

OVERVIEW OF UPDATES ARISING FROM INTERROGATORY RESPONSES

Preamble

In preparing its interrogatory responses, Lakefront Utilities Inc. (“LUI”) reviewed and updated a number of the inputs and models supporting its July 1, 2026, Application. As part of that process, LUI identified certain data corrections and made a limited number of updates arising from the interrogatories.

The following summary is intended to highlight the principal changes reflected in the interrogatory responses and updated models, and to provide OEB staff and intervenors with a consolidated overview of the revisions before turning to the detailed responses. The updates include changes to the load forecast, OM&A, cost of capital and PILs. LUI’s proposed capital expenditure budget remains unchanged.

Load Forecast

In preparing its interrogatory responses, LUI undertook further validation of the historical data underlying its Load Forecast Model and identified two data corrections.

Weetabix

LUI determined that the historical Weetabix energy and demand data reflected in the filed Load Forecast Model did not reflect the customer’s correct historical billing data. LUI subsequently validated the customer’s billed energy and demand for the historical period and replaced the filed values with the corrected data in the revised Load Forecast Model.

In the filed model, the Weetabix load had been removed from historical wholesale purchases without making the corresponding adjustment to the historical billed energy and demand of the GS >50 to 4,999 kW class.

In the revised Load Forecast Model filed with these interrogatory responses, LUI has used the corrected Weetabix billing data and removed the Weetabix load from both historical wholesale purchases and the historical energy and demand of the GS >50 to 4,999 kW class. The Weetabix customer has also been removed from the applicable historical customer count.

The detailed historical corrections are provided in the applicable interrogatory response.

FIT and MicroFIT Generation

LUI also reviewed the FIT and MicroFIT information underlying the filed Load Forecast Model. The information used in the filed model was extracted from billing records associated with FIT customer accounts and reflected customer usage rather than the electricity generated by the FIT and MicroFIT facilities.

LUI has replaced those values with the actual historical FIT and MicroFIT generation in the revised Load Forecast Model.

In the revised model, the corrected FIT and MicroFIT generation has been added to historical wholesale purchases used as the dependent variable in the regression. The revised historical purchase series therefore reflects electricity supplied by LUI's host distributor together with electricity generated by FIT and MicroFIT facilities and supplied into LUI's distribution system.

LUI has rerun the Load Forecast Model using the corrected Weetabix and FIT/MicroFIT data and has carried the resulting revised billing determinants through the applicable downstream models, including cost allocation and rate design.

Operating Expenses

LUI has maintained the OM&A budget included in the filed Application, with the exception of a \$2,000 increase in LEAP funding to reflect more recent spending levels.

Total OM&A therefore increases from \$4,146,221 in the filed Application to \$4,148,221 in the updated models accompanying the interrogatory responses.

Capital Expenditures

LUI has maintained the capital expenditure budget included in the filed Application. No changes to the proposed capital spending have been made as a result of the interrogatory process.

Cost of Capital

LUI has updated certain debt instruments and applied the most recent applicable cost of capital parameters in the models accompanying the interrogatory responses.

These changes result in an increase in deemed interest expense of approximately \$104,000. The return on deemed equity is essentially unchanged. Overall, the updated cost of capital increases the revenue requirement by approximately \$105,000 relative to the filed Application.

PILs

In finalizing the interrogatory responses and updated models, LUI identified that the updated PILs model filed in response to 1-Staff-1 does not yet include the correction related to accelerated CCA for 2026 and 2027 described in response to 6-Staff-33.

As a result, the PILs expense currently reflected in the updated models and related interrogatory responses is overstated by approximately \$60,000.

Correcting this amount requires updates to several interconnected models and affected interrogatory responses. Rather than delay filing the full interrogatory response package, LUI is providing the responses and models at this time so that parties can begin their review, with the understanding that a further update will reduce the PILs-related revenue requirement by approximately \$60,000.

LUI is completing these updates and intends to provide the revised models and affected interrogatory responses prior to the commencement of the settlement conference on September 23, 2026.

Other Revenues

LUI has updated its Other Revenue forecast as part of the interrogatory responses. The change relates to Other Distribution Revenue, which has increased from \$259,296 in the filed Application to \$285,949 in the updated models.

As a result, total revenue offsets increase from \$764,039 to \$790,692, an increase of \$26,653. This increase in revenue offsets reduces the revenue requirement by the same amount.

Summary

Overall, the interrogatory responses reflect:

- corrected Weetabix and FIT/MicroFIT data and a revised load forecast;
- a \$2,000 increase in OM&A;
- an increase in Other Revenues of approximately \$26,700, which reduces the revenue requirement by the same amount;
- an approximately \$105,000 increase in cost of capital;
- no change to the proposed capital expenditure budget; and
- a forthcoming PILs correction expected to reduce revenue requirement by approximately \$60,000.

The detailed calculations and supporting information are provided in the applicable interrogatory responses and accompanying models.

GS >50 kW Class Split Scenario

Several interrogatories requested updated information assuming that the existing GS >50 kW classes remain separate, rather than being combined into the proposed GS >50 to 4,999 kW class. In response, LUI prepared a separate set of models reflecting the existing class structure, including the Load Forecast Model, load profiles, Cost Allocation Model, Revenue Requirement Workform and bill impacts.

The load forecast for this scenario was developed differently from the forecast included in the filed Application. In the filed Application, the historical data for the two GS >50 kW classes was combined before the forecast was developed. For the class split scenario, each of the existing GS >50 kW classes was forecast separately and the resulting forecasts were then combined. As a result, the sum of the two separately forecast classes will not necessarily equal the forecast for the combined GS >50 to 4,999 kW class presented in the filed Application.

LUI has used the resulting class-specific forecasts consistently through the related models. To distinguish these scenario models from LUI's revised proposed-case models, the applicable filenames include "GS 3000 to 4999."

EXHIBIT 1 – ADMINISTRATION

Assigned to:
Application Updates

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 2022 Electricity Distributor Rate Applications webpage.

Response

a) LUI agrees and has filed an updated RRWF and applicable models reflecting the interrogatory responses, as requested.

1-STAFF-2

Conditions of Service

Ref. 1: [Lakefront Utilities Inc. Conditions of Service](#)

Question(s):

- a) When does Lakefront Utilities plan to next revise its Conditions of Service, currently dated 2021?

Response

a) LUI plans to update its Conditions of Service following the completion of the current Cost of Service proceeding, which is its immediate regulatory priority. LUI commits to completing the update by January 1, 2027, to coincide with the implementation of its 2027 rates.

1-STAFF-3**Customer e-Billing****Ref 1: Exhibit 1, p.44****Ref 2: Exhibit 4, p. 15, 38**

Lakefront Utilities states that it upgraded its customer portal in 2025 to a newer version. Customer Billing has increased from \$550,197 in 2022 to \$756,131 in 2027, and Lakefront Utilities plans to hire a Customer Service Representative in 2027

Question(s):

- a) Please provide the latest percentage of customers that receive their billing through e-billing each year since 2024, including currently in 2026, and forecast for 2027.

Response

- a. Lakefront Utilities' e-billing adoption rate has increased steadily since 2024:

Period	E-Billing %
August 2024	42.7%
August 2025	50.8%
August 2026 (current)	54.0%
2027 (forecast)	59.65%

1-STAFF-4

Activity Performance-Based Benchmarking (APB)

Ref. 1: Exhibit 1, pp. 52 – 53, Tables 16 and 17

Question(s):

- Lakefront Utilities has the Highest metering costs in terms of OM&A and CAPEX compared to its peers. Please explain any drivers for this difference, and any measures Lakefront Utilities might be taking to reduce metering costs.
- The Line Transformers CAPEX per transformer is the highest among the peer group. Please explain any drivers for this, and any measures Lakefront Utilities might be taking to reduce costs.

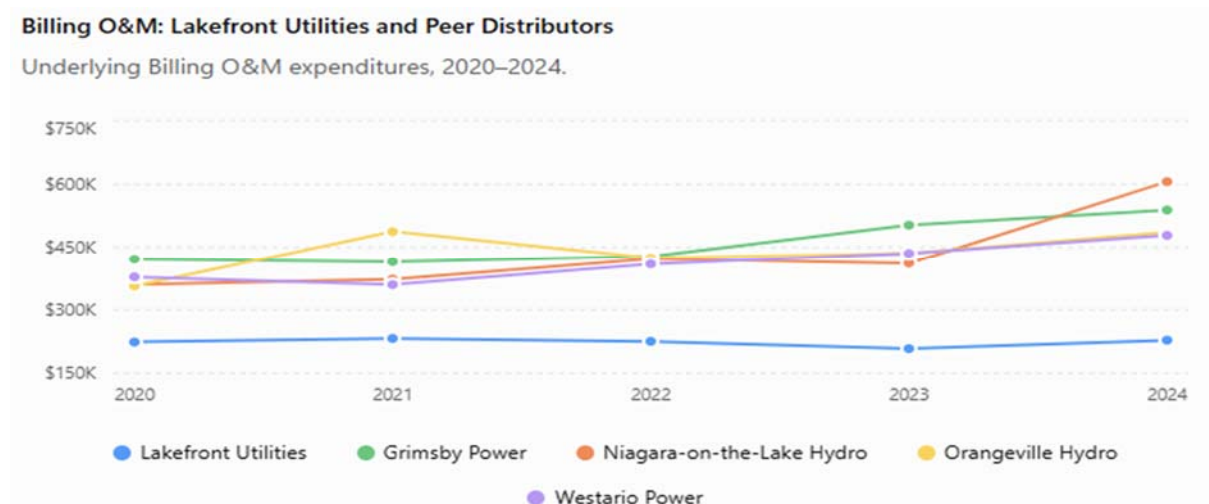
Response

a) LUI cannot fully explain differences in Metering O&M unit costs among distributors without visibility into the underlying costs, operating practices and cost allocation approaches used by the comparator utilities.

LUI notes, however, that its own Metering O&M expenditures have been relatively stable over the 2020 to 2024 period. Metering O&M increased from approximately \$282,000 in 2020 to \$302,000 in 2024, an increase of approximately 7%. Over the same period, the comparator utilities experienced increases ranging from approximately 7% to 35%.

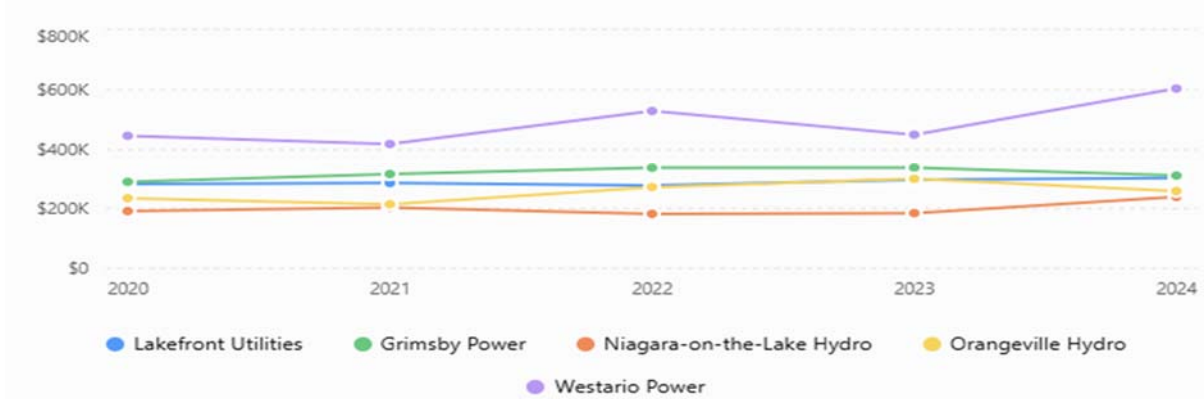
With respect to the broader O&M results, LUI notes that between 2020 and 2024, LUI's Billing O&M increased by approximately 2%, while Vegetation Management O&M decreased by approximately 11% and Lines O&M decreased by approximately 30%.

While LUI's 2024 Metering O&M unit cost is higher than those of the peer group, its actual Metering O&M expenditures have remained relatively stable over the period and within the range of the comparator utilities.

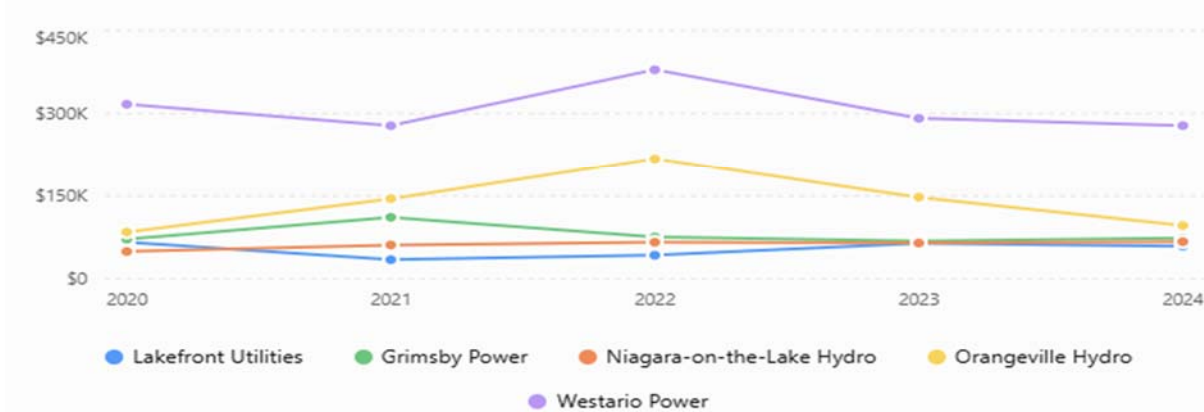


Metering O&M: Lakefront Utilities and Peer Distributors

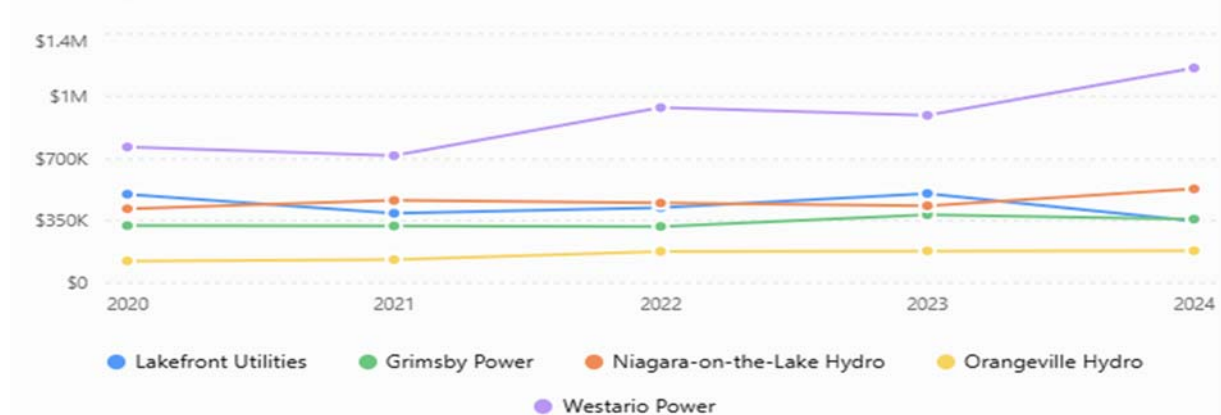
Underlying Metering O&M expenditures, 2020–2024.

**Vegetation Management O&M: Lakefront Utilities and Peer Distributors**

Underlying Vegetation Management O&M expenditures, 2020–2024.

**Lines O&M: Lakefront Utilities and Peer Distributors**

Underlying Lines O&M expenditures, 2020–2024.



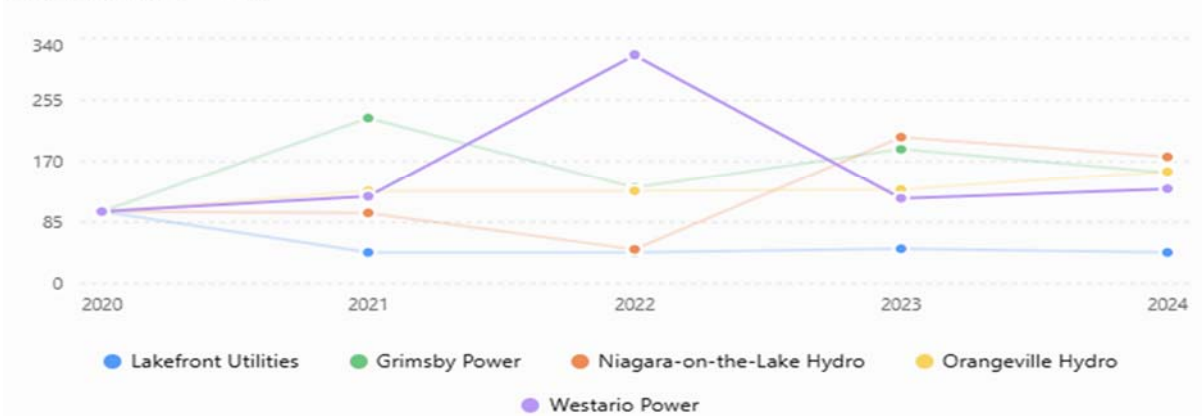
b) Similar to the O&M analysis in part (a), LUI reviewed the longer-term trend in Line Transformer CAPEX to provide additional context for the 2024 APB result. LUI's Line Transformer CAPEX per transformer increased from approximately \$8,500 in 2020 to \$16,400 in 2021 and has remained relatively stable at that level since that time, at approximately \$16,100 in 2022 and \$16,500 in 2024. The 2024 result therefore does not represent a recent escalation in LUI's transformer unit costs.

LUI attributes a significant portion of the higher unit cost to the cost of transformers and associated materials. These costs are largely market-driven and outside of LUI's direct control. The peer results also show considerable variability in transformer unit costs over the 2020 to 2024 period, reflecting the impact of equipment costs and the nature and timing of individual capital additions. LUI continues to manage these costs through its normal procurement and project planning processes, including seeking competitive pricing where practicable. However, LUI has limited ability to influence the underlying market price of transformers and associated materials.

The following tables show the relative changes in costs for all comparators.

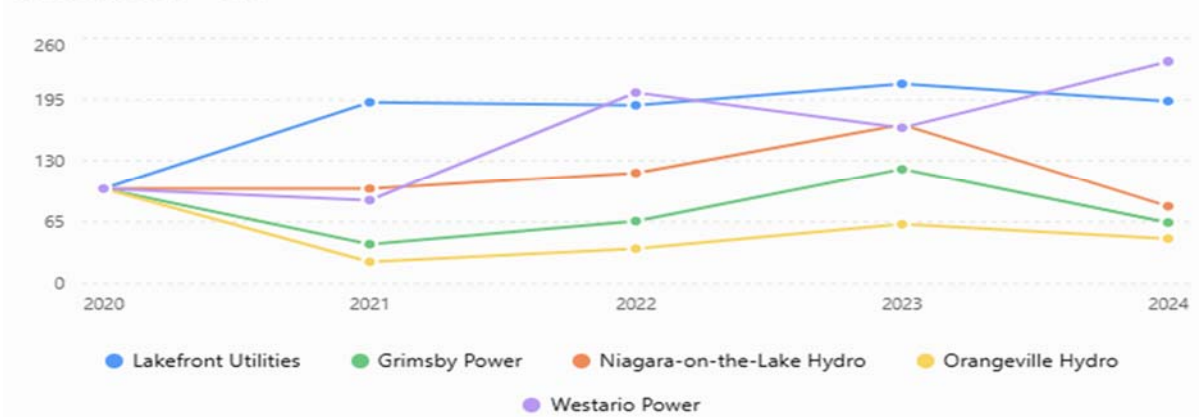
Change in Poles, Towers and Fixtures CAPEX Unit Cost Since 2020

Indexed to 2020 = 100.



Change in Line Transformer CAPEX Unit Cost Since 2020

Indexed to 2020 = 100.



LUI is addressing these costs through the phased AMI 2.0 program, coordinated sampling/replacement, procurement and group-purchasing opportunities, and restoration of internal metering capability through the Metering Technician hired in 2026. The new AMI platform is expected to reduce manual interventions, troubleshooting and truck rolls through remote diagnostics, connect/disconnect and improved communications.

1-STAFF-5

Accounting Standard

Ref. 1: 2027 Chapter 2 Appendices

Ref. 2: Exhibit 1, p. 62

In Reference 2, Lakefront Utilities states that,

... LUI confirms it implemented the regulatory accounting changes for depreciation and overhead capitalization in 2015. The 2027 Cost of Service Application has been filed on an MIFRS accounting basis.

However, OEB staff notes that accounting standard is stated as CGAAP for the fixed asset continuity schedule of 2022 to 2027 in Tab 2BA.

Question(s):

- a) Please clarify why the accounting standard is stated as CGAAP in Tab 2BA of Reference 1. Please update the evidence as applicable.

Response

- a) The applicable accounting standard is MIFRS. The reference to CGAAP in Tab 2-BA was a model default that was inadvertently not changed when the model was completed. LUI confirms that the fixed asset continuity schedules for 2022 to 2027 have been prepared on an MIFRS basis.

LUI has updated Tab 2-BA to identify MIFRS as the applicable accounting standard.

LUI also notes that the OEB model continues to default to CGAAP. Given that distributors have transitioned to MIFRS, LUI suggests that the default accounting standard in future versions of the model be updated to MIFRS.

1.0-VECC-1**Reference: Exhibit 1, page 43**

- a) Please explain why the customer notice for this application provides only the typical residential bill impact for the total bill and not also the increase on the just the distribution portion of the bill?

Response

- a) Publishing the residential bill impact in this manner is consistent with the OEB's current notice format, which presents the expected monthly impact for a typical residential customer on a total bill basis.
- b) LUI has followed the OEB's prescribed format to maintain consistency and avoid potential confusion for customers.

1.0-VECC-2

Reference: Exhibit 1, page 47 /Exhibit 4, page 62

“Lakefront met with representatives from United Way Northumberland, the Salvation Army, and Habitat for Humanity to discuss affordability pressures and barriers facing vulnerable customers. Across these discussions, several consistent themes emerged: ...

Limited awareness and underutilization of assistance programs such as OESP and LEAP.

Table 27 – LEAP Contributions

Year	Agency administration and program delivery	Total grants disbursed	Total funds disbursed	Accepted Applicants	Avg. grant per accepted applicant
2022BA					
2022	1,500	14,722.42	16,222.42	35	420.64
2023	1,500	10,057.57	11,557.57	26	386.83
2024	1,500	10,846.69	12,921.37	27	401.73
2025	1,500				
2026	1,500	8,500	10,000	25	400
2027	1,500	8,500	10,000	25	400

- What steps is LUI taking to address the finding of limited awareness of LEAP funding?
- Why is forecast LEAP funding for 2027 less than that disbursed in years 2022-2024?
- What were the funds disbursed in 2025?
- What amount of funds have been disbursed to date for 2026?

Response

- LUI has taken several steps to increase customer awareness of LEAP and other available assistance programs.

LUI customer service and billing staff contact customers by phone prior to disconnection to discuss available options, including LEAP and OESP. In addition, customers who contact LUI by phone, email or in person and indicate that they are having trouble making payments or concerns regarding electricity costs are proactively advised of available assistance programs and local resources.

LUI is also developing an updated disconnection brochure to be left at the residence at the time of disconnection. The brochure is being revised to make the information easier to navigate and to provide greater prominence to LEAP and other available assistance programs.

LUI distributes approximately three to four customer newsletters annually, each of which includes information regarding LEAP. For customers enrolled in e-billing, this information is also available through LUI's website and customer portal.

In addition, LUI invited the Help Centre, LUI's LEAP administrator, to participate in its 2025 Touch-a-Truck event, providing customers with an opportunity to speak directly with representatives regarding available assistance.

- b) The 2027 forecast LEAP funding of \$12,000 is based on the amount established through LUI's prior cost of service proceeding.

Year	Agency Administration and Program Delivery	Total Grants Disbursed	Total Funds Disbursed	Accepted Applicants	Avg. Grant per Accepted Applicant
2022	\$1,500.00	\$14,722.42	\$16,222.42	35	420.64
2023	\$1,500.00	\$10,057.57	\$11,557.57	26	386.83
2024	\$2,074.68	\$10,846.69	\$12,921.37	27	401.73
2025	\$1,500.00	\$6,459.73	\$7,959.73	20	322.99
2026	\$1,500.00	\$8,500.00	\$12,000.00	25	400
2027	\$1,500.00	\$8,500.00	\$12,000.00	25	400

Actual LEAP disbursements are driven by the level of eligible customer applications received and approved through LUI's LEAP intake agency. Accordingly, actual amounts disbursed may be higher or lower than the forecast amount in any particular year. LUI will continue to make LEAP funding available in response to eligible customer demand in accordance with the OEB's LEAP requirements.

- c) In 2025, LUI disbursed \$6,459.73 in LEAP grants. Including \$1,500 in agency administration and program delivery costs, total funds disbursed were \$7,959.73. Twenty applicants received assistance, with an average grant of \$322.99.
- d) As of the date of this response, \$3,779.16 has been disbursed in 2026 from prior-year LEAP funds. A further approximately \$2,500 in assistance is currently being processed by the Help Centre and has therefore not yet been included in the amount disbursed to date.

1.0-VECC-3

Reference: Exhibit 1, page 50

a) Please update the LUI scorecard for 2025 results.

Response

a)

Scorecard - Lakefront Utilities Inc.

9/3/2026

Performance Outcomes	Performance Categories	Measures	2021	2022	2023	2024	2025	Trend	Target	
									Industry	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	92.89%	94.80%	92.66%	91.30%	90.16%	🟢	90.00%	
		Scheduled Appointments Met On Time	93.62%	98.89%	96.30%	94.62%	95.04%	🟢	90.00%	
		Telephone Calls Answered On Time	95.62%	90.27%	98.76%	98.23%	97.21%	🟢	65.00%	
	Customer Satisfaction	First Contact Resolution	99.46%	99.88%	99.94%	99.96%	99.98%			
		Billing Accuracy	99.95%	99.97%	99.98%	99.93%	99.89%	🟢	98.00%	
		Customer Satisfaction Survey Results	77.70%	77.00%	77.00%	81.17%	81.17%			
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	82.60%	82.60%	83.90%	83.90%	83.50%			
		Level of Compliance with Ontario Regulation 22/04 ¹	C	C	C	C	C	🟢		C
		Serious Electrical Incident Index	0	0	0	0	0	🟢		0
	System Reliability	Number of General Public Incidents Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	🟢		0.000
		Average Number of Hours that Power to a Customer is Interrupted ²	0.99	0.63	2.80	3.22	1.98	🔴		1.41
		Average Number of Times that Power to a Customer is Interrupted ²	0.60	0.36	2.02	1.33	0.87	🔴		0.62
	Asset Management	Distribution System Plan Implementation Progress	Completed	81%	81.25%	81.25%	87.50%			
	Cost Control	Efficiency Assessment	1	1	1	1	1			
		Total Cost per Customer ³	\$518	\$545	\$650	\$673	\$691			
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	Total Cost per Km of Line ³	\$24,743	\$26,234	\$29,514	\$31,102	\$32,333			
		New Micro-embedded Generation Facilities Connected On Time	100.00%	100.00%	100.00%	100.00%		🟢	90.00%	
Financial Performance Financial viability is maintained, and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	0.95	0.78	0.72	1.05	1.03			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	1.09	0.96	1.01	1.40	1.20			
		Profitability: Regulatory Return on Equity	8.78%	8.66%	8.66%	8.66%	8.66%			
		Deemed (included in rates) Achieved	5.93%	10.87%	4.27%	6.60%	8.24%			

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

1.0-VECC-4

Reference: Exhibit 1, pages 59 60

- a) The statement. *“However, achieved ROE has remained below the approved level, with 2024 earnings reaching only 8.24% against an 8.66% target.”* Is inconsistent with Table 20 which shows 2024 achieved ROE of 6.60% (and 8.24% for 2025). Please reconcile.

Response

a) LUI confirms that the reference to 2024 in the quoted statement was incorrect. As shown in Table 20, the achieved ROE was 6.60% in 2024 and 8.24% in 2025, compared with the deemed ROE of 8.66%.

The statement should therefore have referred to 2025 earnings of 8.24%. LUI also notes that achieved ROE has been below the deemed ROE since 2023, whereas 2022 was above the deemed level.

1-SEC-1

[Exhibit 1] Please provide copies of all benchmarking studies, reports, and analyses that Lakefront has undertaken or participated in since the filing of its last rebasing application, that are not already included in the Application.

Response:

LUI has undertaken or participated in the following principal studies and analyses since its last rebasing. Documents already filed in the Application are not duplicated.

Study / Report / Analysis	Date / Period	Purpose	Status in Current Application
MEARIE Management Salary Survey	2022 and subsequent survey participation, as applicable	Compensation benchmarking for management and non-union positions against Ontario LDCs	https://www.rds.oeb.ca/CMWebDrawer/Record/808978/File/document
CGP Compensation Benchmarking Review	February 2023	Independent review of Lakefront's non-union compensation using MEARIE market data and Korn Ferry Hay-point job-sizing methodology.	Filed with IR as supporting document.
CHEC Wage and Benefit / Labour Rate Survey	2024	Peer compensation and labour practice benchmarking	Filed with IR as supporting document.
2025 Customer Satisfaction and Priority Survey	July–August 2025	Customer priorities, reliability, affordability and modernization	Survey results summarized in Exhibit 1/DSP.
Peterborough-to-Kingston Regional Needs Assessment	December 20, 2024	Regional planning with Hydro One, IESO and LDCs	Already included in the DSP Appendices.
Peterborough-to-Kingston Scoping Assessment	April 28, 2025	Regional planning follow-up	Already included in the DSP Appendices.
LUI Asset Condition Assessment	2025	Independent asset-condition health and renewal prioritization	Already included in the DSP Appendices.
LUI Distribution System Plan (DSP) 2027–2031	2026	Five-year capital and asset-management plan	Already filed
Town of Cobourg Integrated Sustainability Plan	Current plan	Municipal GHG, electrification and sustainability context	Public source / considered in planning
OEB Activity and Program-Based Benchmarking ("APB")	Current	Activity-level and total-cost efficiency benchmarking	Results already summarized in Exhibit 1

Compensation benchmarking materials may contain confidential or proprietary participant information. LUI will file them in accordance with applicable OEB confidentiality requirements. LUI does not propose to duplicate the ACA, DSP or regional planning reports already on the record.

1-SEC-2

[Exhibit 1] Please provide details of all productivity and efficiency measures Lakefront has undertaken over the last five years, and any it plans to undertake in the test year and subsequent four years. Please quantify the forecasted savings and explain how they were calculated.

Response

LUI has pursued productivity and continuous-improvement initiatives through technology, asset standardization, shared services, risk-based planning and internalization of recurring core functions. Not all initiatives were established as discrete cost-reduction programs; where no reliable baseline exists, LUI has not retrospectively estimated savings. LUI remains a Group 1 distributor under the OEB's total-cost benchmarking framework.

Initiative	Efficiency / Productivity Benefit	Quantified Impact
Internalization of technical functions	Rebuild engineering, GIS/SCADA, metering and purchasing capability; reduce recurring consultant dependence.	\$41,602 reduction in engineering consulting in 2027
Voltage conversion / standardization	Reduce losses, simplify mixed-voltage operations and avoid reinvestment in legacy 4.16 kV assets.	F9 study: ~547,000 kWh and ~\$25,700 annual savings; not extrapolated system-wide
Distribution automation / SCADA	Remote sectionalizing and switching reduce outage duration, field dispatch and restoration effort.	Representative permanent feeder outage impact may be reduced by ~50%; ~\$606,000 SREP funding reduces net capital requirement
AMI 2.0	Remote diagnostics/connect-disconnect, better outage visibility, fewer manual interventions and truck rolls.	No standalone OM&A savings forecast; deployment is phased and coordinated with recertification
eBilling / customer self-service	Reduces paper billing and routine customer-service handling.	~54% adoption; ~75,600 electronic bills annually
GIS / mobile workforce / ERP modernization	Improves field productivity, asset data, workflow automation, reporting and cost visibility.	No discrete savings separately tracked
Risk-based asset management	ACA/reliability data prioritize highest-risk assets and reduce premature replacement.	Avoided lifecycle costs not separately quantified
Procurement / project controls	Competitive/group procurement, unit-cost tracking, semi-annual reforecasting and standardized project costing.	Savings depend on tender results and project mix
Affiliate/shared-service allocation	Direct assignment and cost-causative allocation improve transparency and prevent inappropriate regulated cost burden.	Governance/cost-allocation improvement; not treated as a savings program

LUI will continue to monitor these initiatives through OEB benchmarking, annual budget variance reporting, reliability metrics, unit-cost tracking and capital reforecasting. It has not

included speculative savings where the timing or measurable benefit cannot yet be reliably forecast.

1-SEC-3

[Exhibit 1, p.17] Please provide the rate impact for the customers in the 50-2,999 kW class and the customer in the 3,000-4,999-kW class if the two classes are not combined.

Response

a) For the legacy GS 3,000–4,999 kW customer, LUI has also filed a bill impact model using the existing GS class structure. This shows the bill impact for a customer using 3,000 kW per month as they move from the current GS 3,000–4,999 kW class to the proposed GS 50–4,999 kW class.

The revised Bill Impact Models, including the versions reflecting the existing GS class structure where required, have been filed with these responses.

1-SEC-4

[Exhibit 1, Table 12] With reference to the corporate structure:

- Please provide the number of positions in each box, if more than one.
- Please indicate which positions reside in the regulated utility, the affiliate and in Holdco.

Response

LUI has updated the organizational structure to identify position counts and the legal employing entity. LUI is the regulated distributor; LUSI is the affiliate/shared-service provider and employs the personnel who provide services to LUI; Holdco has no separate operating workforce. Costs are assigned or allocated to LUI in accordance with Exhibit 4.

Position / Function	FTE / Count	Entity / functional designation
Board of Directors	5	LUI – Regulated Utility Governance
President & CEO	.51	LUSI Employee – Shared Corporate Function (LUI/LUSI/Holdco)
Director of Engineering & Operations	1	Contract Role – LUI Regulated Function
Engineer / Operations Manager	1	LUSI Employee – LUI Regulated Function
Electric Distribution Sub-Foreman	1	LUSI Employee – LUI Regulated Function
Journeyman Lineman	4	LUSI Employees – LUI Regulated Function
Distribution Technician	1	LUSI Employee – LUI Regulated Function
Metering Technician	1	LUSI Employee – LUI Regulated Function
Design Technician	1	LUSI Employee – LUI Regulated Function
GIS/SCADA Technicians	1.5	LUSI Employee – LUI Regulated Function
Locator	1	LUSI Employee – Shared LUI/Water Function
Corp. Service & Comm. Mgr.	.50	LUSI Employee – Shared Corporate Function
HR & H/S Generalist	.36	LUSI Employee – Shared Corporate Function
IT Support Specialist	.50	LUSI Employee – Shared Corporate Function
Acting CFO	.25	Contract Role – Shared Corporate Function
Billing & CS Supervisor	.56	LUSI Employee – Shared LUI/Water Function
Billing & Customer Service Representatives	2.15	LUSI Employees – Shared LUI/Water Function
Data Analyst	.53	LUSI Employee – Shared/Allocated Function
Finance Director	.50	LUSI Employee – Shared Corporate Function
Finance & Regulatory Supervisor	.75	LUSI Employee – LUI Regulated Function
Sr. Financial Analyst	.36	LUSI Employee – LUI Regulated Function
Financial Analyst	.36	LUSI Employees – LUI Regulated Function
Finance Generalist	.34	LUSI Employee – Shared/Allocated Function
Purchasing & Inventory Analyst	.75	LUSI Employee – Shared/Allocated Function

Note: Positions shown as supporting LUI may be legally employed by LUSI. The chart identifies both the employing entity and the principal function supported. Holdco has no dedicated employee complement.

1-SEC-5

[Exhibit 1, p.58] Lakefront states that “[o]ver the five-year period, Lakefront Utilities’ reliability performance trends closely mirror the priorities identified in the Distribution System Plan and 2026–2031 Business Plan and DSP.”

- a. Please provide a copy of the 2026-2031 Business Plan.
- b. Please provide a copy of any other documents provided to the Board of Directors with respect to the application.

Response

a) The business plan is filed with these responses.

b) In addition to the Business Plan, the Board was provided with and reviewed the evidentiary documents supporting the 2027 Cost of Service Application. These included LUI’s Distribution System Plan (“DSP”), Asset Condition Assessment (“ACA”), annual capital and OM&A budgets, financial forecasts, and the complete Cost of Service Application prior to filing with the Ontario Energy Board. These materials support the Board’s governance and oversight of strategic direction, financial sustainability, capital planning, risk and regulatory compliance and major investment decisions.

1-PP-1

Reference: Exhibit 1, page 16 – LUI remains among the most efficient distributors in Ontario. Please provide the full list of deliverables where LUI is among the most efficient distributors in Ontario and for each, please provide the source document that supports that comparison.

Response

LUI clarifies that the statement was intended primarily to refer primarily to overall cost efficiency under the OEB/PEG total-cost benchmarking framework, not to every individual operating or capital metric.

Measure	LUI Result	Relative Position	Source
OEB/PEG Total Cost Benchmarking	~26%–28% below predicted cost; Group 1	Highest efficiency cohort	PEG/OEB benchmarking update; Exhibit 1, Table 14
Billing O&M	\$20.05/customer	1st of selected 5	OEB 2024 APB / Exhibit 1, Table 16
Vegetation O&M	\$18.56/pole	2nd of selected 5	OEB 2024 APB / Exhibit 1, Table 16
Lines O&M	\$1,409.55/circuit km	2nd of selected 5	OEB 2024 APB / Exhibit 1, Table 16
Stations O&M	\$699.84/MVA	1st of selected 5	OEB 2024 APB / Exhibit 1, Table 16
Stations CAPEX	\$191/MVA	1st of selected 5	OEB 2024 APB / Exhibit 1, Table 17

The APB results above compare LUI with the four peer distributors selected in Exhibit 1 and are not province-wide rankings.

Accordingly, LUI proposes to clarify the statement in Exhibit 1 as follows:

“LUI remains among the most cost-efficient electricity distributors in Ontario, as demonstrated by its Group 1 classification under the OEB’s total-cost benchmarking framework.”

1-PP-5

Reference: Lakefront met with representatives of the Town of Cobourg and the Township of Cramahe to discuss infrastructure coordination, growth planning, and community priorities. [Exhibit 1, Page 48]

Please explain how LUI included information from the municipal energy and/or emissions plans into its DSP and overall plan to ensure alignment on outcomes and objectives, including net zero.

Response

LUI considered municipal growth, sustainability and climate objectives as planning inputs to the 2027–2031 DSP, but did not create a separate “net-zero” load forecast or assign a discrete MW value to municipal GHG targets. Instead, municipal plans and consultations informed LUI’s assumptions regarding growth, electrification, DERs, resilience and long-term capacity.

For Cobourg, LUI considered the Integrated Community Sustainability Plan, including its long-term objective of an 80%–100% reduction in community-wide GHG emissions by 2050. For Cramahe, LUI considered the Township’s energy conservation, land-use and climate-planning objectives. Because the timing and location of electrification loads remain uncertain, LUI considers it more prudent to incorporate sufficiently defined projects and connection requirements as they materialize rather than build speculative demand solely from long-term policy targets.

These considerations are reflected in the DSP through:

- maintaining capacity for forecast growth and continuing Cobourg’s 4.16 kV to 27.6 kV conversion;
- advancing automation/SCADA and accommodating DERs, EVs and emerging electrification requirements; and
- coordinating utility renewal with municipal infrastructure and adjusting investments as defined municipal electrification initiatives and actual loads develop.

EXHIBIT 2 – RATE BASE

2-STAFF-6

Incremental Capital Module

Ref. 1: EB-2024-0038 Decision and Order, March 27, 2025 / p. 4

Ref. 2: Exhibit 2 / pp. 25-26

Question(s):

- a) In proceeding EB-2024-0038 Lakefront Utilities requested an incremental capital module for the MS28-3 distribution station which was placed in service in December 2023 at a cost of \$2,535,311. In this proceeding Lakefront Utilities has stated there was an additional capital cost of \$61,772 for the MS28-3 project placed in service in 2024. A USoA breakdown of the expenses were included in reference 2, Table 20 – Assets added to Rate Base.
- a. Please describe the project that resulted in the additional expenditures in 2024 (rather than list the asset classes).
 - b. Please explain/describe the capital additions for line transformers in both 2023 and 2024.

Response

a) The MS28-3 Distribution Station was substantially completed, energized, and placed in service in December 2023. At that time, approximately \$2,535,311 of project costs had been placed in service. A further \$61,772 of costs associated with completion and close-out of the same MS28-3 project were recorded as capital additions in 2024, bringing the total actual project cost to \$2,597,083.

The 2024 expenditures did not represent construction of a second project or a material expansion of MS28-3 following its December 2023 in-service date. Rather, they represented residual work and costs associated with completing the station project and its associated distribution connections following initial energization. The 2024 additions were recorded as follows:

USoA Account Description	2024 Addition
1820 Distribution Station Equipment <50 kV	\$23,351
1830 Poles, Towers and Fixtures	\$301
1835 Overhead Conductors and Devices	\$30,060
1840 Underground Conduit	\$1,258
1845 Underground Conductors and Devices	\$689
1850 Line Transformers	\$6,113
Total	\$61,772

The majority of the 2024 amount relates to station equipment and overhead distribution work, which together account for approximately \$53,400 of the \$61,772 total. These costs are consistent with final construction, connection, commissioning-related and project close-out activities necessary to complete the station and associated feeder infrastructure after the station was initially energized.

These amounts represent post-energization completion costs associated with the original MS28-3 project, rather than incremental scope added after the original project was placed in service.

b) Line transformer additions in 2023 and 2024

The MS28-3 project included capital additions recorded in USoA Account 1850 – Line Transformers of:

- \$7,230 in 2023; and
- \$6,113 in 2024,

for a total project-related line-transformer addition of approximately \$13,342.

These costs were associated with distribution transformers required as part of the feeder and distribution work necessary to integrate the new MS28-3 station into LUI's existing 27.6 kV distribution system. They were not the main station power transformer itself. The principal MS28-3 station transformer and associated substation equipment are recorded in Account 1820 – Distribution Station Equipment <50 kV, which accounts for approximately \$2.263 million of the total project cost.

The Account 1850 additions therefore relate to distribution-level line transformers associated with feeder exits, distribution connections, and the reconfiguration required to place the new station into service, rather than the station transformer. The difference in timing between the 2023 and 2024 additions reflects the sequencing of project completion. The majority of the station and associated distribution infrastructure was installed and placed in service in 2023, while certain remaining distribution components and final connection/close-out work were completed and capitalized in 2024.

LUI notes that the line-transformer costs are relatively small in the context of the overall project, representing approximately \$13,342 of the \$2.597 million total project cost. LUI also confirms that the 2024 capital additions were not the result of a new or expanded scope following the December 2023 in-service date. They represent residual completion and close-out costs associated with the original MS28-3 station project and its required distribution-system connections. Similarly, the amounts recorded in Account 1850 represent distribution-level line transformers associated with integrating the station into the distribution system and should not be confused with the principal MS28-3 station power transformer, which is recorded in Account 1820.

2-STAFF-7

Reliability Metrics

Ref. 1: Distribution System Plan / p. 27 / Table 5.2-9

Question(s):

- a) Please identify the equipment responsible for interruptions under cause code 5, defective equipment

Response

a) Cause Code 5 – Defective Equipment captures interruptions attributable to the failure or malfunction of distribution system equipment. Over the 2021–2025 historical period, LUI recorded 69 interruptions under this cause code, representing approximately 27% of total non-MED outages over the period.

The defective-equipment category includes failures associated with distribution assets such as:

- underground cable;
- pad-mounted transformers;
- overhead distribution equipment and associated hardware;
- switches and switchgear;
- reclosers and protective devices;
- station equipment; and
- other distribution components where the interruption was attributable to an equipment defect or failure.

LUI's filed DSP and supporting capital evidence confirm that defective-equipment outages have informed the utility's system renewal and reliability programs. For example, LUI's Underground Miscellaneous program specifically addresses reactive replacement of failed underground cable, pad-mounted transformers and underground switchgear, with asset failure response and service reliability identified as the primary drivers.

