

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO OEB STAFF

JT4.1-1

References:

Exhibit 1-Tab 5-Schedule 1
Clearspring Report pp. 24, 31-32 (IPD)
Responses to 1-Staff-18, 1-Staff-20, and 1-Staff-21

Preamble:

Clearspring maintains that the GDP-IPFDD is an unsatisfactory proxy for inflation in the prices of materials and services. Clearspring does acknowledge that “Naturally there is a labor price component in the GDP-IPI just as there [is] also a labour component in the materials purchased by a utility”.

Question(s):

Can it also be said that “there is a labor price component in the GDP-IPI just as there [is] also a labour component in the materials and services” purchased by a utility? Why is it reasonable to assume that the labor content of the goods and services covered by the GDP-IPI-FDD is materially less than that of Materials & Services? Doesn’t the GDP-IPI cover the prices of many labor-intensive products that include education, health care, professional services, construction, hotels, and restaurants?

CLEARSPRING RESPONSE:

Yes, the GDP-IPI covers the prices of some labour-intensive items. Clearspring, in our IPD study, is making no assumptions regarding the relative proportions of GDP-IPI and the materials and services purchased by a utility and we agree that there is a labour component in the materials and services purchased by the utility and this may or may not be higher than the labour component in the GDP-IPI. We are using the proxies of GDP-IPI for non-labour and the AWE for labour in our IPD analysis as determined in the 4GIR Decision.

1 In examining the OM&A outside service provider expenses, we essentially assumed the same labour
2 and non-labour components as the utility itself incurred in its other OM&A expenses. This assumes
3 that services have both a non-labour and a labour component in equal proportions as Elexicon has
4 for its non-third party vendor OM&A. This, in Clearspring's view, is a reasonable assumption since
5 we are unable to know the specific labour and non-labour proportions of these outside services.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO OEB STAFF

JT4.1-2

References:

Clearspring Report p. 27

Clearspring response to 1-Staff-15

Preamble:

Clearspring states in its report that there is a large “implicit stretch factor” in CIR. This is based on the contention that the TFP trend of the power distribution industry is negative.

Question(s):

Is there a large implicit stretch factor in the event that

- The OM&A productivity trend of the industry is positive; and
- The capital productivity trend of the industry is negative but CIR ensures that capital revenue escalation is based on a capital cost forecast.

CLEARSPRING RESPONSE:

This is a hypothetical scenario that does not reflect current reality in Clearspring’s view, since there does not appear to be reliable evidence that the OM&A productivity trend of the industry is positive. In fact, there is evidence that the Ontario OM&A productivity trend, after fixing PEG’s productivity study shortcomings, continues to be negative.

Clearspring is of the view that the TFP trend should serve as the basis for the productivity factor in regards to both OM&A and capital due to accounting differences, substitution possibilities between OM&A and capital, and the far lower variation in TFP trends relative to OM&A PFP trends.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO OEB STAFF

JT4.1-3

References:

Clearspring report pp. 29-30

Clearspring response to 1-Staff-17

Preamble:

Clearspring proposes a G factor that is an elasticity-weighted average of Elexicon's forecasts of growth in its customers and peak demand. The weights are elasticity shares derived from econometric total cost research. PEG provides an alternative G factor based on OM&A cost elasticity shares. Clearspring maintains that statistical cost research on OM&A cost is unreliable.

Question(s):

1. PEG reports that the estimated elasticity of cost with respect to customers is 0.593 in its total cost model and 0.745 in its OM&A cost model. The estimated elasticity of cost with respect to peak demand is 0.398 in PEG's total cost model and 0.238 in its OM&A cost model. Regardless of Clearspring's other reservations about OM&A cost and productivity research, don't PEG's OM&A cost elasticity estimates seem reasonable?
2. Why use the forecasted growth in Elexicon's peak demand when Clearspring uses the slower-growing rolling average of peak demand in its econometric cost research?
3. If a rolling average of peak demand was used to measure TFP growth, wouldn't it be inconsistent not to use it in G factor construction?

CLEARSPRING RESPONSE:

1. The PEG cost elasticity estimates are correctly signed and the estimates statistically reject the null hypothesis of having no impact on cost. This aligns with Clearspring's expectations. We are unable to speculate on what we would consider to be a "reasonable" value. Constructing the study and data in the best manner available and allowing the empirical

1 analysis to estimate the values itself will produce the best estimate, in our view. Clearspring
2 is of the view that PEG's peak demand variable calculation in both its total cost and OM&A
3 cost model has some deficiencies. PEG's peak demand variable definition changes over time,
4 as we will further address in Clearspring's Reply Report, and the variable can never decrease
5 over time even after sustained reductions in peak demand over several years or even two
6 decades. These deficiencies likely make cost less related to PEG's variable than what it is in
7 reality, which will have the impact of lowering the coefficient by some amount relative to a
8 variable construction that does not have those deficiencies.

9
10 2. The rationale for using a 10-year historical rolling average is to smooth out the annual
11 fluctuations in peak demand that come from weather. The Elexicon forecasts of annual peak
12 demand are based on normal weather assumptions and, thus, are essentially weather
13 normalized estimates of peak demand. They will not have the fluctuations due to extreme
14 weather that the historic annual peak demands will have. The forecasted growth in peak
15 demand are the more appropriate peak demands to use for the G Factor because it is these
16 forecasts that are the key input into forecasting system needs.

