounts can be applied for in a rebasing year and the totality of LPDL's group 2 accounts is greater than the materiality threshold of $50,000. This would be consistent with historical applications.

(b) Please provide Lakeland Power's thought of writing off the immaterial balances and update the evidence as necessary.

Given that the totality of LPDL's group 2 accounts is greater than $50,000, LPDL does not believe it is prudent to write off these balances.

School Energy Coalition (SEC)

SEC-36
[Ex. 9, p. 15 et. seq.] With respect to the billing errors described in this exhibit:

a. Please provide copies of all final rate orders that include the erroneous amounts.

LPDL has attached the 2019-2022 rate orders as:

- LPDL_Appendix K - 9-SEC-36 - LPDL Rate Order 20190501
- LPDL_Appendix L - 9-SEC-36 - LPDL Rate Order 20200501
- LPDL_Appendix M - 9-SEC-36 - LPDL Rate Order 20210501
- LPDL_Appendix N - 9-SEC-36 - LPDL Rate Order 20220501

b. Please provide a table showing the incremental amounts the Applicant asks to be charged or credited to GS>50 customers in respect of each of the billing errors, both on an aggregate basis and on a per billing determinant basis.

Please see response to 9-Staff-80 a). LPDL is requesting approval to fix the 2019-2021 GA error for the Class A customers in this application, leaving the residual balance in sub-account 2021 under Account 1595 for future disposition. Once the correction is made and audited in 2025, the residual balances can then be requested for disposition in future IRM applications.

c. For any impact of those billing errors for which the Applicant is not seeking disposition at this time, please identify the amount, by rate class, and the expected future handling of that part of the error.

Please see response to part b) above. LPDL will review the residual 1595 balances for each year and request disposition in future IRM applications when the accounts are eligible. The residual balances will be allocated over the Non-RPP metered consumption for Class B customers, excluding WMP, Class A and Class A transitions customers' consumption, for the IRM year being submitted.

Vulnerable Energy Consumers Coalition (VECC)

9.0 –VECC -44
Reference: Exhibit 9, page 27

Table 22 - OEB Assessment Cost

OEB Assessment Variance Costs	USoA	Amount $
2018	1508	11,539
2019	1508	3,471
Interest Costs - projected through to April 30, 2025	1508	3,458
1508 OEB Assessment Variance Claim		**18,468**

a) Please confirm (or correct) that LPDL's last cost of service application included an estimate of annual OEB costs based on the Board's revised methodology.

LPDL confirms that its 2019 cost of service application did include an estimate of annual OEB costs based on the Board's revised methodology.

b) Please confirm (or correct) that the balances claimed to not include any new variances from OEB assessments since the last cost of service application.

LPDL confirms that the balances claimed do not include any new variances from OEB assessments beyond May 2019, when the approved cost of service application rates came into effect.