Similarly, LUI's 2027–2031 capital plan includes condition-based replacement of three-phase pad-mounted transformers because aging units present increased risks of failure and unplanned outages. Replacement locations are to be prioritized using the Asset Condition Assessment so that the highest-risk units are addressed first.

LUI's outage-cause analysis is used directly in its capital planning. The DSP states that defective equipment is one of the leading contributors to customer-hour interruption and that the cause-based analysis informs the prioritization of renewal, automation, resiliency improvements and feeder-level interventions in the 2027–2031 plan.

2-STAFF-8

Asset Condition Assessment

Ref. 1: Distribution System Plan / Appendix I – LUI Asset Condition Assessment / 4.1.5 Underground Primary Cables

Question(s):

- a) Please provide the number of primary cable faults per year, for the past 5 years.

Response

- a) LUI owns approximately 60 km of underground primary cable within its service territory.

LUI's underground system renewal program is partly driven by actual field failures. The DSP appendices identify a recurring Underground Miscellaneous program involving reactive replacement of failed underground cable, pad-mounted transformers and underground switchgear, with asset failure response and service reliability as the primary drivers.

Based on LUI's outage-management, trouble-call and work-order records, the number of primary underground cable faults for the past five years is as follows:

Year Number of Primary Underground Cable Faults

2021	1
2022	0
2023	4
2024	2
2025	1
Total	8

LUI notes that these figures include only confirmed primary cable faults and exclude failures attributable solely to pad-mounted transformers, switchgear, secondary cable, customer-owned equipment or other underground apparatus.

2-STAFF-9

Asset Condition Assessment

Ref. 1: Distribution System Plan / Appendix I – LUI Asset Condition Assessment / 4.2.1 Power Transformers

Ref. 1: Distribution System Plan / Appendix I – LUI Asset Condition Assessment / 4.2.3 Circuit Breakers

Ref. 1: Distribution System Plan / Appendix I – LUI Asset Condition Assessment / 4.2.6 Station Switchgear

Question(s):

- Lakefront Utilities has a total of five power transformers. Please provide the age and the known degradation factors for the power transformer with the “unknown” health index.
- Lakefront Utilities has a total of 11 circuit breakers. Please provide age and the known degradation factors for the three circuit breakers with the “unknown” health index.
- Lakefront Utilities has a total of 3 switchgears. Please provide the age and the known degradation factors for the switchgear with the “unknown” health index.

Response

a) Power transformer with Unknown Health Index

LUI notes that the ACA references 5 power transformers, but LUI actually owns eight station power transformers. The installation date is known for all eight assets.

The power transformer Health Index methodology considers the following degradation factors: service age, dissolved gas analysis (“DGA”), oil quality, insulation resistance, dissipation factor, turns ratio, winding resistance, gaskets and seals, bushing condition, gas-pressure relief condition, control wiring, tap changer, grounding, oil level, and gauges.

The ACA indicates that one of the power transformers did not have sufficient degradation-factor data to calculate a valid Health Index. The filed report does not identify that transformer by station/nameplate or provide its individual age and factor-by-factor results.

BBA also identified specific gaps in LUI’s power-transformer data: three transformers were missing DGA test results and two were missing oil-quality test results. BBA identified these as significant gaps because DGA and oil quality are heavily weighted elements of the Health Index methodology.

Accordingly, LUI will supplement the response using the underlying ACA database as follows:

Power Transformer	Age / Installation Year	Known Degradation Factors	Missing Degradation Factors
D’Arcy MS	1971	Service Age, Insulation Resistance, Dissipation Factor, Turns Ratio Test, Winding Resistance, Gaskets and Seals, Condition of bushing, Control Wiring, Tap Changer, Grounding, Oil Level, Gauges	DGA, Oil Quality, Condition of Pressure Relief Device

LUI notes that the “Unknown HI” classification does not mean that the transformer is known to be in poor condition. It means that the available weighted degradation-factor data did not meet the ACA’s minimum data-availability threshold required to calculate a valid Health Index. Under BBA’s methodology, an asset requires at least 70% weighted data availability to receive a valid HI.

b) Three circuit breakers with Unknown Health Index

LUI owns 11 circuit breakers. A valid Health Index was calculated for eight, or approximately 73%, of the population, and all eight circuit breakers with a known HI were assessed as being in Very Good condition. The remaining three were categorized as “Unknown HI.”

Importantly, the ACA states that installation dates are unknown for all 11 circuit breakers. Therefore, LUI cannot provide an actual chronological age for the three breakers from the information contained in the ACA. Instead, the ACA uses the breaker operation counter reading as a proxy for service age.

The circuit-breaker Health Index incorporates:

Degradation Factor	Data Availability Across 11 Breakers
Counter Reading	100%
Control & Operating Mechanism Condition	73%
Contacts Condition	73%
Foundation / Support / Grounding Condition	73%
Connections Condition	73%
Arc Chutes Condition	64%
Contact Resistance	100%
Insulation Resistance	100%

The filed ACA therefore establishes that counter readings, contact resistance and insulation resistance are available for all 11 breakers, while portions of the visual/mechanical inspection data are unavailable for some units. The filed report does not, however, identify precisely which missing factors correspond to each of the three breakers with an Unknown HI.

LUI proposes to provide the following asset-level supplemental information from BBA’s underlying dataset:

Circuit Breaker	Installation Year / Age	Counter Reading	Known Degradation Factors	Missing Degradation Factors
Feeder 10-D’Arcy MS	N/A	221	Counter Reading, Contact Resistance, Insulation Resistance	Control and Operating Mechanism Condition, Contacts Condition, Foundation Support and Grounding Condition, Connections Condition, Arc Chutes Condition
Feeder 11-D’Arcy MS	N/A	73	Counter Reading, Contact Resistance,	Control and Operating Mechanism Condition, Contacts Condition, Foundation Support and Grounding

Circuit Breaker	Installation Year / Age	Counter Reading	Known Degradation Factors	Missing Degradation Factors
Feeder 12-D'Arcy MS]	N/A	103	Insulation Resistance Counter Reading, Contact Resistance, Insulation Resistance	Condition, Connections Condition, Arc Chutes Condition Control and Operating Mechanism Condition, Contacts Condition, Foundation Support and Grounding Condition, Connections Condition, Arc Chutes Condition

LUI further notes that contact resistance and insulation resistance are among the most heavily weighted technical condition factors in the breaker HI methodology and are available for the full breaker population.

The absence of a valid HI for the three breakers therefore reflects incomplete overall degradation-factor data rather than an identified adverse condition.

c) Switchgear with Unknown Health Index

LUI owns three station primary switchgears. Installation dates are known for two of the three assets (13 years, and 54 years) and one unit with an unknown installation date. For the unit with unknown installation date, considering the switch was installed at the same time as the power transformer, and were not replaced since installation, the age may be assumed to be 50 years old.

A valid HI was calculated for two of the three switchgear units; those units were assessed as Very Good or Good. One switchgear unit had an Unknown HI.

The Health Index methodology for switchgear incorporates:

- service age;
- enclosure condition;
- control and operating mechanism condition;
- overall condition; and
- insulation resistance.

Insulation resistance carries the greatest weighting in the HI calculation. Across the three switchgear units, data availability was:

Degradation Factor	Data Availability
Service Age	67%
Enclosure Condition	100%
Control & Operating Mechanism Condition	100%
Overall Condition	100%
Insulation Resistance	67%

LUI proposes to provide the following asset-level supplemental information from BBA's underlying dataset:

Switchgear	Age / Installation Year	Known Degradation Factors	Missing Degradation Factors
Kerr St MS	1976 (assumed)	Service Age, Enclosure Condition, Control and Operating Mechanism Condition, Overall Condition	Insulation Resistance

LUI notes that an "Unknown HI" designation in the ACA does not represent an assessment that the asset is in deteriorated or unacceptable condition. Rather, it indicates that insufficient weighted degradation-factor data were available to satisfy BBA's minimum 70% Data Availability Index threshold for calculation of a valid Health Index. LUI continues to inspect, maintain and test these assets notwithstanding the absence of a calculated HI and is implementing the ACA recommendations to improve data completeness for future assessments.

2-STAFF-10

Asset Condition Assessment

Ref. 1: Distribution System Plan / Appendix I – LUI Asset Condition Assessment / 4.1.1

Wood Poles

Ref. 2: Distribution System Plan / Appendix I – LUI Asset Condition Assessment / 5.1.1

Wood Poles

Lakefront Utilities refers to pole inspections and pole testing in its application. The Wood Pole H1 Algorithm in the ACA includes degradation factors for overall condition and pole rot.

Question(s):

- a) How is “wood rot” determined for wood poles when Lakefront Utilities uses data from visual inspections?
- b) Could an aged pole in otherwise good condition be given a health index that falls within the “fair” rating?

Responses

a) In LUI’s 2025 ACA, “wood rot” is a separate degradation factor within the Wood Pole Health Index (“HI”) algorithm. The algorithm assigns weights to service age, overall condition, wood rot, out-of-plumb condition and pole treatment. For purposes of the ACA, wood rot was determined from LUI’s existing visual pole-inspection records. The assessment reflects observable evidence of external deterioration rather than a destructive or intrusive test of the pole’s internal fibre strength. The visual inspection also considers other physical indicators that form part of the pole’s overall-condition assessment, including:

- crossarm condition;
- insect infestation;
- cracking;
- woodpecker damage;
- pole-top condition;
- fire damage; and
- hardware condition.

LUI recognizes that visual inspection alone may not identify internal or below-grade deterioration. This is also reflected in BBA’s recommendations for continuous improvement of LUI’s pole-condition information. LUI intends to supplement its visual inspection program with additional pole-testing information where appropriate, to improve the assessment of actual structural condition and remaining strength.

b) **Yes.** Under the current ACA methodology, an older wood pole that is otherwise in good observable condition could receive an overall HI within the “Fair” range, because service age is one of the weighted inputs to the composite Health Index.

Service age has the largest individual weighting in the wood-pole HI calculation at 4 out of 10, or 40% of the total degradation-factor weighting. Overall condition and wood rot each have a

weight of 2, while out-of-plumb condition and pole treatment each have a weight of 1. Accordingly, chronological age can materially reduce the calculated HI even where the other observable condition factors are favourable. However, the pole's rating is not determined by age alone. The final HI reflects the weighted combination of all available degradation factors. Under BBA's methodology, an HI between 50% and less than 70% is categorized as Fair. A Fair rating indicates that additional diagnostic testing and potentially remedial work or replacement may be appropriate depending on asset criticality; it does not automatically mean that immediate replacement is required.

LUI therefore interprets the ACA as a screening and prioritization tool rather than an automatic age-based replacement program. An older pole that falls into the Fair category would be considered together with its observed physical condition, evidence of rot or decay, structural deficiencies, operational importance, location, failure consequence and any additional testing information before a replacement decision is made. This approach is consistent with the ACA results overall. Of LUI's 3,688 wood poles, approximately 32% were assessed as Very Good, 21% Good, 24% Fair, 6% Poor and 1% Very Poor, with the balance having insufficient data for a valid HI.

2-STAFF-11

Distribution Transformer Replacement

Ref. 1: Filing Requirements Chapter 2 Appendices / Tab 2-AA

Question(s):

- a. How many 3-phase pad-mounted transformers are planned to be replaced per year in the forecast period?
- b. How many 1-phase pad-mounted transformers are planned to be replaced per year in the forecast period?
- c. How many poles were replaced per year under the “pole replacement” program in the historic and bridge period?
- d. How many poles are planned to be replaced per year in under the “pole replacement” program the forecast period?
- e. How many poles with health index of poor and very poor are planned to be replaced over the forecast period, under programs other than “pole replacement” (e.g. OH rebuilds and voltage conversion)?

Response

- a) Approximately one three-phase pad-mounted transformer is planned for replacement in each year from 2027 to 2031 under SR-001.
- b) LUI plans to replace approximately 21 single phase pad transformers between 2027-2031. 4 annually in 2027-2030 and 5 in 2031.
- c) The poles replaced under “Pole Replacement Program” were 2 in 2022, 11 in 2023, 3 in 2024, 4 in 2025 and 7 in 2026.
- d) LUI plans to replace approximately 35 poles between 2027-2031.
- e) There are 6 poles identified that fall under the OH rebuilds and voltage conversion projects which are outside of the pole replacement program.

An important note: LUI does not consider this to be a fixed five-year plan. LUI's priority is to ensure that no assets remain in an unsafe condition. If additional poles or transformers are identified as requiring replacement, LUI will reprioritize the budget accordingly.

2-STAFF-12

Alignment with OEB Non-Wires Solution Policy

Ref. 1: Exhibit 2, Distribution System Plan

The OEB's [Non-Wires Solutions Guidelines for Electricity Distributors](#) and [Benefit-Cost Analysis Framework for Addressing Electricity System Needs](#) state that distributors are expected to consider non-wires solutions (NWSs) as part of their distribution system planning process. The Guidelines further indicate that distributors should undertake a preliminary assessment to determine whether there is a reasonable expectation that an NWS could be a viable option for addressing an identified system need.

In its Distribution System Plan, Lakefront Utilities states that it considers NWSs in its distribution planning activities and notes that NWSs are not applicable.

Question(s):

- a) Please describe Lakefront Utilities' process for identifying, screening, and evaluating NWSs as part of its distribution system planning activities.
- b) Please provide any policies, procedures, frameworks, criteria, or other documentation used to assess the applicability and viability of NWSs.
- c) If Lakefront Utilities does not have a formal NWS-specific planning framework, please explain the controls and processes in place to ensure that NWSs are consistently and systematically considered in accordance with the OEB's Non-Wires Solutions Guidelines for Electricity Distributors.

Response

a) LUI identifies distribution system needs based on asset condition, reliability, loading, customer connection requirements and external obligations. As part of the investment-options assessment, LUI considers whether alternatives such as demand response, energy storage, flexible load or third-party DERs could address the identified need, either independently or in combination with a wires solution. The conclusions of that screening are documented in the applicable material investment narratives in Appendix L.

b) LUI does not have a separate stand-alone NWS policy or procedure. The framework used to assess NWS alternatives is incorporated into sections 5.3.1.1, 5.3.5 and 5.4.2.2 of the DSP and the project-specific NWS screening included in Appendix L.

c) NWS consideration is embedded in LUI's investment-planning process. For each material investment, LUI considers the nature of the identified system need and whether a non-wires alternative could reasonably address that need before determining whether further assessment is warranted. The results are documented through the investment narratives and considered as part of management's project prioritization and reforecasting process.

2-STAFF-13

Alignment with OEB Non-Wires Solution Policy

Ref. 1: Exhibit 2, Distribution System Plan / Appendix L

Lakefront Utilities states that the proposed Advanced Metering Infrastructure 2.0 (AMI 2.0) investment will provide communications and data infrastructure to support the integration of distributed energy resources (DERs), net metering, electric vehicle (EV) charging, and other emerging load types expected to grow on Lakefront Utilities system over the planning period.

Question(s):

- a) Please explain how the proposed AMI 2.0 investment would support the integration and management of DERs, net-metered customers, EV charging infrastructure, and other emerging load types on Lakefront Utilities distribution system.
- b) Does Lakefront Utilities expect the integration and management of DERs, net-metered customers, EV charging infrastructure, and other emerging load types supported by investment in AMI 2.0, or the investment in AMI 2.0 itself, to create opportunities to cost-effectively address distribution system needs using NWSs
- c) Are any specific demand response, DER integration, EV management, grid modernization, or other future NWS deployments expected to rely on the proposed AMI 2.0 infrastructure? If so, please describe each initiative and provide any available information or estimates related to expected timing, costs, and benefits. If not, please indicate when Lakefront Utilities expects any NWS-related benefits associated with investment in AMI 2.0 to be realized.

Response

a) AMI 2.0 is intended to provide two-way communications, interval consumption data, voltage/power-quality, real-time visibility, outage notifications, integration with meter-data and customer systems. It will allow us to monitor peak load across the service territory and ultimately guide our NWS plans. These capabilities can improve visibility of changing customer load, net-metering behavior and localized EV/DER impacts, supporting planning and future program measurement. For EV charging and other emerging loads, interval data allows Lakefront to identify and track load growth patterns at the feeder level as adoption increases, supporting more accurate load forecasting and targeted capital planning. Lakefront intends to use internal staff to perform this analytics work following AMI 2.0 deployment.

b) AMI 2.0 may enable future cost-effective NWS opportunities by improving the data available to identify constraints, characterize flexible load and assess program performance. The DSP does not identify a committed rate-funded NWS deployment or quantify avoided distribution investment attributable to AMI.

c) Lakefront confirms that its Distribution System Plan describes AMI 2.0 as an enabling platform for future demand-side and DER-related initiatives, including reference to Lakefront's participation in the PowerShare [conservation/demand-response] collaboration. However, Lakefront does not currently have a committed demand-response, managed-EV charging, or

other NWS deployment with an associated budget and benefits-realization date. AMI 2.0 deployment is planned to begin in 2027 and continue through 2036. Lakefront anticipates that NWS-related benefits enabled by AMI 2.0 such as targeted demand-response or DER dispatch programs would be evaluated on a staged basis as deployment progresses, with more concrete opportunities identifiable once initial deployment phases are complete.

2.0-VECC -5

Reference: Exhibit 2, DSP Final, page 47
Exhibit 3, page 5

Preamble: The Application states (DSP Final, page 47):
“LUI has experienced modest but steady growth in its service territory. New residential subdivisions in LUI’s service territory, as well as incremental commercial development, are expected to contribute to demand over the 2027–2031 planning horizon. Industrial activity is forecast to remain stable, contributing selectively to load requirements. LUI expects overall peak demand to stay roughly flat over the forecast period. The main growth pressure comes from residential subdivisions in Cobourg such as Densmore Meadows rather than broad-based load growth. That said, if a large industrial customer were to electrify a process or if EV adoption accelerates faster than expected, LUI could see localized capacity pressure on specific feeders.”

The Application states (Exhibit 3, page 5):

“While the region continues to market industrial and commercial lands, no confirmed infrastructure or development projects are expected to materially impact load within the bridge or test years.”

- a) Please outline the new residential subdivisions currently expected in LUI’s service territory over the 2027-2031 planning period. As part of the response please indicate the timing, number of new connections and MWs associated with each.
- b) Please outline the incremental commercial development currently expected in LUI’s service territory over the 2027-2031 planning period. As part of the response please indicate the timing and the incremental MWs of load expected.
- c) Please provide a schedule that sets out LUI’s current connection requests and indicate the timing and kW associated with each along with the type of customer involved (e.g., residential or commercial/industrial).

Response

a) Residential subdivisions expected over 2027–2031

LUI clarifies that its 2027–2031 system-planning forecast incorporates expected residential development at an aggregate annual level, based on known and proposed developments, expected unit counts and anticipated timing. Raven Engineering’s updated load forecast states that proposed subdivision developments were specifically incorporated using estimated unit loads, proposed unit quantities and expected development timing.

The principal residential developments that LUI continues to monitor include developments previously identified through its municipal/developer planning process, including:

Subdivision Name	Year									
	2027		2028		2029		2030		2031	
	connection	MW	connection	MW	connection	MW	connection	MW	connection	MW
Cobourg Trails Ph3	0	0	40	0.12	40	0.12	40	0.12	43	0.129
Tribute Ph2	53	0.159	52	0.156	0	0	0	0	0	0
Victoria Meadows	0	0	36	0.108	36	0.108	0	0	0	0
New Amherst Ph3	0	0	30	0.09	30	0.09	30	0.09	30	0.09
20 Park rd	32	0.096	32	0.096	0	0	0	0	0	0
Eastfields Ph3	26	0.078	0	0	0	0	0	0	0	0
Sunnyside Village	19	0.057	34	0.102	18	0.054	18	0.054	0	0
Nickerson Woods	4	0.012	4	0.012	4	0.012	0	0	0	0
Cobourg Trails Ph2	53	0.159	52	0.156	0	0	0	0	0	0

b) Incremental commercial development

Raven's updated load forecast incorporates proposed commercial developments as discrete point loads. The report states that several commercial developments were considered in the forecast, while the remaining underlying system growth is represented through the general historical growth assumption.

The table below outlines the incremental commercial development currently expected in LUI's service territory over the 2027-2031 planning period. The table below includes the timing and the incremental MWs of load expected.

Commercial	Year				
	2027	2028	2029	2030	2031
	MW	MW	MW	MW	MW
New Amherst School		1			
565 Dodge St	0.75				
585 Dodge st	75				
510 Drewery	0.267				
149 Elgin St		0.5			
535 John Keefer			3		
560 Thompson st		0.5			
390 King St	0.75				

c) Current connection requests

Please see below schedule that sets out LUI's current connection requests, timing and kW associated with each along with the type of customer involved (e.g., residential or commercial/industrial).

Customer	Year							
	2025		2026		2027		2028	
	connection	KW	connection	KW	connection	KW	connection	KW
480 Drewery			Residential	167				
473 Ontario			Residential	1500				
565 Dodge St			commercial	750				
585 Dodge St			commercial	750				
675 Brook rd			Residential	1000				
490 Drewery			Residential	267				
500 Drewery			Residential	267				
545 Kingst			Commercial	1000				
321 John st	Residential	280						
149 Egin St							Commercial	500
Kerr St Lot E							Industrial	1000
202 Second St					Residential	750		
189 First st					Residential	750		
390 Kingst			commercial	750				
986 Burnham Street			Residential	500				
510 Drewery			Commercial	267				

The schedule reflects connection requests sufficiently advanced to have an identifiable requested or forecast load. Routine individual residential service requests, panel upgrades and other minor connections that do not have a material system-planning impact have not been separately listed unless specifically requested.

2.0-VECC -6

Reference: Exhibit 2, DSP pages, 24-25

Table 5.2-7: Historical Reliability Performance Metrics - LOS and MED Adjusted

Metric	2021	2022	2023	2024	2025	Average
<i>Loss of Supply Adjusted</i>						
SAIDI	0.99	31.67	2.80	3.22	3.05	8.35
SAIFI	0.60	1.47	2.02	1.33	1.37	1.36
CAIDI	1.63	21.54	1.38	2.42	2.23	5.84
<i>Loss of Supply and Major Event Days Adjusted</i>						
SAIDI	0.99	0.63	2.80	3.22	3.05	2.14
SAIFI	0.60	0.36	2.02	1.33	1.37	1.14
CAIDI	1.65	1.75	1.39	2.42	2.23	1.89

“Figure 5.2-6 shows that average restoration times (CAIDI) have stayed reasonably consistent once LOS and MED events are removed averaging 1.88 hours over the period.”

- Table 5.2-7 shows a noticeable increase in outage duration since 2023 (as measured by both SAIDI and CAIDI / LOS and MED adjusted results). What are the reasons for this trend?
- Does LUI have any specific initiatives during the rate plan aimed at reducing the outage times for both planned and unplanned outages?

Response

a) LUI has identified two distinct events behind the 2024 increase. In reviewing the table in response to this interrogatory, LUI also identified a data correction affecting the reported 2025 figures.

2024 drivers:

- January 12, 2024 – A storm event caused a feeder outage resulting in a large customer impact and a material contribution to 2024 SAIDI and SAIFI. This event resulted in 52% of customers being without power for between 2.25 to 3.25 hours.
- June 3, 2024 – The aging Victoria station failed causing 25% of customers to be without power for 3.5 hours.

This demonstrates that the 2024 increase is attributable to two specific, identifiable events rather than a systemic decline in distribution system performance.

2025 correction – In preparing this response, LUI identified that a storm on March 30, 2025 resulted in two separate F9 feeder interruptions caused by tree impact affecting approx. 2,000 customers for 2.5 hours and approximately 4000 customer for 2 hours. This met the Major event criteria set out in RRR section 2.1.4.2. However, as LUI did not file the major report this event was not excluded in the original results provided in table 5.2-7.

Metric	2021	2022	2023	2024	2025	Average
<i>Loss of Supply Adjusted</i>						
SAIDI	0.99	31.67	2.80	3.22	3.05	8.35
SAIFI	0.60	1.47	2.02	1.33	1.37	1.36
CAIDI	1.63	21.54	1.38	2.42	2.23	5.84
<i>Loss of Supply and Major Event Days Adjusted</i>						
SAIDI	0.99	0.63	2.80	3.22	1.94	1.92
SAIFI	0.60	0.36	2.02	1.33	0.85	1.03
CAIDI	1.65	1.75	1.39	2.42	2.28	1.90

With the above, it can be seen that the events contributing to the increase in scores can be associated with one to two specific events in a given year, rather than a continuous decline in service reliability.

b) Yes. The planned automation program adds remote switching, sectionalizing/tie capability and SCADA support to accelerate isolation and restoration; advanced lateral protection targets sustained lateral interruptions. Renewal and animal-guard work address recurring outage causes, while AMI outage notifications support detection. Automation is intended to improve both planned and unplanned switching/restoration.

2.0-VECC -7

Reference: Exhibit 2 DSP, page 32

Table 5.2-14: RPQR Reliability Performance Targets (2027-2031)¹²

Year	2027	2028	2029	2030	2031
SAIDI Target (hours)	2.45	2.44	2.44	2.43	2.42
SAIFI Target	1.14	1.12	1.10	1.09	1.07

- a) The SAIFI target for 2027 appears to have been set at the 2021-2025 average (see Table 5.2-7). However, the SAIDI target of 2.45 for 2027 is set above the 2021-2025 average (MED and LOS adjusted). Please why.

Response

- a) The 2027 targets were not established using the 2021-2025 averages shown in Table 5.2-7. The methodology in section 5.2.3.3 of the DSP uses the normalized 2020-2024 baseline of 2.46 hours for SAIDI and 1.17 for SAIFI.

Applying the annual improvement factors of 0.25% for SAIDI and 1.50% for SAIFI results in the 2027 targets of 2.45 hours and 1.14, respectively.

The fact that the 2027 SAIFI target is the same as the 2021-2025 average is coincidental.

2.0-VECC -8

Reference: Exhibit 2, DSP, pages, 27 -31

“Defective equipment and supply related events as the primary contributors to reliability outcomes and directly inform LUI’s 2027– 2031 investment plan.”

- a) Please provide the most common type of defective equipment causing “defective equipment cause code outages” in each year 2021 through 2025.
- b) Please explain how the most common types of defective equipment caused outages are being addressed in the proposed DSP.

Response

a) Please see below most common type of defective equipment causing “defective equipment cause code outages” in each year between 2021 and 2025

Year Defective Equipment Causes

2021 Primary fault; blown fuse; downed secondary wire; blown transformer

2022 Open wire secondary, switch, defective connection, insulator damage, hotline clamp damage, faulty meter, damaged conductor

2023 Voltage problem—line side; primary fault; blown transformer; switch issue; blown arrester; blown fuse; secondary fault; tracking/fault in Victoria MS28-1 switchgear cell; animal contact

2024 Downed wire; adverse weather; voltage problem—line side; switch issue; burned squirrel guard; primary fault; blown arrester; blown fuse; blown transformer; leaking transformer

2025 Blown transformer; blown fuse; secondary fault; switch issue; blown arrester; primary fault

b) The DSP addresses primary and secondary faults through targeted overhead and underground asset renewal, including the Overhead Miscellaneous and Underground Miscellaneous programs, planned feeder rebuilds and the replacement of deteriorated line components. Transformer failures are addressed through condition-based transformer renewal, including the 3-Phase Pad-Mounted Transformer Replacement Program, supported by inspections. Fuse and arrester failures are addressed through inspection-driven corrective maintenance, overhead renewal and the replacement of deteriorated pole-mounted equipment. The remaining 4.16 kV-to-27.6 kV conversion projects will also replace or retire legacy equipment and help address recurring line-side voltage and equipment-reliability issues.

Switch and switchgear issues are addressed through regular switchgear servicing, the Reliability Improvement Program, Advanced Lateral Protection and the Distribution System Automation Program, which will install remotely operated switches, reclosers and sectionalizing devices on priority feeders. The specific Victoria MS28-1 switchgear-cell fault is relevant to the planned engineering assessment of that station. However, the current DSP does not include station-refurbishment funding, and LUI may seek funding through a future ICM application once the scope and cost are confirmed. Overall, the DSP uses outage history together with inspection results, asset condition, fault frequency and outage consequences to

prioritize the highest-risk equipment and locations. Distribution automation complements the renewal work by reducing the number of customers affected and shortening restoration time when an equipment failure cannot be prevented.

2.0-VECC -9

Reference: Exhibit 2, DSP, page 62, Table 5.4-4 / APPL_COS_2027 Filing_Requirements Chapter2 Appendices_20260626.xlsm

- a) The amounts for system access and total net capital spending in 2024 shown at Table 5.4-6 do not appear to match those shown at Appendix 2-AB shown in the Excel Model Chapter2 Appendices_20260626.xlsm (e.g. net actual capital expenditures are shown as \$2,222 in the former and \$1,670 in the latter and CWIP is shown as \$2,228). Similar inconsistencies as between the Total net plan and actuals capital expenditures reported in the Table at page 62 of the DSP and that shown in the Chapter 2 Excel model. Please reconcile

Response

a) LUI confirms that the Chapter 2 Appendices workbook_20260626.xlsm originally contained an incorrect version of Appendix 2-AB. This issue was identified through the OEB staff error-checking process, and corrected information was subsequently filed with LUI's August 11, 2026 response to the error-checking questions. The original Appendix 2-AB should therefore be disregarded where it conflicts with the subsequently corrected information.

2.0-VECC -10

Reference: Exhibit 2, Appendix 2-AB

- a) Please explain how the System Access capital contribution forecast of \$728,800 was estimated for 2027.
- b) Please explain how the 2028-2031 estimate of system access capital contributions of \$806,824 was calculated.
- c) Please identify which projects in System Service are expected to attract a capital contribution of \$202,008 (2027 -2029) and how that contribution estimate was calculated.

Response

a) LUI notes that the 2027 System Access capital contribution forecast is \$782,800, not \$728,800. The \$782,800 comprises two components, each escalated 3% (to account for inflation) from LUI's 2026 Bridge Year budget:

- **Component 1:** Subdivision expansions – \$412,000. LUI forecasts \$515,000 in gross subdivision expansion costs in 2027 based on a four-year historical average of developer-driven subdivision activity in its service territory. In accordance with the Distribution System Code, expansions are subject to an economic evaluation and the developer pays a capital contribution. LUI has assumed 80% of gross subdivision cost is recovered by contribution, consistent with recent experience.
- **Component 2:** Commercial connections – \$370,800. LUI forecasts \$370,800 in gross commercial (non-residential) service connection costs based on a historical average. These connections are individually economically evaluated under the DSC and, based on LUI's experience, are fully recovered through customer capital contributions, resulting in a net cost of \$0.

The 2026 Bridge Year base amounts (\$400,000 for subdivisions and \$360,000 for commercial connections) were established with reference to actual capital contributions received from 2022 to 2025 of \$378,206, \$764,807, \$2,240,201 and \$649,760 respectively. The 2024 amount reflects an unusually high concentration of subdivision completions in a single year and was treated as an outlier. The forecast is set between the three-year average excluding 2024 (approximately \$600,000).

b) LUI notes that the 2028 System Access capital contribution forecast is \$806,284, not \$806,824, and that the forecast escalates annually (3% between 2026-2028 and 2.5% between 2029-2031) rather than remaining fixed over 2028–2031:

\$	2027	2028	2029	2030	2031
Subdivision expansions	412,000	424,360	434,960	445,840	457,000
Commercial connections	370,800	381,924	391,464	401,256	411,300
System Access capital contributions	782,800	806,284	826,424	847,096	868,300
SREP grant – System Service	202,008	202,008	202,008	–	–
Total Contributed Capital	984,808	1,008,292	1,028,432	847,096	868,300

The reduction in total Contributed Capital in 2030 reflects the end of the Smart Renewables and Electrification Pathways (SREP) grant, not a change in the System Access forecast.

c)The \$202,008 per year in 2027, 2028 and 2029 is grant funding under Natural Resources Canada's Smart Renewables and Electrification Pathways (SREP) program applied against the Distribution System Automation project in the System Service category. In 2027 the project has a gross cost of \$416,136 and a net cost to LUI of \$214,128 after the grant. The \$202,008 amount is the annual grant value per LUI's SREP application. LUI has presented the grant within Contributed Capital so that only the net cost to ratepayers enters rate base. No other System Service project is forecast to attract a contribution.

2.0-VECC -11

Reference: Exhibit 2, Appendix 2-AA

- a) Please update Appendix 2-AA to show the 2026 January – August spending to-date and the forecast Sept-Dec. year-end forecast.

Response

a) LUI has not updated Appendix 2-AA to reflect January–August 2026 spending to-date, as the appendix is prepared on an in-service basis rather than an expenditure basis. Appendix 2-AA reports capital additions in the year assets are placed in service, consistent with the Chapter 2 Appendices instructions and with the in-service additions reported in Appendix 2-BA (Fixed Asset Continuity Schedule). It does not report expenditures or construction work in progress.

LUI capitalizes projects upon completion and placement in service, which for the majority of its capital program occurs in the fourth quarter of the year. As of August 31, 2026, no 2026 capital projects had been placed in service, and all 2026 spending to that date remains in construction work in progress. There are therefore no January–August 2026 in-service additions to report, and the 2026 Bridge Year figures in Appendix 2-AA remain the full-year forecast of in-service additions as filed.

LUI notes that actual capital expenditures to date, representing costs receipted and recorded to project work orders, are available and can be provided upon request. These amounts would not be directly comparable to the in-service additions in Appendix 2-AA, as expenditures recorded in a given period are capitalized when the related projects are placed in service.

2.0-VECC -12

Reference: Exhibit 2, Appendix L – SS-003, Appendix 2-AA

- a) In Appendix L (Material Investment Narratives Summary Table (PDF page 297) shows the Distribution System Automation (SS-003) project spending in 2027 as \$404,678 (also shown as Table 5.4-15 page 82 of DSP). Appendix 2-AA (Excel) shows the spending on this program in 2027 as \$606,686 (line 83). Please reconcile.
- b) The total for this program at Appendix L is listed as \$1.28M over the 2027-2031 period. The amount in Appendix 2-AA – line 83 shows the cumulative 2027-2030 amount as \$1,891,101. Please reconcile.
- c) Please provide the scope of work on SS-003 in 2027 and (separately) the scope of work in 2028.

Response

a) Table 5.4-15 and Appendix L present the net cost of SS-003, while Appendix 2-AA presents the gross project cost. For 2027:

- Gross project cost: \$606,686
- Funding recovery: \$202,008
- Net project cost: \$404,678

This reconciles the 2027 amounts shown in the two schedules.

b) The same treatment explains the difference over the 2027-2030 period:

- Gross project cost: \$1,891,101
- Funding recovery: \$606,024
- Net project cost: \$1,285,077

Accordingly, the approximately \$1.28 million shown in Appendix L represents the net cost of the program.

c) In 2027, LUI plans to procure and install one 44 kV and four 27.6 kV automated load-break switches and complete the first portion of the SCADA system upgrades, including the procurement and installation of the main and backup servers and cellular communications setup.

a) In 2028, LUI plans to procure and install a further one 44 kV and four 27.6 kV automated load-break switches and complete the remaining SCADA system upgrades.

2.0-VECC -13

Reference: Exhibit 2, DSP, pages 70-, Tables 5.4-11, 5.4-12, 5.4-13, Table 5.4-14 / Appendix 2-AA APPL_COS_2027 Filing Requirements Chapter2 Appendices_20260626.xlsm

- Tables 5.4-11 through -13 do not appear to match the equivalent sums shown in Appendix 2-AA. Please reconcile.
- Table 5.4-14 does not appear to match the figures in Appendix 2-AA for the years 2028, 2029 and 2030. Please reconcile.

Response

a) In Appendix 2-AA, any projects below the materiality threshold are placed under "Miscellaneous" line item. The numbers in Tables 5.4-11 through -13 match the equivalent sums shown in Appendix 2-AA when the "Miscellaneous" line item is incorporated in the totals. See table below

Document	Table #	Category	2027(\$)	2028(\$)	2029(\$)	2030(\$)	2031(\$)
DSP	5.4-10	System Access	438,821	589,301	600,846	586,846	610,910
	5.4-11	System Renewal	478,630	747,936	776,948	866,044	1,089,374
	5.4-12	System Service	895,928	465,315	389,555	468,132	479,851
	5.4-13	General Plant	459,750	352,749	389,756	284,781	82,831
		Total	2,273,129	2,155,301	2,157,105	2,205,803	2,262,966
Appendix 2-AA	N/A	System Access	438,821	589,301	600,846	586,851	610,910
		System Renewal	347,110	734,144	736,170	866,044	1,089,374
		System Service	854,728	422,880	346,059	423,548	434,150
		General Plant	395,375	275,833	289,171	203,972	0
		Misc	237,095	133,143	184,859	125,393	128,532
		Total	2,273,129	2,155,301	2,157,105	2,205,808	2,262,966

b) In Appendix 2-AA, any projects below the materiality threshold are placed under "Miscellaneous" line item. The numbers in Tables 5.4-14 match the figures in Appendix 2-AA when the "Miscellaneous" line item is incorporated in the totals. See table above.

2.0-VECC -14

Reference: Exhibit 2, page 7 of 62 / Appendix 2-BA and Appendix 2-AB

*“All capital expenditures included in this application reflect assets that have been placed into service. LUI does not include work in progress (WIP) in rate base. **Accordingly, capital expenditures and in-service additions are equivalent for the purposes of this application.**”* (emphasis added)

- a) It does not appear that the actual net capital expenditures matches the additions as shown in Appendix 2-BA. For example, in 2025 Additions the Total PP&E for Rate Base Purposes is listed as \$2,764,569. Appendix 2-AB - Capital Expenditures list the 2025 total capital expenditures as \$3.061M with Net Capital Expenditures of \$2.411M. Please clarify how this is consistent with the referenced statement.

Response

- a) The Appendix 2-AA was submitted included the WIP changes by year to balance to the total PP&E from Appendix 2-BA in error. The Appendix 2-AB was submitted excluded the miscellaneous project line from Appendix 2-AA and the incorrect CWIP amounts. The reconciled Appendix 2-AA and 2-AB are submitted as follows:

Appendix 2-AA Capital Projects Table										
Projects	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Reporting Basis	MIFRS	MFRS	MIFRS	MIFRS	Bridge Year	Test Year	MIFRS	MIFRS	MIFRS	MIFRS
System Access										
CUSTOMER DRIVEN - TESLA SUPERCHARGER - CT PARKING	65,458									
NEW SERVICES	56,725	67,147	66,595	94,109	70,000	72,100	74,263	76,118	78,022	79,975
CUSTOMER DRIVEN - TRIBUTE HOMES - NEW POLE LINE	87,423									
SEAL EXPIRY METER REPLACE	128,900	378,527	92,736	122,236	70,000					
CUSTOMER DRIVEN - EAST VILLAGE - BGS HOMES		220,010								
CUSTOMER DRIVEN - FOXTAIL RIDGE		161,495								
CUSTOMER DRIVEN - COAST GUARD - SERVICE UPGRADE		63,340								
CUSTOMER DRIVEN - BATTERY STORAGE - JEBCO		55,377								
NEW 28KV STATION - VICTORIA STN 2		2,535,311								
F1/F7 FEEDER TIE-SWITCH INSTALLATION			57,429							
CUSTOMER DRIVEN - RONDEAU SUBDIVISION - TRIBUTE			1,054,975							
CUSTOMER DRIVEN - GATES OF CAMELOT PH 5			373,549							
CUSTOMER DRIVEN - DENSMORE MEADOWS SUBDIVISION			629,130							
CUSTOMER DRIVEN - NEW AMHERST - STAGE 2 PHASE 1			342,875							
CUSTOMER DRIVEN - DODGE ST - NEW POLE LINE			87,883							
CUSTOMER DRIVEN - 755 DIVISION ST - NET METER				57,534						
POLE REPLACEMENTS				129,374						
CUSTOMER DRIVEN - POLE LINE - DURHAM ST N COLB				342,332						
CUSTOMER DRIVEN - BROOK RD N				97,531						
ECONOMIC EVALUATION					500,000	515,000	530,450	543,700	557,300	571,250
COMMERCIAL SERVICES					360,000	370,800	381,924	391,464	401,256	411,300
KING ST SIDEWALK WIDENING					60,000					
VICTORIA STATION MS28-1 REFURBISHMENT					125,000					
AM# 2.0						263,721	408,948	415,988	397,369	416,685
Moved from CWIP					788,386					
System Access Gross Expenditures	338,506	3,481,207	2,705,172	843,116	1,973,386	1,221,621	1,395,585	1,427,270	1,433,947	1,479,210
System Access Capital Contributions	378,206	764,807	2,240,200	649,760	790,000	782,800	806,284	826,424	847,096	868,300
Sub-Total	(39,700)	2,716,400	464,972	193,356	1,183,386	438,821	589,301	600,846	586,851	610,910
System Renewal										
ELGIN ST - BIRCHWOOD TO CHIPPING	349,023									
ROW 44/28KV - P73 TO BURNHAM ST	292,540									
POLE REPLACEMENTS	75,226	230,727			60,000	61,800	74,263	97,866	156,044	159,950
VICTORIA ST. STATION TO ONT ST	405,156									
KERR ROW - VIC STN TO DIVISION	209,116									
BROOK F5 NEW FEEDER	347,351									
UNDERGROUND MISCELLANEOUS	64,148	97,783		115,780	55,000	58,710	60,471	61,982	63,532	65,123
OVERHEAD MISCELLANEOUS	91,136	60,851	91,508	226,014	75,000	77,250	79,568	81,555	83,595	85,688
DELTA TO WYE CONVERSIONS	63,609									
DURHAM ST - DURHAM STN TO KING		478,410								
KING ST POLE LINE - JEBCO		239,022								
VICTORIA ST - STN TO KING ST		187,821								
LAKEFRONT DEC STORM		122,297								
ELGIN ST - CHIPPING TO ONTARIO			446,477							
KERR ST - BURNHAM ST TO POW			414,215							
BUCK/GEORGE - UNI TO KING - 28KV			180,442							
BROOK N TO D'ARCY (ELGIN)				150,000						
ELGIN - ONTARIO TO WILLIAM				504,874						
ENGINEERING DESIGN AND SUPPORT STAFF				89,578	55,000	77,250	79,568	81,555	83,595	85,688
DELTA-WYE CONVERSIONS							53,045	54,370	111,460	114,250
PARLIAMENT 25-89 (OH Rebuild)					190,000					
3PH PAD TRANSFORMER REPLACEMENTS						72,100	74,263	76,118	78,022	79,975
BOUNDARY - ELGIN TO KERR							249,312			
1Ph PAD TRANSFORMER REPLACEMENTS							63,654	65,244	66,876	91,400
ELGIN - WILLIAM TO STRATHY								217,480		
ELGIN - STRATHY TO NEW AMHERST									111,460	304,475
INDUSRIAL RD REBUILD									111,460	102,825
System Renewal Gross Expenditures	1,897,305	1,416,911	1,132,642	1,086,246	435,000	347,110	734,144	736,170	866,044	1,089,374
System Renewal Capital Contributions	0	0	0	0	0	0	0	0	0	0
Sub-Total	1,897,305	1,416,911	1,132,642	1,086,246	435,000	347,110	734,144	736,170	866,044	1,089,374
System Service										
O&M		509,510								
RELIABILITY IMPROVEMENT PROGRAM			72,474							
BROOK N TO D'ARCY (ELGIN)				558,943						
SPRING - FURNACE TO ORR (4.16 TO 28KV CONVERSION)					241,500	293,550				
COVERT - DIVISION TO GEORGE (4KV TO 28KV CONVERSION)						295,000				
MISC 28KV CONVERSIONS (SPOT REPLACEMENTS)					100,000	51,500				
GIS IMPROVEMENTS					60,000					
ADVANCED LATERAL PROTECTION (TRIPSAVERS)						105,000				
DISTRIBUTION SYSTEM AUTOMATION						606,686	624,888	548,067	111,460	
F7 EXPANSION (BOUNDARY TO NEW AMHERST) + 4.16KV DECOMM									312,088	434,150
System Service Gross Expenditures	0	509,510	72,474	558,943	696,500	1,056,736	624,888	548,067	423,548	434,150
System Service Capital Contributions	0	0	0	0	0	202,008	202,008	202,008	0	0
Sub-Total	0	509,510	72,474	558,943	696,500	854,728	422,880	346,059	423,548	434,150
General Plant										
FLEET - PICKUP TRUCK AND BUCKET TRUCK		53,971		572,550	70,000		63,654	90,177		
SOFTWARE UPGRADES (MISC)					54,563					
TOOLS					59,000					
FACILITIES - BUILDINGS						61,800				
SOFTWARE UPGRADES (ERP)						208,575	53,045			
SOFTWARE UPGRADES (GIS)						125,000				
SOFTWARE UPGRADES (CIS)							159,134	198,994	203,972	
General Plant Gross Expenditures	0	53,971	0	572,550	183,563	395,375	275,833	289,171	203,972	0
General Plant Capital Contributions	0	0	0	0	0	0	0	0	0	0
Sub-Total	0	53,971	0	572,550	183,563	395,375	116,699	90,177	0	0
Miscellaneous	262,084	432,843	552,115	353,475	129,100	237,095	133,143	184,859	125,393	128,532
Total Capital in service	2,119,689	5,129,635	2,222,203	2,764,570	2,627,549	2,273,129	1,996,167	1,958,111	2,001,836	2,262,966

Appendix 2AB - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period:

2027

CATEGORY	2022			2023			2024			2025			2026			Forecast Period (planned)				
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual ²	Var	2027	2028	2029	2030	2031
	\$ '000		%	\$ '000		%	\$ '000		%	\$ '000		%	\$ '000		%	\$ '000				
System Access	145	339	133%	318	3,481	995%	244	2,705	1009%	330	843	155%	336	1,973	487%	1,222	1,396	1,427	1,434	1,479
System Renewal	1,435	1,897	32%	1,131	1,417	25%	869	1,133	30%	1,173	1,086	-7%	1,195	435	-64%	347	734	736	866	1,089
System Service	320	-	-100%	315	510	62%	242	72	-70%	327	559	71%	333	697	109%	1,057	625	548	424	434
General Plant & Miscellaneous	131	262	100%	574	487	-15%	135	552	309%	138	926	571%	440	313	-29%	632	250	275	125	129
TOTAL EXPENDITURE	2,031	2,498	23%	2,338	5,895	152%	1,490	4,462	199%	1,968	3,414	73%	2,304	3,418	48%	3,257	3,005	2,987	2,849	3,132
Capital Contributions		378	--		765	--		2,240	--		650	--		790	--	985	1,008	1,028	847	868
NET CAPITAL EXPENDITURES	2,031	2,120	4%	2,338	5,130	119%	1,490	2,222	49%	1,968	2,764	40%	2,304	2,628	14%	2,273	1,996	1,958	2,001	2,263
CWIP		933			- 638			- 342			502			- 788		-	-	-	-	-
System O&M	1,020	767	-25%	1,039	932	-10%	1,058	775	-27%	1,078	1,026	-5%	1,098	1,402	28%	1,444	1,487	1,532	1,578	1,625
Capital Expenditures by appendices	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031										
Appendix 2-AA in service	2,119,689	5,129,635	2,222,203	2,764,570	2,627,549	2,273,129	1,996,167	1,958,111	2,001,836	2,262,966										
Appendix 2-BA Total PP&E incl WIP change	3,052,221	4,491,446	1,880,155	3,266,291	1,839,163	2,273,129														
Appendix 2-BA in service	2,119,689	5,129,634	2,222,203	2,764,569	2,627,549	2,273,129														
Total WIP movement	932,532	(638,189)	(342,048)	501,722	(788,386)	0														

2.0-VECC -15

Reference: Exhibit 2, section 2.2.6, pages 26, 36 Table 17

“After the ICM proceeding, LUI completed a review of developments benefiting from the station and identified development-related capital contributions totaling \$136,562. One development contribution in the amount of \$32,343 has been collected, and the remaining contributions of \$104,219 are expected to be collected as development proceeds.”