17
18 3. A rolling average of peak demand is not being used to measure TFP growth. The current
19 productivity factor recommended by Clearspring is 0.0%. This recommendation stems from
20 4GIR and CIR precedent. In 4GIR, the TFP trend was found to be negative even when using a
21 ratcheted peak demand variable construction. A ratcheted peak demand construction (while
22 being a problematic approach for multiple reasons) would produce the same G Factor for
23 Elexicon as recommended by Clearspring.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO OEB STAFF

JT4.1-4

References:

Clearspring report, p. 16

PEG's Response to EE-22

Preamble:

Clearspring's cost benchmarking model contains a "Distribution ("Dx") Work" variable that is based on the premise that if a high percentage of a utility's reported transmission lines are high voltage than it is more likely that some equipment with subtransmission voltage is classified as distribution assets. In Ontario, however, transmission services are provided by another utility (Hydro One Networks) and its ownership of lines in the vicinity of Elexicon's service territory is unknown.

Question(s):

1. Please confirm that Clearspring set a value of the Dx Work variable of 1 for Elexicon.
2. What is the rationale for this?
3. How many companies in Clearspring's sample had a Dx Work variable value of 1?
4. Does Elexicon own any lines rated over 50 kV? Is a value of 1 appropriate in light of your answer?
5. Please reestimate your benchmarking model if any alternative value of the Dx work variable now seems appropriate for Elexicon.

RESPONSE:

1. Confirmed.
2. The rationale is that Elexicon's transmission provider (Hydro One) does not own or operate lines below the 50 kV threshold. All (100%) of the electric lines below the 50 kV threshold are owned and operated by Elexicon.
3. There are 51 utilities in the sample that had a value of "1" in at least one year.

- 1 4. Clearspring did not require this information for the variable construction and did not request
2 it from Elexicon. The voltages of distribution lines are not available for the U.S. sample and
3 this is not something Clearspring needed to calculate the Dx Work variable. The variable is
4 calculated based off the voltages of lines of the transmission utility. Yes, the value of "1"
5 continues to be appropriate for Elexicon.
- 6 5. Not applicable, as explained in the responses above.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO OEB STAFF

JT4.1-5

References:

Interrogatory 1-Staff-10

Preamble:

Clearspring states that “It would be helpful, if it were possible, to add more utilities similar to Consolidated Edison to the sample. However, that is not currently feasible.”

PEG has included three Alberta utilities in its econometric research sample and these include those serving Calgary and Edmonton.

Question(s):

Do you think that there are more pluses than minuses to adding Alberta utilities like ENMAX and EPCOR to the samples used for cost benchmarking in CIR proceedings?

CLEARSPRING RESPONSE:

Regarding the preamble, Clearspring’s statement was about including more highly congested urban observations along the lines of New York city and Toronto to the sample. The sample already includes numerous utilities serving urban areas along the lines of Calgary and Edmonton. Adding the Alberta utilities does not address this issue.

Clearspring has not yet had the opportunity to thoroughly examine the Alberta data and determine a position on the inclusion of the Alberta utilities. At a high level, it could be helpful to add somewhat larger utilities that are operating in Canada, assuming all the data is consistent with the existing sample (which we have not had the opportunity to fully review). One disadvantage is that the Alberta utilities don’t perform billing and so consistency with the sample is a concern. Cost and variable data consistency and gathering efforts are added challenges. Our biggest immediate concern with PEG adding the above Alberta utilities is its exclusion of ATCO Electric due to its results being poor. We

- 1 believe this creates a clear bias in the results against all other utilities in the sample if a utility is
- 2 excluded based on it being a poor performer.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO OEB STAFF

JT 4.1-6

References:

Exhibit 1 Tab 5 Schedule 1

Elexicon responses to 1-Staff-16, 1-Staff-19, and SEC-19

Preamble:

In its response to Staff-16, when asked if to confirm that neither the IPD nor the G factor would effect Elexicon's revenue escalation, the Company stated:

Yes, the sum of Elexicon's proposed G Factor, IPD, and RGF, less the impact of X, are equal to Elexicon's forecast Service Revenue Requirement over the 2028 through 2031 period.

Elexicon has proposed a revenue cap whereas Alectra recently proposed a price cap.

Question(s):

1. Please confirm that because of the RGF the proposed IPD and G factor terms don't affect revenue escalation. They only affect how much supplemental capital revenue is requested.

2. Why then were the IPD and G factors proposed?

3. Why has Elexicon proposed to base its OM&A revenue escalation on a forecast when the forecasted growth in OM&A revenue is less than the growth in the otherwise-applicable index?

4. How many distributors in Ontario have had approved CIR plans where their OM&A expenses were based on forecasts? Have any been approved in the last 5 years?

5. Elexicon proposed a true up of capital underspends due in part to the use of forecasted capital in the RGF. Did Elexicon consider a similar true up of OM&A underspends for its proposal?

6. Why did Elexicon propose a revenue cap instead of a price cap?

Response:

1. See response to 1-SEC-19.

- 1 2. See response to 1-SEC-19. The IPD and Growth Factor are included in Elexicon's Custom
2 Revenue Cap Index (CRCI) to align with economic theory.
3
- 4 3. As noted on pages 2 of Exhibit 1 - Tab 5 - Schedule 1, Elexicon considered the pacing of its
5 capital and OM&A spending and made decisions to temporarily accept additional near-
6 term risk in order to mitigate larger rate increases in 2027. As such, 2027 does not reflect a
7 typical rebasing year for the purpose of applying traditional mechanistic adjustments to
8 costs. As discussed in 1-Staff-19, while the 5-year CAGR of Elexicon's OM&A forecast is less
9 than I-X+G, this is not the case in every year. Particularly, in 2028 when the paced OM&A
10 investments discussed in Exhibit 1 - Tab 5 - Schedule 1 enter Elexicon's forecasts.
11
- 12 Using a traditional indexing approach would underfund OM&A by about \$3M in 2028
13 effectively making Elexicon's allowed ROE structurally unachievable in that year. OM&A
14 would also be underfunded by \$1.0M in 2029 which is well above what would be
15 warranted through the productivity factor. Leveraging the RGF allows Elexicon to fund its
16 unique OM&A profile and provides customers with the benefit of an offsetting impact to
17 incremental capital funding requirements in the latter years of the rate term where
18 Elexicon's OM&A growth slows as it sees the results of greater efficiencies and throughput
19 of work volumes through factors such as the Dx NEXT initiative.
20
- 21 4. As noted above in part 3, Elexicon has constructed its investment plan in a manner to
22 mitigate rate impacts for customers, and this requires a novel approach to OM&A in the
23 CRCI in order to fairly balance the interest of customers and the utility. Elexicon is aware of
24 three CIR electricity transmission applications where OM&A expenses were proposed and
25 approved on a forecast basis, in EB-2024-0116, EB-2024-0117, and EB-2024-0216. In terms
26 of distribution, Elexicon is also not aware of any other distributors that are experiencing
27 the mix of business conditions that apply to Elexicon. Namely, the combination of
28 significant growth, capacity constraints, and declining reliability performance which drive
29 the need for investment above status quo levels along with a significant "catch-up" driven

1 by rates that no longer align with costs and an extended period of significant under-
2 earning.¹

- 3
- 4 5. Elexicon does not agree with the characterization Elexicon's proposal in the question.
- 5 Elexicon has not proposed a true-up of capital underspends. As discussed in Exhibit 1 - Tab
- 6 5 - Schedule 1 and further detailed in Exhibit 9 - Tab 4 - Schedule 2, Elexicon has proposed a
- 7 suite of deferral accounts across its capital program with varying treatment. The majority
- 8 of Elexicon's capital program is subject to the Capital In-service Additions Variance Account
- 9 which is not a full true-up mechanism as it is subject to a dead band. Elexicon notes that, all
- 10 other things equal, any underspend in OM&A would drive an increase in earnings which
- 11 would be captured through the proposed Earnings Sharing Mechanism.
- 12
- 13 6. Elexicon proposed a Revenue Cap instead of a Price Cap in alignment with past precedents
- 14 and because it allows for a more direct link between the econometric benchmarking
- 15 analysis and the adjustments to Elexicon's costs (i.e. revenue requirement). This approach
- 16 allows Elexicon to directly leverage the elasticities from the Clearspring analysis to calibrate
- 17 changes to growth in costs in line with scale variables in the models. Rates are then
- 18 calculated using forecast charge determinants of a five-year load forecast to give
- 19 customers the benefit of revenue growth over the term. The OEB previously approved
- 20 custom Revenue Cap approaches for other electricity distributors such as Hydro One (EB-
- 21 2017-0049 and EB-2021-0110), Toronto Hydro (EB-2023-0195) and Hydro Ottawa (EB-
- 22 2024-0116).

¹ See 1-SEC-11 for a quantification of the "catch-up" in rates.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO OEB STAFF

JT 4.1-7

References:

PEG and Clearspring empirical reports, 1-PP-2, 1-PP-6, 1-PP-14, 1-CCC-5

OEB December 20, 2018 Decision and Order in EB-2018-0236

Preamble:

The Clearspring and PEG benchmarking studies both reveal a material decline in the total cost performance of Elexicon from 2019 to 2027. PEG additionally reports a substantial decline in the Company's OM&A cost performance during these years.

In EB-2018-0236, the proceeding which led to the approval of Elexicon's amalgamation, the applicants forecast cumulative OM&A savings of \$48.8 million for the 2019-2029 period, and annual savings of approximately \$6.6 million that would flow through to customers at rebasing. No capital savings were forecasted.

Page 11 of the OEB's Handbook to Electricity... states that At the time of rebasing, the OEB expects the consolidated utility to produce an updated analysis comparing the revenue requirements for the consolidated entity and the status quo (separate LDCs), based on information available on a reasonable efforts basis.

Question(s):

1.Are customers receiving the forecasted OM&A cost savings from the amalgamation? If so, how?

2.Where in the record did Elexicon provide an analysis comparing the revenue requirements of the consolidated entity and as separate LDCs? If it was not provided, please explain why it was not provided.

3.Given the early rebasing, are there additional merger savings that the Company expects to find during the next plan that would be passed on to customers in the next rebasing proceeding?

1 4.Elexicon underearned for a number of years before filing for rebasing. To what extent was that
2 due to not rebasing at the start of its current plan?

3
4 **Response:**

5 1. See response to 1-CCC-5, part j).

6
7 2. Elexicon notes that this type of analysis was not a requirement of the OEB's *Handbook to*
8 *Electricity Distributor and Transmitter Consolidations*, dated January 19, 2016, which applied
9 at the time Elexicon's merger was approved. Consistent with the expectations of the OEB's
10 handbook at the time of merger, there was no revenue requirement information included in
11 the merger application (EB-2018-0236) and, as such, there is no information upon which to
12 provide this analysis.

13
14 3. No. See response to 1-Staff-28, part c) and 1-SEC-26. Elexicon has completed its integration
15 of the two legacy utilities and does not anticipate further merger savings. Elexicon will also
16 be incented to find productivity through its incentive rate setting framework which provides
17 customers with an up-front rate reduction benefit of \$3M over the rate term.