- a) At total of \$489,468 has been identified in contribution for the 2022-2026 period. Is LUI seeking the remainder of the estimated contributions identified? If so how does it propose to account for any future contributions related to these developments identified in Table 17.
- b) Has the collected \$136k in contributions been recognized in the 2027 opening rate base calculation?

a) The \$489,468 shown in Table 17 represents the forecast development-related capital contributions associated with the developments identified during the original MS28-3 planning process. It should not be interpreted as an amount that was due and collectible from developers as of the 2027 Cost of Service filing.

Table 17 identifies approximately 4.756 MVA of forecast development-related load and the corresponding estimated capital contributions that could arise if those developments proceeded as originally contemplated. A number of the developments remained classified as future developments and had not advanced to the stage at which an economic evaluation and enforceable CIAC requirement would be finalized.

As described in Exhibit 2, actual development proceeded more slowly than anticipated. Of the forecast developments considered during the original station planning process, three had advanced sufficiently for LUI to calculate development-related CIAC associated with the additional station capacity:

Development	CIAC Status	Amount
Gates of Camelot Stage 5, Phase 2	Collected	\$32,343
Densmore Meadows	To be collected	\$32,344
Tribute Phase 1 – Cobourg Trails	To be collected	\$71,875
Total		\$136,562

Accordingly, at the time of filing, \$32,343 had been collected and a further \$104,219 had been identified for collection, for total recognized development-related CIAC of \$136,562.

For the remaining developments in Table 17, LUI will continue to assess and collect applicable contributions as those developments proceed, in accordance with LUI's Conditions of Service and the Distribution System Code ("DSC") requirements in effect at the time of connection. LUI notes that the OEB amended the DSC in December 2024 to extend the connection horizon from the previous five-year standard to a maximum of 15 years for Qualifying Housing Developments, subject to the applicable eligibility and transitional requirements. Accordingly, where a Table 17 development qualifies under the current DSC provisions, LUI will apply the

extended connection horizon in determining the appropriate economic evaluation and CIAC. This provides a mechanism to recognize qualifying residential development that proceeds over a longer period than originally contemplated when MS28-3 was planned.

Any additional CIAC arising from these developments will be recorded when the associated development proceeds and the contribution become determinable. The contribution will be accounted for in accordance with LUI's normal CIAC accounting treatment and reflected as an offset to the associated capital investment. Exhibit 2 confirms that LUI's CIAC is determined in accordance with its Conditions of Service and applicable OEB requirements.

To the extent that additional contributions associated with qualifying developments arise during the remaining applicable connection horizon, potentially extending through approximately 2038 for qualifying developments, those amounts will reduce the applicable net capital additions and future rate base.

b) LUI clarifies that the full \$136,562 had **not** been collected at the time of filing. As noted above, \$32,343 had been collected and \$104,219 remained to be collected.

However, for purposes of the 2027 Cost of Service application, LUI has already reflected the full \$136,562 in its calculation of rate base, including both the amount collected and the amounts identified but not yet collected. The effect is to reduce the MS28-3 station cost considered for revenue requirement purposes from \$2,597,083 to \$2,460,521.

Exhibit 2 further confirms that, subsequent to the ICM proceeding, LUI included both the collected and the as-yet-uncollected CIAC associated with the three developments.

2.0-VECC -16

Reference: Exhibit 2, section 2.2.6, pages 29-

Component	Cost Share	Index Source	Q1 2022 Index	Q4 2025 Index	Escalation Factor	Original Cost	Escalated Cost
Labour / Construction	42%	StatCan Table 18-10-0289	94.7	109.5	1.1563	\$1,092,034	\$1,262,719
Equipment	58%	StatCan Table 18-10-0284	111.5	141.5	1.2691	\$1,505,049	\$1,910,057
Total	100%	Weighted composite			1.2206	\$2,597,083	\$3,172,776

- a) LUI presents evidence of escalating the cost of MS28-3. It is unclear to us the purpose of this evidence. IS LUI proposing to recover the calculated \$3.172M?

Response

- a) No. LUI is not proposing to recover the \$3.173 million escalated amount.

The escalation analysis was provided solely as supporting evidence for the prudence review of the MS28-3 project. It illustrates the potential cost impact had the project been deferred in the context of rapidly increasing cost pressures and supports the reasonableness of proceeding with the project when LUI did.

The actual cost of the MS28-3 project was \$2,597,083. The OEB previously approved 50% of the ICM funding request and deferred consideration of the remaining 50% pending a prudence review.

2-SEC-6

[Exhibit 2, Appendix 2-AA]

- a. Please provide the most recent 2026 actuals in the Appendix 2-AA format.
- b. Please provide actuals to the same date as provided in part a), for the historical years 2022-2025 in the Appendix 2-AA format.
- c. Please update the 2027 forecast based on the 2026 actuals if required.

Response

- a) please refer to response to 2-VEC-11
- b) Please see the response to part a)
- c) No update to the 2027 forecast is required based on 2026 actuals.

2-SEC-7

[Exhibit 2, Appendix 2-AA]

- a. Please provide a copy of the updated Appendix 2-AA from the question above, which breaks out the capital contributions by line item.
- b. Please explain how the capital contributions for 2027 to 2031 were forecasted.
- c. Please explain what is included under the line entitled "Economic Evaluation" in 2-AA and provide details of each project included under this line.
- d. Please provide the actuals for 2022-2025 for all projects which would fall under "Economic Evaluation".

Response

a) LUI confirms that it did not receive any capital contributions during 2026 YTD. Please refer to the response for 2-SEC-6 for the updated Appendix 2-AA

b) Please refer to the response to 2-VECC-10

c) The "Economic Evaluation" line in Appendix 2-AA captures development-related distribution connection investments and the associated economic evaluation true-ups. These investments support new subdivisions and other customer-initiated developments requiring distribution system extensions or upgrades. Depending on the development, the work may include conductors, transformers, poles, switchgear and related infrastructure required to accommodate new or increased customer load.

For these developments, LUI performs an economic evaluation in accordance with the Distribution System Code to determine the customer or developer's required capital contribution and the portion of the investment funded by LUI.

The evaluation considers estimated construction costs, anticipated customer connections, connection timing, forecast load and expected distribution revenues over the applicable revenue horizon. As developments progress, the evaluation is updated to reflect actual costs and actual connection activity, as required by the Distribution System Code.

These true-ups may result in additional contributions, refunds, or adjustments to LUI's net investment, and may give rise to negative amounts in a given year where a prior-period accrual is reversed or a refund is issued.

Please refer to part d of this response for list of historical projects that fall under this category.

d) Please see breakdown below for projects that fall under "Economic Evaluation" between 2022 and 2025:

Year	Name	Actuals
2022	NEW AMHERST - ACCRUAL UPDATE	-\$ 41,722.81
2023	EAST VILLAGE PHASE 1 STAGE 3	\$ 14,715.96
2023	EAST VILLAGE PHASE 1 STAGE 4	\$ 13,061.27
2023	NEW AMHERST STAGE 1B	\$ 4,015.63
2023	NEW AMHERST STAGE 2 PHASE 2	\$ 34,360.35
2023	NEW AMHERST - STAGE 1/2	\$ 5,564.57
2023	EAST VILLAGE - BGS HOMES	\$ 220,009.95
2023	FOXTAIL RIDGE	\$ 161,494.53
2023	Mason Homes - 425 King St E	\$ 20,960.27
2023	Cat Hollow, Colborne	\$ 454.86
2023	CASTLEGROVE HOMES	\$ 749.70
2023	Elgin St-William to New Amherst	\$ 276.00
2024	Rondeau Subdivision - Tribute	\$ 189,514.72
2024	Foxtail Ridge-additional costs	\$ 194.88
2024	Nickerson Wood Subdivision	\$ 6,111.68
2024	Gates of Camelot PH 5 STG 2	-\$ 2,000.99
2024	Densmore Meadows Subdivision	\$ 122,678.29
2024	NEW AMHERST - STAGE 2 PHASE 1	\$ 2,898.57
2024	Rondeau Sub Ph2 - Tribute	\$ 859.22
2024	EAST VILLAGE - BGS HOMES	\$ 1,332.69
2024	Cat Hollow Road Development	\$ 28,821.39
2024	Cat Hollow Road Development	\$ 1,292.10
2025	Rondeau Subdivision-Tribute	\$ 263.00
2025	New Amherst-Stage 2 Phase 1	\$ 200.00
2025	Eastfield Subdivision - Colb	\$ 26,631.00
2025	East Village - BGS Homes	\$ 312.00

2-SEC-8

[Exhibit 2, p. 7, Tables 1, 4-9, p.7 and Appendix 2-BA] Lakefront states "...capital expenditures and in-service additions are equivalent for the purposes of this application." Appendix 2-BA shows that there has been construction work in progress ("CWIP") in previous years with \$526,815.88 in CWIP in 2027.

- Please explain what asset(s) made up the CWIP in 2022-2027.
- When are the assets that make up the \$526,815.88 in 2027 CWIP expected to be put into service?
- Please explain why the average net fixed asset shown in 2-BA does not agree with Table 1 or Table 9.
- Please provide a version of 2-BA which agrees with Table 1 and Tables 4-9.

a) The assets making up the CWIP balance in 2022-2027 are as follows:

CWIP balances 000's						
Job description	2022	2023	2024	2025	2026	2027
Foxtail ridge	159					
New substation	380					
Outage management system	374					
Victoria St - Stn to King St	170					
Jebco battery storage	55					
Kerr St - Burnham St to POW drive	24					
Subdivisions	227	141		96		
Elgin St-Chipping to Ontario		149				
Kerr St - BurnhamSt to POW Dr		373				
Elgin-Ontario to William			154			
Brook N to D'Arcy		479	483			
F5 Feeder Elgin Brook to Trail				113		
ESRI UN GIS Upgrade				138		
Miscellaneous	57	17	14	19	179	179
Transformers	222	98	264	746	350	350
Meters	228	0	0	305	100	100
Total	1,896	1,257	915	1,417	629	629

b) The CWIP 2027 ending balance is expected to be put in service within 2028 and 2029. It is expected the 2028 CWIP ending balance will reflect any 2028 jobs not put into service and the yearend inventory for meters and transformers.

c) The submitted 2-BA schedule excludes the 2022 opening balances for capital costs and accumulated depreciation.

d) Lakefront is submitting an updated 2-BA to include the 2022 opening balances and have verified the updated 2-BA amounts agree with Table 1 and Tables 4-9.

2-SEC-9

[Exhibit 2, p.27-28]

- a. Please put a copy of Raven Engineering's 2020 Station Capacity Study on the record.
- b. Five alternatives were identified by Raven Engineering. Lakefront has explained the alternative analysis which was done for the "upgrading the MS28-2 transformer primary cables and conductors" alternative. Please provide the analysis which was done for the other four alternatives.

Response

a) A copy of Raven Engineering Inc.'s 2020 Station Capacity Study – Town of Cobourg, final issue dated December 15, 2020, is provided as part of this interrogatory response. LUI notes that the same study was previously placed on the public record in proceeding EB-2024-0038.



203110 Lakefront
Station Capacity Study

b) The Raven study did not include separate detailed cost estimates, financial evaluations or business cases for each of the five alternatives. Rather, the study identified and technically assessed a number of measures available to address LUI's capacity and contingency requirements.

For the four alternatives referenced in the question:

- **Add F3 at MS28-1:** This would improve feeder contingency and operating flexibility but would not increase MS28-1 transformer capacity or address the station-level contingency identified in the study.
- **Replace the MS28-1 transformer:** This would increase MS28-1 capacity from approximately 26.6 MVA to 32 MVA, but would retain the existing two-station configuration and would not provide an additional independent station source.
- **Add a second transformer at MS28-1:** This would provide additional transformation capacity and operating flexibility. Raven nevertheless recommended construction of a separate new 20/32 MVA station as the preferred long-term solution.
- **Add F5 at MS28-2:** Similar to F3, this would improve feeder contingency and load distribution but would not increase transformer capacity or resolve the broader station-level contingency.

Raven's study concluded that LUI's existing facilities were already inadequate under the loss of one station and that forecast development, load growth and the transfer of approximately 5.689 MVA from the 4.16 kV system would worsen this condition. Raven consequently recommended a staged approach: immediate release of the available capacity at MS28-2 through the cable upgrade, followed by construction of an additional 20/32 MVA station before the 2023 summer peak, with voltage conversion deferred until the new station was available.

LUI ultimately proceeded directly with the new station rather than first undertaking the approximately \$171,000 MS28-2 interim upgrade. As described in Exhibit 2, this avoided

expenditure on a temporary measure that would not eliminate the underlying contingency limitation and advanced the infrastructure Raven had identified as necessary for the longer-term system configuration.

2-SEC-10

[Exhibit 2, Table 22, p.31] With respect to the forecasted load growth:

- a. Please show the anticipated incremental load from planned developments by year. (Note Table 17 on page 36 provides a list, however the total load is not equal to the total load in Table 22.)
- b. Please identify each development that makes up the incremental load in part a.
- c. For each development identified in part b, please indicate what stage it was at (e.g. developer enquiry, development plan submitted, approved, construction started, etc.), at the time of the 2020 study.
- d. Please show the anticipated voltage conversion incremental load by year.
- e. Please identify each voltage conversion area that makes up the incremental load in part d.
- f. Please provide a table that shows the actual incremental load for each development by year.
- g. Please provide a table that shows the actual voltage conversion incremental load by area and year.

Response

LUI notes that Table 22 and Table 17 were prepared for different purposes and at different points in time. Table 22 reproduces the aggregate capacity-planning assumptions from Raven Engineering's 2020 Station Capacity Study, whereas Table 17 was developed subsequently as part of LUI's post-ICM review of development-related CIAC. As a result, the development totals of 3.970 MVA and 4.756 MVA do not represent the same forecast snapshot and should not have been presented as directly reconcilable. LUI provides the requested clarification below.

a) LUI clarifies that the 3.970 MVA of forecast development load shown in Exhibit 2, Table 22 is Raven Engineering's December 2020 Station Capacity Study. Raven's assessment identified approximately 3.970 MVA of incremental development load together with approximately 5.689 MVA of load expected to transfer from the legacy 4.16 kV system to the 27.6 kV system through LUI's voltage conversion program.

The 4.756 MVA appearing in Table 17 is not the same forecast snapshot. Table 17 was prepared subsequently as part of LUI's review of development-related capital contributions following the OEB's ICM Decision. That later review included a broader and updated list of developments and associated approximate transformer loading. Accordingly, Table 17 should not have been presented in a manner that implied that its 4.756 MVA total reconciled directly to Raven's 3.970 MVA forecast. Based on the later Table 17 development schedule, the anticipated loading by scheduled year was as follows:

Scheduled Year	Approx. Development Load (kW/MVA)
2022	1,932 kW / 1.932 MVA
2023	256 kW / 0.256 MVA
2024	1,668 kW / 1.668 MVA
2025	416 kW / 0.416 MVA
2026	484 kW / 0.484 MVA
Total – subsequent Table 17 review	4,756 kW / 4.756 MVA

These values are derived from the approximate transformer loading shown in Table 17. Table 17 values shall supersede Table 22 which was used in the Raven Engineering's December 2020 Station Capacity Study.

b) The developments included in the subsequent Table 17 review are:

Development	Scheduled Year	Approx. Load
Gates of Camelot Stage 5, Phase 2	2022	616 kW
Densmore Meadows	2022	492 kW
Tribute Phase 1 – Cobourg Trails	2022	728 kW
Nickerson Woods	2022	96 kW
265–327 Elgin Street East, Phase 1	2023	160 kW
440–448 Elgin Street	2023	96 kW
Cobourg Trails Phase 2	2024	456 kW
New Amherst Stage 2, Phase 3	2024	640 kW
Castlegrove Homes / CTC Lands	2024	288 kW
Gates of Camelot Phase 5, Stage 3	2024	284 kW
Gates of Camelot Phase 5, Stage 4	2025	408 kW
867–869 William Street	2025	4 kW
Industrial – 987–989 Division St	2025	4 kW
540 Elgin Street East	2026	356 kW
Block 95 East Village	2026	128 kW
Total		4,756 kW

LUI reiterates that this list was developed during the subsequent CIAC review and therefore should not be interpreted as a reproduction of the 3.970 MVA development forecast used by Raven in 2020.

c) At the time of Raven's 2020 Station Capacity Study, the developments were at varying stages of advancement. The study treated the development **forecast** as information reasonably available to LUI for system-planning purposes and included residential and mixed-use developments expected to proceed over the planning horizon.

Development	Scheduled Year	Status in 2020
Gates of Camelot Stage 5, Phase 2	2022	Developer Inquiry
Densmore Meadows	2022	Developer Inquiry
Tribute Phase 1 – Cobourg Trails	2022	Developer Inquiry
Nickerson Woods	2022	Developer Inquiry
265–327 Elgin Street East, Phase 1	2023	Developer Inquiry
440–448 Elgin Street	2023	Developer Inquiry
Cobourg Trails Phase 2	2024	Developer Inquiry
New Amherst Stage 2, Phase 3	2024	Developer Inquiry
Castlegrove Homes / CTC Lands	2024	Developer Inquiry
Gates of Camelot Phase 5, Stage 3	2024	Developer Inquiry
Gates of Camelot Phase 5, Stage 4	2025	Developer Inquiry
867–869 William Street	2025	Developer Inquiry
Industrial – 987–989 Division St	2025	Developer Inquiry
540 Elgin Street East - Tribute Phase 2	2026	Developer Inquiry
Block 95 East Village	2026	Developer Inquiry

d) Raven's 2020 study identified 5.689 MVA as the total planned transfer associated with voltage conversion but did not allocate by project but rather by station. The total voltage conversion used in Raven Engineering's 2020 Station Capacity Study is as follows by year:

Feeder	Load (MVA)	Timing
Kerr F19	1.671	2021
D'Arcy F9	0.701	2022
Orr F13	1.307	2024
Orr F14	2.010	2024
Total	5.689	-
<i>Table 6 – Voltage Conversion</i>		

The voltage conversion efforts were deferred following the 2020 Station Capacity Study. LUI's more recent system capacity assessment identifies approximately 4.5 MW of remaining 4.16 kV load as of August 2025, which is expected to transfer progressively to the 27.6 kV system between 2026 and 2031.

e) The principal voltage conversion areas identified in LUI's historical and forecast capital programs include:

- Brook Road North to D'Arcy;
- Buck/George – University to King;
- Spring Street – Furnace to Orr, including Orange Street;
- Covert Street – Division to George;
- miscellaneous 27.6/28 kV spot conversions; and
- the future F7 Expansion / Boundary to New Amherst and associated 4.16 kV decommissioning.

Buck/George project was completed in 2024 which converted approximately 0.3MW from Orr F13 Feeder to the F9 Feeder from Victoria MS28-3. The capital program shows Spring St and Covert St in 2026/2027, miscellaneous conversions in 2026/2027, and the F7 expansion/remaining 4.16 kV decommissioning in 2030–2031. The filed evidence further identifies Kerr, Orr and D'Arcy as the remaining Cobourg 4.16 kV substations intended for decommissioning as load is transferred to 27.6 kV.

f) Many of the subdivisions which were identified in Table 17 and as shown in part B above, did not proceed with their expected construction due to COVID-19 and market uncertainty. The following updated Table 17 shows the developments which have been connected and the associated load by year:

Development	Scheduled Year	Approx. Load	2023	2024	2025	2026
Gates of Camelot Stage 5, Phase 2	2022	616 kW	2.0	16.4	69.1	57.3
Densmore Meadows	2022	492 kW	0.0	89.6	210.8	152.9
Tribute Phase 1 – Cobourg Trails	2022	728 kW	6.8	145.6	385.1	269.5
Nickerson Woods	2022	96 kW	6.8	20.4	36.5	38.8
266–327 Elgin Street East Phase 1	2023	160 kW	3.6	61.2	112.5	108.3

Please note that the 2026 values are as of September 1st and does not include any connections which may occur after the dataset or incremental loading to the end of the year.

g) The following table shows the projects that are identified in LUI's capital program and the respective loads which have been converted to the 27.6kV system:

Voltage Conversion Area	Year Converted	Actual Load Transferred to 27.6 kV	Affected Area/Station
Buck/George – University to King	2024	0.3MW	George St area / Orr Station
Covert – Division to George	2026 / forecast	0 MW	Division St area / Orr Station
Spring – Furnace to Orr	2026–2027 / forecast	0 MW	Spring St area / Orr Station
Miscellaneous spot conversions	Various	0.6MW	College St area / D'Arcy Station
F7 / remaining 4.16 kV decommissioning	Future	N/A	Kerr St area / Kerr Station
Total actual transferred to date		0.9 MW	

The DSP confirms that the remaining Cobourg 4.16 kV system carried approximately 4.5 MW at the August 12, 2025 peak, with that load expected to migrate to the 27.6 kV system as conversion proceeds.

The completion of Covert St will facilitate the conversion of the 1.0MW that is currently on the F13 from Orr Station. The Covert St area is expected to be completed by November 2026. Spring St conversion will be completing efforts in 2027 and will capture the conversion of approximately 1.0 MW on the F14 Feeder from Orr Station. Miscellaneous spot conversions has already accounted for 0.6MW converted on the D'Arcy F10 feeder and will also attribute to upcoming conversions of 1.0 MW remaining on the F10 Feeder as well as the F14 Feeder from Orr Station. F7 Feeder and remaining 4.16kV project in 2030-2031 will see the remaining 4.16kV load on Kerr Station removed and allow for the 3 stations to be decommissioned.

2-SEC-11

[Exhibit 2, Tables 23 and 24] With respect to reliability:

- a. Please provide the same reliability information as provided in Tables 23 and 24 for the service area that encompasses the load served by the new MS28-3 Distribution Station (e.g. at the station level and/or the feeder level).
- b. Please explain why Lakefront chose to compare the 2025 reliability to 2024, when the station was completed in 2023.
- c. Please compare the reliability information provided in part a. for 2025 to the equivalent reliability data in 2022. If the information for part a. is not available, please provide this comparison analysis for the reliability data for the Lakefront service territory.

Response

a) MS28-3 was placed in service in December 2023, with remaining distribution connection and project completion work continuing into 2024. The load supplied by MS28-3 has also changed through voltage conversion. For example, as described in 2-SEC-10, the Buck/George conversion transferred approximately 0.3 MW from Orr Station's F13 feeder to F9 supplied by MS28-3 in 2024.

A comparable historical series for the MS28-3 service area cannot be derived from the aggregate reliability indices in Tables 23 and 24. Establishing such a series would require matching historical customer and feeder boundaries across the comparison years, including customers transferred from the 4.16 kV system.

In addition, the Cobourg 27.6 kV system includes feeder ties that permit load transfers between MS28-1, MS28-2 and MS28-3 during outages. The reliability benefit of MS28-3 can extend to customers normally supplied from the other two stations, so a station-level index for MS28-3 alone would not capture its full system benefit. LUI has accordingly provided the service-territory comparison contemplated by part (c).

b) Table 24 compares the two most recent complete calendar years, 2024 and 2025. As noted above, MS28-3 entered service in December 2023, so 2024 was the first full year of operation. Remaining distribution connection and project completion work continued into 2024. LUI acknowledges that this comparison does not establish performance against a pre-commissioning baseline. The comparison is provided below.

c) The service-territory results for 2021–2025 are set out below with the five-year average, since the annual indices vary materially with weather and supply events. The 2025 results excluding LOS and MED incorporate the correction described in 2.0-VECC-6.

Excluding LOS and MED	2021	2022	2023	2024	2025	5-yr avg
SAIDI (hours/customer/year)	0.99	0.63	2.80	3.22	1.94	1.92
SAIFI (interruptions/customer/year)	0.60	0.36	2.02	1.33	0.85	1.03

All cause codes	2021	2022	2023	2024	2025	5-yr avg
SAIDI (hours/customer/year)	1.11	32.09	3.55	6.40	4.27	9.48
SAIFI (interruptions/customer/year)	1.06	1.69	3.02	3.15	1.79	2.14

As explained in 2.0-VECC-6, two F9 interruptions associated with the March 30, 2025 storm were included in the originally reported MED-adjusted results because the major-event report had not been filed. The revised figures above reflect the exclusion of those interruptions. This correction does not change the all-cause figures. Ten events in 2022 were classified as major-event interruptions, which largely explains the all-cause SAIDI of 32.09 hours in that year.

Comparing 2025 to 2022 directly: on an all-cause basis, SAIDI decreased from 32.09 to 4.27 hours and SAIFI increased from 1.69 to 1.79. Excluding LOS and MED, SAIDI increased from 0.63 to 1.94 hours and SAIFI from 0.36 to 0.85. As noted in DSP section 5.2.3, 2022 excluding LOS and MED was LUI's best year of the five-year period. The five-year results provide context for annual variability but do not alter the observed increases between 2022 and 2025.

Using the revised figures, 2025 SAIDI of 1.94 hours is close to the five-year average of 1.92 hours, while SAIFI of 0.85 is below the five-year average of 1.03. SAIFI in 2025 was approximately 58% lower than in 2023. These system-wide changes do not, by themselves, isolate the contribution of MS28-3.

LUI does not consider the aggregate indices to be a sufficient measure of MS28-3's contribution. The station also restores contingency margin on the 27.6 kV network, which is not measured directly by SAIDI or SAIFI. This capability was used on October 26, 2025, when an equipment failure at MS28-1 required affected load to be transferred to the other two distribution stations. This included approximately 7.6 MVA of load normally supplied from MS28-1 being transferred to MS28-3. This event demonstrates the practical contribution of MS28-3's additional capacity and load-transfer capability to service restoration and contingency support.

2-SEC-12

[Exhibit 2, p.35] Please explain the reasons for the outage on October 26, 2025.

Response

a) The October 26, 2025 outage resulted from moisture and water intrusion at MS28-1, which caused the current transformers to short and resulted in the loss of the station. LUI transferred the affected load to its other two distribution stations while repairs were completed.

2-SEC-13

[Exhibit 2, Appendix B, Distribution System Plan (“DSP”), p.14] Lakefront refers to July–August 2025 customer engagement. Please provide details of the extent of the engagement (e.g. number of customers who participated, questions asked, and the specific outcomes of the consultation).

Response

LUI’s July–August 2025 customer engagement formed part of the broader customer and stakeholder consultation undertaken in support of the 2027–2031 Distribution System Plan and 2027 Cost of Service Application. The principal quantitative component was LUI’s 2025 Customer Satisfaction and Priority Survey, which consisted of 34 questions. After excluding respondents who were not LUI electricity customers, 399 electricity customers participated in the survey.

The survey sought customer input across a number of areas relevant to distribution planning, including overall satisfaction with LUI, power quality, communications, reliability, infrastructure renewal, affordability, grid modernization, outage restoration, emerging technologies, and customer understanding of electricity distribution charges. The engagement also included perspectives from residential, commercial and institutional customers.

Rather than reproducing all 34 survey questions in this response, LUI summarizes below the principal areas tested and the resulting findings:

Engagement Area	Key Customer Feedback / Result	DSP or Planning Response
Overall service and power quality	76% of respondents were very or somewhat satisfied with LUI’s overall service, and 76% were satisfied with power quality.	Supports continued focus on maintaining existing service quality while addressing targeted areas of system risk.
Customer communications	70% expressed satisfaction with communications related to electricity service.	Continued investment in outage communications, customer education and improved communication tools.
Reliability and infrastructure renewal	Maintaining and upgrading equipment ranked as the highest priority; 62% indicated reliability and grid modernization required immediate or near-term action; 87% strongly or somewhat supported replacement of aging equipment.	Reinforced the priority assigned to asset renewal, voltage conversion, automation, system hardening and replacement of aging infrastructure.
Reliability versus cost	53% preferred somewhat higher rates in exchange for improved reliability; 70% preferred faster storm restoration	Supported targeted reliability investments while maintaining an emphasis on prudent

	even where this resulted in a modest rate increase.	project sequencing and affordability.
Affordability	Affordability concerns were particularly evident among seniors and fixed-income customers.	Capital investments were phased and discretionary projects deferred where appropriate to moderate rate impacts.
Understanding of bills and distribution charges	45% indicated that they were not at all familiar with the portion of their electricity bill attributable to LUI's distribution services.	Reinforced the need for improved customer education and clearer communication regarding rates, bill components and cost drivers.
DERs and emerging technologies	Customers expressed growing interest in rooftop solar, net metering and electric vehicles.	DER accommodation, system access planning and modernization considerations were incorporated into the DSP.
Sustainability and resiliency	Customers expressed concern regarding long-term system sustainability and climate resilience.	Supported system hardening, infrastructure renewal and coordination with municipal partners.

The detailed survey evidence confirms that customers placed high value on reliability and infrastructure investment, while also emphasizing the need to manage affordability. The DSP consequently adopted a balanced approach under which renewal work is phased, non-discretionary work is prioritized, and discretionary expenditures may be deferred where appropriate to moderate customer rate impacts.

Customer feedback also influenced the nature of LUI's reliability initiatives. Customers indicated that reliability was a key priority and identified concerns with specific areas experiencing outages. In response, LUI incorporated targeted renewal and automation investments intended to maintain system performance and address areas of underperformance.

Similarly, growing customer awareness of distributed energy resources, including rooftop solar, net metering and electric vehicles, was considered in LUI's system access and modernization planning. Customer concerns relating to long-term resiliency and climate impacts were also reflected through system-hardening initiatives and municipal infrastructure coordination.

In addition to the survey, LUI undertook targeted stakeholder engagement during 2025. This included discussions with community organizations representing low-income and vulnerable customers, Municipal representatives and other stakeholders. These discussions reinforced concerns regarding affordability, awareness of OESP and LEAP, outage communications, infrastructure coordination, growth readiness and emerging electrification requirements.

Accordingly, the principal outcomes of the consultation were incorporated into the DSP through:

- phasing of capital expenditures to moderate rate impacts;
- prioritization of asset renewal and replacement of aging equipment;
- targeted reliability and distribution automation investments;
- continued modernization of LUI's 27.6 kV distribution system;
- consideration of DERs, EVs and other emerging technologies in system planning;
- strengthened outage communications and customer education; and
- continued attention to affordability, resiliency and municipal infrastructure coordination.

Taken together, LUI considers the engagement to have demonstrated broad alignment between customer priorities and the 2027–2031 DSP: customers expect LUI to maintain reliable service and renew aging infrastructure, but to undertake those investments prudently and in a manner that considers affordability.

2-SEC-14

[Exhibit 2, DSP, Table 5.3-7 and p.46] Table 5.3-7: Municipal Substation Listing shows five 4.16 kV stations. Lakefront states that the “[m]ajority of the service territory now operates at 27.6 kV”, and “[c]onversion efforts will be completed in the 2027–2031 planning horizon”.

- Please confirm that it is only the 4.16 kV for the Cobourg service territory that will be converted by the end of 2031.
- Are there any plans to convert the 4.16 kV system in Colborne in the future? If so, when? If not, please explain.
- Please provide the details of the 4.16 kV conversion program, including when the program started, which 4.16 kV stations that have already been retired and which are planned for the next five years.
- Please explain what Lakefront has done with the 4.16 kV stations that have been retired, e.g. decommissioned the building, reused the equipment, sold the land, etc.
- Please provide details of Lakefront’s plans for those stations which will be retired in the next five years.

Tarek Response

a) Yes. Appendix F specifically identifies conversion of the remaining Cobourg 4.16 kV system to 27.6 kV during 2026-2031. It assesses continued 4.16 kV operation in Colborne separately.

The five 4.16 kV municipal substations identified in Table 5.3-7 consist of:

Service Area	Station	Voltage	Capacity
Cobourg	D’Arcy MS	4.16 kV	5 MVA
Cobourg	Orr MS	4.16 kV	5 MVA
Cobourg	Kerr MS	4.16 kV	5 MVA
Colborne	Victoria MS	4.16 kV	6.7 MVA
Colborne	Durham MS	4.16 kV	5.5 MVA

The DSP also identifies three 27.6 kV distribution stations serving Cobourg: MS28-1 Victoria, MS28-2 Brook Road and MS28-3 Ontario Street. Accordingly, LUI proposes to clarify the DSP wording as follows:

“LUI plans to complete the conversion of the remaining **Cobourg** 4.16 kV distribution system to 27.6 kV during the 2027–2031 planning horizon. The Colborne distribution system will continue to operate at 4.16 kV.”

- The supplied 2027-2031 DSP does not identify a Colborne voltage-conversion project. Appendix F finds the existing 4.16 kV system has sufficient capacity over the study period.
- The conversion approach first builds the 27.6 kV infrastructure, then transfers the 4.16 kV load and decommissions the redundant system. Current Cobourg 4.16 kV stations listed in the DSP are D’Arcy, Orr and Kerr.

No 4.16kV stations have been decommissioned as yet, and the D'Arcy, Orr and Kerr stations are proposed to be decommissioned by 2031. The preliminary voltage conversion effort commenced in 2016.

d) There are no previously decommissioned 4.16kV stations that have been retired at this time.

e) LUI has not yet made a final decision regarding the ultimate disposition of the D'Arcy, Orr and Kerr station sites or all equipment associated with those stations once the Cobourg voltage conversion program is completed.

The current capital plan focuses first on completing the electrical conversion and transferring the remaining load safely and reliably to the 27.6 kV system. The DSP expressly identifies eventual decommissioning of the legacy Cobourg 4.16 kV stations as an outcome of completing the conversion program.

Once an individual station is no longer required for distribution service, LUI intends to undertake a station-specific assessment before determining its final disposition. That assessment would consider, as applicable:

- whether any transformers, breakers, relays, switchgear or other equipment have useful remaining life and can economically be reused elsewhere;
- salvage or disposal opportunities for equipment that cannot be reused;
- environmental, safety and site-remediation requirements;
- whether the building or property has an ongoing utility use;
- demolition, repurposing, retention or sale of the property;
- any municipal planning or land-use considerations; and
- the appropriate accounting and regulatory treatment of any retirement costs or disposition proceeds.

No proceeds from the future disposition of these stations have been assumed in LUI's 2027–2031 capital forecast because no final disposition decisions have been made and the timing and value of any potential sale or salvage cannot presently be determined.

2-SEC-15

[Exhibit 2, DSP, p.68] Lakefront states that “[e]ach annual capital budget and the five-year forecast considers the relative priority of proposed investments, distinguishing between non-discretionary and discretionary items.”

- a. How does Lakefront determine the priority of non-discretionary projects?
- b. Please provide a priority list for all non-discretionary projects in Lakefront’s five-year capital budget.

Response

a) LUI determines the priority of non-discretionary capital projects primarily through an assessment of regulatory or statutory obligation, safety risk, asset condition, reliability/customer impact, operational necessity, and timing constraints. For clarity, LUI considers an investment to be non-discretionary where the underlying need cannot reasonably be avoided without compromising a regulatory or customer connection obligation, public or worker safety, system reliability, asset integrity, metering compliance, or the utility's ability to safely operate the distribution system. Where appropriate, LUI may sequence or pace work within the 5-year DSP horizon based on updated condition information, outage availability, customer/developer timing, procurement and material lead times, available internal and external resources, and affordability considerations.

LUI applies the following considerations, generally in descending order of urgency:

1. **Immediate safety, legislative and regulatory requirements.** Investments necessary to address an identified public or worker safety hazard, regulatory compliance requirement, mandatory meter seal expiry, or other prescribed obligation receive the highest priority.
2. **Customer connection and externally driven obligations.** System Access projects required to connect customers, accommodate customer-requested load, or respond to municipal/road authority requirements are undertaken according to customer readiness and required service dates. LUI's DSP expressly recognizes its obligation to connect customers and uses economic evaluations and capital contributions to ensure appropriate cost responsibility.
3. **Failed, imminently failing or high-risk assets.** Assets identified through the Asset Condition Assessment ("ACA"), inspections, failure history, repeat-trouble locations and field observations are prioritized according to probability and consequence of failure. For example, pole and transformer replacement locations are selected to address the highest-risk assets first.
4. **Reliability and contingency risk.** Investments that address known reliability deficiencies, limited switching capability, repeat outage locations, feeder contingency limitations or significant customer interruption exposure are prioritized based on the magnitude and consequence of the identified risk.
5. **System configuration and lifecycle requirements.** Work necessary to complete LUI's transition from legacy 4.16 kV infrastructure to its 27.6 kV standard, retire obsolete

equipment and avoid continued investment in legacy assets is prioritized in conjunction with asset condition, reliability and project coordination considerations.

6. **Core operational and business continuity requirements.** Fleet, software, cybersecurity, GIS/SCADA and facility investments necessary to safely maintain utility operations are prioritized based on asset conditions, vendor end-of-support dates, cybersecurity exposure, regulatory requirements and operational criticality. The DSP expressly characterizes forecast fleet replacement as enabling and largely non-discretionary.

Within these categories, LUI does not replace assets solely because they have reached a particular age or condition classification. The DSP recognizes that replacing every asset rated Fair, Poor or Very Poor within one planning period would neither be affordable nor operationally practical. Accordingly, LUI targets the highest-risk assets first and phases remaining work over subsequent years or DSP cycles.

b) LUI did not assign a single absolute numerical ranking to every non-discretionary project in the filed DSP because the relative urgency of some projects changes as customer requests, asset condition, failures and other circumstances evolve. Instead, LUI applies the priority framework described above.

For purposes of responding to this interrogatory, the following presents LUI's current priority grouping of the non-discretionary or substantially non-discretionary investment needs included in the 2027–2031 capital plan:

- ERP upgrade
- 4.16 kV to 27.6 kV Conversion completion
- GIS upgrade
- AMI 2.0
- CIS & SCADA upgrade
- Pole replacement program
- FLISR (automated switching)

Although the System Automation portfolio is considered discretionary, the government funding is approved and it would be prudent to complete this project at this time from a cost saving perspective.

LUI notes that the timing of some of the above investments remains flexible even though the underlying need is not discretionary.

Further, the resulting five-year plan is deliberately paced. LUI forecasts approximately \$2.2 million of net capital investment per year over 2027–2031 and has structured the program to address the highest-priority safety, compliance, asset condition, connection and reliability requirements while avoiding unnecessary capital expenditure and material year-to-year rate impacts.

2-SEC-16

[Exhibit 2, DSP, Appendix H, p.11 and Appendix B - Budget] With respect to the Distribution Automation Strategy:

- a. Please confirm that, whether SAIDI and SAIFI are reduced by 50%, depends on the distribution of customers on a feeder and the location of the reclosure.
- b. Has Lakefront done any analysis of each feeder to determine the optimum location of a reclosure? If so, please provide. If not, please explain.
- c. The total budget shown in Appendix B is \$2.4M. The total budget in Appendix 2-AA for 2027-2030 is \$1.9M. Please explain the difference.

Response

a) Yes. The estimated 50% reduction in SAIDI and SAIFI assumes that the recloser can be located such that approximately half of the customers on a divided feeder can be isolated from an outage. The actual reduction will depend on how and number of customers distributed along the feeder, the location of the fault relative to the sectionalizing device, the location of the recloser and where an outage occurs, feeder configuration and loading and the ability to isolate the faulted section. The 50% reduction is therefore an estimate for planning purposes and not a guaranteed outcome.

Accordingly, the 50% figure in Appendix H represents an illustrative event-level benefit of sectionalization, rather than a guaranteed 50% reduction in LUI's annual system-wide SAIDI or SAIFI.

b) No, LUI has not yet completed a detailed feeder-by-feeder analysis to determine the optimal location of each recloser. LUI clarifies, however, that the Distribution Automation Strategy that was done is a planning-level roadmap and not a detailed final engineering design for every feeder. That work will be completed during detailed engineering, at which time LUI will review the feeder configuration, customer distribution and available locations for the switches.

Accordingly, the locations identified in Appendix H should be considered preferred/candidate locations rather than final engineered locations.

Prior to installation, LUI will complete detailed engineering to confirm the final device location, taking into consideration actual customer distribution, feeder loading, protection coordination, available fault current, communications coverage, constructability, transfer capability, critical customers and expected reliability benefit. Therefore, LUI has undertaken sufficient feeder-level analysis to prioritize deployment and identify candidate locations, while detailed engineering will determine the optimum final installation point for each device as individual phases of the program proceed.

c) The approximately \$2.4 million identified in Appendix H represents the broader, longer-term conceptual cost of implementing the Distribution Automation Strategy/roadmap. Appendix H was developed as a strategic planning document and identifies the potential automation architecture, devices, communications and related implementation requirements necessary to advance distribution automation across LUI's system.

The amount included in Appendix 2-AA is different because it represents the specific capital expenditures LUI is proposing to undertake during the 2027–2031 DSP period as the initial phased implementation of that broader roadmap.