18
19 4. While Elexicon was already investing capital and OM&A at levels above what is funded in
20 rates in 2019, the primary drivers of under-earnings over the deferred rebasing period were
21 the changing business conditions described in Exhibit 1 - Tab 4 - Schedule 1. These factors
22 drove the need for increasing levels of investment year-over-year to meet mandatory
23 obligations (e.g. infrastructure relocation and customer connections) and address
24 deteriorating asset condition and declining reliability performance, among other factors.
25 While rebasing prior to merger may have provided some benefit in the initial years, the
26 increasing levels of investment in capital and OM&A would have applied pressure on the
27 business regardless and caused the increasing gap between the level of investment and
28 funding in rates which drove the increase in under-earnings over time.

1 **TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO OEB STAFF**

2

3 **JT4.2**

4

5 **Question(s):** PROVIDE A WALKTHROUGH OF THE DRAFT INVESTMENT PLAN THE BOARD SAW TO
6 SHOW A FULL LINE OF SIGHT IN TERMS OF THE GRID MODERNIZATION INVESTMENTS

7

8 **RESPONSE:**

9 Please see Attachment 1 for the draft investment plan that was presented to the Elexicon Energy
10 Board.

Elexicon Energy – Board of Directors

Early Rebasing Application Update Proposed Investment Plan for 2027 to 2031

Presented on November 18, 2024

Updated on November 27, 2024

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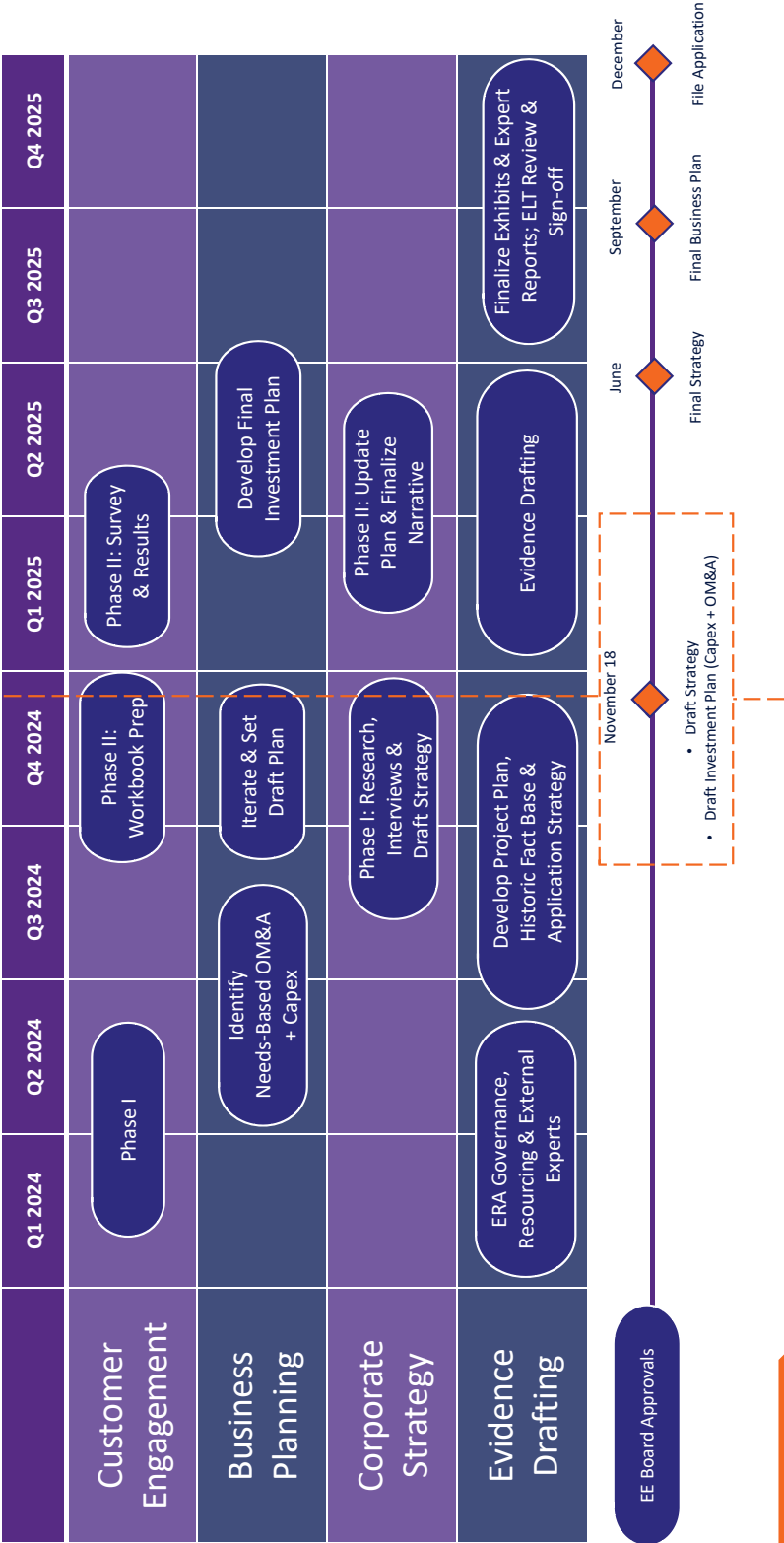
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Application Roadmap

We are halfway through our 2-year journey to prepare our early rebasing application.



Today's Objective

Seek Board alignment on the **draft** business plan that will go out to customers for Phase 2 engagement in February 2025.



Recap: Customer Priorities

Results from Phase One of Customer Engagement identified customer priorities.

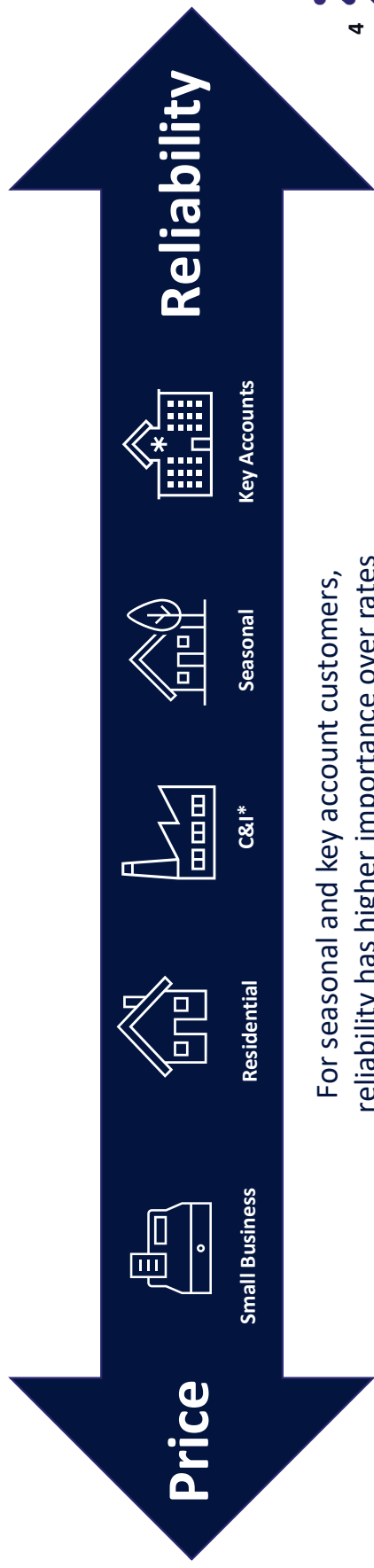
Top Three Priorities Across Rate Classes