Appendix 2-AA identifies the following Distribution System Automation expenditures:

Year Distribution System Automation

2027 \$607,000

2028 \$625,000

2029 \$548,000

2030 \$111,000

2031 \$0

Total \$1,891,000

Accordingly, the approximately \$509,000 difference between the \$2.4 million strategy estimate and the \$1.891 million included in Appendix 2-AA represents portions of the broader conceptual automation roadmap that are not proposed for implementation as part of the 2027–2031 Distribution System Automation capital program, together with differences arising from refinement and phasing of the strategy into LUI's actual five-year capital plan. The DSP expressly describes the proposed program as implementation of the “first phase” of the automation roadmap and focuses the forecast-period investment on feeders serving critical facilities and circuits with higher outage exposure. LUI has therefore not included the entire \$2.4 million conceptual strategy amount in its 2027–2031 capital forecast. Only the approximately \$1.891 million of work prioritized for implementation during the DSP period is reflected in Appendix 2-AA and the revenue requirement.

2-SEC-17

[Exhibit 2, DSP, Appendix I] With respect to the Asset Condition Assessment - ACA Report:

- a. Please outline Lakefront's plans to improve the data for those assets for which data is missing.
- b. Please provide a list of assets for which age is used as an input in determining the Health Index of the asset.
- c. For those assets identified in part b., please re-run the determination of the Health Index with age removed as an input.
- d. Please provide a list of assets in which age is the determining factor in whether replacement is required.

Response

a) LUI recognizes the data availability limitations identified in the 2025 Asset Condition Assessment ("ACA") and intends to address these limitations through ongoing inspection, testing, GIS/data-management improvements, and incorporation of additional condition parameters in future ACA updates. The ACA notes that data availability is fundamental to producing objective and reliable Health Index (HI) results. Where less than 70% of the weighted degradation-factor data is available for an individual asset, the methodology does not calculate a valid HI. BBA therefore recommended that LUI continue collecting condition information for degradation factors with limited availability so that a progressively greater portion of the asset population can receive valid Health Indices.

LUI's planned improvements include:

- continuing and improving routine visual inspection records for wood, concrete and composite poles;
- incorporating additional pole-testing information, including remaining-strength testing where practical;
- improving overhead conductor records, including visual-condition information and asset installation/age records;
- improving underground cable records in GIS and work-management systems, including installation date, loading history, failure history and number/location of splices;
- supplementing pole-mounted and pad-mounted transformer information with loading history and visual inspection results;
- completing missing dissolved gas analysis (DGA) and oil-quality testing for station power transformers;
- expanding infrared (IR) scanning and loading-history information for transformer assets;
- collecting service-age, IR scan and breaker timing information for station equipment where not currently available;
- improving station inspection records and equipment installation-date information; and
- incorporating the identified data gaps into LUI's broader GIS, ERP/CIS and asset-data modernization initiatives.

Accordingly, LUI views the 2025 ACA as both an asset-condition assessment and a baseline for continuous improvement in asset information. Future ACA updates are expected to rely

progressively less on assumptions and incomplete records as additional inspection, testing and asset-history information becomes available.

b) Service age is an input to the Health Index calculation for the following nine asset classes in the 2025 ACA:

Asset Class	Service Age Included in HI?	Age Weight / Total Weight
Wood Poles	Yes	4 / 10
Concrete Poles	Yes	3 / 8
Composite Poles	Yes	3 / 11
Overhead Primary Conductors	Yes	5 / 7
Pole-Mount Transformers	Yes	7 / 9
Pad-Mount Transformers	Yes	7 / 9
Station Power Transformers	Yes	12 / 64
Station Switches	Yes	3 / 28
Station Switchgear	Yes	2 / 13

Breakers use operation counts as a proxy rather than service age. Underground-cable age is reported, but no valid cable HI was calculated.

c) The Health Index is formulated using various parameters which was developed based on industry best practices. Any alterations to the methodology will require careful consideration and evaluation prior to implementation.

d) LUI does not identify any asset for which age alone is the determining factor requiring replacement under the 2027–2031 DSP. Service age is one input used in determining asset condition for several asset classes, but LUI does not apply an automatic “replace at age X” policy based solely on chronological age. Asset replacement and renewal decisions consider a combination of:

- Health Index and available condition information;
- visual and test results;
- failure history and operational experience;
- safety risk;
- reliability/customer consequence;
- asset criticality;
- maintenance requirements;
- system configuration and planning needs; and
- available capital and resource capacity.

This distinction is reflected directly in the DSP. LUI does not propose to replace every asset rated Fair, Poor or Very Poor during a single DSP cycle; instead, it targets the highest-risk assets first and phases remaining work over multiple planning cycles.

For example, the Pole Replacement Program identifies approximately 40 poles for replacement over the 2027–2031 period based on ACA recommendations and prioritizes deteriorated/high-risk assets rather than replacing poles solely because they have reached a particular age. Similarly, pad-mounted transformer replacements are selected using ACA results, system-performance considerations, reliability and safety risk, with the highest-risk units addressed first.

Accordingly, the answer to part (d) is none. Age is a useful indicator of degradation and remaining life, and in some asset classes it is a relatively significant HI input, but it is not by itself LUI's replacement criterion.

2-SEC-18

[Exhibit 2, DSP, Appendices K, L and N] With respect to pole replacements:

- a. Please provide the number of poles replaced in each year 2022-2025 by project for those projects listed in Appendix K, and please provide the condition of the poles replaced, i.e. the number of very poor, poor, etc.
- b. Please provide the number of poles forecasted to be replaced in 2026 by project for projects listed in Appendix K, and please provide the forecasted condition of the poles scheduled to be replaced, i.e. the number of very poor, poor, etc.
- c. Please provide the number of poles forecasted to be replaced in 2027-2031 by year for projects listed in Appendices L and N and please provide the forecasted condition of the poles scheduled to be replaced, i.e. the number of very poor, poor, etc.

Response

a) The table below shows the poles that have been replaced in each year 2022-2025 by project as listed in Appendix K and their respective pole condition composition. As shown, approximately 32% of the poles that were replaced are very poor or poor condition.

Historic pole replacement	Year	Condition
Elgin St - Ontario to William	2025	very poor: 8, fair: 5, good: 3
Brook to D'Arcy (trailsview)	2025	poor: 5 , fair: 14
King St Pole Line - Jebco	2023	very poor : 3 poor: 3 , fair: 17
Buck/George - University to King 28kV Voltage Conversion	2024	fair: 11, good: 5
Elgin St pole line rebuild - Chipping park to Ontario st	2023	very poor : 8, fair : 5
Durham st pole line - Durham station to King	2023	very poor : 3, poor: 1, fair: 10, good : 3
Victoria st to Ontario st	2022	fair : 3
ROW 44/27.6kV pole 73 to Durham St	2022	no poles replaced
Brook Rd/F5 Feeder - New 27.6kV Feeder	2022	fair : 8 , good : 3
Kerr street rebuild - Burnham st to Prince of Whales	2023	very poor : 3, poor 3, fair 4
Elgin st pole line rebuild - Birchwood to Chipping Park	2022	very poor : 1, poor 5, fair 10

- b) The table below shows the poles that have been and are projected to be completed in 2026 by project. As shown, approximately 37% of poles are identified as being very poor or in poor condition.

Pole replacement				
	very poor	poor	fair	good
Parliament St	2		20	3
Covert St	6		4	
Spring St	7		4	7
Pole replacement	3	4		

c) The following table shows the poles that are projected to be replaced in the various projects listed from 2027-2031 by year and condition. As shown, approximately 39% of the poles being replaced are either very poor or poor in condition. The fair and good poles are associated with the Elgin St – Strathy to New Amherst, Boundary Rd – Elgin to Kerr, Elgin – William to Strathy and Industrial Rd. All poles being targeted by the pole replacement program will be addressing very poor and poor poles throughout LUI territory.

forecasted pole replacement	Year				
	2027	2028	2029	2030	2031
Very Poor	8	8	7	5	4
Poor	5	5			
Fair		16	28	10	10
Good		2			

2-SEC-19

[Exhibit 2, DSP, Appendix L] With respect to SR-001, 3-Phase Pad-Mounted Transformer Replacement Program:

- a. Please confirm that this program covers both 3-Phase and 1-Phase Pad-Mounted Transformers.
- b. Please provide the Health Index for each of the transformers scheduled to be replaced.
- c. Please explain why Lakefront is planning to replace transformers based on end of useful life instead of Health Index.

Response

a) SR-001 is specific to three-phase pad mounted transformers.

b) At the time of filing, LUI had identified the proposed transformer candidates to have a health index of 61%. Each year, LUI will reassess the replacement candidate based on the most current asset information, including age, Health Index, inspection and infrared-scan results, loading, operating and failure history, customer criticality, consequence of failure, and opportunities to coordinate the work with other planned projects.

c) LUI is not proposing to replace transformers on the basis of age alone. End of expected useful life is used as an initial screening criterion to identify candidates. For pad-mounted transformers, service age is also the most heavily weighted input to the Health Index so the two criteria are consistent rather than alternatives. The Health Index results reflect data valid as of 2025. The units in question were 36 years old at that time. Because service age is the dominant input to the Health Index for this asset class, these units will move from the Fair band into the Poor band within the 2027–2031 period.

The ACA also recommends incorporating visual-inspection results or loading history into future assessments. Infrared scanning identifies thermal anomalies at a point in time and does not assess internal insulation, oil, windings or bushings. Moreover, the Health Index reflects asset condition only and does not account for the consequence of failure (i.e. units servicing critical customers)

Before executing a replacement, LUI will reassess the candidate transformer using the most current condition and operating information. Where the evidence does not support replacement, the work may be deferred or another unit substituted within the approved program envelope.

2-SEC-20

[Exhibit 2, DSP, Appendix L] With respect to Project SA-003, Advanced Metering Infrastructure 2.0 (AMI 2.0):

- a. Please provide an update on the work scheduled for 2026 (e.g. AMI 2.0 platform selection, communications infrastructure assessment, procurement, and vendor contracting).
- b. Please provide a table showing the total number of meters expiring each year for all meters owned by Lakefront. Please distinguish between residential and commercial meters.
- c. Please provide the total number of meters forecasted to be replaced and the total number of meters forecasted to be resealed for 2026-2031. Please distinguish between residential and commercial meters.
- d. Please provide the cost to replace a meter and the cost to reseat a meter.
- e. How many years does resealing a meter add to its useful life?

Response

a) In 2026, Lakefront is undertaking preparatory work for the AMI 2.0 program, including:

- selection of the AMI 2.0 platform;
- assessment of the supporting communications infrastructure;
- development and execution of the procurement process; and
- vendor selection and contracting.

This preparatory work is intended to confirm the preferred technology, communications requirements, implementation approach and final deployment schedule. Physical deployment of AMI 2.0 meters has not yet commenced and is planned to begin in 2027.

b)

Year	Residential	Commercial	Total
2027	7,897	27	7,924
2028	965	41	1,006
2029	170	260	430
2030	197	4	201
2031	212	71	283
Total	9,441	403	9,844

Lakefront currently owns approximately 11,460 residential and commercial meters. Accordingly, approximately 1,616 meters have seal-expiry dates after 2031.

c) Lakefront intends to use Measurement Canada's authorized statistical sampling process to address the meter populations reaching seal expiry. The current forecast assumes that approximately 10% of the meters in each expiry cohort will be sampled. Rather than reinstalling the sampled meters following testing, Lakefront plans to replace the 989 sampled meters (946 residential and 43 commercial) with AMI 2.0 meters. In addition to the 989 meters associated

with the reseals, LUI is planning to replace an additional 4,654 single phase meters and any commercial meters that fail the sampling process during the forecast period.

Lakefront is not forecasting the physical resealing and reinstallation of the sampled meters. The sampled meters will instead be replaced with AMI 2.0 meters. Where a sampled meter lot satisfies the applicable Measurement Canada requirements, the remaining meters in that lot may receive a seal-period extension and remain in service until they are reached by the AMI 2.0 replacement program. The exact number of meters receiving a seal-period extension cannot be confirmed in advance because it depends on the sampling results. If all scheduled meter lots satisfy the applicable requirements, up to approximately 8,855 non-sampled meters within the 2027–2031 expiry cohorts could receive a seal-period extension.

New meters installed for subdivisions and other new customer connections are not included in the replacement quantities above because they are new installations rather than replacements.

d) Lakefront's current unit-cost assumptions are:

Activity	Residential/1-phase	Commercial/3-phase
Sampling Cost	\$20 per sampled meter	\$80 per sampled meter
Meter Cost	\$300 per meter	\$1,000 per meter

The replacement costs represent Lakefront's current planning assumptions for the meter and associated replacement activities. The sampling costs represent the incremental cost of selecting and testing meters to determine whether the applicable meter lot qualifies for a seal-period extension. Because the sampled meters are expected to be replaced with AMI 2.0 meters, Lakefront has not included a separate cost to reseal and reinstall the sampled meters. These unit costs are preliminary and will be refined through the AMI 2.0 platform-selection, procurement and vendor-contracting processes. They do not include common program costs such as communications infrastructure, head-end systems, system integration, project management and customer communications.

e) Resealing or granting a seal-period extension does not physically extend the technical or economic useful life of a meter. It extends the period during which the meter, or an accepted batch may legally remain in service before its next Measurement Canada reverification date. For eligible electronic meters having a 10-year initial reverification period, the first seal-period extension may be up to eight years. The actual extension depends on the applicable Measurement Canada requirements, meter type, lot size, sampling history and testing results. Subsequent extensions may be shorter. Accordingly, for planning purposes, Lakefront assumes that a qualifying meter lot may receive a seal-period extension of up to eight years following successful sampling and testing.

2-SEC-21

[Exhibit 2, DSP, Appendix L and M] With respect to Project GP-002, Software Upgrades (ERP) and GP-003, Software Upgrades (GIS):

- a. Lakefront states that for the ERP “[t]his program will be executed over multiple years within the 2027–2031 forecast period ... [s]equencing and timing will be finalized through detailed project planning and procurement.” Expenditures in 2-AA show \$.209M in 2027 and \$.05M in 2028. Please provide an update on the timing or an explanation on when the timing will be finalized.
- b. Did Lakefront assess moving to cloud solutions for either the ERP or GIS upgrades? If so, please provide the results of that assessment. If not, please explain why not.
- c. Please provide information on the expenditures planned for the Software Upgrades (CIS) in 2028-2030, shown in Appendix M.

Response

a) The detailed Appendix M budget concentrates ERP spending in 2027 (\$208,575) and 2028 (\$53,045). The scope includes configuration, migration, integration, testing, training and change management, with sequencing finalized through planning/procurement.

b) The supplied ERP and GIS narratives do not document a cloud-versus-on-premises assessment. A GIS platform migration or modern integration architecture does not by itself establish the hosting decision. ERP has yet to enter the RFQ phase to determine if a cloud solution is feasible. GIS is being upgraded to UN (cloud) model and will be completed by 2027.

c) LUI plans to invest in the upgrade of its Customer Information System (CIS) to enhance business operations and maintain reliable, efficient customer and billing services. The project will be implemented over multiple years due to the complexity of the implementation and the need for adequate risk mitigation, system testing, training, and change management. The CIS is a core utility system that supports customer account management, meter and consumption data, billing and invoicing, payment processing, rate and tariff configuration, customer communications, reporting, and interfaces with other utility systems.

The planned CIS expenditures, as shown in Appendix M, are \$159,135 in 2028, \$198,994 in 2029, and \$203,972 in 2030, for a total of \$562,101 over the three-year period. The expenditures include software licensing and implementation-related activities such as system configuration, data conversion and migration, integration with existing utility systems, testing, training, and implementation support. Approximately 60% of the project costs are budgeted to be covered by LUI, with the remaining costs attributable to the Water affiliates. The expenditures forecast in Appendix M for 2028–2030 represent the utility’s planned portion of the CIS upgrade costs, including the licensing and implementation-related expenditures incurred over the project period.

The CIS upgrade is intended to modernize LUI’s billing and customer information capabilities, improve the accuracy and timeliness of billing processes, enhance customer service, reduce manual processes, and ensure that the system remains reliable and capable of supporting LUI’s operational and customer service requirements.

EXHIBIT 3 – OPERATING REVENUE

3-STAFF-14

Customer Connections

Ref. 1: Load Forecast Model / Tab Monthly Load & Customer Input sheet

From 2016 to 2020, General Service > 50 kW customer counts have fallen from 126 to 108. Since then, they have increased slightly into the 111 to 112 range from 2022 to 2025. Connections are then forecast to start decreasing again by two per year, reaching 108 in 2027.

Residential customer connections have exhibited a 2.86% increase in 2024 relative to 2023, and a 2.07% increase in 2025 relative to 2024.

The number of streetlight connections have remained constant at 3,082 from 2017 to 2025 while residential customers have increased from 9,043 to 10,168 in the same period.

Question(s):

- a) Please explain why GS > 50 customers are expected decrease in 2026 and 2027 at a rate unseen since 2020?
- b) Please provide details on all new subdivision residential customers energized in 2023-2025, and forecast to be energized for 2026 and 2027.
- c) Please explain how streetlight connections have remained constant for nine historic years, and why they are forecasted to start increasing in 2026 and 2027.
- d) Please provide the number of customers in each rate class for all months available in 2026

Response

a) The decrease in GS >50 kW customers is the result of applying the geometric mean methodology to the historical customer counts from 2016 to 2025. The resulting 10-year geometric mean growth factor for the class is 0.9822. Applying this factor to the 2025 actual customer count of 112 results in forecast customer counts of approximately 110 in 2026 and 108 in 2027.

LUI has not made any separate adjustments or assumption that specific GS >50 kW customers will leave the class in 2026 or 2027. The forecast simply reflects the application of the historical geometric mean methodology used in the load forecast model.

b)

Subdivision Name	2023 Connections	2024 Connections	2025 Connections
Densmore Meadows	31	101	0
425 King	27	0	0
Tribute Phase 1	27	148	13
Nickerson Woods	5	2	3
Cat Hollow	2	9	0
Gates of Camelot Phase 5 Stage 2	4	36	0
Eastfield's Phase 1	0	6	41

Subdivision Name	Forecast 2026 Connections	Forecast 2027 Connections
Eastfields 1B and 2	76	0
20 Park Street	0	32
Tribute Phase 1	13	0
Nickerson Woods	4	4
Cobourg Trails Phase 2	0	53
Gates of Camelot Phase 5 Stage 2	41	0
Eastfield's Phase 1	0	26
Eastfields Phase 3	0	19
Sunnyside Village	0	53
Tribute Phase 2	76	0

- c) Streetlight counts are normally provided by the Town of Cobourg and Township of Cramahe. It has come to LUI's attention that the count had not been recently updated and Lakefront did not have confidence in the data provided by the Town and Township electricians. LUI took the initiative to conduct a comprehensive inventory of all streetlights including type and wattage in the summer of 2026 in order to more accurately bill the municipalities. Additionally, Lakefront will be installing meters for all new developments in order to capture streetlight usage as General Service <50 kW customers until the streetlights ownership transfers from developers to the Town and Township.

d)

	January	February	March	April	May	June	July	August
Residential	10,268	10,271	10,274	10,274	10,276	10,279	10,285	10,303
GS<50	1,171	1,170	1,172	1,175	1,175	1,175	1,174	1,174
GS>50	114	114	114	114	114	114	114	114
Unmeter	96	96	96	96	96	96	96	96
Sentinel	49	49	49	49	49	49	49	49
StreetLights	3,082	3,082	3,082	3,082	3,082	3,082	3,082	3,082

3-STAFF-15

Energy Forecast

Ref. 1: Load Forecast Model / Tabs Adjustments and Var, Weather Sensitive Forecast

Ref. 2: Exhibit 3, p. 4

OEB staff observes that Unadjusted Wholesale purchases are adjusted to subtract load related to Weetabix to arrive at a Revised Wholesale purchases. This Revised Wholesale Purchases is then used as input to the regression model. OEB staff notes that this is likely due to the ultimate loss of this customer.

There do not appear to be any adjustments to the historic load of the GS > 50 to 4,999 rate class to account for the loss of the customer. Indeed, the total reported 2024 load of the Residential class (80.6 GWh), GS < 50 kW class (35.5 GWh), GS > 50 to 4,999 kW class (118.4 GWh), USL class (0.6 GWh) and Street Light class (1.1 GWh) total 236.3 GWh, which is greater than the adjusted wholesale for the same year of 200.8 GWh.

Question(s):

- a) Please confirm OEB staff's explanation or confirm.
- b) Please provide any reasons for not removing the Weetabix load from the GS > 50 to 4,999 kW rate class.
- c) As a scenario, please provide a forecast for the GS > 50 to 4,999 kW rate class where Weetabix is removed from the historic energy, and historic demand.

Preamble:

In preparing its response to this interrogatory, LUI reviewed and validated the historical Weetabix load data used in the Load Forecast Model. Through this review, LUI identified that the Weetabix load data used in July 1, 2026, filed model did not reflect the correct historical billing data. The table below shows the Weetabix data used in the filed Load Forecast Model:

LUI subsequently confirmed the historical billed energy and demand for the customer. The corrected data are provided below:

Year	Filed Weetabix Energy (kWh)	Corrected Weetabix Energy (kWh)	Difference (kWh)
2016	41,006,851	10,157,832	(30,849,019)
2017	37,833,820	9,585,039	(28,248,781)
2018	40,686,035	10,037,962	(30,648,073)
2019	47,861,667	12,055,870	(35,805,797)
2020	43,865,390	10,577,765	(33,287,625)
2021	41,561,895	10,421,213	(31,140,682)
2022	40,756,951	10,224,714	(30,532,237)
2023	33,562,082	8,524,110	(25,037,972)
2024	35,837,562	9,158,446	(26,679,116)
2025	26,833,138	6,931,832	(19,901,306)

The filed Weetabix energy data overstated the historical customer load. LUI has replaced these values with the corrected historical billing data and has used the corrected data to rerun the load forecast.

Response

- a) Confirmed. LUI removed the Weetabix load from historical wholesale purchases to derive Revised Wholesale Purchases for use in the regression model. As noted in the preamble, LUI has corrected the underlying Weetabix data as part of its response to this interrogatory.
- b) LUI agrees with OEB staff that a corresponding adjustment should also be made to the historical retail GS >50 to 4,999 kW class energy and demand. In the filed model, the Weetabix adjustment was made to wholesale purchases but not to the historical billed load of the GS >50 to 4,999 kW class. LUI has corrected this in the revised Load Forecast Model.
- c) LUI has rerun the Load Forecast Model using the corrected Weetabix data, removing the sole customer Weetabix from the customer count, from both historical wholesale purchases and the historical retail energy and demand of the GS >50 to 4,999 kW class.

3-STAFF-16

Energy Forecast

Ref. 1: Load Forecast Model / Tabs Adjustments and Var, Weather Sensitive Forecast

The only adjustment to wholesale purchases was to subtract load related to Weetabix.

Question(s):

- a) Does Lakefront Utilities have any connections with embedded generation, either through FIT or MicroFIT? If so, please provide historical monthly volumes, and explain why wholesale was not adjusted for these.

Response

- a) LUI does not have any connections with embedded generations other than FIT and MicroFit Below is the corrected Fit/MicroFit load and customer count.

Year	FIT kWh	FIT Cust.	MicroFIT kWh	MicroFIT Cust.	Total Embedded Generation kWh
2016	3,974,757.30	15	287,774.20	32	4,262,531.50
2017	5,456,728.50	15	253,283.30	35	5,710,011.80
2018	5,739,306.60	15	332,790.30	41	6,072,096.90
2019	5,569,450.50	15	344,742.50	41	5,914,193.00
2020	6,273,451.50	15	368,791.80	41	6,642,243.30
2021	6,393,896.40	15	365,504.80	42	6,759,401.20
2022	5,870,521.42	15	348,243.12	42	6,218,764.54
2023	6,267,870.69	15	345,814.22	42	6,613,684.91
2024	6,304,068.11	15	354,973.01	42	6,659,041.12
2025	5,858,885.22	15	319,475.22	42	6,178,360.44
2026 YTD Jan–Jul	3,513,274.20	15	191,829.70	42	3,705,103.90

3-STAFF-17

Energy Forecast

Ref. 2: Exhibit 3, pp. 12-17

From 2016 to 2025, the load forecast exhibited significant customer growth, and with the exception of Weetabix, significant load growth. In its regression models, Lakefront Utilities did not include any economic variables, nor any simple time trend variables. In fact, the only variable that would capture a trend of growth over time, was the customer connection variable.

Question(s):

- a) Did Lakefront Utilities attempt other economic or trending variables to capture the growth trend, and if so, what was the result?

Response

a) LUI considered whether additional economic or trend variables should be included in the regression but did not include them in the final model.

Customer connections were included to capture growth in LUI's service territory and improved the adjusted R-squared from 79.97% to 84.25%. LUI considered this to be a more direct measure of growth than a general time-trend variable.

LUI did not consider it appropriate to also include a time trend. Customer growth is already reflected through the customer connection variable. Adding a trend variable could capture some of that same growth again and potentially double count the effect of growth in the model. A time trend would also assume that historical growth continues simply with the passage of time, rather than linking that growth to an identifiable forecast variable.

LUI also considered broader economic and development trends. Growth within LUI's service territory has not been uniform over the historical period. LUI experienced periods of comparatively strong customer growth, including growth exceeding 3% around 2024, before the pace of development moderated as economic, financing and housing-market conditions changed. Given this variability, LUI concluded that a generalized economic or time-trend variable would not improve the forecast as reliably as actual customer connections.

Accordingly, LUI considered customer connections to be the most appropriate variable for capturing growth in the regression model. This load-forecast methodology does not alter the separate engineering and system-capacity considerations used in LUI's infrastructure planning, which consider known and anticipated developments, load requirements, system configuration, contingency requirements and long-term capacity needs.

3.0-VECC -17

Reference: Exhibit 3, pages 3 and 20

- a) Please provide revised versions of Tables 1 and 2 based on the existing customer classes (i.e., GS 50-2,999 and GS 3,000 -4,999).
- b) Please provide versions of Table 15 based on the existing customer classes (i.e., GS 50-2,999 and GS 3,000-4,999).

Response

a) Please refer to the suite of updated models filed with these interrogatory responses, including the revised Load Forecast model. The model provides the historical and forecast data separately for the existing GS 50–2,999 kW and GS 3,000–4,999 kW customer classes.

3.0-VECC -18

Reference: Exhibit 3, page 4

Preamble: The Application states: “Historically, the GS 3,000-4,999 kW rate class has contained a single customer. LUI's review of customer demand and billing characteristics indicates that the customer's demand exceeds the 3,000 kW threshold only intermittently and does not consistently exhibit the load characteristics for which the class was originally established.

Following a review of current and forecast customer demand levels, LUI has determined that maintaining separate GS 50-2,999 kW and GS 3,000-4,999 kW rate classes is no longer appropriate. The GS 3,000-4,999 kW class contains only a single customer whose demand exceeds 3,000 kW on a limited number of occasions during the year.”

- a) For the one customer currently in the GS 3,000-4,999 class please provide a schedule that indicates for each of the past 5 years the number of months in each year that the customer's billing demand was 3,000 kW or greater..
- b) For the one customer currently in the GS 3,000-4,999 class please provide a schedule that indicates the customer's average annual billing demand (i.e., average billing demand for the 12 months) for each of the past 5 years.

Response

a) The customer referenced in this interrogatory is the existing customer currently classified in the GS 3,000-4,999 kW rate class that LUI proposes to transfer to the GS 50-2,999 kW rate class. This is a different customer from the departing Weetabix facility referenced elsewhere in the interrogatory responses. The customer's monthly billing demand is provided below. The number of months in each year in which billing demand was 3,000 kW or greater is also shown.

	January	February	March	April	May	June	July	August	September	October	November	December
2021	3,950.93	4,062.83	3,809.61	3,977.51	3,718.72	3,599.52	3,999.91	3,358.56	2,938.10	2,907.39	2,762.51	3,428.96
2022	3,469.08	3,645.12	3,760.31	3,588.96	3,491.16	3,430.20	3,244.92	2,754.48	3,237.84	2,703.48	2,830.56	3,018.00
2023	3,198.60	3,185.64	3,118.56	3,221.40	3,339.48	2,406.00	2,869.32	2,643.13	2,291.92	2,275.76	2,650.43	2,080.11
2024	2,838.04	3,016.14	2,941.69	2,969.83	2,504.88	2,830.80	2,419.32	2,899.08	2,063.76	2,355.36	2,142.96	1,871.64
2025	2,806.20	3,136.56	2,637.84	3,062.28	2,539.56	2,384.64	2,772.48	3,242.39	2,903.00	2,996.40	2,607.57	2,197.31
2026	2,593.82	2,657.16	2,468.16	2,932.80	3,119.04	2,771.74	2,775.22					

b)

Year	Avg Monthly Demand
2021	3,542.88
2022	3,264.51
2023	2,773.36
2024	2,571.13
2025	2,773.85
2026 (YTD, 7 mo.)	2,759.71

3.0-VECC -19

Reference: Exhibit 3, page 5

Preamble: The Application states:

“Residential customer growth has generally been modest and aligned with historical trends. While customer additions increased by approximately 3% in 2024, this is considered an above-average year rather than a new long-term growth trend. The bridge and test year forecasts therefore reflect continued growth from known development activity but do not assume sustained annual growth at 2024 levels.”

- a) What does LUI consider to be the “historical trend” in Residential customer growth?
- b) What was the Residential customer growth for 2025 and how does this align with the “historical trend”?

Response

a) LUI considers the historical trend in Residential customer growth to be the average annual growth over the 2016 to 2025 period. Based on the geometric mean, this is approximately 1.45% per year.

The 2026 and 2027 Residential customer forecasts were developed using this historical growth rate.

b) The Residential customer count increased from 9,962 in 2024 to 10,168 in 2025, or approximately 2.07%.

While 2025 growth was above the longer-term historical average, it was lower than the approximately 2.86% growth experienced in 2024. LUI therefore continued to use the longer-term historical average of approximately 1.45% for the 2026 and 2027 forecast rather than extending the higher growth experienced in the most recent years.

3.0-VECC -20

Reference: Exhibit 3, pages 6-7

Preamble: The Application states:
“The most significant adjustment relates to the cessation of manufacturing operations at Weetabix Canada Inc. Following the public announcement by Post Holdings in April 2025 and the subsequent cessation of production activities, a substantial and permanent reduction in electricity consumption occurred within LUI's service territory. Historical production-related consumption associated with the facility was removed from the historical wholesale purchase data used to develop the regression model.” (page 6)
 and
“The forecast therefore reflects underlying system demand excluding the former manufacturing load while retaining the residual facility load expected to remain connected during the bridge and test years.”(pg. 7)

- a) How did LUI determine the “former manufacturing load” and distinguish it from the residual facility load?

Response

A) LUI used the historical metered consumption for the Weetabix facility, together with the timing of the plant closure, to distinguish the former manufacturing load from the residual facility load.

Weetabix permanently ceased manufacturing operations at the end of December 2025. Accordingly, LUI considers the manufacturing load to be zero beginning in January 2026. Consumption has continued at the site, but at substantially lower levels, as shown below.

	Jan 2026	Feb 2026	Mar 2026	Apr 2026	May 2026	Jun 2026	Jul 2026
kWh	126,260	103,855	100,104	69,200	64,289	54,258	59,799
kW	236.52	257.76	225.36	148.68	159.48	149.04	124.56

3.0-VECC -21

Reference: Exhibit 3, page 7

Preamble: The Application states:
“The bridge and test year forecasts reflect continued residential and commercial development activity within the Cobourg, Port Hope and Cramahe service territory and incorporate known customer additions included in the customer forecast. No additional material customer-specific or economic adjustments were required.”

- a) Please outline the “continued residential and commercial development activity within the Cobourg, Port Hope and Cramahe service territory”.
- b) Please explain why, based on known continued residential and commercial development activity within the Cobourg, Port Hope and Cramahe service territory, no additional customer-specific or economic adjustments were required.

Response

LUI first clarifies that Port Hope is not within LUI's licensed service territory. The reference to Port Hope in Exhibit 3 was a typographical error.

a) The referenced development activity is more accurately described as continued residential development and routine/incremental commercial activity within LUI's service territory.

Residential development has been the principal source of customer growth. LUI experienced approximately 3% customer growth in 2024, which was above historical levels and is not assumed to recur annually. Development activity includes Gates of Camelot/East Village, Densmore Meadows, Cobourg Trails, New Amherst and other residential developments and infill projects identified through LUI's development and connection processes.

These developments are at varying stages of planning, construction and connection and are not assumed to be fully connected in the 2026 Bridge or 2027 Test Year.

Commercial activity primarily consists of routine small and medium-sized connections and service upgrades. LUI is not aware of a new material commercial or industrial customer expected to materially affect Bridge or Test Year load.

Accordingly, the reference in Exhibit 3 is intended to describe continued residential development and incremental commercial connection activity, rather than broad-based economic growth or a new material large-load customer.

b) No additional customer-specific or economic adjustment was required because LUI's customer forecast is based on historical customer growth, using a geometric mean methodology. Known development activity was considered as a reasonableness check on the resulting forecast, rather than being separately added to it.

This approach avoids double counting development activity already reflected in historical customer-growth trends. It is also consistent with LUI's load profile: residential customers

continue to grow modestly, while commercial and industrial customer counts and larger-customer demand remain relatively stable.

The exception is the former Weetabix manufacturing load, where the cessation of manufacturing operations at the end of December 2025 represented a known and material structural change. LUI therefore made a specific adjustment for that load. No comparable known customer-specific event was identified for the Bridge or Test Year.

Accordingly, LUI concluded that historical customer growth, tested for reasonableness against known development activity, appropriately captures expected customer growth without requiring a separate development or macroeconomic adjustment.

3.0-VECC -22

Reference: Exhibit 3, pages 10-11
Load Forecast Model, Adjustments and Var Tab

Preamble: The Application states (Table 5 Note):
“Wholesale purchases reflect net system load delivered to LUI. Embedded generation (e.g., MicroFIT) is not included in wholesale purchases and reduces the amount of energy required from the host distributor.”

- a) Please explain why embedded generation purchases (e.g., MicroFIT) were excluded from the “purchase” values used to estimate the regression model.
- b) Please provide:
 - i. a revised version of Table 5 that also includes both purchases for HONI and embedded generation purchases.
 - ii. a revised Load Forecast Model where the purchase values used as the dependent variable included embedded generation

Response

a) As noted in Table 5 of the Application, the historical wholesale purchase values used in the original Load Forecast Model reflected electricity supplied to LUI by HONI. Embedded generation, including MicroFIT generation, was excluded because this generation is supplied directly into LUI’s distribution system and does not flow through the HONI wholesale meter.

b)

i) Please refer to the revised Load Forecast Model filed with these interrogatory responses. The model includes the historical HONI purchases and embedded generation purchases separately, as well as the combined purchase values used for purposes of the revised load forecast.

ii) LUI has rerun the Load Forecast Model to include embedded generation in the wholesale purchase series used as the dependent variable. Accordingly, the dependent variable in the revised model reflects monthly HONI purchases plus monthly embedded generation. Please refer to the revised Load Forecast Model filed with these interrogatory responses.

3.0-VECC -23

Reference: Exhibit 3, page 12

Preamble: The Application states:
"LUI tested and included a "Customer Count" variable."

a) What customer classes are included in the customer count variable?

Response

a) LUI included the 3 main weather sensitive classes namely Residential, GS<50 and GS 50-4999kW.

3.0-VECC -24

Reference: Exhibit 3, page 14

- a) Why does LUI use the HDD and CDD value as reported at the Ottawa International Airport? Are there not closer locations that could provide the required data?

Response

- a) Page 14 should have said Toronto – specifically Pearson Airport

Origin of variables

- | | |
|--------------------|--------------------------------------|
| • HDD: | Stats Canada (Toronto International) |
| • CDD: | Stats Canada (Toronto International) |
| • Days per month | Computed by the utility |
| • Customer Count | Computed by the utility |
| • Spring Fall Flag | Computed by the utility |
| • Covid Flag | Computed by the utility |

3.0-VECC -25

Reference: Exhibit 3, page 17

Preamble: The text preceding the last table on page 17 states:
"After completing the regression, the coefficients are applied to the historical wholesale purchases to produce weather-normalized values."

- a) Is the last table on page 17 meant to provide the weather normalized historical purchase values?
- b) If yes please explain how this is accomplished.
- c) Please provide a schedule (in Excel format) that sets out the following for each of the years 2016-2025:
 - a. The total actual HDD values
 - b. The annual HDD value based on "normal weather"
 - c. The difference between item (i) and item (ii)
 - d. The product item (iii) and the HDD coefficient from the regression model
 - e. The total actual CDD values
 - f. The annual CDD value based on "normal weather"
 - g. The difference between item (v) and item (vi)
 - h. The product item (vii) and the CDD coefficient from the regression model
 - i. The sum of items (iv) and (viii)

Response

a) No. The last table on page 17 compares actual historical wholesale purchases to the values predicted by the regression model using the historical explanatory variables. The 2026 and 2027 forecast values are weather normalized through the use of the 10-year average HDD and CDD values.

b) Not applicable. As explained above, the historical predicted values in the table use the actual HDD and CDD experienced in each historical month. For the 2026 and 2027 forecast, LUI replaces actual weather with the 10-year average monthly HDD and CDD values. Those normal weather values, together with the other forecast variables, are applied to the regression coefficients to determine the weather-normalized wholesale forecast.

c) The Excel Worksheet is filed with these responses

3.0-VECC -26

Reference: Exhibit 3, pages 18-21
Load Forecast Model, Weather Sensitive Forecast Tab and
Non-Weather Sensitive Tab

Preamble: The Application states:
“A trend analysis was applied to the historical allocation ratios to develop forecast allocation ratios for 2026 and 2027. This approach was selected because it better reflects the observed evolution of class consumption patterns than a simple historical average.” (page 18)

- a) Please confirm that for those classes which have load that is weather sensitive the historical annual allocation ratios will be impacted by the annual HDD and CDD values.
- b) For each of the customer classes where the results of the trend analysis were used to forecast 2026 and 2027, please indicate whether the trend was statistically significant?
- c) Please explain why USL customer class load is considered to be weather-sensitive.
- d) For each of the Residential, GS<50, GS 50-4,999 and USL classes please provide the forecasts for 2026 and 2027 based on the historical (10-year) average allocation ratio (as opposed to the trend).

Response

a) Confirmed for the Residential, GS < 50 kW and GS 50-4,999 kW classes. For these weather-sensitive classes, the historical annual allocation ratios may be affected by annual HDD and CDD values, as weather conditions may affect class consumption and therefore the resulting allocation ratios.

The utility agrees that USL is not a weather-sensitive class. USL was grouped with the weather-sensitive classes for purposes of forecasting energy consumption because it is an energy-only class and does not have a demand billing determinant. The same historical allocation approach was therefore used to forecast USL consumption. The characterization of USL as weather-sensitive in the Application should not be interpreted as indicating that USL consumption is affected by HDD or CDD.

- a) The utility reviewed the statistical significance of the linear trends in the annual allocation ratios over the 2016-2025 period. The results are as follows:

Customer Class	Trend	R ²	p-value	Statistically Significant at 5%
Residential	Increasing	0.597	0.0088	Yes
GS < 50 kW	Increasing	0.362	0.0657	No
GS 50-4,999 kW	Decreasing	0.800	0.0005	Yes
USL	Essentially flat	0.001	0.9483	No

c) The utility agrees that USL is not a weather-sensitive class. In the filed load forecast, USL was grouped with the weather-sensitive classes for purposes of forecasting energy consumption because it is an energy-only class and does not have a demand billing determinant. The same historical allocation methodology was therefore used to forecast USL consumption.

Accordingly, the inclusion of USL on the Weather Sensitive Forecast tab reflects the forecasting methodology applied to the class and should not be interpreted as indicating that USL load has a demonstrated relationship with HDD or CDD.

d) The table below compares the forecasts resulting from the trend methodology used in the Application with forecasts calculated using the simple 10-year average of the 2016-2025 historical allocation ratios. The same forecast wholesale purchases were used under both approaches.

Customer Class	Year	Trend Ratio	10-Year Average Ratio	Trend Forecast (kWh)	10-Year Average Forecast (kWh)	Difference: Average less Trend
Residential	2026	40.13%	37.81%	80,608,108	75,947,879	(4,660,229)
	2027	40.55%	37.81%	82,105,951	76,554,423	(5,551,528)
GS < 50 kW	2026	17.32%	16.64%	34,785,709	33,423,284	(1,362,425)
	2027	17.44%	16.64%	35,313,211	33,690,213	(1,622,998)
GS 50-4,999 kW	2026	56.01%	62.67%	112,506,141	125,887,095	13,380,954
	2027	54.80%	62.67%	110,952,320	126,892,469	15,940,149
USL	2026	0.30%	0.30%	601,423	602,463	1,040
	2027	0.30%	0.30%	606,035	607,275	1,240

3.0-VECC -27

Reference: Exhibit 3, pages 4 (Table 3) and 20-22
Load Forecast Model, Weather Sensitive Forecast Tab,
Non-Weather Sensitive Tab and Final LF Tb

Preamble: The Application states:
“The demand forecast for this class is based on a long-term average intensity method, which is appropriate given the small, non-weather-sensitive, and highly stable nature of the customer group. A 10-year average kW-per-customer value is used to represent the class’s typical demand intensity, and the forecast customer count is based on the geometric mean of historical customers to avoid overstating year-to-year fluctuations in this very small population.” (page 21)

- a) In the Application the GS 50-4,999 class’ kWh load forecast for 2027 is based on using the trend allocation approach applied to weather sensitive classes (per page 20 and the Weather Sensitive Tab). However, the class’ kW load forecast for 2027 is based on an average/customer allocation approach (per Non-Weather Sensitive Tab) which produces a different kWh forecast for the class. Please explain this inconsistency.
- b) Please explain why for the GS 50-4,999 and Sentinel classes a 10-year average of the kW/customer was used to forecast the 2027 billing kW when in each case the values in the initial years vary materially from those in the later years of the period.
- c) For the GS 50-4,999 class does each customer only have one connection (i.e., does the number of customers equal the number of connections)?

Response

a) LUI does not consider this to be an inconsistency. The kWh and kW billing determinants are forecast separately and may appropriately use different methodologies.

For GS 50-4,999, the two determinants are measuring different things. The kWh forecast is annual energy consumption. The kW forecast is the billing demand determinant. A customer can reduce annual energy use without reducing peak demand proportionately, or vice versa. So there is no reason the two necessarily have to be forecast with the same methodology.

b) LUI generally begins with a 10-year historical average and then reviews the resulting bridge and test year forecasts for reasonableness. Where the result does not reasonably reflect historical experience, alternative methodologies are considered.

LUI considered the variation in historical kW/customer for both the GS 50-4,999 and Sentinel classes. In both cases, the forecast resulting from the 10-year average was considered reasonable. LUI therefore did not consider an alternative trend methodology necessary.

c) Yes. For the GS 50-4,999 class, the number of customers and connections is the same. The Cost Allocation Model reflects 108 customers/connections for the class.

3.0-VECC -28

Reference: Exhibit 3, page 29

Preamble: The Application states:
“LUI’s persisting CDM impacts are reflected in historical wholesale purchases and are therefore embedded in the load forecast. As a result, no separate adjustment has been made. LUI has not been responsible for delivering CDM programs since April 2019 and is not planning or aware of any distributor-initiated CDM activities during the test year. While provincial programs such as Save on Energy (Stream 1 and Stream 2) continue to operate, these initiatives are administered by the IESO and are not forecasted at the distributor level at this time.”

- a) Is LUI current planning on implementing any local eDSM (Stream 2) programs in 2027?
- b) Please confirm that the historical purchased power values used by LUI to determine its regression model included the impacts of new CDM programs that were implemented in each of the years 2016-2025.
 - i. If not confirmed please explain why.
 - ii. If confirmed, does this not mean that the forecast implicitly assumed the continued introduction of similar new CDM programs in 2026 and 2027?

Response

- a) LUI is not currently planning to implement any local eDSM (Stream 2) programs in 2027.
- i. LUI confirms that the historical purchased power used in the regression reflects actual system load over the 2016–2025 period. To the extent that earlier CDM programs resulted in lasting reductions in consumption, those impacts would therefore be reflected in the historical load. That said, LUI cannot separately identify or quantify those impacts. For example, equipment replaced through an earlier CDM program may have since been replaced again. The regression simply captures the actual load that occurred; it does not track the continuing savings from individual CDM measures. LUI also note that there was not a consistent introduction of similar new CDM programs throughout the historical period. Earlier provincial programs ended, there was limited activity during the COVID period, and the newer eDSM programs are only now being introduced and taking shape.
- ii. For that reason, LUI does not believe the forecast assumes that similar new CDM programs will continue to be introduced in 2026 and 2027. The forecast carries forward the historical relationship observed in the load data. Any conservation or efficiency that is already reflected in that load is captured as part of the historical data, but the model does not make a separate assumption about new CDM programs going forward.