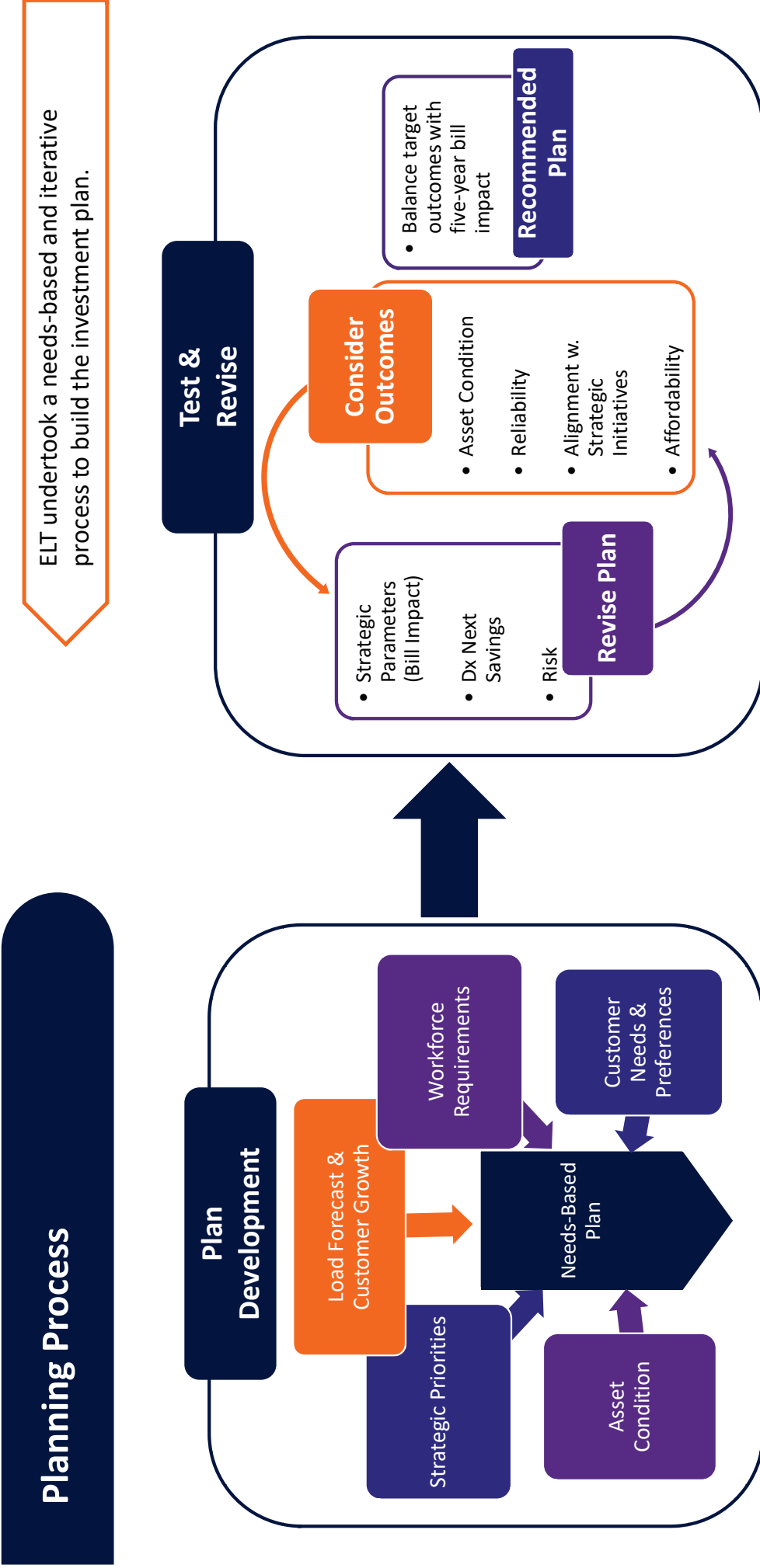


Delivering electricity at reasonable rates

Providing reliable electrical service

Ensuring the grid can withstand severe weather events



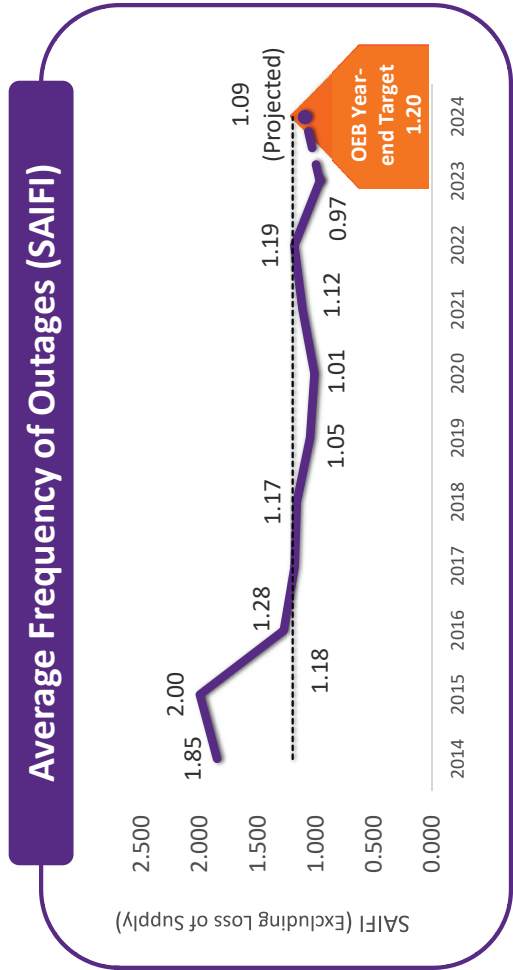
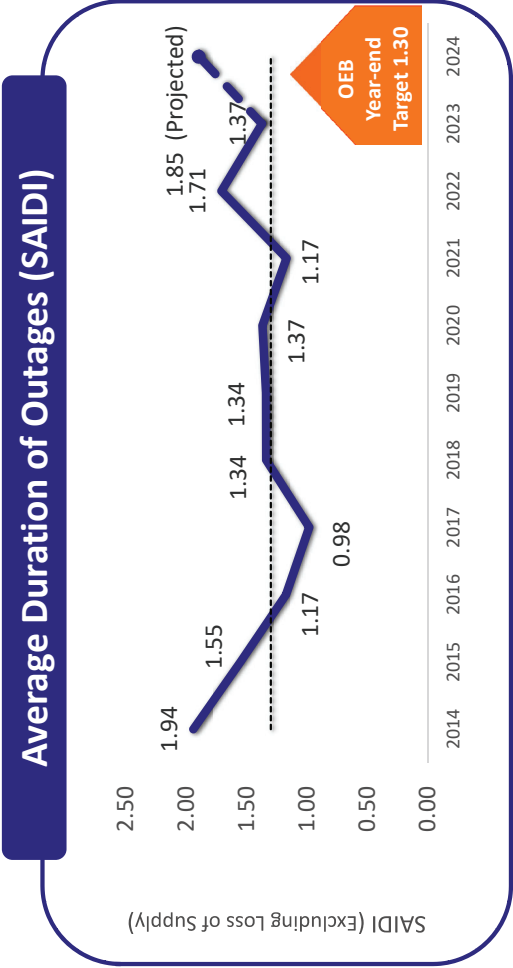


Asset Context Investment Drivers

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Historical Reliability Performance

Ellexicon’s reliability performance is declining



- While the frequency of outages (SAIFI) is relatively stable, the duration of outages (SAIDI) has been increasing.
- 2024 SAIDI is anticipated to reach its worst levels in 10 years.

Top Drivers of Outage Duration (SAIDI)



Defective Equipment (36%) - Overhead Sleeves, Switches, U/G Cables)

Tree Contacts (20%)

Foreign Interference (19%)

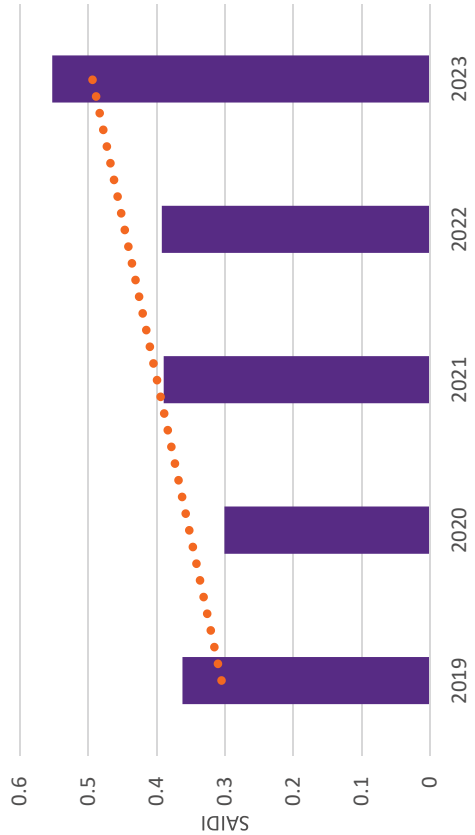


Impact of Defective Equipment

Ellexicon's Defective Equipment is progressively worsening

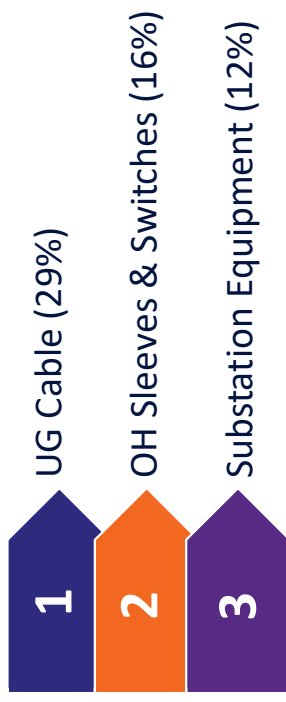
- Defective equipment is the leading contributor to SAIDI.
- While the frequency of defective equipment related outages has been stable, the duration of outages has been steadily worsening.

Outage Duration Caused by Defective Equipment (DE SAIDI)*

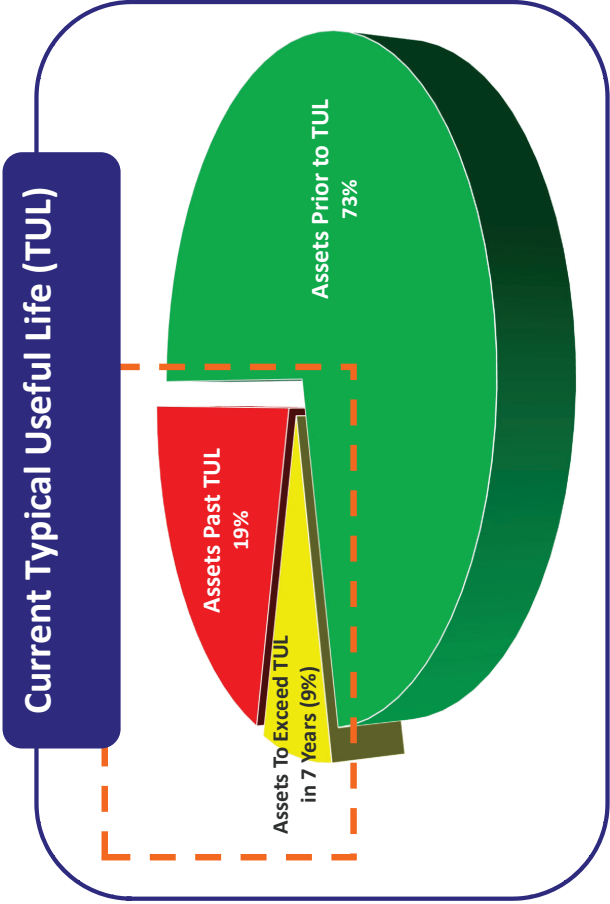


* DE SAIDI values exclude outages caused by loss of supply of major event days.

Top Three DE SAIDI Contributors (2019-2023)

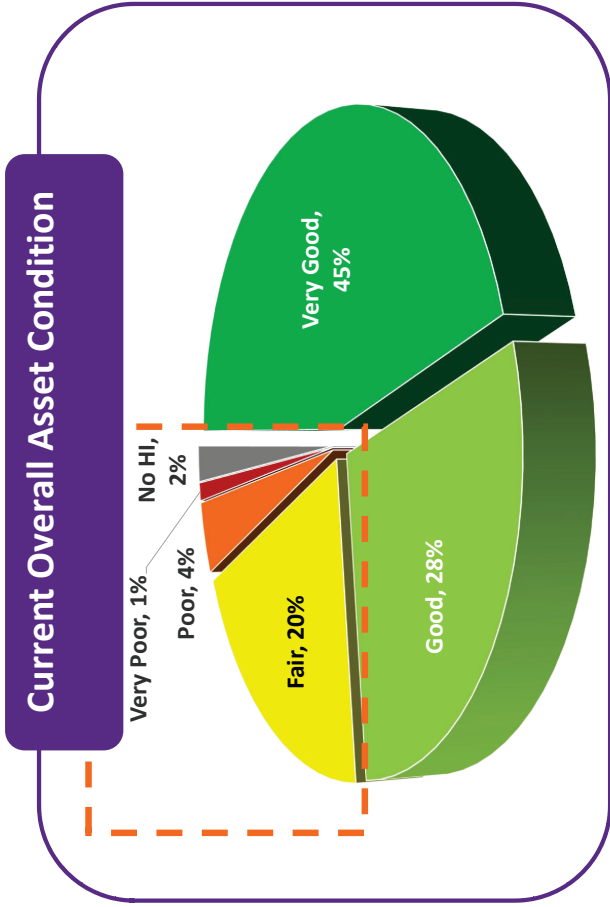


Asset Demographics – Age & Condition



28% of assets have already exceeded or will exceed their TUL in the next 7 years (by 2031).

*% are based on the quantity of assets (%), as of October 2024.



25% of assets are in Very Poor, Poor or Fair condition and will require attention over the next 10-year period.

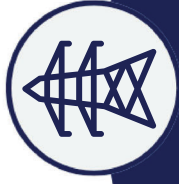


Key Asset Risks



UG RENEWAL

- UG Cable has been a top contributor to defective equipment SAIDI/SAIFI during the last five years.
- UG Cable has seen minimal capital spending in the historical period.
- Overall, currently 42% of UG Cables are in Poor and Very Poor Condition.



STATION RENEWAL

- Substation equipment: 3rd biggest contributor of defective equipment to SAIDI over past five years (4th for SAIFI).
- Station renewal has seen minimal spending in the historical period.
- Significant increase in the cost to building a substation.