3-SEC-22

[Exhibit 3, Appendix 2-IB]

- Please provide year to date actual customer numbers/connections by class for 2026.
- Please confirm whether the customer numbers/connections shown in 2-IB are mid-year or year-end.
- Please provide year to date actual billing determinates by class for 2026.
- Please update the load forecast with the 2026 actuals provided above and any other updated variables.

Response

a)

	January	February	March	April	May	June	July	August
Residential	10,268	10,271	10,274	10,274	10,276	10,279	10,285	10,303
GS<50	1,171	1,170	1,172	1,175	1,175	1,175	1,174	1,174
GS>50	114	114	114	114	114	114	114	114
USL	96	96	96	96	96	96	96	96
Sentinel	49	49	49	49	49	49	49	49
StreetLights	3,082	3,082	3,082	3,082	3,082	3,082	3,082	3,082

b) They are based on an average by month.

c)

Year	Residential	General Service < 50 kW	General Service > 50 to 4999 kW		Unmetered Scattered Load
	kWh	kWh	kWh	kW	kWh
Jan 1, 2026	9,071,041.41	3,563,327.43	10,821,345	28,911.71	53,873.00
Feb 1, 2026	7,852,386.57	3,077,035.46	9,355,199	25,980.16	53,873.00
Mar 1, 2026	7,598,640.96	3,010,662.02	10,467,402	27,040.62	53,873.00
April 1, 2026	6,269,813.59	2,548,296.75	9,507,795	26,760.42	53,873.00
May 1, 2026	5,918,905.33	2,489,103.32	9,650,277	26,810.03	53,873.00
June 1, 2026	6,194,538.99	2,605,665.77	9,851,573	27,401.95	53,873.00
July 1, 2026	8,204,868.49	3,035,451.56	9,809,520	26,806.61	53,873.00

d)

Year	Sentinel		Street Lights		FIT		MicroFIT	
	kWh	kW	kWh	kW	kWh	kW	kWh	kW
Jan 1, 2026	3,563.34	9.00	113,632.05	244.37	49,488.40	2,176.26	4,813.50	90.65
Feb 1, 2026	3,573.60	9.00	74,082.80	244.37	128,082.40	3,619.49	9,918.00	199.83
Mar 1, 2026	3,569.04	9.00	94,999.00	244.37	445,355.30	4,227.89	23,780.50	232.35
April 1, 2026	3,569.04	9.00	80,642.10	244.37	526,818.90	4,318.19	28,142.50	234.59
May 1, 2026	3,569.04	9.00	73,861.22	244.37	787,827.50	4,304.28	41,858.80	233.17
June 1, 2026	3,569.04	9.00	65,979.90	244.37	801,209.60	4,062.93	42,592.30	222.08
July 1, 2026	3,569.04	9.00	70,073.33	244.37	774,492.10	4,087.20	40,724.10	217.64

3-SEC-23

[Exhibit 3, p.6] With respect to the adjustment made as a result of losing a GS 50-2,999 kW customer, please provide the details of the historical production-related consumption, associated with the facility, which was removed.

Response

Please see Staff-15 for update and exact load.

The adjustment referenced in this interrogatory relates to the departing Weetabix facility, which is a separate customer from the existing GS 3,000-4,999 kW customer addressed in response to 3.0-VECC-18.

Historical production-related consumption associated with the Weetabix facility, which was removed from the historical wholesale purchase data used to develop the regression model, is provided below:

Year	Filed Weetabix Energy (kWh)	Corrected Weetabix Energy (kWh)	Difference (kWh)
2016	41,006,851	10,157,832	(30,849,019)
2017	37,833,820	9,585,039	(28,248,781)
2018	40,686,035	10,037,962	(30,648,073)
2019	47,861,667	12,055,870	(35,805,797)
2020	43,865,390	10,577,765	(33,287,625)
2021	41,561,895	10,421,213	(31,140,682)
2022	40,756,951	10,224,714	(30,532,237)
2023	33,562,082	8,524,110	(25,037,972)
2024	35,837,562	9,158,446	(26,679,116)
2025	26,833,138	6,931,832	(19,901,306)

EXHIBIT 4 – OPERATING COSTS

4-STAFF-18

Customer Focus

Ref 1: Exhibit 4, pp. 19, 57

The Customer Billing expense is increased from 236,478 in 2025 to 255,736 in 2026 (19,258 increase) and then to 312,832 in 2027 (57,095 increase). This is attributed to July 1 compensation adjustments and to a new FTE for billing and collection.

Question(s):

- a) When does / did the new billing and collection position commence?
- b) Is the new billing and collecting position currently filled?
- c) Did Lakefront Utilities look for opportunities to introduce a part-time resource?
- d) Does Lakefront Utilities have opportunities for a new or existing billing and collecting resource to take on multiple functions?

Response

- a) The new Customer Service Representative position was planned to commence July 1, 2026. Recruitment has taken longer than anticipated and the position has not yet commenced.
- b) No. As of the date of this response, the position remains vacant and LUI continues to recruit for the role.
- c) No. LUI did not pursue a part-time resource. The position is a unionized full-time position intended to address an ongoing workload requirement in customer service, billing and collections, rather than a temporary or intermittent need.
- d) The position will support the existing Customer Service function, including billing and collections. The additional capacity is intended to support current workload requirements, improve follow-up on outstanding customer accounts, and respond to increasing billing and customer service demands.

4-STAFF-19

OM&A Variance

Ref 1: Exhibit 4, pp. 41, 46-57

The Miscellaneous Distribution expense increased from \$3k in 2023 to 456k in 2027. Lakefront Utilities attributes this, in part to SCADA support having been transferred from account 5630 which resulted in a \$91k increase in 2025 over 2024, and in 2026, the recruitment of a GIS/SCADA/Engineering Design resource, a Purchasing and Inventory Analyst, and a recruitment Metering Support resource.

Question(s):

- a) Are each of the positions currently filled?
- b) Do the new resources replace the SCADA consulting expense from 2025? If so, does that mean it's incrementally \$189k more expensive to do the work in-house in 2026? Please explain.

Response

a) Please refer to LUI's response to *VECC question 35*

b) No. The \$189,000 increase from 2025 to 2026 does not represent the incremental cost of replacing the 2025 SCADA consulting expense with in-house resources.

The increase in Miscellaneous Distribution expense includes the following new positions:

- GIS/SCADA/Engineering Design position: \$21,000
- PUI Meter Support position: \$33,000
- Lineperson position: \$123,000
- Purchasing/Inventory position: \$3,000

The above positions have a combined impact of approximately \$189,000 in 2026. However, these positions were added to address different operational requirements and should not all be attributed to SCADA activities.

The GIS/SCADA/Engineering Design position is the position most directly associated with providing additional in-house SCADA capability. Accordingly, it would not be appropriate to compare the full \$189,000 increase in staffing costs against the 2025 SCADA consulting expense or to conclude that performing the SCADA work in-house is \$189,000 more expensive.

4-STAFF-20

OM&A Variance

Ref 1: Exhibit 4, pp. 23, 46-57

The Outside services budget was 232k in 2022 and increased by 326k in 2023. This was attributed to consultants supporting a vacancy in the Director of Engineering, and director of Finance and Regulatory, as well as consultation costs related to exploration of consolidation activities. In 2025, an additional \$299k was required, attributed Finance and Regulatory consultants, and to Cyber Security costs of \$55k.

In 2025, \$345k was spent on outside services, which remains \$123k higher than the level from 2022. In 2025, 91k of SCADA expenses had been transferred to Miscellaneous Distribution expenses, which would have had a downward pressure on Outside Services expenditure.

Question(s):

- a) Please provide a comparison of 2025 expenditure on Outside Services to 2022, including the impact that the removal of SCADA expenses would have had.

Response

- a) The following table compares Outside Services APH 5630 actuals for 2022 to 2025 with and without the reallocated Engineering costs. The reallocated Engineering costs include SCADA and engineering consultants and GIS and engineering software costs totaling \$147,690.

Analysis of Outside services expense APH 5630			
2025 vs 2022			
Description	without Eng costs	with Eng costs	2022
Finance professional services	46,842	46,842	47,956
Finance consultants	108,255	108,255	0
Regulatory consultants	21,205	21,205	0
Engineering consultants	0	112,633	49,448
IT consultants	109,879	109,879	84,717
HR consultants & recruiting	49,487	49,487	18,404
Finance ERP software	19,148	19,148	13,315
Legal	26,651	26,651	1,150
Miscellaneous	(36,362)	(1,305)	17,494
Total	345,105	492,795	232,484

4-STAFF-21

Employee Costs

Ref 1: Exhibit 4, pp. 69

Lakefront Utilities was approved for 3 Management FTEs in 2022. 2022 Actual reflected 4.83 FTEs. In 2027, there are forecast to be 6.06 FTEs.

The incremental FTE increase from 2022 to 2027 actuals is 1.23, while the incremental wages over the same period is \$479k or 93%.

Question(s):

- a) Please provide details which management positions were included in the 2022 Approved and in the 2022 Actual, as compared to the 2027 Proposed.
- b) Are management performing functions that were previously performed by non-management staff?
- c) Please describe any benchmarking undertaken of compensation levels with peer distributors, along with any results.
- d) What commensurate value are customers receiving for the increase in staffing and compensation levels?

Response

a) Please refer to 4-SEC-30-c

The chart provides a position-by-position reconciliation constructed for the management and supervisory resources reflected in the 4.83 FTEs reported in 2022 Actual and the 6.06 FTEs proposed for 2027.

The three management positions included in the 2022 OEB-approved complement were the President & CEO, Director of Regulatory & Finance, and Director of Engineering & Operations.

The Appendix 2-K amounts reflect the portion of management resources allocated to LUI and therefore include fractional allocations for shared resources rather than a simple count of individual positions.

The change between 2022 Actual and 2027 reflects vacancies, organizational changes and the rebuilding of internal management and supervisory capacity following several years of staffing transitions and reliance on external resources. Exhibit 4 identifies a number of management, engineering, finance and operational transitions over this period.

b) To some extent, responsibilities were redistributed between management and non-management staff during periods of vacancy. However, the increase in management resources is not primarily the result of transferring non-management duties to management.

The more significant change has been the restoration of internal management and supervisory capacity in areas that had been supported through temporary arrangements, reassignment of responsibilities and external consultants, particularly in engineering, operations, finance and regulatory functions.

c) LUI benchmarks compensation using the MEARIE Management Salary Survey, the CHEC compensation/labour-rate survey and a review completed by Compensation Governance Partners using MEARIE market data and Korn Ferry Hay job-sizing methodology.

The CGP review found LUI's benchmarked compensation to be approximately 18% below P50 using the All-Organizations comparator and approximately 9.5% below P50 using the revenue-under-\$10-million comparator. After the compensation adjustments reflected in the 2027 Test Year, LUI estimates the benchmarked positions remain approximately 10% below P50 in aggregate.

d) The staffing and compensation changes are intended to provide a more stable internal workforce, strengthen succession and operational continuity, and reduce reliance on consultants for core utility functions.

LUI's total staffing increases from 17.58 FTEs in 2022 to 20.91 FTEs in 2027 but remains below the 22.20 FTEs approved in 2012. The increase in compensation also reflects more than the 1.23 increase in management FTEs, including changes in workforce structure, compensation adjustments, employee progression, benefit costs and the transition of consultant-supported functions to internal resources.

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4-STAFF-22

Procurement

Ref. 1: Exhibit 4, pp. 64-67

Question(s):

- a) On a dollar basis, what percentage of capital equipment/material and outside services, received or placed in service, per year in the test period, will have been sourced from Canadian suppliers? Please explain.
 - a. What are the total forecast amounts received or placed in service per year in the forecast period.
- a) On a dollar basis, what percentage of OM&A spend for each equipment/material and services in the test year will have been sourced from Canadian suppliers?
 - a. What is the total forecast amount in the test year.

Response

LUI does not currently track supplier country of origin or the manufacturing origin of individual equipment and materials. Accordingly, the percentages below are management estimates based on historical purchasing practices, known vendors and contractors, and the nature of the 2027–2031 capital plan and 2027 Test Year OM&A forecast.

For this response, a purchase is considered Canadian-sourced where LUI contracts with a supplier, distributor, contractor, consultant or service provider operating through a Canadian business establishment. This does **not** necessarily mean the underlying equipment was manufactured in Canada. LUI's Procurement Policy does not prescribe a Canadian-content target.

a) Capital equipment/material and outside services

LUI estimates that approximately 90%–95% of capital equipment, materials and externally procured services, on a dollar basis, will be sourced through Canadian suppliers or service providers over the 2027–2031 period. For purposes of this response, LUI uses a central estimate of approximately 92%. This estimate reflects that most construction, engineering, civil and field services are provided by Canadian contractors, and most electrical materials are purchased through Canadian distributors or Canadian operations of manufacturers. Certain specialized GIS, SCADA, AMI, telecommunications and IT equipment may originate outside Canada. Applying the 92% estimate illustratively to LUI's forecast net capital expenditures:

Year	Forecast Net Capital	Approx. Canadian-Sourced Equivalent
2027	\$2.273M	\$2.091M
2028	\$2.155M	\$1.983M
2029	\$2.157M	\$1.984M
2030	\$2.206M	\$2.029M
2031	\$2.263M	\$2.082M
Total	\$11.054M	\$10.170M

b) Total forecast amounts received or placed in service

LUI's forecast net capital expenditures are:

2027: \$2.273 million
 2028: \$2.155 million
 2029: \$2.157 million
 2030: \$2.206 million
 2031: \$2.263 million

The five-year total is approximately \$11.054 million. Actual amounts placed in service may differ from annual expenditures because of project timing, construction work in progress, customer contributions, procurement lead times and in-service dates.

c) 2027 Test Year OM&A equipment/material and services

LUI similarly does not track supplier nationality for OM&A expenditures. Based on the expected Test Year procurement mix, management estimates that approximately 90% of externally procured OM&A equipment, materials and services will be sourced through Canadian suppliers or service providers.

Estimated Canadian-sourced shares are:

Category	Estimated Share
Materials, supplies and equipment	80%–90%
Contractor, engineering and field services	90%–95%
Professional, legal, accounting and regulatory services	98%+
Software, IT and technology services	70%–85%
Overall externally procured OM&A	~90%

The lower percentage for technology reflects the use of multinational software and equipment vendors, even where procurement occurs through Canadian distributors or operations.

d) Total 2027 Test Year amount

LUI's total filed 2027 Test Year recoverable OM&A forecast is \$4,146,221.

LUI notes that the estimated 90% Canadian-supplier proportion should **not** be applied to total OM&A because the \$4.146 million includes salaries, wages, employee benefits and other costs that are not externally procured equipment, materials or services.

Accordingly, the 90% estimate applies only to the externally procured component of OM&A.

LUI considers the above percentages to be reasonable management estimates based on its historical supplier relationships and expected procurement activities. A precise calculation would require a vendor-by-vendor review and, for equipment purchases, would still not necessarily establish the country of manufacture.

4-STAFF-23

Compensation

Ref 1: Exhibit 4, pp. 73

Lakefront Utilities states that compensation levels for unionized employees are established through the collective agreement with CUPE Local 3839.

Question(s):

- a) Please indicate the term of the current collective agreement.
- b) For all years 2022 to 2027, please indicate the number of unionized FTEs
- c) For all years from 2022 to 2031 where a collective agreement was / is in force, please provide the annual adjustment to compensation, and when the adjustment takes effect.
- d) For any non-unionized non-management employees, please describe the approach to annual increases.

Response

a) LUI's current collective agreement with CUPE Local 3839 covers the period from February 1, 2022 to January 31, 2027.

b) LUI will provide the number of unionized FTEs for each year from 2022 through 2027 as follows:

Year	Unionized FTEs
2022 Actual	8.13
2023 Actual	8.11
2024 Actual	8.92
2025 Actual	9.20
2026 Bridge	8.76
2027 Test Year	11.22

The FTE figures will reflect the portion of unionized employee time attributable to LUI's regulated electricity distribution activities, consistent with the FTE methodology used in Appendix 2-K.

c) The general wage adjustments established under the current collective agreement are as follows:

Effective Date	General Wage Adjustment	Status
February 1, 2022	1.85%	Collective agreement
February 1, 2023	3.00%	Collective agreement
February 1, 2024	3.00%	Collective agreement

February 1, 2025	3.00%	Collective agreement
February 1, 2026	3.00%	Collective agreement
February 1, 2027	Not yet determined	Current collective agreement expires January 31, 2027
2028–2031	Not yet determined	Subject to successor collective agreement(s)

d) For non-unionized, non-management employees, compensation is reviewed periodically by management and approved through LUI's applicable governance and budgeting processes.

The review considers a combination of factors, including:

- external compensation benchmarking against comparable Ontario electricity distributors;
- labour market conditions and recruitment and retention experience;
- inflationary conditions;
- the responsibilities, scope and complexity of the position;
- internal compensation relationships and equity;
- employee progression and changes in responsibilities, where applicable; and
- LUI's operational requirements and overall ability to manage employee-related costs prudently.

4-STAFF-24

Corporate Cost Allocation

Ref 1: Exhibit 4, pp. 85-86

Lakefront Utilities indicates that it pays Lakefront Utility Services Inc. for services without markup, profit allowance, or percentage-based surcharge. It indicates that resources dedicated to Lakefront Utilities, have been passed through at cost, while an allocation, assessed by KPMG is used for shared services.

Question(s):

- a) Please allocations used for the “Allocated Share of General Management Services”.
- b) For costs were Lakefront Utilities has both “Directly Benefiting” costs, and an “Allocated share of General Management Services” such as accounts 5615, and 5630, what steps have been taken to avoid a double count – e.g. Lakefront Utilities paying for a shared resource when it’s already served by and paying for a dedicated resource.

a) Response

a) Allocated Share of General Management Services

KPMG’s September 3, 2026 draft review refined LUI’s shared-services allocation methodology by distinguishing between:

1. costs directly attributable to a specific affiliate; and
2. residual shared corporate costs that benefit multiple entities and cannot reasonably be directly assigned.

LUI’s 2025 Office and General cost pool was \$529,903. Of this amount, \$345,606 was directly allocated to specific service recipients and the remaining \$184,296 was treated as residual shared corporate services.

The residual pool was allocated as follows:

Recipient	Allocation Amount	
LUI	47.5%	\$87,541
WaterWorks	47.5%	\$87,541
HoldCo	5.0%	\$9,215
Third-party Townships	0%	\$0

Accordingly, LUI’s total allocation was \$230,663, consisting of \$143,122 of directly attributable costs and \$87,541 of residual shared corporate costs. The residual allocation is applied only after directly attributable costs have been removed from the pool. It is not a markup or surcharge on costs already assigned to LUI.

For example:

Account	Directly Benefiting LUI	Allocated Share of Residual Costs	Total
5615 – General Administrative Salaries & Expenses	\$39,102	\$22,395	\$61,497
5630 – Outside Services Employed	\$18,666	\$22,605	\$41,271

The amounts in the two columns represent different underlying costs.

b) Measures to Prevent Double Counting

LUI's methodology uses a sequential allocation process designed to prevent duplication:

- costs identifiable to LUI are assigned directly using timesheets, vendor invoices, job coding and other supporting records;
- once directly assigned, those costs are removed from the residual shared-cost pool;
- only costs that cannot reasonably be assigned to a single recipient are allocated as shared corporate services; and
- dedicated LUI resources are distinguished from separate corporate support costs such as HR, payroll, finance, IT, insurance and governance.

Accordingly, if an employee's salary is already directly charged to LUI, that salary is not also included in the residual general-management allocation.

For Accounts 5615 and 5630, the direct and allocated amounts therefore represent separate expenditures, not duplicate recovery.

Additional controls include reconciliation to the general ledger, documented allocation drivers, annual true-ups, standardized cost-centre mapping, supporting documentation, and preparer/reviewer approval.

LUI therefore confirms that direct assignment takes precedence over indirect allocation, and no cost is allocated to LUI a second time after it has already been directly assigned.

4-STAFF-25

Other Post-Employment Benefits Cost (OPEB) Accounting Method

Ref. 1: Exhibit 4, August 12, 2026, p. 77

Ref. 2: EB-2015-0040, OEB report on Regulatory Treatment of Pension and Other Post-employment Benefits Costs, September 14, 2017

Ref. 3: 2027 DVA Continuity Schedule, Tab 2b

Ref. 4: EB-2021-0039, Exhibit 4, April 30, 2021, p. 37

Ref. 5: Exhibit 1, Appendices A - 3 years of Financial Statements

In Reference 1, Lakefront Utilities states that “its post-retirement benefit obligations on a pay-as-you-go (cash) basis through retiree benefit premiums. The actuarially determined obligation is recorded for financial reporting purposes.”. Additionally, in Table 33 of Reference 1, Lakefront Utilities outlines the historical and forecast retiree premium costs and the actuarially determined net benefit liability.

Table 33 – Post Retirement Costs

Item	2022 Historical	2023 Historical	2024 Historical	2025 Historical	2026 Bridge	2027 Test
Retiree premiums	16,139	16,862	17,689	15,043	15,495	15,960
RSM OPEB Net Benefit Liability as of Dec 31	415,543	467,349	447,861	427,088	413,643	NA

In Reference 4, Lakefront Utility confirms that accrual accounting method is used in rate setting for pension and OPEB amounts and there has been no change in the accounting method for pension and OPEB costs since Lakefront’s last rebasing application.

Page 8 of Reference 2 states that,

...If the accrual accounting method is used, a variance account will be used to track the difference between the forecasted accrual amount in rates and actual cash payment(s) made. An asymmetric carrying charge sub-account in favour of ratepayers will be used.

In the 2027 DVA Continuity Schedule, OEB staff notes that there is nil amount reported in Account 1522, Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential account from 2021 to 2025.

Furthermore, in Reference 1, Lakefront Utilities confirms the most recent actuarial valuation of the post-retirement non-pension benefit plan prepared by RSM Canada Consulting LP is included as Appendix 4A. However, OEB staff notes that the actuarial report filed in Appendix 4A of the original Exhibit 4 submission has been removed from the August 12th version of the same exhibit.

Question(s):

- a) Please confirm whether the actuarial report as of December 31, 2023, prepared by RSM Canada Consulting LP and filed in Appendix 4A of the original Exhibit 4 submission, is also intended to be filed as part of the August 12 version of the same exhibit.
 - i. If not, please explain why the report was removed from the updated filing and provide a copy of a most recent actuarial valuation report of the post-retirement non-pension benefit.
 - ii. Please explain why there is no updated actuarial valuation procured for the 2027 test year.
- b) Please confirm whether Lakefront Utilities continues using the accrual accounting method OPEB amounts in rate setting as approved in its 2022 Cost of Service.
 - i. If yes, please explain why there is no amount reported in Account 1522, Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential account from 2021 to 2025.
 - ii. If not, please provide sufficient supporting rationale and evidence for the change in reporting method and quantify the impact of the change.
- c) Please provide the forecasted OPEB net benefit liability for 2027.
 - i. Please provide a breakdown of the OPEB net benefit liability for 2026 and 2027 in the same format as the post-employment benefits disclosure presented in Note 4 of Lakefront Utilities' 2025 Audited Financial Statements.

Response

a) Yes. LUI confirms that the December 31, 2023 actuarial valuation prepared by RSM Canada Consulting LP is the most recent actuarial valuation of LUI's post-retirement non-pension benefit plan and is intended to form part of the evidence supporting the August 12, 2026 updated Exhibit 4 filing.

The report was inadvertently omitted from the August 12, 2026, version of Exhibit 4. LUI will provide the December 31, 2023 RSM actuarial valuation report as part of its response to this interrogatory.

- a) ii. The December 31, 2023 RSM actuarial valuation provides projections through 2026 and remains the most recent completed actuarial valuation available to LUI.

LUI did not obtain a new actuarial valuation specifically for the 2027 test year because the plan remains substantially unchanged and the existing actuarial valuation provides a reasonable basis for forecasting the obligation. LUI has used the available actuarial information, together with the historical and forecast retiree premium costs and the 2025 audited financial statement information, in developing its 2027 OPEB forecast.

LUI recognizes that the actuarial valuation does not provide a specific December 31, 2027 liability. Accordingly, the 2027 amount presented for rate-setting purposes is a forecast rather than a new actuarially determined valuation.

b) Yes. LUI confirms that it continues to use the accrual accounting method for OPEB amounts in rate setting, consistent with the methodology approved in its 2022 Cost of Service proceeding.

LUI recognizes the OPEB obligation for financial reporting purposes based on the actuarially determined obligation. The retiree benefits themselves are funded on a pay-as-you-go basis through retiree benefit premiums.

i) The nil balance in Account 1522 does not represent a change from the accrual accounting methodology.

The annual change in the OPEB obligation is recognized in Account 5646 – Employee Pensions and OPEB. Accordingly, the year-over-year movement in the OPEB obligation is reflected in the employee pension and OPEB expense rather than being recorded as a balance in Account 1522.

LUI's accounting treatment recognizes the actuarially determined OPEB expense and the related changes in the obligation, while the retiree benefits are funded on a pay-as-you-go basis through retiree benefit premiums.

c) LUI forecasts the 2027 OPEB net benefit liability at \$399,793. This amount is a forecast for rate-setting purposes based on the available actuarial information and the expected movement in the post-employment benefit obligation.

The year-over-year change in the OPEB obligation is reflected in Account 5646 – Employee Pensions and OPEB.

i) The following table provides the 2026 and 2027 forecasted OPEB obligation in the same format as the Note 4(b) disclosure in LUI's 2025 Audited Financial Statements:

Post-employment benefits

Reconciliation of the obligation	2027	2026	2025	2024
Defined benefit obligation, beginning of the year	413,642	427,088	448,267	467,343
Included in profit or loss:				
Current service cost	10,093	9,799	9,241	8,830
Interest cost	19,446	18,880	19,670	20,595
	29,539	28,679	28,911	29,425
	443,181	455,767	477,178	496,768
Benefits paid	(43,389)	(42,125)	(50,090)	(48,501)
Actuarial (gain) loss				
Post-employment benefits obligation ending balance	399,793	413,642	427,088	448,267
Year over year change	(13,849)	(13,446)	(21,179)	(19,076)

4-STAFF-26

OPEB

Ref. 1: Exhibit 4, p. 23

Ref. 2: APH, Article 220, p. 189

Ref. 3: Exhibit 1, Appendices A - 3 years of Financial Statements

In Reference 2, the OEB Accounting Procedure Handbook provides guidance for Account 5646, Employee Pensions and OPEB, which states that,

The cost of non-OMERS pension expense and OPEB expense as determined by IAS 19 *Employee Benefits* shall be recorded in this account. Sub-accounts should be used to record the components of the expense recognized during each period, for example current service cost, interest cost, expected return on plan assets, actuarial gains and losses and past service costs are reported in separate sub-accounts.

Table 7 in Reference 1 shows that, between 2022 and 2027, the only amount reported for Account 5645, Employee Pensions & OPEB, is a \$21,179 credit in 2025, while all other years are nil.

OEB staff has outlined the benefits paid amounts reported in Lakefront Utilities audited financial statements from 2022 to 2025 in the table below.

Audited Financial Statements	2022 (2023 Financial Statement, Note 14)	2023 (2023 Financial Statement, Note 14)	2024 (2024 Financial Statement, Note 4)	2025 (2025 Financial Statement, Note 4)
Benefits Paid	- \$ 65,014	- \$ 51,000	- \$ 48,501	- \$ 50,090

Question(s):

- a) Please explain why there is a one-time credit of \$21,179 recorded in 2025 between the periods of 2022 and 2026.
 - i. Please provide a breakdown of the \$21,179 credit.
 - ii. Please clarify why there is no forecasted non-OMERs pension expense and other post-employment retirement benefits (OPEBs) expenses in the bridge year 2026 or the test year 2027.
- b) Depending on the response to part b) of OEB Staff Interrogatory 4-staff-2,
 - i. If the cash method is adopted, please explain why the amounts reported in Account 5645, as presented in Table 7, do not align with the benefit payments reported in Lakefront's audited financial statements.
 - ii. If the accrual method is adopted, please explain how the components of the actuarially determined OPEB costs, including the current service cost, interest

cost, expected return on plan assets, actuarial gains and losses and past service costs, is reflected in Account 5645.

c) Please provide an updated Exhibit 4 and applicable appendices, if necessary.

Response.

a) LUI has reviewed the OPEB reconciliation and the amounts reported in Account 5646 – Employee Pensions and OPEB.

LUI confirms that the OPEB amounts were incorrectly reported under APH Account 4235 – Miscellaneous Service Revenues from 2022 to 2024. This was an accounting classification error. Beginning in 2025, the amounts were corrected and reported under the appropriate APH Account 5646 – Employee Pensions and OPEB.

One-time \$21,179 credit recorded in 2025. The \$21,179 credit reported in 2025 represents the year-over-year decrease in Lakefront's post-employment benefits obligation, as reflected in the reconciliation below.

Post-employment benefits

Reconciliation of the obligation	2027	2026	2025	2024	2023	2022
Defined benefit obligation, beginning of the year	413,642	427,088	448,267	467,343	415,543	643,928
Included in profit or loss:						
Current service cost	10,093	9,799	9,241	8,830	14,600	25,940
Interest cost	19,446	18,880	19,670	20,595	19,700	16,508
	29,539	28,679	28,911	29,425	34,300	42,448
	443,181	455,767	477,178	496,768	449,843	686,376
Benefits paid	(43,389)	(42,125)	(50,090)	(48,501)	(51,000)	(65,014)
Actuarial (gain) loss					68,500	(205,819)
Post-employment benefits obligation ending balance	399,793	413,642	427,088	448,267	467,343	415,543
Year over year change	(13,849)	(13,446)	(21,179)	(19,076)	51,800	(228,385)

i). Breakdown of the \$21,179 credit

The 2025 change in the obligation is calculated as follows:

- Opening obligation: \$448,267
- Plus: Current service cost: \$9,241
- Plus: Interest cost: \$19,670
- Less: Benefits paid: (\$50,090)
- Ending obligation: \$427,088
- \$427,088 – \$448,267 = (\$21,179)

The resulting \$21,179 credit reflects the net decrease in the post-employment benefits obligation.

ii. 2026 Bridge Year and 2027 Test Year

The absence of a separate forecasted amount in Account 5646 for 2026 and 2027 was due to the presentation of the forecast rather than an assumption that LUI has no post-employment benefit obligations.

As shown in the post-employment benefits reconciliation, LUI continues to have an obligation and associated costs in both years:

- 2026: Current service cost of \$9,799 and interest cost of \$18,880, for total costs of \$28,679, with benefits paid of \$42,125.
- 2027: Current service cost of \$10,093 and interest cost of \$19,446, for total costs of \$29,539, with benefits paid of \$43,389.

The year-over-year change in the obligation is forecast to be a \$13,446 credit in 2026 and a \$13,849 credit in 2027.

LUI will update Exhibit 4 to appropriately reflect these amounts and ensure that the OPEB-related expenses and changes in the obligation are presented in the appropriate APH account.

b)

i) N/A

ii) LUI confirms that the accrual accounting method continues to be used for OPEB amounts.

Under the accrual method, LUI records the actuarially determined OPEB expense when the benefits are earned, rather than when cash is paid. The expense is recorded in Account 5646 – Employee Pensions and OPEB.

The OPEB expense is separate from the cash benefits paid. Benefits paid reduce the OPEB liability and therefore may be higher or lower than the annual OPEB expense.

LUI does not have plan assets and has no forecasted actuarial gains/losses or past service costs for 2026 or 2027.

The \$21,179 credit in 2025 represents the net reduction in the OPEB obligation after recognizing the actuarially determined expense and benefits paid, it is not the cash benefit payment.

LUI has corrected the prior-year classification and will report OPEB amounts under APH Account 5646 going forward.

c)

LUI will provide an updated Exhibit 4 and applicable appendices, as necessary, to correct the presentation of the OPEB amounts and ensure that the amounts are reported under the appropriate APH Account 5646 – Employee Pensions and OPEB.

LUI acknowledges the prior-year classification error under APH Account 4235 and has corrected the reporting in 2025 and going forward.

4.0 -VECC -29

Reference: Exhibit 4, page 22

- a) Does account 5130 "Maintenance of Overhead Services" include services other than vegetation management? If yes, please provide just the vegetation management costs for each year 2022 to 2027.

Response

- a) Account 5130 includes repairs, replacement of deteriorated components, storm response and restoration activities.
Account 5135 includes the vegetation management activities and costs as follows:

Tree trimming costs APH 5135							
	2027	2026	2025	2024	2023	2022	2022 BA
Total	63,885	62,024	59,754	58,903	64,068	42,534	55,068

4.0 -VECC -30**Reference: Exhibit 4, page 19**

a) How was the bad debt estimate of 58,987 for 2027 calculated?

Response

a) The 2027 bad debt estimate is based on the 2025 actual write off's and adjusted for inflation per the following table:

Actual bad debt writeoffs				
Write off period	# of mths	Total writeoffs	Monthly	Annualized
2025	12	57,821	4,818	57,821
Q1 2026	3	18,435	6,145	73,740
*Q2 2026 incl 48% commercial	3	43,142	14,381	172,567
Q2 2026 excl 48% commercial	3	22,434	7,478	89,735
2026 budget in line with 2025 actual write offs.				57,269
2027 budget 3% increase				58,987
*48% of the bad debt write off's are for 4 commercial accounts.				

4.0 -VECC -31

Reference: Exhibit 4, page 29

“During 2023, the increase was primarily driven by consulting costs incurred to support vacancies in the Director of Engineering and Operations and Director of Finance and Regulatory positions. These transitional consulting costs contributed to the increase in Administrative and General OM&A”

- a) Please identify and provide all the consulting costs separately (by category /r consultant) for each year 2022 to 2025.

Response

- a) The following table provides consulting costs by major category for 2022-2025

Consultant costs 2022-2025				
	2025	2024	2023	2022
Finance consultants	108,255	159,824	38,706	0
Regulatory consultants	21,205	126,798	41,790	0
Engineering consultants	112,633	224,840	234,521	49,448
IT consultants	109,879	117,472	62,215	84,717
HR consultants	12,154	8,058	14,886	18,404
Total	364,126	636,992	392,118	152,569

4.0 -VECC -32

Reference: Exhibit 4, page 32

- a) Please explain the nature of the exceptionally large bad debt costs of \$210,278 in 2025.

Response

- a) It became apparent that the receivables in the 90+ days aging category were rising at a multiplying rate from 2022 to 2024. In 2025, LUI undertook a review of its aged receivables and ensured the reserve was properly established. Bad debt expense was higher in 2025 than in prior years due to:
- The reserve percentages for the outstanding AR balances between the 60 and over 90 increased from 25% and 50% to 40% and 80% respectively due to the increase over 60 days
 - The 2025 total over 60 days aging has increased over 400% since 2022 noted in the table below 'NorthStar AR aging electric'.

NorthStar AR aging electric								
Year	Current	31-60 days	61-90 days	over 91 days	Total	Total 60 days +	% Changes	
							Annually	Cummulative
June 30/26	2,438,513	97,343	50,228	197,225	2,783,310	247,453	-8%	421%
2025	2,784,959	77,241	61,807	207,085	3,131,092	268,892	83%	466%
2024	2,681,779	62,667	33,068	114,109	2,891,622	147,177	120%	210%
2023	2,583,314	39,555	16,493	50,487	2,689,849	66,980	41%	41%
2022	2,204,105	28,877	13,606	33,860	2,280,447	47,466		

The 2025 allowance for doubtful accounts (AFDA) reserve is based on the following outstanding AR aging:

Allowance for doubtful accounts reserve analysis APH 1130					
	Current	31-60 days	61-90 days	over 91 days	Total
NorthStar AR	2,784,958.97	77,240.86	61,807.01	207,085.13	3,131,091.97
Less: Retailers (cycle 0088)]	(47,695.94)	6,253.11	5,097.98	17,444.72	(18,900.13)
Adjusted NorthStar AR	2,832,654.91	70,987.75	56,709.03	189,640.41	3,149,992.10
Misc AR				34,846.06	34,846.06
Total	2,832,654.91	70,987.75	56,709.03	224,486.47	3,184,838.16
Reserve % average	0%	0%	40%	80%	
Reserve amount average	-	-	(22,683.61)	(179,589.18)	(202,272.79)

The bad debt expense (APH 5335) and AFDA reserve (APH 1130) 2025 account reconciliations are provided below to assist explaining the bad debt expense account is reflecting the reserve debit expense while the AFDA is recording the reserve credit, and the actual account write offs.

Note the account write offs posted in 2025 are 2024 account write offs. 2025 write offs were written off to the AFDA in March 2026.

Bad debt expense APH 5335	2025
Bad debt reserve	210,053
Write offs	0
Collection costs	225
Total Bad debt expense	210,278
AFDA APH 1130	2025
Bad debt reserve	(210,053)
Write offs	57,047
Yearend AFDA balance	(202,273)

4.0 -VECC -33

Reference: Exhibit 4, page 40

- a) Please provide a copy of the KPMG Governance Review report.
- b) Please provide any additional KPMG (other than that at Appendix 4E) or other consulting reports with respect to the cost allocation review

Response

- a) Lakefront is submitting the KPMG Cost allocation draft report, subject to review and finalization.
- b) The list of studies can be found at 1-SEC-1 and documents filed separately.

4.0 -VECC -34**Reference: Exhibit 4, page 56**

a) Please provide the annual EDA membership fees for each year 2022 through 2027.

Response

LUI was not a member of the EDA from 2022 through 2025. LUI rejoined the EDA in 2026. The annual membership fees are shown below: The 2027 amount reflects the forecast annual membership fee following LUI's rejoining the EDA in 2026.

EDA annual membership fee						
	2027	2026	2025	2024	2023	2022
Total	41,200	40,000	0	0	0	0

4.0 -VECC -35

Reference: Exhibit 4, page 72

“Beginning in 2026, LUI initiated a plan to strengthen internal capabilities and reduce dependence on consultant-supported functions. Key staffing additions included:

- Director of Engineering and Operations;*
- Engineering and Distribution Supervisor;*
- GIS/SCADA and Engineering Design resource;*
- Purchasing and Inventory support resource;*
- Metering support resource; and*
- Additional customer service support.”*

- a) Please provide an update on the referenced 2026 additions, identifying if the position has been filled, and if not the current status of the recruitment effort, and the salary band for the position (as advertised for recruitment).

Response

a) LUI provides the following update on the staffing additions identified in Exhibit 4. The positions were included as part of LUI's 2026 workforce stabilization strategy to strengthen internal engineering, operational, technical and customer-service capacity and reduce reliance on external resources. The status below reflects the most current information available as of September 2026.

Position	Current Status	Recruitment / Appointment Update	Salary Band / Compensation Advertised
Director of Engineering & Operations	Filled – Contract Position	A Director of Engineering & Operations was engaged on a contract basis effective January 3, 2026. The position provides engineering and operational leadership, capital-program oversight, system planning and departmental continuity while LUI rebuilds its internal Engineering & Operations capabilities.	The position was filled through a contractual arrangement rather than a conventional salaried recruitment. Accordingly, no salary band was advertised.
Engineering & Distribution Supervisor	Recruitment substantially complete / employment offer being made	Recruitment was undertaken during 2026 and an employment offer is being made on September 11, 2026. This position will provide permanent internal supervisory capacity for engineering, distribution operations, asset management, system planning, metering,	\$93,019–\$137,569 annually, including a performance incentive component, as advertised.

		GIS/SCADA and capital execution.	
GIS/SCADA & Engineering Design Resource	Not yet filled – recruitment commencing	LUI intends to post the position during September 2026. The resource will support GIS data integrity, SCADA, engineering design, system planning and related operational technology functions that have historically required consultant support.	Not yet advertised. The salary range will be established and disclosed as part of the recruitment process.
Purchasing & Inventory Support Resource	Recruitment underway	The position is currently posted and applications are being received. The role has evolved into a broader Procurement & Finance Coordinator position supporting purchasing, inventory control, fixed assets, capital projects, fleet administration and selected finance functions.	The current posting does not specify a numerical salary range; it states that this is a non-union position and that salary will be commensurate with qualifications and experience.
Metering Support Resource / Metering Technician	Filled	A Metering Technician was hired effective March 12, 2026, replacing capacity lost following the previous Meter Technician vacancy. The position supports meter installation, testing, verification, AMI/meter communications and related distribution activities.	The recruitment posting identified an hourly range of approximately \$32.17–\$45.96 per hour, dependent on qualifications and consistent with the applicable collective agreement.
Additional Customer Service Support	Not yet filled – recruitment planned	The additional Customer Service Representative remains planned and is expected to be posted toward the end of Q4 2026. The position is intended to provide additional capacity associated with customer growth, billing complexity, service-quality requirements, succession planning and increasing customer-service workload.	Not yet advertised. Accordingly, there is no advertised salary band at this time.

4.0 -VECC -36

Reference: Exhibit 4, Table 41/Appendix 2-N

- a) In 2023 LUI's payments for shared services to LUSI (\$3.218k – 58k Office Rental to LUSI) exceeded the actual LUI OM&A for that year (\$3,132,855). Please explain how that is possible.
- b) Using the format of Appendix 2-JA and for each year 2022 through to 2027 please show the LUSI and the non-LUSI costs by each OM&A category.

Response

LUI reviewed the 2023 amounts reported in Appendix 2-N and identified that the shared-services amount was incorrect. The amount reported in Appendix 2-N did not reflect the correct 2023 shared-services data.

The corrected 2023 cost of services provided by LUSI to LUI is approximately \$2.697 million. LUI also incurred approximately \$435,402 of non-LUSI OM&A costs, resulting in total 2023 OM&A of approximately \$3.133 million.

Accordingly, the corrected 2023 shared-services costs do not exceed LUI's total 2023 OM&A. Appendix 2-N will be corrected to reflect the 2023 amounts shown below and in part (b).

Year: 2023 Actual					
Shared Services					
Name of Company		Service Offered	Pricing Methodology	Price for Service	Cost for Service
From	To				
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Distribution Operations Wages and Benefits	Cost Based	510,316	510,316
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Distribution Maintenance Wages and Benefits	Cost Based	337,354	337,354
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Customer Billing and Collecting Wages	Cost Based	426,274	426,274
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Miscellaneous Customer Accounts Expenses	Cost Based	64,718	64,718
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Community Relations	Cost Based	20,655	20,655
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Management and Administrative Wages and Benefits	Cost Based	548,603	548,603
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Office Supplies and Expenses	Cost Based	146,857	146,857
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Outside Services	Cost Based	558,170	558,170
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Maintenance of General Plant	Cost Based	84,506	84,506
Lakefront Utilities Inc.	Lakefront Utility Services Inc.	Office Rental	Cost Based	57,936	57,936
			Total	2,755,389	2,755,389

b) Updated Appendix 2-JA showing LUSI vs non-LUSI costs by OM&A category

Appendix 2-JA

Summary of **Recoverable** OM&A Expenses

	2022 Last Rebasing Year OEB Approved	2022 Last Rebasing Year Actuals	2023 Actuals	2024 Actuals	2025 Actuals	2026 Bridge Year	2027 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Operations-LUSI cost	\$ 707,393	\$ 402,525	\$ 510,316	\$ 434,954	\$ 482,076	\$ 644,703	\$ 751,746
Operations-non LUSI cost	\$ -	\$ -	\$ -	\$ -	\$ 186,129	\$ 347,116	\$ 267,488
Maintenance-LUSI costs	\$ 257,473	\$ 321,569	\$ 337,354	\$ 280,795	\$ 169,714	\$ 131,164	\$ 135,075
Maintenance-non LUSI costs	\$ 55,068	\$ 42,534	\$ 64,068	\$ 58,903	\$ 188,444	\$ 240,604	\$ 247,846
SubTotal	\$ 1,019,934	\$ 766,628	\$ 911,738	\$ 774,651	\$ 1,026,363	\$ 1,363,587	\$ 1,402,155
%Change (year over year)			18.9%	-15.0%	32.5%	32.9%	2.8%
%Change (Test Year vs Last Rebasing Year - Actual)	37.5%						
Billing and Collecting-LUSI cost	\$ 516,279	\$ 493,834	\$ 490,992	\$ 474,506	\$ 456,381	\$ 261,482	\$ 387,124
Billing and Collecting-non LUSI cost	\$ 64,004	\$ 56,363	\$ 84,885	\$ 85,723	\$ 349,835	\$ 424,642	\$ 369,008
Community Relations-LUSI cost	\$ 19,757	\$ 29,397	\$ 20,655	\$ 17,837	\$ -	\$ 0	\$ 0
Community Relations-non LUSI cost	\$ -	\$ -	\$ -	\$ -	\$ 13,521	\$ 14,035	\$ 14,456
Administrative and General-LUSI cost	\$ 943,282	\$ 959,773	\$ 1,338,135	\$ 1,602,606	\$ 1,354,044	\$ 1,145,868	\$ 1,105,980
Administrative and General-non LUSI cost	\$ 258,985	\$ 272,151	\$ 286,449	\$ 285,699	\$ 445,241	\$ 719,155	\$ 867,498
SubTotal	\$ 1,802,306	\$ 1,811,518	\$ 2,221,117	\$ 2,466,372	\$ 2,619,022	\$ 2,565,182	\$ 2,744,066
%Change (year over year)			22.6%	11.0%	6.2%	-2.1%	7.0%
%Change (Test Year vs Last Rebasing Year - Actual)	52.3%						
Total	\$ 2,822,241	\$ 2,578,145	\$ 3,132,855	\$ 3,241,023	\$ 3,645,385	\$ 3,928,768	\$ 4,146,221
%Change (year over year)			21.5%	3.5%	12.5%	7.8%	5.5%

4.0 -VECC -37

Reference: Exhibit 4, Appendix 2-K

- a) Please provide a table showing:
- the name of each LUI job/position category for the 21 proposed FTE roles in 2027;
 - the number of FTEs proposed for each job position;
 - the number of FTEs currently employed in each category;
 - the salary band of each category
 - the average time allocated in a given position category to LUI (based on last full year 2025 and for the average of all employees in that category).

Response

a) i, ii, iii,& v) The following table provides the LUI job/position categories included in the proposed 2027 staffing, the proposed FTE allocation for each position, the applicable salary band and the average percentage of employee time allocated to LUI based on 2025.

LUI job positions - 2027								
S.No.	Description	Salary Band	Time allocated to electric affiliate	Department	Mgt	Trades	Office	FTE
1	President / CEO	8	50.6%	Management	1.00			0.51
2	Finance Director	6	50.0%	Management	1.00			0.50
3	Billing and Customer Service Supervisor	3	55.9%	Management	1.00			0.56
4	Director of Engineering and Operations	6	100.0%	Management	1.00			1.00
5	Acting CFO	7	49.2%	Management	0.50			0.25
6	Design and Engineering Technician	3	100.0%	Management	1.00			1.00
7	HR Generalist/ Health and Safety	2	35.7%	Office			1.00	0.36
8	Finance Analyst	3	35.7%	Office			1.00	0.36
9	Finance Analyst	3	35.7%	Office			1.00	0.36
10	Finance Generalist	1	33.9%	Office			1.00	0.34
11	Billing & Customer Service Representative	Unionized	39.6%	Office			1.00	0.40
12	Billing & Customer Service Representative	Unionized	43.0%	Office			1.00	0.43
13	Billing & Customer Service Representative	Unionized	43.0%	Office			1.00	0.43
14	Billing & Customer Service Representative	Unionized	43.0%	Office			1.00	0.43
15	Data Analyst	1	53.0%	Office			1.00	0.53
16	Line Work	Unionized	100.0%	Trade		1.00		1.00
17	Technical Staff - Distribution	Unionized	100.0%	Trade		1.00		1.00
18	Line Work	Unionized	100.0%	Trade		1.00		1.00
19	Line Work	Unionized	98.7%	Trade		1.00		0.99
20	Line Work	Unionized	100.0%	Trade		1.00		1.00
21	SCADA, Feeders & Substation Engineering	3	98.0%	Trade		0.50		0.49
22	GIS Technician	2	99.3%	Trade		1.00		0.99
23	Technical Staff - Meters	Unionized	100.0%	Trade		1.00		1.00
24	Purchasing / Inventory Management (vacant, hiring Oct 2026)	2	75.0%	Trade		1.00		0.75
25	Lineman (vacant, hiring Oct 2026)	Unionized	100.0%	Trade		1.00		1.00
26	Locator	Unionized	100.0%	Trade		1.00		1.00
27	Corporate Manager & Executive Assistant	4	50.0%	Management	1.00			0.50
28	Regulatory and Finance Supervisor (vacant, hiring Oct 2026)	3	75.0%	Management	1.00			0.75
29	Engineering and Distribution Supervisor (vacant, hiring Oct 2026)	3	100.0%	Management	1.00			1.00
30	Billing & Customer Service Representative (vacant, hiring Jan 2027)	Unionized	50.0%	Office			1.00	0.50
31	IT and Cyber Security Services	3	100.0%	Office			0.50	0.50
					8.5	10.5	10.5	20.9

iv) The applicable salary band for each LUI job/position category is identified in the table above. For non-unionized positions, the corresponding minimum and maximum salary rates are provided based on the applicable salary band. For unionized positions, the applicable collective agreement wage schedule governs the salary range.

4-SEC-24

[Exhibit 4, p.17] With respect to vegetation management:

- a. Please provide actual spending on vegetation management for 2022-2025 and forecasted spending for 2026 and 2027.
- b. Please indicate whether vegetation management is provided by in-house staff or external resources. If external resources are used, what is the contract period?
- c. Please explain how Lakefront determines its vegetation management schedule.

Response

a) Please see breakdown below as requested:

Type	2022A	2023A	2024A	2025A	2026B	2027F
Cycle trimming	37,161	51,792	29,400	40,600	54,600	Not confirmed
Reactive	-	-	-	11,690	-	-
Total	37,161	51,792	29,400	52,290	54,600	N/A

b) Vegetation management is performed by external resources. LUI retains Ontario Line Clearing & Tree Experts Inc. for all cycle and demand trimming; LUI staff handle scheduling, coordination, inspection and verification. Pricing is established under three-year agreements aligned with the trimming cycle, authorized annually by purchase order. The current period runs 2024–2026, following 2021–2023. Pricing for 2027–2029 will be established prior to the 2027 program.

c) Vegetation management is performed on a three-year cycle. The service territory is divided into three areas in Cobourg and corresponding areas in Cramahe (Colborne North and South), per Figures 5.3-3 and 5.3-4 of the DSP. One area is trimmed each year, aligned with LUI's three-year visual inspection cycle, from June 1 to December 1. Work is coordinated continuously with LUI's inspector to confirm the correct area is addressed and completed. The program is refined using outage data and inspection feedback, and hazard trees identified outside the scheduled area are addressed on a demand basis.

4-SEC-25

[Exhibit 4, Appendices 2-JC and 2-JD]

- Please provide a version of the above Appendices that show 2026 actuals to date.
- Please provide Appendices 2-JC and 2-JD that include historical actuals for each year to the actual date used to update 2026 in part a.
- Please revise the 2026 and/or 2027 forecast in the Appendices, if required due to updating 2026 actuals.

Response

Appendix 2-JC OM&A Programs Table								
Programs	2022 OEB Approved	2022 Actuals	2023 Actuals	2024 Actuals	2025 Actuals	Ytd July 2026	2026 Bridge Year	2027 Test Year
Reporting Basis								
Customer Focus								
5175 Maintenance of Meters	55,385	65,472	78,106	116,004	84,898	37,513	88,124	90,768
5310 Meter Reading	202,868	210,919	218,356	185,861	229,801	143,812	238,533	245,689
5315 Customer Billing	257,637	225,141	207,918	227,987	236,478	143,539	255,736	312,832
5320 Collecting	28,029	34,966	44,515	49,080	44,325	31,722	46,009	47,390
5325 Cash Over & Short	0	(1,479)	(399)	(1,780)	0	(1,447)	0	0
5330 Collection Charges	10,225	0	0	0	478	0	496	511
5335 Bad Debt Expense	25,750	22,875	40,769	38,423	210,278	33,407	57,269	58,987
5340 Misc. Customer Accounts	55,773	57,774	64,718	60,658	84,856	16,936	88,081	90,723
5410 Community Relations	19,757	29,397	20,655	17,837	13,521	8,082	14,035	14,456
6205 LEAP Funding	6,247	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Sub-Total	661,671	655,065	684,638	704,070	914,635	423,564	798,283	871,356
Operational Effectiveness								
5005 Operation Supervision & Engineering	204,628	87,321	92,696	31,465	43,588	72,048	155,742	134,681
5016 Distribution Station Equipment - Operation Labour	69,822	57,450	88,419	71,146	93,759	22,431	97,322	100,242
5017 Distribution Station Equipment - Operation Supplies & Expense	4,706	0	514	238	0	0	0	0
5020 Overhead Distribution Lines - Operation Labour	202,971	120,630	121,945	165,523	111,719	89,234	115,964	119,443
5025 Overhead Distribution Lines - Supplies & Expense	33,064	37,423	94,477	22,302	22,217	1,088	23,061	23,753
5040 Underground Distribution Lines - Operation Labour	29,842	13,514	18,617	9,480	5,013	25,241	5,203	5,360
5045 Underground Distribution Lines - Supplies & Expense	10,457	9,767	29,383	0	0	0	0	0
5070 Customer Premises - Operation Labour	91,371	65,910	60,986	47,618	122,444	81,538	104,950	108,099
5085 Miscellaneous Distribution Expense	60,533	10,511	3,280	65,519	202,857	399,218	420,437	456,444
5095 Rental Paid	0	0	0	21,665	0	0	0	0
5096 Other Rent	0	0	0	0	66,608	13,241	69,139	71,213
5110 Maintenance of Dist Stations	0	0	0	0	0	3,110	0	0
5120 Maintenance of Poles	0	0	0	0	0	22,156	0	0
5130 Maintenance of Overhead Services	100,777	210,238	201,741	130,320	158,534	59,319	164,558	169,495
5135 Right-of-Way Maintenance	55,068	42,534	64,068	58,903	59,754	12,474	62,025	63,885
5155 Maintenance of Underground Services	46,186	30,697	35,787	19,127	54,972	3,303	57,061	58,773
5160 Maintenance of Line Transformers	55,126	15,162	21,719	15,344	0	879	0	0
5620 Office Supplies & Expenses	100,064	108,170	146,857	141,799	154,929	84,022	160,816	165,641
5665 Miscellaneous General Expenses	49,366	43,582	43,901	45,317	45,505	28,735	87,234	89,851
5675 Maintenance of General Plant	66,523	71,849	84,506	145,362	179,864	92,930	164,194	169,120
Sub-Total	1,180,504	924,758	1,108,896	991,128	1,321,763	1,010,967	1,687,706	1,736,000
Public and Regulatory Responsiveness								
5605 Executive Salaries & Expenses	7,820	17,473	13,776	15,266	15,663	12,520	16,259	16,746
5610 Management Salaries & Expenses	143,731	146,204	161,763	150,801	177,965	159,381	228,591	260,095
5615 General Administrative Salaries & Expenses	413,968	401,066	386,840	307,803	655,199	140,331	623,123	649,665
5630 Outside Services Employed	222,496	232,485	558,170	856,842	345,105	315,159	325,177	346,691
5635 Property Insurance	32,000	32,756	35,012	37,909	36,633	20,099	47,625	39,166
5640 Injuries & Damages	49,030	40,149	49,515	43,933	46,209	28,425	47,965	49,404
5646 Employee Pensions & OPEB	0	0	0	0	(21,179)	0	0	0
5655 Regulatory Expenses	114,523	122,077	131,028	128,726	152,441	113,909	153,052	176,084
5660 General Advertising	0	6,064	3,218	717	950	554	986	1,016
6205 Donations	0	50	0	3,831	0	0	0	0
Sub-Total	983,568	998,324	1,339,322	1,545,828	1,408,986	790,378	1,442,778	1,538,867
Total	2,825,743	2,578,147	3,132,856	3,241,026	3,645,384	2,224,909	3,928,767	4,146,223

a)

b) The following table provides the 2026, 2025 and 2024 July year to date actuals. Lakefront is unable to provide the requested information from 2022 to 2023 due to the lack of monthly financial closes resulting in the lack of monthly financial statements.

Appendix 2-JD								
OM&A by USoA Account Table								
USoA Account Name	2022 OEB Approved	2022 Actuals	2023 Actuals	2024 Actuals	2025 Actuals	Ytd July 2026	2026 Bridge Year	2027 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
5005-Operation Supervision and Engineering	204,628	87,321	92,696	31,465	43,588	72,048	155,742	134,681
5016-Distribution Station Equipment - Operation Labour	69,822	57,450	88,419	71,146	93,759	22,431	97,322	100,241
5017-Distribution Station Equipment - Operation Supplies and Expense	4,706	0	514	238	0		0	0
5020-Overhead Distribution Lines and Feeders - Operation Labour	202,971	120,630	121,945	165,523	111,719	89,234	115,964	119,443
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expense	33,064	37,423	94,477	22,302	22,217	1,088	23,061	23,753
5040-Underground Distribution Lines and Feeders - Operation Labour	29,842	13,514	18,617	9,480	5,013	25,241	5,203	5,360
5045-Underground Distribution Lines and Feeders - Operation Supplies and Expense	10,457	9,767	29,383	0	0		0	0
5070-Customer Premises - Operation Labour	91,371	65,910	60,986	47,618	122,444	81,538	104,950	108,099
5085-Miscellaneous Distribution Expense	60,533	10,511	3,280	65,519	202,857	399,218	420,437	456,444
5095-Overhead Distribution Lines and Feeders - Rental Paid	0	0	0	21,665	0		0	0
5096-Other Rent	0	0	0	0	66,608	13,241	69,139	71,213
5110-Maintenance of Buildings and Fixtures - Distribution Stations	0	0	0	0	0	3,110	0	0
5120-Maintenance of Poles, Towers and Fixtures	0	0	0	0	0	22,156	0	0
5130-Maintenance of Overhead Services	100,777	210,238	201,741	130,320	158,534	59,319	164,558	169,495
5135-Overhead Distribution Lines and Feeders - Right of Way	55,068	42,534	64,068	58,903	59,754	12,474	62,025	63,885
5155-Maintenance of Underground Services	46,186	30,697	35,787	19,127	54,972	3,303	57,061	58,773
5160-Maintenance of Line Transformers	55,126	15,162	21,719	15,344	0	879	0	0
5175-Maintenance of Meters	55,385	65,472	78,106	116,004	84,898	37,513	88,124	90,768
5310-Meter Reading Expense	202,868	210,919	218,356	185,861	229,801	143,812	238,533	245,689
5315-Customer Billing	257,637	225,141	207,918	227,987	236,478	143,539	255,736	312,832
5320-Collecting	28,029	34,966	44,515	49,080	44,325	31,722	46,009	47,390
5325-Collecting- Cash Over and Short	0	(1,479)	(399)	(1,780)	0	(1,447)	0	0
5330-Collection Charges	10,225	0	0	0	478	0	496	511
5335-Bad Debt Expense	25,750	22,875	40,769	38,423	210,278	33,407	57,269	58,987
5340-Miscellaneous Customer Accounts Expenses	55,773	57,774	64,718	60,658	84,856	16,936	88,081	90,723
5410-Community Relations - Sundry	19,757	29,397	20,655	17,837	13,521	8,082	14,035	14,456
5605-Executive Salaries and Expenses	7,820	17,473	13,776	15,266	15,663	12,520	16,259	16,746
5610-Management Salaries and Expenses	143,731	146,204	161,763	150,801	177,965	159,381	228,591	260,095
5615-General Administrative Salaries and Expenses	413,968	401,066	386,840	307,803	655,199	140,331	623,123	649,665
5620-Office Supplies and Expenses	100,064	108,170	146,857	141,799	154,929	84,022	160,816	165,641
5625-Administrative Expense Transferred/Credit	0	0	0	0	0		0	0
5630-Outside Services Employed	222,496	232,485	558,170	856,842	345,105	315,159	325,177	346,691
5635-Property Insurance	32,000	32,756	35,012	37,909	36,633	20,099	47,625	39,166
5640-Injuries and Damages	49,030	40,149	49,515	43,933	46,209	28,425	47,965	49,404
5646-Employee Pensions and OPEB	0	0	0	0	(21,179)		0	0
5655-Regulatory Expenses	114,523	122,077	131,028	128,726	152,441	113,909	153,052	176,084
5660-General Advertising Expenses	0	6,064	3,218	717	950	554	986	1,016
5665-Miscellaneous General Expenses	49,366	43,582	43,901	45,317	45,505	28,735	87,234	89,851
5675-Maintenance of General Plant	66,523	71,849	84,506	145,362	179,864	92,930	164,194	169,120
6205-Donations	0	50	0	3,831	0		0	0
6205-Sub-account LEAP Funding	6,247	10,000	10,000	10,000	10,000	10,000	10,000	10,000
	2,825,741	2,578,145	3,132,855	3,241,023	3,645,385	2,224,909	3,928,768	4,146,221

c)

LUI OM&A Expenses			
as at July 31st 2024 2025 and 2026			
Operations	2024	2025	2026
5005-Ops Supervision & Eng	30,742	25,051	72,048
5016-Dist Station Equip-Ops Labour	54,580	18,716	22,431
5020-OH Dist Lines & Feeders-Ops Labour	81,658	74,905	89,234
5025-OH Dist Lines & Feeders-Ops Supplies & Exp	23,788	16,890	1,088
5040-UG Dist Lines & Feeders-Ops Labour	9,396	1,565	25,241
5070-Cust Premises-Ops Labour	31,676	59,698	81,538
5085-Misc Dist Exp	67,586	40,285	399,218
5096 - Other Rent - JUOP	21,665	-	13,241
Total Operations Expense	321,091	237,109	704,040
Maintenance	2024	2025	2026
5110-Maintenance of Dist Stations	-	-	3,110
5120-Maint of Poles	-	-	22,156
5130-Maint of OH Services	75,055	58,298	59,319
5135-OH Dist Lines & Feeders-ROW	472	7,939	12,474
5155-Maint of UG Services	15,263	5,298	3,303
5160-Maint of Line Transformers	13,541	-	879
5175-Maintenance of Meters	60,397	60,726	37,513
Total Maintenance Expense	164,728	132,261	138,754
Billing and Collecting	2024	2025	2026
5310-Meter Reading Exp	70,220	98,303	143,812
5315-Customer Billing	137,743	123,999	143,539
5320-Collecting	25,303	33,361	31,722
5325-B&C COLLEC.CASH OVER/SHORT	(2,455)	240	(1,447)
5335-Bad Debt Expense	15,433	28,374	33,407
5340-Misc Customer Accts Exp	35,429	45,703	16,936
Total Billing and Collecting Expense	281,673	329,981	367,969
5410-Community Relations - Sundry	10,561	8,702	8,082
Administration	2024	2025	2026
5605-Exec Salaries & Exp	17,529	5,676	12,520
5610-Mgt Salaries & Exp	80,475	107,960	159,381
5615-General Admin Salaries & Exp	178,431	191,734	140,331
5620-Office Supplies & Exp	68,459	81,357	84,022
5630-Outside Services Employed	515,773	397,771	315,159
5635-Property Insurance	20,172	21,414	20,099
5640-Injuries and Damages	25,628	26,955	28,425
5655-Regulatory Expenses	72,326	94,025	113,909
5660-General Advertising	417	-	554
5665-Misc General Exp	46,621	41,558	28,735
5675-Maint of General Plant	70,156	89,112	92,930
6205-Donations LEAP Funding	10,000	10,000	10,000
Total Administration Expense	1,105,987	1,067,562	1,006,064
Total OM&A Expenses	1,884,040	1,775,614	2,224,909

4-SEC-26

[Exhibit 4, p. 19 and 23 and Appendix 2-JC]

- a. Please explain what Lakefront is doing to increase eBilling from 54%.
- b. Please provide details of what is included under Outside Services.

Response

a) LUI continues to promote eBilling to customers through several customer service touchpoints. New customers completing the online move-in form are provided with the option to enrol in eBilling. In addition, when customers contact LUI for a copy of their bill, account balance or other account-related assistance, customer service and billing staff encourage customers to register for the customer portal and enrol in eBilling.

LUI will continue to promote eBilling through these customer interactions and opportunities to increase customer participation.

b) The following table provides the details of the costs included in Account 5630 – Outside Services Employed from 2022 to 2027.

Outside Services APH 5630							
Description	2027	2026	2025	2024	2023	2022	COS
Finance professional services	45,403	73,622	46,842	38,487	41,713	47,956	40,600
Finance consultants	43,412	41,415	108,255	159,824	38,706	0	0
Regulatory consultants	11,842	11,409	21,205	126,798	41,790	0	0
Engineering consultants	0	0	0	224,840	234,521	49,448	55,195
IT consultants	120,239	115,838	109,879	117,472	62,215	84,717	77,479
HR consultants & recruiting	2,033	29,174	49,487	8,058	14,886	18,404	6,742
Finance ERP software	88,631	19,875	19,148	21,889	14,006	13,315	13,439
Legal	28,715	27,663	26,651	5,415	1,520	1,150	9,000
Business strategy	0	0	0	136,375	74,775	0	0
Miscellaneous	6,415	6,180	(36,362)	17,685	34,038	17,494	20,041
Total	346,691	325,177	345,105	856,842	558,170	232,485	222,496

4-SEC-27

[Exhibit 4, p.39] Lakefront states “for the 2026 Bridge Year and 2027 Test Year, LUI used the OEB's 3.30% Price Cap Inflation Factor as a budgeting assumption while continuing to develop budgets through a detailed account-by-account review” and “[h]owever, the utility does not apply the inflation factor uniformly across all accounts.”

- a. Please provide details for any account for which the OEB's inflation was not applied.
- b. Has Lakefront included a productivity/stretch factor in its planning assumptions? If so, please explain. If not, why not?

Response

a) LUI's budgeting model begins with the applicable OEB Price Cap Adjustment as a reference point for developing the 2026 Bridge Year and 2027 Test Year budgets. This provides an initial benchmark against which account-level forecasts can be assessed.

Each account is then reviewed individually and adjusted, where appropriate, to reflect the known and expected costs, activities and requirements applicable to that account. As a result, the final budgets were not developed by simply applying the OEB inflation factor to historical costs. All accounts were subject to this account-by-account review.

Accordingly, there are no accounts that were excluded from the review process or for which the final forecast was determined solely by applying the OEB inflation factor.

b) LUI did not apply a separate productivity or stretch factor to the final 2026 Bridge Year or 2027 Test Year budgets. The OEB Price Cap Adjustment used as the initial reference point in LUI's budgeting model incorporates the OEB's productivity and stretch factors.

As noted above, that amount serves as a starting reference only. The final budgets are established through the subsequent account-by-account review based on the costs and requirements expected for each account.

4-SEC-28

[Exhibit 4, Appendix 2-JB] Please provide further details on what charges make up the miscellaneous line and assign them to the appropriate account. For example, bad debt expense in 2026 should show a decrease and outside services employed in 2025 should show a decrease.

Response

OM&A Cost Drivers-Identified cost drivers grouped with Misc (Residual)						
	2022 Actuals	2023 Actuals	2024 Actuals	2025 Actuals	2026 Bridge Year	2027 Test Year
5005 Operation Supervision and Engineering	-\$ 117,307	-	-\$ 61,231	-	-	-
5016 Distribution Station Equipment – Operation Labour	-	-	-\$ 17,273	\$ 22,613	-	-
5020 Overhead Distribution Lines and Feeders – Operation Labour	-\$ 82,341	-	-	-\$ 53,804	-	-
5025 Overhead Distribution Lines and Feeders – Supplies & Expenses	-	-	-\$ 72,175	-	-	-
5045 Underground Distr Lines and Feeders-Operation Supplies & Exp	-	\$ 19,616	-\$ 29,383	-	-	-
5070 Customer Premises – Operation Labour	-\$ 25,461	-	-\$ 13,368	-	-	-
5085 Miscellaneous Distribution Expense	-\$ 50,022	-	-	\$ 11,845	-	-
5096 Other Rent	-	-	-	\$ 66,608	-	-
5130 Maintenance of Overhead Services	\$ 109,461	-	-\$ 71,421	\$ 28,214	-	-
5135 Overhead Dist Lines and Feeders ROW	-	\$ 21,534	-	-	-	-
5155 Maintenance of Underground Services	-	-	-\$ 16,660	\$ 35,846	-	-
5160 Maintenance of Line Transformers	-\$ 39,963	-	-	-	-	-
5175 Maintenance of Meters	-	\$ 12,635	\$ 37,897	-\$ 31,106	-	-
5310 Meter Reading Expense	-	-	-\$ 32,495	-	-	-
5315 Customer Billing	-\$ 32,496	-	\$ 20,068	-	\$ 19,258	\$ 57,095
5335 Bad Debt Expense	-	\$ 17,894	-	-	-\$ 153,009	-
5615 General Administrative Salaries & Expenses	-	-	-\$ 79,037	-	-\$ 32,076	\$ 26,542
5620 Office Supplies and Expenses	-	\$ 38,687	-	-	-	-
5630 Outside Services Employed	-	-	-	-\$ 511,737	-\$ 19,929	\$ 21,514
5646 Employee Pensions and OPEB	-	-	-	-\$ 21,179	\$ 21,179	-
5655 Regulatory Expense	-	-	-	\$ 23,715	-	\$ 23,032
5665 Miscellaneous General Expense	-	-	-	-	\$ 41,729	-
5675 Maintenance of General Plant	-	\$ 12,657	-	-	-	-
Total Identified Cost Drives grouped within misc (residual)	-\$ 238,129	\$ 123,023	-\$ 335,078	-\$ 428,985	-\$ 122,848	\$ 128,183

Appendix 2-JB						
Recoverable OM&A Cost Driver updated for cost drivers expanded from Misc (Residual)						
OM&A	2022 Actuals	2023 Actuals	2024 Actuals	2025 Actuals	2026 Bridge Year	2027 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Opening Balance ²	\$ 2,822,241	\$ 2,578,145	\$ 3,132,855	\$ 3,241,023	\$ 3,645,385	\$ 3,928,768
5005 Operation Supervision and Engineering	-\$ 117,307	-	-\$ 61,231	-	\$ 112,154	-
5016 Distribution Station Equipment – Operation Labour	-	\$ 30,969	-\$ 17,273	\$ 22,613	-	-
5020 Overhead Distribution Lines and Feeders – Operation Labour	-\$ 82,341	-	\$ 43,577	-\$ 53,804	-	-
5025 Overhead Distribution Lines and Feeders – Supplies & Expenses	-	\$ 57,054	-\$ 72,175	-	-	-
5045 Underground Distr Lines and Feeders-Operation Supplies & Exp	-	\$ 19,616	-\$ 29,383	-	-	-
5070 Customer Premises – Operation Labour	-\$ 25,461	-	-\$ 13,368	\$ 74,826	-	-
5085 Miscellaneous Distribution Expense	-\$ 50,022	-	\$ 62,239	\$ 137,338	\$ 217,580	\$ 36,007
5096 Other Rent	-	-	-	\$ 66,608	-	-
5130 Maintenance of Overhead Services	\$ 109,461	-	-\$ 71,421	\$ 28,214	-	-
5135 Overhead Dist Lines and Feeders ROW	-	\$ 21,534	-	-	-	-
5155 Maintenance of Underground Services	-	-	-\$ 16,660	\$ 35,846	-	-
5160 Maintenance of Line Transformers	-\$ 39,963	-	-	-	-	-
5175 Maintenance of Meters	-	\$ 12,635	\$ 37,897	-\$ 31,106	-	-
5310 Meter Reading Expense	-	-	-\$ 32,495	\$ 43,940	-	-
5315 Customer Billing	-\$ 32,496	-	\$ 20,068	-	\$ 19,258	\$ 57,095
5335 Bad Debt Expense	-	\$ 17,894	-	\$ 171,855	-\$ 153,009	-
5610 Management Salaries & Expenses	-	-	-	-	\$ 50,626	\$ 31,504
5615 General Administrative Salaries & Expenses	-	-	-\$ 79,037	\$ 130,642	-\$ 32,076	\$ 26,542
5620 Office Supplies and Expenses	-	\$ 38,687	-	-	-	-
5630 Outside Services Employed	-	\$ 325,685	\$ 298,673	-\$ 511,737	-\$ 19,929	\$ 21,514
5646 Employee Pensions and OPEB	-	-	-	-\$ 21,179	\$ 21,179	-
5655 Regulatory Expense	-	-	-	\$ 23,715	-	\$ 23,032
5665 Miscellaneous General Expense	-	-	-	-	\$ 41,729	-
5675 Maintenance of General Plant	-	\$ 12,657	\$ 60,856	\$ 34,502	-	-
5615 General Administrative Salaries & Expenses (overhead)	-	-	-	\$ 216,755	-	-
5315 Customer Billing (overhead)	-	-	-	\$ 3,706	-	-
5085 Miscellaneous Distribution Expense (overhead)	-	-	-	\$ 11,844	-	-
Miscellaneous (Residual)	-\$ 5,967	\$ 17,979	-\$ 22,099	\$ 19,784	\$ 25,871	\$ 21,759
Closing Balance ²	\$ 2,578,145	\$ 3,132,855	\$ 3,241,023	\$ 3,645,385	\$ 3,928,768	\$ 4,146,221
Previous version						
Miscellaneous (Residual)	-\$ 244,096	\$ 141,002	-\$ 357,177	-\$ 409,201	-\$ 96,977	\$ 149,942
Closing Balance ²	\$ 2,578,145	\$ 3,132,855	\$ 3,241,023	\$ 3,645,385	\$ 3,928,768	\$ 4,146,221
Variance						
Miscellaneous (Residual)	\$ 238,129	-\$ 123,023	\$ 335,078	\$ 428,985	\$ 122,848	-\$ 128,183
Closing Balance ²	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Variance/new Miscellaneous (Residual)						
Miscellaneous (Residual)	-\$ 5,967	\$ 17,979	-\$ 22,099	\$ 19,784	\$ 25,871	\$ 21,759

4-SEC-29

[Exhibit 4, p.68] With respect to vacancy rates:

- Please provide for the actual vacancy rate ((# of positions minus # of FTEs)/# of positions) for 2022-2025.
- Please indicate which positions were vacant in each historical year.
- Please provide the assumed vacancy rate for 2026 and 2027.

Response

a) Historical vacancy rates

LUI calculated vacancy rates using the formula specified in the interrogatory:

$$\text{Vacancy Rate} = (\text{OEB-Approved FTEs} - \text{Actual FTEs}) / \text{OEB-Approved FTEs}$$

LUI used the 22.20 FTE complement approved by the OEB as the benchmark. Actual FTEs are annualized FTE equivalents and therefore reflect partial-year vacancies, departures, hires and other staffing transitions.

Year OEB-Approved FTEs Actual FTEs FTE Shortfall Vacancy Rate

2022	22.20	17.58	4.62	20.81%
2023	22.20	17.52	4.68	21.08%
2024	22.20	18.83	3.37	15.18%
2025	22.20	18.50	3.70	16.67%

The vacancy rates represent annualized FTE shortfalls and do not mean that an equivalent number of discrete positions were vacant for the entire year. LUI operated materially below its OEB-approved staffing complement throughout 2022–2025.

b) Positions vacant during historical years

The principal positions/functions experiencing vacancies during each year were:

Year	Position / Function Affected	Vacancy / Transition
2022	Director of Engineering & Operations	Incumbent resigned August 26, 2022. Position remained vacant thereafter and engineering/operational support was supplemented through external engineering resources.
	Finance Assistant	A Finance Assistant resigned February 18, 2022; temporary and internally reassigned resources were used to support the function.
	Data Analyst	Incumbent resigned October 27, 2022.
	Billing & Customer Service Representative	Incumbent resigned September 9, 2022; replacement/customer-service resources were recruited during the year.
	Lineperson / Journeyman staffing	One lineperson resigned July 8, 2022 and another retired August 31, 2022 following a period of LTD. Recruitment occurred during the year to restore line staffing.
	Technical Staff – Stations	Incumbent resigned February 10, 2022. Technical/engineering support was supplemented externally.
2023	Director of Engineering & Operations	Remained vacant throughout 2023. Engineering and operational responsibilities continued to be supported by consultants.

	Director of Regulatory & Finance	Incumbent resigned September 29, 2023. Acting Regulatory Director and Acting CFO resources were retained beginning in October 2023.
	Regulatory Compliance / Senior Finance function	Employee departed in August 2023 and returned in December 2023, resulting in a temporary vacancy during the intervening period.
	Lineperson	A lineperson departed in March 2023. Additional linepersons were hired in May 2023.
2024	Director of Engineering & Operations	Continued to remain vacant, with engineering and operational support provided through consultants.
	Manager Electric Distribution	Incumbent retired August 20, 2024. External operational management support commenced later in 2024.
	Finance management	Finance Department Manager resigned July 2, 2024. A Finance Director was subsequently hired effective August 1, 2024.
	Billing & Customer Service Supervisor	The incumbent resigned April 26, 2024. Temporary staffing support was subsequently utilized.
	Finance support positions	Finance staffing gaps were addressed during the year through temporary Finance Analyst/Finance Generalist resources.
2025	Director of Engineering & Operations	Continued to remain vacant as a permanent internal position; engineering and operational oversight continued through consultant-supported arrangements.
	Finance Director	Position became vacant following the incumbent's departure in October 2025; a replacement Finance Director commenced in November 2025.
	Engineering Supervisor	Position became vacant in October 2025.
	Billing & Customer Service Supervisor	Incumbent departed in January 2025. Replacement support was not in place until July 2025, resulting in a material vacancy period.
	Meter Technician	Incumbent resigned effective September 2025, requiring contractor and internal support for meter-related activities.
	Lineperson / Journeyman	A lineperson position became vacant in February 2025.
	Communications Coordinator	Position became vacant in January 2025.

c) 2026 and 2027 assumed vacancy rates

Using the same 22.20 FTE benchmark:

Year	OEB-Approved Benchmark	Forecast FTEs	FTE Shortfall	Assumed Vacancy Rate
2026 Bridge	22.20	19.42	2.78	12.52%
2027 Test Year	22.20	20.91	1.29	5.81%

The declining vacancy rate reflects LUI's workforce stabilization strategy following several years of significant turnover and reliance on temporary and external resources. Planned additions in engineering and operations, GIS/SCADA/design, purchasing and inventory, metering and customer service are intended to restore internal capability and improve operational continuity.

Importantly, LUI's 2027 forecast of 20.91 FTEs remains below the 22.20 FTE complement approved by the OEB in 2012.

4-SEC-30

[Exhibit 4, Appendices 2-K]

- a. Does Lakefront provide incentive payments to any of its employees? If so, please provide the details of how the incentives are calculated.
- b. Please break down the compensation in Appendix 2-K into base salary, incentive (if applicable) and overtime.
- c. Please indicate the total management and non-management FTEs which reside in the affiliate for each year.

Response

a) Yes. In 2025, LUI introduced a performance-based incentive program for management employees as part of its employee retention strategy, recognizing the ongoing challenges in attracting and retaining qualified resources in Ontario's electricity distribution sector.

Incentive payments are not automatic. At the beginning of each year, eligible employees are assigned Specific, Measurable, Attainable, Relevant and Time-bound/Trackable ("SMART") performance objectives. Performance against these objectives is assessed through a 100-point weighted evaluation matrix as follows:

Performance Component	Weight
Development Plan	6%
Core Responsibilities	10%
Corporate Objectives	34%
Department Objectives	24%
Personal Objectives	20%
Organizational Values	3%
Overall Performance/Feedback	3%
Total	100%

The largest weighting, **58%**, is attributable to corporate and departmental objectives, thereby linking incentive compensation primarily to the achievement of organizational and departmental results. Individual performance and development objectives, core responsibilities, organizational values and overall performance comprise the remaining weighting.

At year-end, management performance is evaluated against the pre-established objectives and the resulting score determines the applicable incentive payment in accordance with the approved incentive framework. Accordingly, incentive compensation is performance-based and contingent upon demonstrated achievement of established objectives, rather than forming a guaranteed component of compensation.

The LUI electricity utility share of incentive payments made in 2025 was \$22,532.

b) Please see below for the breakdown of the compensation included in Appendix 2-K into base salary, incentive payments, and overtime, including the electric affiliate's share of incentive payments, for 2025 actuals, the 2026 bridge year, and the 2027 test year, for both management and non-management employees.

Description	2025 Actual	2026 Bridge	2027 Test
Management			
Salary	789,966	905,584	932,449
Incentive	22,532	69,624	64,800
Overtime	-	-	-
Total	812,498	975,208	997,249
Non-Management			
Salary	1,129,026	1,171,278	1,347,245
Incentive	-	-	-
Overtime	118,012	88,174	90,758
Total	1,247,037	1,259,453	1,438,003
Net Total	2,059,535	2,234,660	2,435,252

c) Employees allocate their time among three affiliates and LUI. For each year from 2022 through 2027, the total FTEs allocated across all companies are as follows:

Number of Employees (FTEs including Part-Time)	2022	2023	2024	2025	2026 Bridge	2027 Test
Management (including executive)	4.83	4.50	5.09	5.31	6.29	6.06
Non-Management (union and non-union)	12.75	13.02	13.74	13.19	13.14	14.85
Total Electric affiliate	17.58	17.52	18.83	18.50	19.43	20.91
FTE for 3 affiliates	16.28	16.41	17.07	17.66	17.87	18.09
Total FTE all affiliates	33.86	33.93	35.90	36.16	37.29	39.00

4-SEC-31

[Exhibit 4, p.73] With respect to compensation:

- a. Please provide a copy of the CGP compensation analysis.
- b. Please provide the dates for Lakefront's last approved union contract and the agreed upon percentages.

Response

- a) Copy of CGP compensation analysis included as attachment.
- b) Lakefront's last approved Collective Agreement was February 3rd, 2023. The Agreement expires on January 31st, 2027.

4-SEC-32

[Exhibit 4, p.80-83, Appendix 4E] With respect to the Management Fee:

- a. In the past ten years has Lakefront had any compliance audits done by the OEB? If yes, please provide copies of the results.
- b. The KPMG letter states: "This letter reflects KPMG's preliminary observations and recommendations..." Please provide any further correspondence from KPMG with respect to the Cost Allocation Review.

Response

a) 2024 - See supporting documents filed under the 4-SEC-32 label. (Ontario Energy Board review and acceptance on Assurance of Voluntary Compliance OEB File No. EB-2024-0171)

b) Please refer to **4 VECC-33** KPMG Cost Allocation Report.

4-SEC-33

[Exhibit 4, p. 93 and Appendix 2-N] For 2022-2024 the utility was providing office space to the affiliate and from 2025-2027 the affiliate is providing office space to the utility. Please explain this change.

Response

- a) a) Appendix 2-N 2025 to 2027 Office Rental was submitted incorrectly. The utility is providing office space to the affiliate and utility is charging the affiliate for the office space.**

EXHIBIT 5 – COST OF CAPITAL

5-STAFF-27

Debt Rate

Ref 1: Exhibit 5, PDF p. 7

Ref 2: Chapter 2 Appendix 2-OB

Ref 3: EB-2025-0303, Letter regarding 2026 Cost of Capital Parameters, October 31, 2025

In reference to the Promissory note with the Town of Cobourg, Lakefront Utilities states: “The promissory note was amended and restated in 2019 to reflect an interest rate consistent with OEB-approved parameters, with the rate to be updated at each approved cost of service proceeding.”

The rate used for this debt in calculating the weighted average cost of capital is 3.49%.

OEB staff notes that the current Deemed Long Term Debt rate is 4.73%, with potential further updates through the course of this proceeding.

Question(s):

- a) Which rate is proposed for the Town of Cobourg debt?

Response

a) a) Lakefront is proposing to use the OEB’s Deemed Long Term Debt rate for the promissory note with the Town of Cobourg. The current placeholder rate in the application of 3.49% is the deemed rate that was applied in the 2022 cost of service application. The 2026 Deemed Long Term Debt Rate of 4.73% has been included in the updated information filed in OEB Staff 1, understanding that it will be further updated when the 2027 deemed rate is released by the OEB.

5-STAFF-28**Return on Equity****Ref 1: Exhibit 5, PDF p. 6****Question(s):**

- a) Please provide the up to date 2026 forecast ROE.

Response

- a) 2.96%

	BOARD APPR.	2022	2023	2024	2025	2026	2027
Board Approved	8.66%	8.66%	8.66%	8.66%	8.66%	8.66%	9.11%
(Appendix 1) Non-rate regulated items and other adjustments		-\$2,667	-\$2,868	\$34,859	\$2,415	\$7,934	
Actuarial (gains)/losses on OPEB		-\$151,277			-\$15,188	-\$83,233	
(Appendix 2) non-recoverable donations (Appendix 2)		\$3,803	\$3,753	\$7,584	\$3,753	\$4,723	
(Appendix 3) Net interest/carrying charges from DVAs (Appendix 3)		-\$5,510	\$28,231	-\$113,774	-\$53,917	-\$36,242	
(Appendix 4) Interest adjustment for deemed debt		\$88,701	\$89,681	\$335,899	-\$149,324	\$91,239	
Subtotal							
Adjusted Net Regulated Income		\$842,519	\$282,052	\$757,990	\$1,078,118	\$451,655	
Add: Future/deferred taxes expense (6115)		\$177,043	\$0	\$0	-\$137,458	\$0	
Add: Current income tax expense (Does not include future income tax) 6110		\$26,106	\$164,349	\$136,366	\$198,269	\$0	
Deduct: Current income tax expense for regulated ROE purposes (Appendix 6) tax) 6111		\$26,106	\$0	\$136,366	\$146,045	\$77,129	
Subtotal							
Adjusted regulated net income		\$1,019,562	\$446,401	\$757,990	\$992,884	\$374,526	
Deemed equity-based Rate Base filed in ROE		\$9,379,074	\$10,454,065	\$11,478,848			
ROE as per filing		10.87%	4.27%	6.60%	8.24%	0.00%	
Achieved ROE		10.87%	4.27%	6.60%	8.24%	2.96%	
Variance from Board Approved		-2.21%	4.39%	2.06%	0.42%	5.70%	

5.0-VECC-38

Reference: Exhibit 5, Table 4

“The promissory note was amended and restated in 2019 to reflect an interest rate consistent with OEB-approved parameters, with the rate to be updated at each approved cost of service proceeding. The debt remains outstanding today as a long-term financing instrument supporting LUI’s capital structure, rather than a short-term or temporary borrowing”

- a) Appendix 2-OB shows a rate of 3.49% for the affiliated debt from the Town of Cobourg and 3.46% of the Affiliated debt from LUSI. The Board’s current long-term debt rate is 4.73% (OEB Letter of October 31, 2025). Please clarify if either or both affiliated debt issuances are meant to be presented at the Board’s current long-term debt rate (i.e. prior to the 2026 expected update). If so please recalculate the weighted cost of long-term debt and provide this in a revised Appendix 2-OA and Appendix 2-OB.

Response

- a) Per 5-Staff-27, Lakefront is proposing the OEB’s Deemed Long Term Debt rate for the Town of Cobourg promissory note. The 2026 rate of 4.73% has been included in the revised Appendix 2-OA and Appendix 2-OB as a revised placeholder pending the release of the OEB’s 2027 Deemed Long Term Debt rate.

With respect to the affiliate debt from LUSI, LUI notes that the same debt was applied on the basis of and accepted at the applicable Deemed Long Term Debt rate in 2022. On review of the evidence it appears the 3.46% rate noted in the preamble was a transcription error, as 3.46% was the approved average weighted cost of debt that was approved in 2022, not the rate on that instrument that was used to calculate the average weighted cost of debt in 2022. Having said that, on reflection, LUI expects that the debt issued by LUSI to LUI is more in the nature of short-term debt to the extent that it supports LUI’s working capital requirements, such that LUI is prepared to exclude the LUSI instrument from the calculation of the applicable weighted average cost of long-term debt. The recalculated weighted cost of long-term debt provided by the revised Appendix 2-OA and revised Appendix 2-OB excludes the LUSI instrument; the effect of the exclusion is a reduction in the (rounded) updated weighted average cost of Long-Term Debt from 4.42% to 4.39%, a reduction of .0445%.

5-SEC-34

[Exhibit 5, Appendix 2-OB] Please explain how the 2026 and 2027 principal for the Lakefront Utility Services Inc. affiliate debt is determined.

Response

Lakefront Utility Services Inc affiliate debt is determined based on the net cash flow funds Lakefront Utilities Inc requires for working capital. LUI notes that, in recognition of the relationship between LUI's working capital requirements and this particular debt, it has, as explained in 5-VECC-38, excluded this instrument from the calculation of LUI's weighted average long-term debt, instead treating it as short-term debt.

1 EXHIBIT 6 – REVENUE REQUIREMENT

6-STAFF-29

Retail Service Charges

Ref 1: EB-2026-0175, [Decision and Order](#), June 16, 2026

On June 16, 2026, the OEB issued is Decision updating the retail service charges charged by rate-regulated electricity distributors, effective January 1, 2027.

Question(s):

- a) Please update Lakefront Utilities' retail service charges based on the OEB's Decision and Order.

Response

- a) Retail Service Charges have been updated accordingly, and the effects flow through to the Cost of Power, Revenue Requirement and Rates.

6-STAFF-30**Distribution Pole Attachment Charge****Ref 1: EB-2026-0176, [Decision and Order](#), June 16, 2026**

On June 16, 2026, the OEB issued is Decision setting the distribution pole attachment charge to be charged by licensed electricity distributors at \$41.81 per attached, per year, per pole, effective January 1, 2027.

Question(s):

- a) Please update Lakefront Utilities' distribution pole attachment charge based on the OEB's Decision and Order.

Response

- a) The tariff sheet has been updated accordingly.

6-STAFF-31

Other Revenues

Ref 1: Chapter 2, Appendix 2-H

Question(s):

- Please provide an updated Appendix 2-H reflecting the most recent 2026 estimates.
- Please explain the methodology applied to the forecast amounts.
- Please explain the material changes to Other Income or Deductions.

Response

- The 2026 and 2027 pole attachment charge forecasts have been updated. The revised amounts are highlighted in yellow.

Please refer to the response in IR 6-SEC-36 (a).

USOA & Description	2025 Actuals	2026 Bridge Submitted	2026 Bridge Revised	2026 Bridge year changes	Basis for 2026 forecasts
4082-Retail Services Revenues	(11,156)	(11,669)	(11,669)	-	The 2026 forecast reflects a 4.6% increase over 2025 actual revenues. The 2027 forecast reflects a 3.7% increase over the 2026 forecast.
4084-Service Transaction Requests (STR) Revenues	(2,709)	(2,834)	(2,834)	-	The 2026 forecast reflects a 4.6% increase over 2025 actual revenues. The 2027 forecast reflects a 3.7% increase over the 2026 forecast.
4086-SSS Administration Revenue	(42,093)	(44,029)	(44,029)	-	The 2026 forecast reflects a 4.6% increase over 2025 actual revenues. The 2027 forecast reflects a 1.0% increase over the 2026 forecast.
4205-Interdepartmental Rents	(28,687)	(63,308)	(63,308)	-	The 2026 and 2027 forecasts reflect a 3.0% annual increase to the rates approved in 2022.
4210-Rent from Electric Property	(268,139)	(135,000)	(156,556)	(21,556)	2026 pole attachment charge forecast updated
4225-Late Payment Charges	(57,177)	(58,892)	(58,892)	-	The 2026 forecast reflects a 3.0% increase over 2025 actual charges. The 2027 forecast reflects a further 3.0% increase over the 2026 forecast.
4235-Miscellaneous Service Revenues	(364,762)	(396,719)	(396,719)	-	The forecast reflects a 3.0% change from the 2025 balances for 2026 and from the 2026 balances for 2027, including changes associated with occupancy, NSF charges, disconnects and recoverables. In addition, the forecast includes an increase in contributions of approximately \$29,000 in 2026 and \$35,000 in 2027.
4340-Profits and Losses from Financial Instrument Investments	(15,188)	-	-	-	No change from 2025 actuals is forecast for 2026 or 2027.
4355-Gain on Disposition of Utility and Other Property	(6,681)	-	-	-	No change from 2025 actuals is forecast for 2026 or 2027.
4375-Revenues from Non-Utility Operations	(38,402)	(24,371)	(24,371)	-	The 2026 forecast reflects the applicable forecast assumptions, with the 2027 forecast reflecting a 3.0% increase over the 2026 forecast.
4380-Expenses of Non-Utility Operations	27,591	21,371	21,371	-	The 2027 forecast reflects a 3.0% increase over the 2026 forecast.
4405-Interest and Dividend Income (excluding DVA)	(141,348)	(5,328)	(5,328)	-	The 2026 forecast reflects a 4.0% interest on 2026 forecasted DVA balances, and the 2027 forecast reflects a 3.0% interest on 2026 forecast DVA balances.
Total	(948,751)	(720,779)	(742,335)	(21,556)	

b) Please refer to the response to Question (a) for the basis of the 2026 forecasts.

c) There are no material changes, other than those already discussed in Exhibit 6 Section 6.4.1 – Other Revenue Variance Analysis.

6-STAFF-32

Payments in Lieu of Taxes (PILs)

Ref. 1: Exhibit 6, Appendix 6A, 2025 Income Tax Return

Ref. 2: 2027 PILs Workform, Tab H0

Ref. 3: 2027 PILs Workform, Tab H8

OEB staff notes reporting discrepancies between the 2025 income tax return filed and the corresponding amounts reported in the 2027 PILs Workform. The discrepancies are outlined in the table below.

2025 Historical Year	A. 2027 PILs Workform Historical Year Tabs	B. 2025 Tax Return	Variance (A-B)
Net Income for Tax Purpose	2,385,074	2,415,720	\$ 30,646
Taxable Income	782,244	825,919	\$ 43,675
Tax Payable	207,295	218,869	\$ 11,574
End of Year UCC	22,908,472	22,939,118	\$ 30,646

Question(s):

- a) Please confirm and explain the discrepancies observed by the OEB staff.
- b) Please provide an itemized reconciliation for the UCC ending balance as of December 31, 2025.

Response

- a) Lakefront is submitting the 2027 PILs workform updated for the 2025 tax return.
- b) Please see the updated 2027 PILs workform question a) for the reconciled UCC ending balances.

6-STAFF-33

Accelerated Capital Cost Allowance (CCA)

Ref. 1: 2027 PILs Workform, Tabs B8 and T8

Ref. 2: Exhibit 6, Appendix 6A, 2025 Income Tax Return, Schedule 8 CCA

Ref. 3: OEB [Letter](#): Accounting and Rates Direction Regarding Bill C-15 for the Reaccelerated Investment Incentive for Capital Cost Allowance, May 6, 2026

In 2026, Bill C-15, the Budget Implementation Act, 2025, No. 1, received Royal Assent. The Bill included a RII (i.e., accelerated CCA) for specific property acquired after 2024 and available for use before 2030, with an expected phase-out from 2030 to 2033.

In Reference 3, the OEB has provides direction regarding the reaccelerated investment incentive (RII) for CCA. The OEB expects distributors to continue to adhere to the OEB's July 25, 2019 accounting direction. Distributors shall continue to use Account 1592 - PILs and Tax Variances – CCA Changes to address the revenue requirement impacts of the RII and of any future CCA rule changes. The OEB also expects utilities taking the maximum deductions allowed under the RII, and utilities continue to have the option of proposing smoothing mechanism.

OEB staff notes that, in its 2025 income tax return, Lakefront Utility reported \$672,279 in Column 4 of Schedule 8 as the cost of acquisition that are All property or property acquired before 2025 that is included in Classes 54 to 56, and \$2,092,290 in Column 5 of Schedule 8 as the cost of acquisitions that are RII property or property acquired after 2024 that is included in Classes 54 to 56. However, OEB staff also notes neither the All property nor the RII property was reflected in the CCA calculation for the 2026 bridge year and 2027 test year, according to Reference 1. Instead, the legacy CAA half-year rule was applied in both years.

Question(s):

- a) Please confirm OEB staff's observations regarding the CCA calculation for 2026 bridge year and 2027 test year.
 - i. if confirmed, please explain in detail why the accelerated CCAs for the capital additions were not considered for the CCA calculation in 2026 and 2027 PILs.
- b) Please provide corrected 2027 PILs Workform reflecting the appropriate CCA rules in accordance with the accounting directions in accordance with the requirements outlined in the OEB letter issued in May 2026.
- c) Please clarify whether Lakefront Utilities has considered smoothing out the tax impacts over the five-year IRM term for the CCA changes. If not, why not? Otherwise, please provide a proposed tax smoothing method and compare the revenue requirement impacts with the PILs without smoothing adjustment.

Response

a) Lakefront Utilities confirms the OEB staff's observation that the accelerated Capital Cost Allowance (CCA) provisions related to the Re accelerated Investment Incentive (RII) were not reflected in the CCA calculations for the Bridge and Test year.

Based on guidance received from the OEB, the applicable factor in column U of the updated PILs model available on the OEB website should be adjusted to reflect the accelerated CCA treatment. However, after updating the relevant factors in column U of the modified tax model, no change was observed in the calculated CCA amounts.

As a result, the model does not appear to automatically incorporate the enhanced CCA deductions available for eligible RII property. Consequently, the CCA calculations for the Bridge year and Test year continue to be based on the standard half-year rule rather than the accelerated treatment permitted under the applicable tax rules.

b) Lakefront Utilities has updated the PILS model to reflect the applicable factors for both the Bridge year and the Test year. However, because the model formulas do not properly incorporate the factor input in the relevant column, no change is reflected in the CCA calculations.

Accordingly, Lakefront Utilities has independently recalculated the CCA amounts in accordance with the newly enacted accelerated CCA rules. Please refer Schedule A for detailed calculations.

The table below summarizes the resulting adjustment to the Test year.

SUMMARY OF ADJUSTMENTS AND IMPACT TO TEST YEAR

BRIDGE YEAR

Bridge Year Taxable Income, before CCA Adjustment	115,965
Additional CCA Claim	(318,496)
Revised Regulatory Taxable Income (Loss) - Bridge Year	(202,531)
Losses carried to Test Year	(202,531)
Years in Rate Period	5.00
Impact to Test Year	(40,506)

TEST YEAR

Test Year Taxable Income, before CCA Adjustment	636,656
Additional CCA Claim	(178,002)
Losses applied from Bridge Year	(40,506)
Revised Regulatory Taxable Income	418,147
Tax Rate (as determined by PILS Model)	21.62%
Corporate PILs / Income Tax Provision for Test Year	90,403
Corporate PILs / Income Tax Provision Gross Up	78.38%
Revised Income Tax (grossed up)	115,340
Income Tax (grossed up) per PILS Model	175,565
Change in Grossed Up Income Tax	(60,225)

c) Lakefront Utilities considered whether to smooth the tax impacts arising from the Reaccelerated Investment Incentive (RII) over the five-year term but has decided **not** to pursue this approach.

Instead, Lakefront Utilities proposes to record the revenue requirement impacts associated with the RII in Account 1592, PILs and Tax Variances – CCA Changes. This approach will capture the actual tax effects resulting from accelerated CCA deductions and allow those impacts to be addressed through the OEB's established deferral and variance account framework.

For illustrative purposes, if the tax impacts were smoothed over the five-year term, the resulting annual adjustment to PILs rates would be approximately \$8,424. This amount is calculated by comparing the corrected CCA claimed in the Test year to the CCA that would arise if the same UCC balances and capital additions were incurred in each of the 2027 through 2031 taxation years.

A summary of this smoothing calculation is provided below. However, Lakefront Utilities is not proposing to smooth the impacts associated with the phase-out of the RII. Rather, it intends to track the resulting revenue requirement impacts through Account 1592, PILs and Tax Variances – CCA Changes, where actual tax variances can be recorded and addressed through the OEB's existing regulatory mechanisms.

Description	2027	2028	2029	2030	2031	Total
CCA In Rates *	2,178,548	2,178,548	2,178,548	2,178,548	2,178,548	4,357,097
CCA, Including RII Phase Out	2,178,548	2,178,548	2,178,548	2,102,202	2,102,202	4,204,404
Difference in CCA	-	-	-	76,346	76,346	152,692
Tax Impact @ 21.62% **	-	-	-	16,506	16,506	33,012
Grossed up PILS				\$ 22,457	\$ 22,457	\$ 42,118
Smoothed out over 5 years						\$ 8,424

* After adjustments are made to the TEST Year to correct the PILS Model

** Tax rate as per the 2027 PILS Model

6.0-VECC-39

Reference: Exhibit 6, page 15

- a) Please provide the basis for the 2026 and 2027 forecasts for the each of the USOAs in Table 8.
- b) In the case of USOA #4210 please provide a schedule that sets out the number of poles, the applicable rates and the resulting revenues for 2024 through 2027.
- c) In the case of USOA #4082 and #4084, do the forecast revenues for 2027 reflect the proposed 2027 Retail Service Charges as set out in Exhibit 8, page 17?

- a) The basis for the 2026 Bridge Year and 2027 Test Year forecasts for the USOAs identified in Table 8 is set out below.

USOA & Description	2025 Actuals	2026 Bridge	2027 Test	Basis for 2026 and 2027 Forecasts
4082 – Retail Services Revenues	(11,156)	(11,669)	(12,101)	The 2026 forecast reflects a 4.6% increase over 2025 actual revenues. The 2027 forecast has been updated to reflect the OEB-approved 2027 Retail Service Charges and the applicable forecast number of occurrences.
4084 – Service Transaction Requests (STR) Revenues	(2,709)	(2,834)	(2,939)	The 2026 forecast reflects a 4.6% increase over 2025 actual revenues. The 2027 forecast has been updated to reflect the OEB-approved 2027 Retail Service Charges and the applicable forecast number of occurrences.
4086 – SSS Administration Revenue	(42,093)	(44,029)	(44,470)	The 2026 forecast reflects a 4.6% increase over 2025 actual revenues. The 2027 forecast reflects a 1.0% increase over the 2026 forecast.
4205 – Interdepartmental Rents	(28,687)	(63,308)	(65,178)	The 2026 and 2027 forecasts reflect a 3.0% annual increase to the rates approved in 2022.
4210 – Rent from Electric Property	(268,139)	(156,556)	(161,261)	2026 and 2027 pole attachment charge forecast updated
4225 – Late Payment Charges	(57,177)	(58,892)	(60,659)	The 2026 forecast reflects a 3.0% increase over 2025 actual charges. The 2027 forecast reflects a further 3.0% increase over the 2026 forecast.
4235 – Miscellaneous Service Revenues	(364,762)	(396,719)	(436,998)	The forecast reflects a 3.0% change from the 2025 balances for 2026 and from the 2026 balances for 2027, including changes associated with occupancy, NSF charges, disconnects and recoverables. In addition, the forecast includes an increase in contributions of approximately \$28,000 in 2026 and \$35,000 in 2027.
4340 – Profits and Losses from Financial Instrument Investments	(15,188)	-	-	No change from 2025 actuals is forecast for 2026 or 2027.
4355 – Gain on Disposition of Utility and Other Property	(6,681)	-	-	No change from 2025 actuals is forecast for 2026 or 2027.
4375 – Revenues from Non-Utility Operations	(38,402)	(24,371)	(25,102)	The 2026 forecast reflects the applicable forecast assumptions, with the 2027 forecast reflecting a 3.0% increase over the 2026 forecast.

4380 – Expenses of Non-Utility Operations	27,591	21,371	22,012	The 2027 forecast reflects a 3.0% increase over the 2026 forecast.
4405 – Interest and Dividend Income (excluding DVA)	(141,348)	(5,328)	(3,996)	The 2026 forecast reflects 4.0% interest on 2026 forecast DVA balances, and the 2027 forecast reflects 3.0% interest on 2025 forecast DVA balances.
Total	(948,751)	(742,335)	(790,692)	

b) The following schedule sets out the number of poles, applicable pole attachment charges, rate incorporated in LUI's existing rates and resulting revenues for 2024 through 2027.

Year	Number of Poles	OEB-Approved Pole Charge	Rate Embedded in Base Rates	Difference	Revenue Embedded in Base Rates	Total Revenue at Approved Charge
2024	3,857	\$37.78	\$34.76	\$3.02	\$134,069	\$145,717
2025	3,857	\$39.14	\$34.76	\$4.38	\$134,069	\$150,963
2026	3,857	\$40.59	\$34.76	\$5.83	\$134,069	\$156,556
2027	3,857	\$41.81	\$41.81	—	\$161,261	\$161,261

Prior to rebasing, the difference between the annual OEB-approved pole attachment charge and the \$34.76 charge incorporated in LUI's existing rates is recorded in Account 1508, Sub-account Pole Attachment Revenue Variance.

Joint-use pole revenue attributable to 2024 was not recognized in 2024. Accordingly, the 2025 actual amount reported in USOA 4210 includes the revenue recognized in respect of both 2024 and 2025.

Effective with 2027 rebasing, LUI has updated its forecast of USOA 4210 revenue using the 2027 OEB-approved pole attachment charge of \$41.81 per pole. Based on 3,857 pole attachments, the revised 2027 forecast is \$161,261.

c) No. As originally filed, the 2027 forecasts for USOA 4082, Retail Services Revenues, and USOA 4084, Service Transaction Requests Revenues, were not developed using the 2027 Retail Service Charges set out in Exhibit 8, page 17.

LUI has updated the 2027 forecasts to reflect the OEB-approved 2027 Retail Service Charges and the applicable forecast number of occurrences. The detailed calculations are provided in response to 6-SEC-36(b).

6-SEC-36

[Exhibit 6, p.21]

- a. Please update the revenue related to the pole attachments using the updated pole attachment charge as per the OEB Decision EB-2026-0176, issued on June 16, 2026. Please show the detailed calculation, i.e. # of attachments x rate.
- a. Please update the revenue related to the energy retailer service charges as per the OEB Decision EB-2026-0175, issued on June 16, 2026. Please show the detailed calculations, i.e. rate x # of occurrences.

Response

LUI has updated its 2027 forecast of pole attachment revenue to reflect the pole attachment charge approved in OEB Decision EB-2026-0176.

4210-Rent from Electric Property				
Year	Number of poles	Pole Attachment Charge (\$/pole)	Decision	Revenue (\$)
2026	3857	40.59	EB-2025-0200	156,556
2027	3857	41.81	EB-2026-0176	161,261

The Application originally included forecast pole attachment revenue of \$135,000 for 2027. LUI has therefore revised its 2027 forecast for USOA 4210, Rent from Electric Property, to \$161,261.

For completeness, the applicable 2026 pole attachment charge is \$40.59, resulting in total pole attachment revenue of \$156,556 based on 3,857 attachments. The difference between the charge incorporated in LUI's existing base rates and the applicable 2026 charge is recorded in Account 1508, Sub-account Pole Attachment Revenue Variance through the effective date of LUI's rebased rates.

- a) See VECC-39

EXHIBIT 7 – COST ALLOCATION

7-STAFF-34

Load Profiles

Ref 1: Load Profile Model / Tab ALL_CP_NCP

The Cost Allocation Inputs in cells Sentinel and USL in Q9134:R9147 appear to be reversed from the source data in columns G and H. This appears to have lead to demand allocators in the cost allocation model being reversed between these two rate classes.

Question(s):

- a) Please confirm or correct OEB staff's observation, and correct models as appropriate.

Response

- a) The model has been corrected and is filed with these responses.

7-STAFF-35

Revenue to Cost

Ref 1: Exhibit 7, p. 25

The USL, Sentinel and Street Lighting rate classes are proposed to have revenue-to-cost ratios moved to the nearest boundary. In order to maintain revenue neutrality, it is proposed to reduce the revenue-to-cost ratio of the Residential class from 102.33% to 101.61%.

Question(s):

- a) Why was residential selected for a revenue-to-cost reduction when there are other rate classes with a higher revenue-to-cost ratio?
- b) As a scenario, please reduce the rate class with the highest revenue-to-cost ratio first until it either achieves revenue neutrality or reaches the revenue-to-cost ratio, whichever comes first. If necessary to achieve revenue neutrality, reduce the two rate classes with the highest revenue-to-cost ratio in tandem to achieve revenue neutrality.

Response

a) In the Application, Residential was used as the balancing class to maintain revenue neutrality after the proposed revenue-to-cost adjustments.

Following OEB staff's question, LUI reviewed the approach and agreed that it is more appropriate to first reduce the class with the highest revenue-to-cost ratio, rather than applying the offset directly to Residential.

Based on the updated cost allocation results, USL has the highest calculated revenue-to-cost ratio at 117.48%, followed by Residential at 104.41%. LUI has therefore revised the proposed revenue-to-cost ratios using the approach outlined by OEB staff.

b) LUI has recalculated the proposed revenue-to-cost ratios based on the scenario requested by OEB staff.

Street Lighting, with a calculated revenue-to-cost ratio of 73.25%, has been increased to the minimum target ratio of 80.00%.

To maintain revenue neutrality, LUI first reduced USL, as it has the highest calculated revenue-to-cost ratio. Once USL was reduced to approximately the Residential ratio, the remaining adjustment was shared between USL and Residential.

Rate Class	Calculated R/C Ratio	Revised Proposed R/C Ratio
Residential	104.41%	104.21%
GS < 50 kW	96.58%	96.58%
GS > 50 to 4,999 kW	93.95%	93.95%
USL	117.48%	104.14%
Sentinel	96.03%	96.03%
Street Lighting	73.25%	80.00%

7.0-VECC-40

Reference: Exhibit 7, pages 4-5

Preamble: The Application states:
“In sheet I4, Break-out of Assets, LUI reviewed its primary and secondary assets to ensure that the model uses the most up-to-date information.”

- a) What was the review undertaken by LUI regarding the split between primary and secondary assets based on?

Response

a) LUI reviewed the information available to support the allocation of assets between primary and secondary categories in Sheet I4 of the Cost Allocation Model.

Based on that review, LUI did not identify more current asset information that would support a revised allocation. LUI therefore retained the existing primary/secondary asset split used in its previous cost allocation information.

The reference in the Application to using the “most up-to-date information” reflects LUI’s review of the information available at the time the model was prepared. Where updated information was available, it was incorporated into the model. In this instance, the existing allocation was retained.

7.0-VECC-41

Reference: Exhibit 7, pages 8-9
CA B&C and Services Weighting Factor Model,
B&C Inputs Tab

Preamble: The Application states:
“Customer service and collection-related activities (e.g., call handling, staff time) are allocated using a time-based approach, which reflects the relative level of effort required to serve each customer class.”
(page 8)

- a) Please explain how the Time Allocation percentages used in the B&C Inputs Tab were derived.
- b) Why are the same time-based allocation factors used for USOA #5320 and #5330?
- c) What activities are included in USOA #5340?

Response

a) The time allocation percentages were developed based on input from LUI staff involved in customer service, billing and collection activities, using their experience to estimate the relative time and effort associated with each customer class.

The percentages are judgment-based estimates rather than the result of formal study, as LUI has not historically tracked these activities by rate class. The B&C model is intended to establish a transparent and repeatable framework that can be maintained and further developed over time. As LUI gains experience with the methodology and better information becomes available, the underlying inputs and allocation assumptions can be reviewed and refined.

b) The same time-based allocation factors were used for USOA Accounts 5320 and 5330 because both relate to collection activities and are generally performed by the same customer service resources. LUI therefore considered the same relative allocation by customer class to be reasonable at this time.

The model allows different allocations to be used for individual sub-accounts where information supports a different approach.

c) USOA Account 5340 includes billing-related services and other customer account costs associated with the administration and processing of customer bills. These costs are separate from the internal staff payroll time identified elsewhere in the model.

7.0-VECC-42

Reference: Exhibit 7, page 10 /Cost Allocation Model, Tab I6.1

- a) Please confirm that, in Tab I6.1, the existing rates used for the GS 50-4,999 class were the 2026 rates for the GS 50-2,999 class.
- b) What would be the existing blended rates for the new GS 50-4,999 class where:
 - a. The monthly service charge is based on the sum of the 2026 service charges for each of the GS 50-2,999 and GS 3,000-4,999 classes weighted by the forecast 2027 number of customers in each class (assuming the existing customer classes continued)
 - b. The monthly volumetric charge (\$/kW) is based on the sum of the 2026 volumetric charges for each of the GS 50-2,999 and GS 3,000-4,999 classes weighted by the forecast 2027 volumes for each class (assuming the existing customer classes continued).
- c) Please provide a revised version of the Cost Allocation Model which used the result from part (b) as the existing rates for the GS 50-4,999 class.

Response

a) Confirmed. In the originally filed Cost Allocation Model, LUI used the 2026 rates applicable to the existing GS 50–2,999 kW class as the existing rates for the proposed GS 50–4,999 kW class. This was done because 107 of the 108 forecast customers in the proposed combined class are currently in the GS 50–2,999 kW class, with only one customer currently in the GS 3,000–4,999 kW class.

b) In response to VECC's request, LUI has calculated blended existing rates for the proposed GS 50–4,999 kW class using the rates applicable to the two existing classes.

The blended monthly service charge is based on the forecast 2027 number of customers in each existing class:

he blended monthly service charge is:

$$[(107 \times \$108.33) + (1 \times \$6,486.66)] / 108 = \$167.39/\text{month}$$

The blended distribution volumetric rate is:

$$[(281,652 \times \$4.3243) + (37,997 \times \$2.4012)] / 319,649 = \$4.0957/\text{kW}$$

c) LUI has provided a scenario revised Tab I6.1 of the Cost Allocation Model to use the blended existing monthly service charge of \$167.39 and blended distribution volumetric rate of \$4.0957/kW for the GS 50–4,999 kW class. The revised Cost Allocation Model has been provided with these responses.

7.0-VECC-43

Reference: **Exhibit 7, page 11**
 Cost Allocation Model, Tabs I6.2, I7.1 and I7.2

- a) Please explain why Tab I6.2 shows 108 GS 50-4,999 customers but Tab I7.1 only shows 107 meters for the class.
- b) Does each Residential, GS<50 and GS>50 customer only have one meter that is owned and read by LUI.
 - i. If not, please explain which class have more meters that are owned or read by LUI and, in each case, indicate the additional number of meters owned and/or read.
- c) Please explain why, in Tab I6.2, the Secondary Customer count for Street Lighting is only 2.

Response

a) LUI confirms that the meter count in Tab I7.1 should be consistent with the 108 projected GS 50-4,999 kW customers shown in Tab I6.2. The 107 meter count was an input error and has been corrected in the revised Cost Allocation Model.

b) Yes. LUI confirms that each Residential, GS<50 and GS>50 customer has one LUI-owned meter that is read by LUI.

c) The Secondary Customer Base reflects the number of Street Lighting customers using LUI's secondary distribution system, rather than the number of individual streetlight devices or connections. LUI has two Street Lighting customers and has therefore reflected a Secondary Customer Base of 2. The 3,117 streetlight devices/connections are reflected separately in Tab I6.2. This treatment is consistent with LUI's previous cost allocation models. This is also consistent with the 2022 and 2017 Cost of Service Cost Allocation models.

7.0-VECC-44

Reference: Exhibit 7, page 14

Preamble: The Application states:
“In implementing the regression model, LUI specified hourly load as a function of weather and calendar effects, together with intra-day load variation. The model includes hourly Heating Degree Days (HDD) and Cooling Degree Days (CDD), a weekend indicator, and a set of hourly indicator variables (H0–H23).”

a) Did the weekend indicator also capture statutory holidays?

Response

No. The weekend indicator captures Saturdays and Sundays only. Statutory holidays were not separately identified in the model.

7.0-VECC-45

Reference: Exhibit 7, page 24

Preamble: The Application states:
“Accordingly, the Unmetered Scattered Load class was adjusted downward from 1.3780 to 1.2000, while the Sentinel and Streetlight classes were adjusted upward from 0.3774 and 0.6614, respectively, to 0.8000. No material adjustments were made to customer classes whose calculated ratios were already within the acceptable range.”

- a) Please confirm that that adjustments outlined to the revenue to cost ratios for the USL, Sentinel and Streetlight classes result in a revenue surplus.
- b) If confirmed, were any explicit adjustments made to the ratios for the other classes to account for this surplus and, if so, which classes' ratios were adjusted and by how much?

Response

a) Confirmed. The adjustments proposed in the Application for USL, Sentinel and Street Lighting resulted in an overall revenue surplus.

b) In the Application, the Residential class was reduced from 102.33% to 101.61% to offset that surplus and maintain revenue neutrality.

LUI has since updated its cost allocation results and revised the proposed revenue-to-cost adjustments. As set out in the response to 7-Staff-35, Sentinel is now within the target range and no adjustment is proposed for that class. Street Lighting is increased from 73.25% to 80.00%.

To maintain revenue neutrality, LUI first reduced the USL class, which has the highest calculated revenue-to-cost ratio. Once the USL ratio was brought down to approximately the Residential ratio, the remaining adjustment was shared between USL and Residential.

The revised proposed ratios are 104.14% for USL and 104.21% for Residential, compared with calculated ratios of 117.48% and 104.41%, respectively.

7-SEC-37

[Exhibit 7, Table 1] Please provide an explanation of the drivers which resulted in the Revenue/Cost ratio for the GS < 50 kW class moving from 98.9% to 80.2%, and the GS 50-2,999 kW class moving from 103.3% to 113.2%, between 2022 and 2027.

Response

The ratios referenced in the question are based on the cost allocation model filed with the Application. LUI has since updated the model, and the revised 2027 revenue-to-cost ratios are 96.58% for GS < 50 kW and 93.95% for GS 50-4,999 kW.

The change from the 2022 approved ratios reflects updated cost allocation inputs, including customer and billing determinants, demand and energy allocators, and the allocation of shared distribution costs.

With the updated model, the significant movement shown in the originally filed ratios is no longer present. Both revised ratios are within the OEB's acceptable range.

1 EXHIBIT 8 – RATE DESIGN

8-STAFF-36

RTSRs

Ref 1: Exhibit 8, p. 12

Ref 2: RTSR Workform / Tab RRR Data

Lakefront utilities indicates that it does not have any identified EV charging facilities in its service territory. However, 100% of the GS 50-2,999 kW load is included both with the main rate class, and with the EV Charging specific load.

Question(s):

- a) Please adjust the RTSR model to remove the volume from the EV charging sub-class.

Response

a) LUI confirms that there are EV charging facilities within its service territory; however, no customers have opted into the OEB's Electric Vehicle Charging Rate.

LUI agrees with OEB staff that the volume included under the EV Charging rate in the RTSR Workform should therefore be removed. The RTSR Workform has been updated accordingly.

8-STAFF-37**Specific Service Charges****Ref 1: Exhibit 8, p. 18**

Lakefront Utilities states that Miscellaneous Service Charges were updated for inflation. OEB staff notes that the bulk of the Specific Service charges do not appear to be updated, nor are they normally updated.

Question(s):

- a) Please explain what was updated for inflation.

Response

a) LUI clarifies that the reference to Miscellaneous Service Charges being updated for inflation referred specifically to the charges identified under the “Miscellaneous Service Charges” section of the Tariff Schedule and Bill Impacts Model.

The 3.00% inflation factor was applied in the model to the Wireline Pole Attachment Charge to arrive to the \$41.81 OEB approved 2026 rate. The Retail Service Charges are also updated by an PriceCap inflation factor as inputted by the OEB.

8-STAFF-38**Loss Factor****Ref 1: Exhibit 8, p. 18****Ref 2: Decision and Order “Distribution Pole Attachment Charge for 2027”, June 16, 2026**

Lakefront Utilities has proposed a pole attachment charge of \$42.09.

Question(s):

- a) Please update the pole attachment charge to \$41.81 per the decision and order.

Response

- a) LUI has updated the projections to use \$41.81 per pole and has updated the tariff sheet accordingly.

8-STAFF-39

Loss Factor

Ref 1: Exhibit 8, p. 13

Ref 2: EB-2025-0025, Decision and Rate Order, Dec 11 2025

Ref 3: EB-2021-0039, Chapter 2, Appendix 2-R

Lakefront Utilities calculated a proposed loss factor of 4.35% based on a supply facility loss factor of 3.4% and a distribution loss factor of 0.91%. It states that the proposed loss factor of 4.35% reflects a decrease from 7.86% approved. Lakefront Utilities attributes it to “lower average distribution system losses observed over the historical period”. However, the current tariff indicates a loss factor of 3.88%.

In Lakefront Utilities’ 2022 cost of service proceeding, it calculated a loss factor of 3.88% based on a supply facility loss factor of 0.34%, and a distribution loss factor of 3.53%

Question(s):

- a) Please provide the source of information for each row on the loss factor calculation, including which information is derived.
- b) Please provide a description of Lakefront Utilities’ connection points, including the proportion of energy received from each connection point, a description of the nature of Hydro One Distribution assets required including approximate distance travelled between the last transmission asset, and the wholesale meter used to measure Lakefront Utilities’ usage.

Response

a) The loss factor calculation filed in Appendix 2-R is populated as follows.

Row	Source / derivation
Wholesale energy – higher value	IESO settlement quantities for LUI’s wholesale supply points, including the applicable upstream loss adjustment.
Wholesale energy – lower value	Metered wholesale quantities for the same supply points before the upstream loss adjustment.
Embedded generation	LUI internal system records for generation connected within LUI’s distribution system. These amounts are added to the wholesale supply quantities because the generation is supplied within LUI’s system and does not pass through the upstream Hydro One supply facilities.
Large Use adjustment	No amount is applicable.
Net wholesale energy	Derived from the lower-value wholesale energy plus embedded generation and any separately identified MicroFIT generation, less any applicable Large Use adjustment.
Retail energy	Billed consumption by rate class from LUI’s customer information system.
Large Use retail adjustment	No amount is applicable.
Net retail energy	Derived from retail energy less any applicable Large Use adjustment.

Distribution Loss Factor	Derived as net wholesale energy divided by net retail energy.
Supply Facilities Loss Factor	Derived by comparing the higher-value and lower-value wholesale supply quantities, with embedded generation included in both sides of the calculation because it does not pass through the upstream supply facilities.
Total Loss Factor	Derived as the Distribution Loss Factor multiplied by the Supply Facilities Loss Factor.

LUI notes that the originally filed loss factor calculation did not appropriately reflect embedded generation. Appendix 2-R has been revised to include embedded generation based on LUI's internal system records. Based on the revised calculation, the five-year average Distribution Loss Factor is 1.0361, the Supply Facilities Loss Factor is 1.0119, and the resulting Total Loss Factor is 1.0484.

The reference in the application to a previously approved loss factor of 7.86% was also made in error. The correct comparator is LUI's currently approved Total Loss Factor of 3.88%, as set out in the Decision and Rate Order in EB-2025-0025 dated December 11, 2025.

b) LUI receives all of its wholesale energy through Hydro One facilities associated with the Port Hope Transformer Station, settled under a single wholesale settlement account and recorded at four wholesale revenue meters. The proportions below are based on metered quantities for 2025:

Wholesale meter	Area supplied	2025 metered energy (kWh)	Proportion
Port Hope TS M2	Cobourg	135,674,447	56.9%
Port Hope TS M4	Cobourg	82,486,757	34.6%
Colborne MS #1	Colborne / Cramahe	10,785,929	4.5%
Colborne MS #2	Colborne / Cramahe	9,581,343	4.0%
Total		238,528,476	100.0%

M2 and M4 are express Hydro One feeders supplying LUI's Cobourg distribution system running approximately 6.7km and 9.7km respectively. Colborne MS #1 and Colborne MS #2 supply LUI's Colborne/Cramahe service area through Hydro One distribution facilities comprising approximately 30.5km and 32.7km respectively of 4.16 kV line from Port Hope TS. LUI's wholesale usage is measured at each of the four wholesale revenue meters identified above.

8-STAFF-40

Bill Impacts

Ref 1: Exhibit 8, pp. 14-16

Question(s):

- a) Please provide the following bill impact scenarios:
- i. A customer using 2,000 kWh per month in the legacy GS < 50 kW rate class.
 - ii. One customer in the USL rate class (Billing Determinant Applied to fixed charge = 1)
 - iii. One customer in the Sentinel rate class (Billing Determinant Applied to fixed charge = 1)
 - iv. One customer in the Street Lighting rate class (Billing Determinant Applied to fixed charge = 1)
 - v. A customer using 3,000 kW per month in the legacy GS 3,000 to 4,999 kW rate class transitioning to the GS 50 to 4,999 kW rate class.

Response

a) LUI has updated the Bill Impact Models to provide the scenarios requested by OEB staff. Specifically:

- i. The GS < 50 kW bill impact has been revised to reflect a customer consuming 2,000 kWh per month.
- ii. The USL bill impact has been revised to reflect a billing determinant of 1 for the fixed charge.
- iii. The Sentinel bill impact has been revised to reflect a billing determinant of 1 for the fixed charge.
- iv. The Street Lighting bill impact has been revised to reflect a billing determinant of 1 for the fixed charge.
- v. For the legacy GS 3,000–4,999 kW customer, LUI has also filed a bill impact model using the existing GS class structure. This shows the bill impact for a customer using 3,000 kW per month as they move from the current GS 3,000–4,999 kW class to the proposed GS 50–4,999 kW class.

The revised Bill Impact Models, including the versions reflecting the existing GS class structure where required, have been filed with these responses.

8.0-VECC-46

Reference: Exhibit 8, pages 4-5

- a) Why is the proposed monthly service charge for the GS 50-4,999 class \$108.33 (same as the existing rate) when the application of the current fixed-variable split yields a value (\$125.66) that is less than the maximum fixed value (\$166.43) produced by the Cost Allocation model?
- b) Why is the proposed monthly service charge for the Streetlight class \$2.19 (same as the existing rate) when the application of the current fixed-variable split yields a value (\$3.14) that is less than the maximum fixed value (\$4.23) produced by the Cost Allocation model?
- c) Why is the proposed monthly service charge of the Sentinel class \$6.97 (same as the existing rate) which is less than both the maximum fixed value (\$9.33) provided by the Cost Allocation model and the value (\$20.41) based on the current fixed-variable split?

Response

- a) The updated maximum fixed charge for the GS 50-4,999 kW class is \$170.52. Maintaining the current fixed-variable split results in a fixed charge of \$128.16, which is within the applicable range. LUI has therefore revised the proposed fixed charge to \$128.16.
- b) The updated maximum fixed charge for the Street Lighting class is \$4.33. Maintaining the current fixed-variable split results in a fixed charge of \$2.86, which is within the applicable range. LUI has therefore revised the proposed fixed charge to \$2.86.
- c) The updated maximum fixed charge for the Sentinel class is \$15.97. Maintaining the current fixed-variable split results in a fixed charge of \$8.22, which is within the applicable range. LUI has therefore revised the proposed fixed charge to \$8.22.

For the GS < 50 kW class, maintaining the current fixed-variable split would result in a fixed charge of \$35.22, which exceeds the updated maximum fixed charge of \$30.62. The proposed fixed charge has therefore been set at \$30.62, with the remaining revenue requirement recovered through the variable charge.

8.0-VECC-47

Reference: Exhibit 8, pages 7-10

a) In Table 10, how were the forecast LV charges for 2026 (\$753,270) determined?

Response

a) LUI used an average of 2022-2025 as a forecast. This can be seen in the RTSR model.

8.0-VECC-48

**Reference: Exhibit 8, page 13
Chapter 2 Appendices, Appendix 2-R**

- a) Please provide a revised version of Appendix 2-R that includes LUI's purchases of embedded generation.
- b) Please provide a revised version of Appendix 2-R where the Supply Facilities Loss Factor is calculated as directed in the footnotes (i.e., "Actual Supply Facility Loss Factor as calculated by dividing (A + C + D) by (B + C + D)").

Response

a) LUI has revised Appendix 2-R to include purchases of embedded generation. Embedded generation purchases have been included in rows C and D, as applicable, for each of the historical years. The revised Appendix 2-R is provided below.

	2021	2022	2023	2024	2025	5-Year Avg.
A – Wholesale kWh, higher value	246,536,388	252,934,760	240,524,902	239,494,564	248,063,425	245,510,808
B – Wholesale kWh, lower value	243,619,589	249,967,447	237,506,346	236,593,694	245,115,610	242,560,537
C + D – Embedded Generation	6,759,401	6,218,765	6,613,685	6,659,041	6,178,360	6,485,850
E – Large Use	0	0	0	0	0	0
F – Net Wholesale = B+C+D-E	250,378,990	256,186,212	244,120,031	243,252,735	251,293,970	249,645,588
I – Net Retail	242,787,842	245,955,782	234,669,498	236,289,594	242,115,103	240,363,564
Distribution Loss Factor = F ÷ I	1.0313	1.0416	1.0403	1.0295	1.0379	1.0361
SFLF = (A+C+D) ÷ (B+C+D)	1.0116	1.0116	1.0124	1.0119	1.0117	1.0119
Total Loss Factor	1.0433	1.0537	1.0531	1.0417	1.0501	1.0484

b) LUI has also revised the Supply Facilities Loss Factor calculation in accordance with the footnote to Appendix 2-R. The Supply Facilities Loss Factor is calculated for each year as:

$$(A + C + D) \div (B + C + D)$$

Based on the revised calculation, the five-year average Supply Facilities Loss Factor is approximately 1.0119. Including the embedded generation purchases also results in a revised five-year average Distribution System Loss Factor of approximately 1.0361 and a revised Total Loss Factor of approximately 1.0484. The revised Appendix 2-R is provided below.

8.0-VECC-49

Reference: Load Forecast Model, Weather Sensitive Forecast Tab and Non-Weather Sensitive Tab RTSR Workform, Tabs 3 and 5

- a) For the Residential and GS<50 classes, please reconcile the kWh volumes used for the Residential and GS<50 classes in the RTSR Workform (Tab 3) with the 2025 kWh values in the Weather Sensitive Forecast Tab.
- b) Please confirm that the values used for the Units Billed in the RTSR Workform (Tab 5) are based on 2025 actuals.

Response

- a) The RTSR Workform was initially prepared using the 2025 actual volumes reported in LUI's RRR filing.

In preparing the load forecast, LUI undertook a more detailed review of the historical billing data. That review identified certain billing adjustments and corrections that may not be reflected in the original RRR data. The 2025 values in the Weather Sensitive Forecast tab reflect those corrected amounts.

LUI has updated the RTSR Workform to use the corrected 2025 volumes so that the two models are consistent.

- b) LUI confirms that the Units Billed in Tab 5 of the RTSR Workform are based on 2025 actuals as reported in the RRR as instructed by the OEB.

Response to Interrogatories
2027 Electricity Distribution Rates Application
Lakefront Utilities Inc. (Lakefront Utilities)
EB-2026-0054
September 17, 2026

Please note, Lakefront Utilities is responsible for ensuring that all documents it files with the OEB, including responses to OEB staff interrogatories and any other supporting documentation, do not include personal information (as that phrase is defined in the *Freedom of Information and Protection of Privacy Act*), unless filed in accordance with rule 9A of the OEB's *Rules of Practice and Procedure*.

1 EXHIBIT 9 – DEFERRAL AND VARIANCE ACCOUNTS

9-STAFF-41

**Ref. 1: Chapter 3 Filing Requirements for Electricity Distributors, July 14, 2026 /
Section 3.2.3.6 Disposition of Account 1595**

Ref. 2: Exhibit 9, Table 2 p.7

Ref. 3: EB-2021-0039 Decision and Order, October 28, 2021 / p.3

Ref. 4: EB-2022-0046 Decision and Order, December 8, 2022 / p.9

Per Chapter 3 of the Filing Guidelines, distributors are expected to request disposition of residual balances in Account 1595 sub-accounts for each vintage year only once, on a final basis. Distributors only become eligible to seek disposition of these residual balances two years after the expiry of the rate rider.

The eligibility criteria for disposition of Account 1595 sub-accounts depends on the distributor's rate year. For example: For January 1 rate year – If 2023 rate riders expire the same year which is on December 31, 2023, the balance of sub-account 1595 (2023) is eligible to be disposed after the account balance as of December 31, 2025, which is two years after the rate riders' expiration, has been audited. Therefore, sub account 1595 (2023) would be eligible for disposition in the 2027 rate year.

Per Exhibit 9, Lakefront notes the disposition status of Account 1595 as follows:

Table 2 – Disposition Status of Account 1595

Rate Year	Fisc Yr	Disposition Period	Sunset Reached	Audit Year	Plus 2 Years	Eligible
2022	2021	2 yr	2024	2025	2027	2028
2023	2022	1 yr	2023	2024	2026	2028
2024	2023	1 yr	2024	2025	2027	2029
2025	2024	1 yr	2025	2026	2028	2030
2026	2025	1 yr	2026	2027	2029	2031

Question:

- a) OEB staff has recomputed the disposition status of Account 1595 as per the Chapter 3 Filing Requirements in the following table:

Rate Year	Fiscal Year	Disposition Period (yrs)	Sunset Reached	Plus 2 years	Eligible
2022	2021	2	2023	2025	2027
2023	2022	1	2023	2025	2027
2024	2023	1	2024	2026	2028
2025	2024	1	2025	2027	2029
2026	2025	1	2026	2028	2030

Please confirm whether Lakefront agrees with the revised disposition status of Account 1595 as per the above table. If not, please explain why not.

- b) Please explain why Lakefront believes it is not eligible to request disposition of Account 1595 (2022) and Account 1595 (2023) in 2027? Please update the applicable evidence as needed.

a) LUI agrees with the revised disposition status of Account 1595 presented by OEB staff.

b) LUI confirms that the Account 1595 (2022) and Account 1595 (2023) residual balances are eligible for disposition in the 2027 rate year. The applicable rate riders expired on December 31, 2023, and, in accordance with the Chapter 3 Filing Requirements, the December 31, 2025 audited residual balances are eligible for disposition in 2027.

LUI has updated Exhibit 9 and the DVA Continuity Schedule accordingly and is requesting disposition of the eligible Account 1595 (2022) and Account 1595 (2023) balances.

9-STAFF-42

Ref. 1: DVA Continuity Schedule 20260626

Ref. 2: EB-2021-0039 Decision and Order, October 28, 2021 / p.3

Ref. 3: EB-2021-0039 DVA Continuity Schedule, Tab 2b

Per the EB-2021-0039 Decision and Order and 2022 DVA continuity schedule, the OEB approved disposition of Group 2 account balances as of December 31, 2020, over 2 years including the following accounts:

Account	Principal	Interest
1508 (pole attachment revenue variance)	-\$171,277	-\$613
1508 (customer choice initiative cost)	\$19,300	\$107
1508 (other regulatory asset)	\$504	-\$333
1508 (cost assessment – over board-approved)	\$76,962	\$2,339
1518 (RCVA – retail)	\$15,151	-\$1,024
1548 (RCVA – STR)	\$23,734	-\$3,598

Questions:

- Please explain why the signs for OEB approved dispositions during 2022 captured in column AA of the 2027 DVA continuity schedule, is the opposite sign of the balances approved for disposition (noted in the table above) for the aforementioned accounts per the EB-2021-0039 Decision and Order and 2022 DVA continuity schedule.
- Please explain why the transactions during 2022 (captured in column Z of the 2027 DVA continuity schedule) is double the amount of the OEB approved principal disposition balance recorded under column AA.
- For the aforementioned accounts, please reconcile how the OEB approved interest disposition during 2022 was captured in the current DVA continuity schedule. The amounts appear to vary from the balances noted in column AF of the 2027 DVA continuity schedule.
- Please update the evidence as applicable.

Response

a) The signs for the OEB-approved dispositions during 2022, as reflected in Column AA of the 2027 DVA Continuity Schedule, were presented incorrectly. The signs should reflect the opposite of the balances approved for disposition, consistent with the accounting treatment in the continuity schedule.

The signs have now been corrected in Column AA of the 2022 activity, and the evidence has been updated accordingly.

b) The 2022 transactions recorded in Column Z of the 2027 DVA Continuity Schedule were erroneously recorded at twice the amount of the OEB-approved principal disposition balances recorded in Column AA.

This was an error in preparing the continuity schedule and has now been corrected. The correction to Column Z, together with the corresponding correction to Column AA, will not results in any adjustment to the net balance of the affected accounts.

c) The OEB-approved interest dispositions during 2022 for the aforementioned accounts have been reconciled to the amounts approved in the EB-2021-0039 Decision and Order and the 2022 DVA Continuity Schedule. Column AF of the 2027 DVA Continuity Schedule has been updated to reflect the reconciled amounts.

Group 2 Deferral and Variance Account	USOA	Principal	Interest	Total
Other Regulatory Assets	1508	(74,511)	1,074	(73,437)
Retail Cost Variance Account	1518	15,151	(937)	14,214
Retail Cost Variance Account	1548	23,734	(3,463)	20,271
PILs and Tax Variance for 2006 and Subsequent Years	1592	(101,606)	(1,282)	(102,888)
Group 2 Sub-Total		(137,232)	(4,608)	(141,840)

Please refer to the attached updated DVA Continuity Schedule for the reconciliation and revised amounts.

d) The evidence has been updated to reflect the corrections described above. The updated evidence is attached herewith.

9-STAFF-43

Ref. 1: Exhibit 9, Table 4 p.9

Ref. 2: EB-2021-0183 Accounting Order for the Establishment of a Deferral Account to Record Impacts Arising from Implementing the Green Button Initiative, November 1, 2021

Per Ref. 2, the OEB approved the establishment of a generic deferral account for rate regulated distributors to record the incremental costs directly attributable to the **implementation** of the Green Button initiative, in a manner that accords with the requirements set out in the Green Button Regulation.

The Accounting Order states that “the OEB will assess any claimed costs recorded in the sub-account at the time the sub-account is requested for disposition, subject to the causation, materiality and prudence criteria.”

Per Exhibit 9, Lakefront provided a cost breakdown for Green Button:

Table 4 – Green Button Implementation Costs

Green Button Cost Category	Amount (\$)
Initial implementation, configuration and deployment activities	60,444
Software support and maintenance	15,000
Additional implementation-related costs and adjustments	14,369
Total Green Button Costs Recorded in Account 1508	89,813

Questions:

- Please provide more details as to the nature and make up of the \$15,000 in “software support and maintenance” costs. Please clarify why Lakefront believes these costs fall into the classification of implementation costs for Green Button.
- Please provide details on how Lakefront has met the causation, materiality and prudence criteria for the claimed costs recorded in the Green Button subaccount requested for disposition.

Response

a) The \$15,000 represents two years of incremental software support costs associated specifically with LUI's Green Button platform. The costs include SaaS fees, server and hosting support, data management and customer/third-party support associated with the Green Button functionality.

These costs were incremental to LUI's existing operations and were incurred specifically as a result of the Green Button implementation. They were not included in LUI's existing base OM&A funding.

b) LUI considers the Green Button costs to satisfy the causation, materiality and prudence criteria as follows:

Causation: The costs were incurred directly as a result of the Green Button requirements. LUI would not have incurred the implementation, platform and associated support costs in the absence of the Green Button initiative.

Materiality: The total amount requested for disposition is \$89,813. The costs represent a discrete incremental regulatory initiative and were not otherwise recovered through LUI's existing distribution rates.

Prudence: LUI used an experienced vendor that was implementing Green Button solutions for multiple Ontario distributors. This allowed LUI to leverage an established solution and implementation experience rather than developing a customized platform, thereby reducing implementation risk and cost.

9-STAFF-44**Account 1589****Ref. 1: 2027 DVA Continuity Schedule, Tab 2a****Ref. 2: 2027 Commodity Accounts Analysis Workform**

OEB staff notes a reporting discrepancy in the 2027 DVA Continuity Schedule and 2027 Commodity Accounts Analysis Workform related to the 2025 transaction amount in Account 1589. The discrepancy is outlined in the table below.

Account 1589	2025 Transaction
A. Ref. 1: Tab 2a, Cell BD32	- 213,352
B. Ref. 2: Tab GA2025, Cell C75	- 241,663
Variance (A-B)	28,311

Question(s):

- a) Please confirm the reporting discrepancy observed by the OEB staff.
 - i. Please explain the discrepancy.
 - ii. Please update the 2027 DVA Continuity Schedule, if applicable.

Response

a) LUI confirms the apparent reporting difference identified by OEB staff.

i) The difference arises because Cell C75 of the Commodity Accounts Analysis Workform reflects the RSVA Global Adjustment Principal balance of \$(241,663), while the DVA Continuity Schedule reflects the net Account 1589 balance, which also includes the RSVA Global Adjustment A – Principal balance of \$28,310

The reconciliation is provided below:

Account 1589 Component	Amount (\$)
RSVA Global Adjustment Principal	(241,663)
RSVA Global Adjustment A – Principal	28,310
Net Account 1589 balance	(213,352)

Accordingly, the difference between the two referenced amounts relates to the separate RSVA Global Adjustment A – Principal balance and does not represent an omitted transaction.

ii) No substantive update to the 2027 DVA Continuity Schedule is required. LUI has confirmed that the DVA Continuity Schedule reflects the net Account 1589 balance. Any minor difference resulting from rounding will be corrected, as applicable.

9-STAFF-45

Account 1592, CCA Changes

Ref. 1: EB-2021-0039, Draft Rate Order, 2022 Income Tax PILs Workform, November 18, 2021

Ref. 2: Accelerated Depreciation DVA Account Support excel, June 26, 2026

Ref. 3: 2027 Chapter 2 Appendices, Tab 2BA

Ref. 4: 2027 DVA Continuity Schedule. Tab 2b

Ref. 5: EB-2021-0039, Settlement Proposal, 2022 DVA Continuity Schedule, Tab 2b, October 22, 2021

OEB staff notes that the total All additions for 2021 reported in Tab “YE 2025 1592 adjustment” of Reference 2 are \$2,078,778, while the total 2021 All additions reported in Tab B8 of Reference 1 are \$1,562,500 for the same year.

OEB staff also notes that the total 2024 All additions reported in Tab “YE 2025 1592 adjustment” of Reference 2 are \$2,211,403, while the total additions reported in Reference 3 are \$2,222,203 for 2024.

In Tab “YE 2025 1592 adjustment” of Reference 2, Lakefront Utilities outlined the annual GL additions to its subaccount 1592, PILs CCA from 2022 to 2025. A lump sum debit adjustment of \$184,167.11 was recorded in 2025 to correct the closing balance to a credit balance of \$20,869.56, reflecting the total CCA variance from 2021 and 2024. Below is the GL transaction table provided by Lakefront Utilities in Reference 2.

PILS & tax savings - GL 02-100-1592-0000					
Year	Opening Balance	Additions	Disposition	Adjustment	Closing Balance
2022	(101,605.60)	(56,181.92)	101,606.00		(56,181.52)
2023	(56,181.52)	(99,461.38)			(155,642.90)
2024	(155,642.90)	(99,999.98)			(255,642.88)
2025	(255,642.88)	50,606.21		184,167.11	(20,869.56)
				check	\$ -

OEB staff has summarized the Account 1508, CCA Changes transactions, as reported in the 2027 DVA Continuity Schedule, in the table below. OEB staff also notes a discrepancy between the 2022 opening balance and the previously approved 2021 closing balance.

Summary of Account 1508, CCA Changes Transactions

Year	Reference 5	Reference 4					Reporting Variance between the 2022 COS and 2027 DVA Continuity Schedule (B-A)
	A. 2021 Closing Balance as Reported in Ref. 5	B. Opening Balance	Transactions	Approved Dispositions	Principal Adjustments	Closing Balance	
2021	- 101,606						
2022		-	- 45,520		- 101,606	- 147,126	101,606
2023		- 147,126		- 101,606		- 45,520	
2024		- 45,520	-			- 45,520	
2025		- 45,520	24,650		-	- 20,870	

OEB staff further notes that, while the closing balance reported in the 2027 DVA Continuity Schedule reconciles with the GL schedule provided in Reference 5 for the CCA Changes subaccount, the yearly transactions and adjustments reported in these two schedules are not consistent.

Question(s):

- a) Please confirm the CCA difference calculation for 2021 is driven by the difference between the All property additions reported in actual 2021 tax return and the previously approved 2021 All property additions.
 - i. If confirmed, please provide a similar annual CCA difference calculation for 2022 and 2023.
- b) Please reconcile the difference between the All property additions and the total PP&E additions in 2024 observed by the OEB staff.
 - i. Please confirm whether the calculated CCA difference for 2024 is mainly driven by the phased-out All rate claimed in the 2024 tax return compared to the previously approved full All rate embedded in rates.
 - ii. If confirmed, please provide the similar annual CCA difference calculation for 2025.
- c) Please explain why Lakefront Utilities sought a true-up of the CCA differences for 2021 and 2024 only, but not for the years 2022, 2023, and 2025.
 - i. Please provide an updated supporting CCA difference schedule including the true-up of the CCA difference calculations from 2021 to 2025.
- d) Please explain why the total debit adjustment of \$184,167.11 related the 2022 to 2025 CCA variances was booked in 2025 instead of the applicable years.
- e) Please confirm the Summary of Account 1508, CCA Changes Transactions table provided by the OEB for the transactions reported in the 2027 DVA Continuity Schedule for Account 1508, CCA Changes.
 - i. Please explain the discrepancy of \$101,606 identified by the OEB staff between the 2021 closing balance and the 2022 opening balance.
- f) Please provide an updated 2027 DVA Continuity Schedule reflecting any changes to Account 1592, CCA Changes.

Response

a) Response from KPMG a b and c

- a) The balance in Account 1592 for 2021 is driven by the difference between the CCA using the full rate of Accelerated Investment Incentive (AII) property additions reported in the 2021 tax return and the CCA that would have been claimed had the historical CCA rules remained in effect.

No adjustment / calculation is required for the 2022 and 2023 years, as the accelerated CCA rates applicable in those years are consistent with the accelerated tax depreciation rates reflected in the 2022 PILs model test year.

- b) i) The calculated CCA difference for 2024 is entirely attributable to the phase-out of the AII. Specifically, it reflects the difference between the reduced AII rate claimed in the 2024 tax return and the full AII rate embedded in the previously approved rates (i.e., 2022 PILs model, Test year).

The \$10,800 difference between total 2024 PP&E additions in the actual tax return and 2024 AII additions relates to Class 12 asset additions. The CCA rate applied to Class 12 assets in the 2022 PILs model is the same rate that Lakefront Utilities claimed in its 2024 tax return. As a result, the Class 12 additions were excluded from the Account 1592 CCA difference calculation, as they did not give rise to any difference between the Test year in the 2022 PILs model and the actual tax treatment.

(ii) Consistent with the approach applied for 2024, an annual CCA difference calculation was prepared for 2025 to quantify the impact of the phased-out AII rates claimed in the 2025 tax return relative to the full AII rates incorporated into the approved 2022 PILs model. This calculation captures the resulting variance in CCA deductions between the approved model and actual tax treatment.

Refer to updated AII calculations that include a difference of \$7,136 (before gross-up) for the 2025 year.

- c) In its 2022 Cost of Service application, Lakefront Utilities disposed of the balance in Account 1592, which reflected the difference between the AII rules enacted at that time and the historical CCA rules embedded in the previous rate period. The balance disposed of in the 2022 application captured the CCA differences through 2020.

Because the 2021 taxation year was not included in the 1592 balance in the 2022 Cost of Service application, Lakefront Utilities recorded the resulting 2021 CCA difference in Account 1592.

No true-up calculation was required for the 2022 and 2023 taxation years because the Test year in the approved 2022 PILs model already incorporated the full AII-enhanced CCA rates applicable during those years.

However, as the AII CCA provisions began to phase out in 2024, a true-up calculation was required to capture the difference between the phased-out CCA rates claimed in the

tax return and the full accelerated CCA rates reflected in the approved 2022 test-year PILs model.

For 2025, while the re-accelerated CCA rules were in effect, certain assets did not qualify for the Reaccelerated Investment Incentive (RII). Consequently, Account 1592 must capture the difference between the full accelerated CCA reflected in the rates (2022 PILS Model) and the CCA actually claimed in the 2025 tax return. The attached calculation quantifies this difference and presents the updated amount to be recorded in Account 1592 for the 2025 taxation year.

d) The 1592 account was reconciled in 2025, which resulted in the \$184,167.11 adjustment being recorded in 2025. We have also reconciled the 2025 balance to the actual 2025 tax return and identified an additional tax-related adjustment of \$7,135.79 required for 2025.

As the 2025 books have already been closed, this additional adjustment will be recorded in 2026. Accordingly, the total adjustment will increase from \$184,167.11 to \$191,302.89.

Once the \$7,135.79 adjustment is recorded in 2026, the 1592 account balance and the claim will be reduced from (\$20,869.56) to (\$13,733.78).

Changes will be made accordingly to the DVA continuity schedule.

e) Please note that the disposition of Account 1592 was requested for the \$101,606 balance as at December 31, 2020. The 2021 closing balance reflects the transactions recorded during the period from January 1, 2021 to December 31, 2021, as well as the \$101,606 principal adjustment related to the previously approved disposition of the December 31, 2020 balance.

As shown in the 2021 continuity schedule, the 2021 transactions totaled \$45,520, and the \$101,606 principal adjustment resulted in a December 31, 2021 closing balance of \$147,125 debit.

Please see the extract from the 2020 COS filing below in support of the disposition of the \$101,606 balance.

Account 1592 – 2020 Continuity	Principal (\$)
Opening balance, January 1, 2020	(32,756)
2020 principal adjustment	(68,850)
Closing balance, December 31, 2020	(101,606)

f) Based on the clarification provided in response to Question (e), no changes are required to the 2027 DVA Continuity Schedule for Account 1592, CCA Changes. The DVA continuity schedule reflects the appropriate balances following the disposition of the \$101,606 balance related to the December 31, 2020 closing balance.

9-STAFF-46

Management Fee Refund Variance Account

Ref. 1: Exhibit 9, Section 9.2.9, pp. 21-22

Ref. 2: Exhibit 9, Appendix 9A: Accounting Order, p. 27

Ref. 3: Exhibit 4, Section 4.4, pp. 79

Ref. 4: 2027 DVA Continuity Schedule, Tab 2b

Ref. 5: OEB letter “Adjustments to Correct for Errors in Electricity Distributor “Pass-Through” Variance Accounts After Disposition” October 31, 2019 (OEB’s retroactivity letter)

Ref. 6: Chapter 2 Filing Requirements for Electricity Distribution Rate Applications – 2026 Edition for 2027 Rate Applications, December 16, 2025, pp. 72-73

In Reference 1, Lakefront Utilities proposes to refund the customer impact associated with the historical management fee of \$995,813 plus carrying charges of \$115,911 through a 4-year declining rider.

The proposed refund reflects the historical management fee embedded in previously approved distribution rates, as outlined in Table 34 of Reference 3.

Period	Methodology	Amount (\$)
2017 Cost of Service	Management fee identified within approved revenue requirement	85,194
2018-2021 IRM Period	2017 amount escalated using approved annual IRM adjustment factors	338,023
2022 Cost of Service	Management fee identified within approved revenue requirement	102,954
2023-2026 IRM Period	2022 amount escalated using approved annual IRM adjustment factors	469,642
Total Estimated Management Fee Embedded in Rates		995,813
Carrying Charges	Calculated to December 31, 2026	155,911
Total Estimated Customer Impact		1,151,724

A draft accounting order is provided in Reference 2, stating that a new Group 2 account: the Management Fee Refund Variance Account under Account 1508, is proposed in this application for the purpose of recording customer refund arising from the review of historical affiliate management fee charges. The proposed effective date for this account is January 1, 2027.

Lakefront Utilities further provided a disposition schedule in Table 17 of Reference 1.

Table 17 – Proposed Management Fee Refund Disposition

Year	%	Principal	Carrying Charges	Total Refund
Year 1	35%	\$348,534	\$54,569	\$403,103
Year 2	30%	\$298,744	\$46,773	\$345,517
Year 3	20%	\$199,163	\$31,182	\$230,345
Year 4	15%	\$149,372	\$23,387	\$172,759
Total	100%	\$995,813	\$155,911	\$1,151,724

OEB staff notes that the total claim amount of a credit 403,103 for Account 1508, Management Fee Refund, reported in the 2027 DVA Continuity Schedule, reflects only the Year 1 principal amount and carrying charges outlined in the disposition schedule shown in the table above.

In Ref. 4, 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

Question(s):

- a) Please explain when Lakefront Utilities became aware of this management fee issue.
- b) Please confirm that the proposed refunding of the management fees back to 2017 constitute rates retroactivity.
 - i. if confirmed, please provide comments based on the four factors outlined in the 2019 OEB's retroactivity letter (Reference 5).
 - ii. if not confirmed, please explain why not.
- c) Please provide a revised continuity schedule for Account 1508, Management Fee Refund, including:
 - i. The appropriate amounts recorded in the respective years, consistent with the amounts and period outlined in Table 34 of Reference 3.
 - ii. The total claim amount includes a closing principal amount of a credit balance of \$995,813 and updated carrying charges,
 - iii. A proposed disposition period of 48 months for the rate rider calculation
- d) Please comment on the three eligibility criteria for the establishment of a new DVA as outlined in Section 2.9.2 of Reference 3.
- e) Please provide an updated draft accounting order including examples of journal entries.

Response

a) LUI became aware of the management fee issue through its review of historical affiliate service costs undertaken in preparation for this cost-of-service application in March of 2026.

b) LUI is not proposing to reopen or recalculate previously approved rates or to re-bill customers for prior periods. Rather, LUI has voluntarily proposed, through this proceeding, to refund the identified customer impact prospectively beginning January 1, 2027.

LUI acknowledges that the proposed refund relates to amounts associated with historical rate periods and has therefore considered the factors identified in the OEB's 2019 letter.

i) With respect to those factors:

- The underlying management fee arrangement and affiliate cost allocation were within LUI's control. Once the issue was identified, LUI quantified the customer impact and brought forward the proposed refund in this application.
- LUI is not aware of a recurring pattern of similar adjustments.
- The issue does not arise from a failure to correct a pass-through variance account previously disposed of by the OEB. It relates to affiliate management fees reflected in LUI's historical revenue requirement.
- LUI is not relying on the treatment of other distributors in support of its proposal. The refund has been proposed based on LUI's own circumstances and its determination that the identified amount should be returned to customers.

c) LUI has revised the DVA Continuity Schedule to reflect the full principal amount proposed for refund, together with applicable carrying charges, rather than only the Year 1 amount.

The revised model reflects a 48-month disposition period consistent with LUI's proposed four-year refund.

d) LUI considers the proposed Management Fee Refund Variance Account to satisfy the applicable criteria for establishment of a new variance account.

Causation: The account is required specifically to record and track the refund approved by the OEB, associated carrying charges and amounts returned to customers through the approved rate rider.

Materiality: The amount proposed for refund is material and requires a separate mechanism to ensure that the approved amount is transparently tracked and returned to customers.

Prudence: A separate account provides a transparent and auditable mechanism for tracking the opening refund obligation, carrying charges and amounts refunded over the approved disposition period.

e) LUI has updated the draft Accounting Order to include illustrative journal entries for the establishment of the approved refund balance, carrying charges and amounts refunded through the Management Fee Refund Rate Rider.

9-STAFF-47

MS28-3 Substation ICM Accounts

Ref. 1: Exhibit 9, p. 11 and pp. 21-22

Ref. 2: EB-2024-0038, Decision and Order, March 27, 2025

Ref. 3: 2027 Lakefront Utilities DVA Continuity Schedule, Tab 2b

Ref. 4: OEB Accounting Procedures Handbook March 2015 Guidance, #13, 14

Ref. 5: EB-2024-0038 Decision

Page 11 of Reference 2 the OEB stated

...the OEB is basing its 50% approval on the revised maximum eligible incremental capital calculated by OEB staff as \$2,117,497, with a resulting annual revenue requirement impact of \$142,837. The remaining portion of the funding request will be tracked in a deferral account, with recovery contingent upon the utility's satisfactory completion of specific undertakings that must be included in the utility's next rebasing application.

The amount OEB staff expected to be contained in account *1508 ICM MS28-3 Substation Expenditure* is 50% of \$142,837 (71,418.50) for each of 2025 and 2026, for a total of \$142,837 plus carrying charges.

Additionally, the Accounting Order attached to the Decision and order (Reference 2) states that the approved 50% portion of the revenue requirement impact associated with the maximum eligible incremental capital of \$2,117,497 should be recorded in accordance with the OEB's ICM accounting procedures. The draft account order further outlines the mechanics of the new deferral account and its six subaccounts, effective May 1, 2025, for the remaining unapproved 50% portion, along with sample journal entries.

Sections 13 and 14 of Reference 4 provides accounting guidance for Advanced Capital Module and Incremental Capital Module. It states that Account 1508, Sub-account Incremental Capital Expenditures Rate Rider Revenues account shall record amounts including "the actual rate rider revenues collected in relation to the Board-approved rate riders determined for the ACM/ICM projects". The guidance further states that the balances in the ACM/ICM accounts are expected to have zero balances following their approved disposition after the approved disposition.

Schedule A of Reference 2 contains the approved ACM/ICM Capital Module. The approved 50% portion of the revenue requirement is calculated as shown below.

Incremental Revenue Requirement			
Return on Rate Base - Total	Q	\$	57,047
Amortization Expense - Total	S	\$	23,397
Grossed-Up Taxes/PILs	Z	-\$	9,026
Incremental Revenue Requirement		\$	71,418

The OEB approves that the ICM rate riders set out in Schedule A of Reference 2 be effective May 1, 2025, and the accounting order be effective May 1, 2025.

In Reference 3, OEB staff notes Lakefront Utilities recorded a project cost of \$2,535,311 in 2023 and an additional cost of \$61,772 in 2024 under ICM MS28-3 Substation Expenditure subaccount. These costs differ from the approved maximum eligible incremental capital cost of \$2,117,497 as approved in Reference 2. Furthermore, OEB staff has summarized the 2025 closing principal balances adjusted for dispositions during 2026 reported in the 2027 DVA Continuity Schedule for the ICM MS28-3 associated accounts in the table below.

1508 Subaccounts	Closing Principal Balance as of Jan-1-25	Transactions during 2025	Principal Adjustments during 2025	Closing Principal Balance as of Dec-31-25	Principal Disposition during 2026	Closing Principal Balances as of Dec 31-25 Adjusted for Dispositions during 2026
ICM Rate Rider	\$ -	-\$ 50,044	-\$ 71,418	-\$ 121,462	-\$ 121,462	\$ -
ICM Depreciation	\$ 84,685	\$ 57,318	\$ 57,318	\$ 199,321	\$ 199,321	\$ -
ICM Accumulated Depreciation	-\$ 84,685	-\$ 57,318	-\$ 57,318	-\$ 199,321	-\$ 199,321	\$ -
ICM MS28-3 Substation Expenditure	\$ 2,597,083	\$ -	\$ -	\$ 2,597,083	\$ 2,597,083	\$ -
Deferred Funding Request	\$ -	\$ 50,044	\$ 71,418	\$ 121,462		\$ 121,462

Question(s):

- Lakefront Utilities has included the depreciation associated with the additional \$61,772 spent in 2024 as part of the calculations for the principal amount in the DVA even though this amount was not included in the ICM approval. Please explain.
- Please provide a version of the DVA Continuity Schedule which excludes the addition of \$61,772 in 2024.
- Please explain why a total cost of \$2,597,083 is recorded as the substation capital expenditure in Account 1508 sub-account MS28-3 Substation expenditures instead of 50% of the approved capital expenditure amount of \$2,117,497 as directed in the accounting order (Schedule B of Reference 2).
- Please explain why a credit amount of \$121,462 is reported in Account 1508, ICM Rate Rider for 2025 while the approved ICM revenue is \$71,418.
 - Please clarify and provide a monthly breakdown of the actual ICM rate revenue collected through the approved ICM Rate Rider in the 2025 IRM application.
- Please elaborate on how the 2025 transactions totaling \$50,044 and the principal adjustments totaling \$71,418 reported in Account 1508, Deferred Funding Request, are

reflected in the sub-accounts established under the MS28-3 Substation Deferral Accounts, as approved in Lakefront Utilities' 2025 IRM application (Schedule B of Reference 2).

- i. Please provide a breakdown of the amounts reported in each of the six sub-accounts established under Account 1508, MS28-3 Substation Deferral Account.
- f) Please comment on why the closing principal balances as of December 31, 2025, for the ICM Rate Rider, ICM Depreciation, ICM Accumulated Depreciation and ICM MS28-3 Substation Expenditures account, are reduced to zero by the principal disposition during 2026 amounts reported in Reference 3.
 - i. Please confirm whether Lakefront is seeking OEB's approval for the disposition of these accounts.
 - ii. If yes, please provide an updated DVA Continuity Schedule reflecting the appropriate proposed disposition balances in these accounts.
 - iii. If not, please explain why not.
- g) Please provide a detailed annual CCA continuity schedule for 50% of the MS28-3 substation approved project cost.
 - i. Please confirm whether the impact of the CCA associated with the approved substation cost is reflected in Account 1592, CCA changes balance for disposition.
 - ii. If not, please explain why not.

Response

a) LUI included depreciation associated with the full actual cost of the MS28-3 project, including the additional \$61,772 incurred in 2024. The \$61,772 forms part of the actual completed project cost and associated depreciation recorded in LUI's fixed asset records.

Upon review, LUI acknowledges that the \$61,772 was not included in the capital amount underlying the OEB-approved ICM funding. LUI has therefore excluded the depreciation associated with the \$61,772 from the ICM-related regulatory account calculations in the revised DVA Continuity Schedule.

The \$61,772 and related depreciation remain part of the actual project cost for purposes of rebasing, subject to the OEB's prudence review.

b) A revised DVA Continuity Schedule is provided with this response that excludes the \$61,772 from the ICM-related regulatory account calculations.

The \$61,772 remains part of the actual MS28-3 project cost reflected in LUI's fixed asset records and proposed rate base, subject to the OEB's prudence review in this proceeding.

c) The \$2,597,083 represents the total actual cost of the completed MS28-3 Substation project. The amount was reflected in the filed DVA Continuity Schedule to track the actual project cost through rebasing.

LUI acknowledges that the regulatory accounting for the approved and deferred portions of the ICM is governed by the specific accounting treatment approved in EB-2024-0038. LUI has therefore revised the DVA Continuity Schedule, as applicable, to distinguish the amounts subject to the approved ICM funding and the MS28-3 Substation Deferral Account from the total actual project cost.

At rebasing, the actual project cost is transferred to the appropriate PP&E accounts and is subject to the OEB's prudence review in this proceeding.

d) The \$121,462 reflected in the filed DVA Continuity Schedule consisted of \$50,044 of actual ICM rate rider revenue recorded for May to December 2025 and \$71,418 representing the approved annual ICM revenue requirement for 2026.

Upon review, LUI acknowledges that the ICM Rate Rider Revenue sub-account is intended to reflect actual rate rider revenues collected. LUI has therefore revised the continuity, as applicable, to distinguish the actual 2025 rate rider revenues from the 2026 amounts.

i) The monthly breakdown of actual ICM rate rider revenues collected in 2025 is provided below.

Monthly breakdown of ICM rate rider collected in 2025			
2025	Amount	Unbilled	Total \$
Aug	-	(10,083)	(10,083)
Sep	(10,145)	236	(9,909)
Oct	(10,001)	(84)	(10,085)
Nov	(10,017)	9,931	(86)
Dec	(9,975)	(9,907)	(19,882)
Total 2025	(40,137)	(9,907)	(50,044)

e) The \$50,044 recorded for 2025 and the \$71,418 recorded for 2026 were intended to reflect the deferred portion of the MS28-3 revenue requirement corresponding to the portion not recovered through the approved ICM rate riders. Together, these amounts resulted in the \$121,462 principal balance presented as the Deferred Funding Request in the filed DVA Continuity Schedule.

The filed DVA Continuity Schedule presented this amount on an aggregate basis. The supporting reconciliation provided with this response shows how the amount is reflected through the six MS28-3 Substation Deferral Account sub-accounts established under Schedule B

Description	2025	2026	Deferred Funding Request
1. Account 1508 - Other Regulatory Assets, Sub-account MS28-3 Substation Deferral Account, Capital Expenditures	2,597,083	-	-
2. Account 1508 - Other Regulatory Assets, Sub-account MS28-3 Substation Deferral Account, Capital Contribution	-	-	-
3. Account 1508 - Other Regulatory Assets, Sub-account MS28-3 Substation Deferral Account, Depreciation Expense	142,003	57,318	199,321
4. Account 1508 - Other Regulatory Assets, Sub-account MS28-3 Substation Deferral Account, Accumulated Depreciation	(142,003)	(57,318)	(199,321)
5. Account 1508 - Other Regulatory Assets, Sub-account MS28-3 Substation Deferral Account, Return and PILs	(50,044)	(71,418)	(121,462)
6. Account 1508 - Other Regulatory Assets, Sub-account MS28-3 Substation Deferral Account, Carrying Charges	(1,276)	(1,821)	(3,097)

f) The balances are reduced to zero at rebasing because the ICM-related balances are transferred to their permanent accounting classifications in accordance with the OEB's ACM/ICM accounting guidance.

Specifically, the capital expenditure balance is transferred to PP&E, depreciation is transferred to depreciation expense, accumulated depreciation is transferred to accumulated depreciation of utility plant and previously collected ICM rate rider revenues are transferred to Account 4080, Distribution Services Revenue.

i) Yes. LUI is seeking OEB approval for disposition of these ICM sub-accounts as part of rebasing. The disposition results in the accounting reclassifications described above; LUI is not seeking a separate rate rider in respect of these balances.

ii) The revised DVA Continuity Schedule reflects the applicable disposition balances.

iii) Not applicable.

g) LUI has provided a detailed annual CCA continuity schedule for the 50% portion of the MS28-3 project approved for ICM funding.

2023 additions	No adjustment / calculation is required for 2023, as the accelerated CCA rates applicable in those years are consistent with the accelerated tax depreciation rates.				
2024 additions					
Class	CCA rate	All Additions	CCA claimed per T2	Full All	Difference
47	8%	61,772	4,942	7,413	(2,471)
<u>Tax on Difference:</u>		2024			
CCA Claim per T2		\$ 4,942			
CCA Claim (Full All)		7,413			
		(2,471)			
Tax Rate		26.50%			
		\$ (654.78)			

i) Yes. The impact of CCA associated with the actual capital expenditure for the MS28-3 substation is reflected in Account 1592, CCA Changes Balance for Disposition, based on the accounting records in Uniform System of Accounts (USoA) Account Class 47. The CCA impact reflected in Account 1592 is based on the actual capital expenditures incurred and does not reflect the CCA calculated based on the approved ICM amount.

ii) N/A

9.0 – VECC -50

Reference: Exhibit 9, page 21
DVA Continuity Schedule, Tab 5
Exhibit 4, page 99 of 102
Cost Allocation Model, E4 Tab

Preamble: The Application states:
“The total balance has been allocated to customer classes using the approved Distribution Revenue Allocation factors, consistent with the manner in which distribution revenues are recovered from customer classes for Group 2 accounts.”

- a) Please confirm that per Tab 5 of the DVA Continuity Schedule that Management Fee Refund is allocated to customer classes based on kWh.
- b) With respect to the table setting out the analysis of the Management Fee for LUSI (Exhibit 4, page 99 of 102) please provide a schedule that sets out for each of the cost centers identified (e.g., Executive, Finance, etc.) the USOA account where the costs are recorded. If recorded in more than one USOA please provide a percentage breakdown by account.
- c) Based on how these costs are allocated to customer classes (per the Cost Allocation Model, Tab E4), please explain why kWh is the appropriate allocator for the Management Fee refund.

Response

a) LUI confirms that the filed DVA Continuity Schedule used kWh to allocate the Management Fee Refund. LUI has revised the DVA Continuity Schedule to use Distribution Revenue by class.

b)

Analysis of Management fee from LUSI by APH														
	APH	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Grand Total
Executive	5605	17,217	21,536	16,362	13,025	13,072	15,336	15,246	16,438	13,767	15,618	17,670	1,548	176,835
Finance	5615	15,096	18,243	20,765	23,402	23,553	25,655	27,106	32,312	25,690	26,057	27,179	58,198	323,256
Customer Service admin	5615	20,401	2,118	4,899	5,210	6,634	6,317	5,826	8,558	6,942	8,967	9,798	0	85,670
HR General	5615	9,165	6,194	4,729	1,327	1,188	3,319	3,380	3,943	3,056	3,587	298	0	40,186
Operations general admin	5615	1,284	99	0	0	0	0	3,775	5,341	373	653	103	332	11,960
Customer Service billing	5315	0	16,448	16,226	21,689	21,894	24,385	23,693	24,332	20,506	23,514	27,681	26,729	247,097
Customer Service collectin	5320	3,511	1,982	2,090	2,082	2,106	2,545	2,491	3,182	2,859	4,434	5,615	6,077	38,974
Operations admin	5005	18,613	7,590	6,211	1,595	1,956	2,334	24,661	12,446	8,231	9,667	3,551	6,400	103,255
Total		85,287	74,210	71,282	68,330	70,403	79,891	106,178	106,552	81,424	92,497	91,895	99,284	1,027,233

c) The filed DVA Continuity Schedule allocated the Management Fee Refund to customer classes based on kWh. Upon further review, LUI determined that Distribution Revenue by class is a more appropriate allocator because the management fee formed part of LUI's distribution revenue requirement and was recovered from customer classes through distribution rates.

Accordingly, LUI has revised the allocation of the Management Fee Refund using Distribution Revenue by class. Once the refund is allocated among customer classes, the resulting class-specific rate riders are calculated using the applicable billing determinant for each class.

9.0 – VECC – 51

Reference: Exhibit 9, Section 9.2.4, page 12

Table 7 – Continuity of ICM Rate Rider Revenues

Description	Amount (\$)
Rate rider revenues collected in 2025	50,044
Additional approved funding recorded in 2026	71,418
Total ICM rate rider revenues at rebasing	124,559
Transfer to Account 4080 upon rebasing	(124,559)
Closing balance	0

- a) It is unclear to us the derivation/origin of the \$71,418. Please clarify how this amount was calculated and where it was approved.

Response

The \$71,418 represents the annual revenue requirement associated with the 50% portion of the MS28-3 ICM approved by the OEB in EB-2024-0038.

The OEB determined a maximum eligible incremental capital amount of \$2,117,497, with an annual revenue requirement of \$142,837. The approved 50% portion therefore results in an annual revenue requirement of approximately \$71,418.

- 2025 rate rider revenue: \$50,044
- 2026 approved annual amount: \$71,418
- Principal balance: \$121,462
- Carrying charges: \$3,097
- Total: \$124,559

9.0 – VECC – 52

Reference: Exhibit 9, Exhibit 4, page 63

LUI states at Exhibit 4: *“Consistent with OEB policy, if actual LEAP EFA grant payments exceed the approved budget due to customer need, LUI will record the incremental amount in the established LEAP EFA Funding Deferral sub-account for future disposition.”*

The following extract is from the current (EB-2026-0029) Canadian Niagara Power Inc. cost of service application

*“For regulatory efficiency, the OEB also established a generic deferral account, effective March 1, 2024, to allow rate-regulated electricity and natural gas distributors to record incremental LEAP EFA contributions that are beyond the amounts embedded in distribution rates. This has helped to ensure that no eligible LEAP EFA applicant should be denied assistance due to lack of funding. This deferral account was effective March 1, 2024, and given the ongoing need in CNPI’s service territory, CNPI has accumulated material balances into this deferral account and is seeking disposition (see Exhibit 9). **The Accounting Order (EB-2023-0135) within the February 2024 OEB letter states that it is not expected that distributors will need the new deferral accounts beyond their next cost-base rate applications.**”* (emphasis added)

- a) What is the basis for LUI’s proposal to maintain a LEAP variance account?

Response

a) LUI has included a forecast LEAP budget for the test year of \$12,000, delivered through The Help and Legal Centre.

While 2025 experienced less than \$12,000 in LEAP disbursements, more accounts are now going to collections, which has led to more customers being referred to and booking appointments with The Help and Legal Centre. These appointments cover not only LEAP but also OESP enrollment, tax return preparation, and other community resources.

Since LUI cannot deny funding to an eligible applicant simply because the annual budget has been used up, LUI anticipates that demand may exceed the \$12,000 budget in future years as this referral volume grows. Rather than increase the embedded LEAP budget at this time, given the recent history of disbursements under \$12,000, LUI proposes to retain the deferral account as a safeguard to ensure no eligible applicant is denied assistance, while continuing to monitor actual need and revisit the embedded budget amount at its next cost-based rate application if the higher demand proves sustained.

Year	Agency Administration and Program Delivery	Total Grants Disbursed	Total Funds Disbursed	Accepted Applicants	Avg. Grant per Accepted Applicant
2022	\$1,500.00	\$14,722.42	\$16,222.42	35	420.64
2023	\$1,500.00	\$10,057.57	\$11,557.57	26	386.83
2024	\$2,074.68	\$10,846.69	\$12,921.37	27	401.73
2025	\$1,500.00	\$6,459.73	\$7,959.73	20	322.99
2026	\$1,500.00	\$10,500.00	\$12,000.00	25	400
2027	\$1,500.00	\$10,500.00	\$12,000.00	25	400

9.0 – VECC – 53

Reference: Exhibit 9, , page 15

- a) Please provide a list of all Group 2 deferral or variance accounts LUI is seeking to continue for 2027.

Response

a) LUI is seeking to continue the following Group 2 deferral and variance accounts for 2027:

- Account 1592 – PILs and Tax Variance, Sub-account CCA Changes;
- Account 1508 – LEAP EFA Funding Deferral Account; and
- Account 1508 – Management Fee Refund Variance Account, which LUI is proposing to establish effective January 1, 2027.

LUI is proposing to discontinue the remaining Group 2 accounts identified in Section 9.2.4 of Exhibit 9 following disposition of the applicable balances.

9-SEC-38

[Exhibit 9, p. 8-10]

- a. Lakefront notes that costs related to Green Energy Button and the implementation of ULO are included in the utility's OM&A. Please provide further details on the amounts and in which USoA these costs are included.
- b. With respect to Account 1508, Pole Attachment Revenue Variance, please calculate the difference between what was built into rates versus the actual revenue for 2023-2025 and provide a forecast for 2026.
- c. With respect to Account 1508, Green Button Implementation Costs, please provide details on which costs shown in Table 4 were provided by external resources and by internal resources.
- d. With respect to Account 1508, Ultra-Low Overnight Pricing Costs, please provide details on which costs shown in Table 5 were provided by external resources and by internal resources.

Response

a) LUI clarifies that costs related to Green Button implementation and Ultra-Low Overnight (ULO) pricing were recorded in Account 1508. No additional costs related to these initiatives were recorded in OM&A accounts.

b) Effective January 1, 2022, LUI's pole attachment charge has been updated annually through the OEB's IRM process. Accordingly, the OEB-approved charge applicable in each year was the same charge billed by LUI, and no additional principal amounts were recorded in the Pole Attachment Revenue Variance Account after 2021.

The table below provides the requested comparison for 2023 to 2026.

Year	OEB-Approved / Billed Charge per Pole	Pole Attachments	Actual / Forecast Pole Attachment Revenue	Revenue Variance
2023	\$36.05	3,852	\$138,865	\$0
2024	\$37.78	3,857	\$145,717	\$0
2025	\$39.14	3,857	\$150,963	\$0
2026 Forecast	\$40.59	3,857	\$156,556	\$0

c) All costs shown in Table 4 related to Green Button Implementation Costs were incurred through external resources. No internal resource costs are included in the amounts shown in Table 4.

d) All costs shown in Table 5 related to Ultra-Low Overnight Pricing Costs were incurred through external resources. No internal resource costs are included in the amounts shown in Table 5.

9-SEC-39

[Exhibit 9, Tables 1 and 3, and Appendix 2-H]

- a. Please confirm that Lakefront is requesting disposition of accounts including the interest.
- b. Please confirm that Lakefront has also included the interest in Account 4405 – Interest and Dividend Income as part of Other Revenue.

Response

- a) Yes, Lakefront is requesting disposition of accounts including the interest.
- b) Yes, Lakefront has also included the interest in Account 4405 – Interest and Dividend Income as part of Other Revenue.

9-SEC-40

[Exhibit 9] Please confirm that Lakefront has not recorded any activity recorded in the following Group 2 Deferral and Variance Accounts:

- a. LEAP Funding
- b. Cloud Computing
- c. Lost Revenue - Collection of Account Charges
- d. GOCA

Response

- a) LUI confirms that no activity has been recorded in the LEAP Funding Deferral Account.
- b) LUI confirms that no activity has been recorded in the Cloud Computing Deferral Account.
- c) LUI confirms that there is currently no balance in the Lost Revenue – Collection of Account Charges account. The last disposition of this account occurred in LUI's 2022 Cost of Service application.
- d) LUI confirms that no activity has been recorded in the GOCA Variance Account.