FLEET

- Fleet investment has been targeted at repair and extension of life of the fleet rather than replacement.
- Many of the fleet vehicles are well beyond their useful life and in need of full replacement.



FACILITIES

- Capacity has been reached on-garage and storage space.
- Office space requires augmentation to accommodate workforce.
- Investment will be required to address these constraints.



CYBER

- End of life and unsupported critical IT systems (e.g. CIS).
- New and emerging evolving requirements in OEB cyber security framework.
- Increasing capability and maturity required to maintain insurance coverage.

Investment Plan Scenarios

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Updated on November 27, 2024

Summary of Plans

Through an iterative planning process, ELT considered multiple scenarios. Scenarios differ on ability to address risk and meet strategic objectives.

OM&A/CAPEX

2022 - 2026

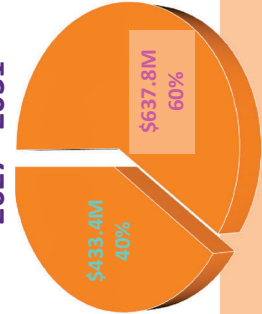


2025 – 2026 are forecast

- Constrained funding. Renewal investments deferred.
- Dx Next Implementation (Phase One – Meter to Cash) addresses immediate risk.
- Asset risks persist and reliability declines.

DX = Distribution

2027 - 2031



BALANCED PLAN - RECOMMENDED

Balances rate impact and system needs

- 73% increase.
- Provides resources to deliver on draft corporate strategy.
- Paced renewal and modernization investment.

DX Rate Impact 9.6%



NEEDS-BASED PLAN

Addresses nearly all system needs

- 117% increase over prior period ('22-'26).
- Accelerated investment in renewal and modernization initiatives (e.g. grid automation, AMI 2.0).

DX Rate Impact 13.2%



LOW CAPITAL PLAN

Prioritizes rate impact by minimizing spend

- 64% increase.
- Reliability degradation and asset risks unaddressed and slowed modernization.
- Insufficient resources to deliver on draft corporate strategy.

DX Rate Impact 8.8%

System Access

Outcome*	Needs-based (\$175M)	Balanced (\$142M)	Low (\$122M)
Mandatory Obligations			
Modernization – AMI2.0			

*reflects performance at end of planning period (2031)



Key Objectives

Mandatory Obligations Include:

- **Connect customer** efficiently.
- **Accommodate relocations** for third-party development, municipal and transit projects.
- **System Expansion** to accommodate future load, with increased electrification and customer growth factors.
- Begin the **modernization of advanced metering infrastructure (AMI)** to improve operational flexibility and customer data to enhance operations and planning.

Risks

- AMI2.0 will be completed over a longer period of 8 years and start in 2028.
- Functionality will not be fully realized in this rate period.



System Renewal

Outcome*	Needs-based (\$316M)	Balanced (\$211M)	Low (\$189M)
Safety			
SAIDI			
SAIFI			
System Health Index			

*reflects performance at end of planning period (2031)

 Exceed (improved)

 At Risk (caution)

 Achieve (stable)

 Risk Realized

Risks

- Any reduced spending on renewal will have a negative impact on reliability, larger growth in assets being in poor and very poor condition.
- Long lead items for substations (e.g. transformers) must be ordered between 2-4 years in advance.

Key Objectives

- Replace assets that have **safety and environmental** concerns in a timely manner.
- Targeted asset specific investments is expected to **improve reliability** from current levels.
- Maintain** a similar overall health demographics of the asset population.
- Address **obsolete assets** in a timely and prudent manner.



System Service			
Outcome*	Needs-based (\$244M)	Balanced (\$203M)	Low (\$187M)
SAIDI			
SAIFI			
Capacity			
Standardization			
System Efficiency			
Modernization			

* reflects performance at end of planning period (2031)

Risks

- Any reduction in spending in station growth will impact Elexicon’s ability to meet future customer capacity demands.
- Safety of crews impacted if rear-lot installations do not continue to be addressed.
- Incremental improvements to reliability will not be realized if grid enhancement investments are reduced.

Key Objectives

- Improve **system reliability** through grid modernization investments (e.g. enhanced fault management, leveraging automation) and grid enhancements on worst performing feeders.
- Invest in additional stations capacity** to meet projected load growth.
- Paced implementation of replacement of **legacy or non-standard** assets and installations. (e.g., rear-lot conversion).
- Enhance **system efficiency** through continued targeted voltage conversion.



General Plant

Outcome*	Needs-based (\$121M)	Balanced (\$83M)	Low (\$80M)
Operational Efficiency			
Cyber Security			
Modernization			
Fleet & Facilities Condition			

*reflects performance at end of planning period (2031)

Risks

- Delayed fleet investment will result in more unexpected failure of fleet. Negative impact on Elexicon’s ability to respond to outages/emergencies, carry out planned work.
- Backbone support tools need upgrading and replacing to ensure continued operation of all Elexicon functions and minimize cyber security risk.

Key Objectives

IT & OT:

- Support Grid of the Future objectives, through targeted OT investments
- Minimize cybersecurity risks
- Ensure IT infrastructure is available and reliable with minimal service disruption.
- Dx Next implemented and benefits realized

Fleet & Facilities:

- Replace fleet vehicles in **poor condition**
- Address **facilities constraints** to ensure efficient operations can be carried out by Elexicon.



Updated on November 27, 2024

Distribution Rate Impact - Explained

Estimated increases to distribution rates reflect the urgent funding gap.

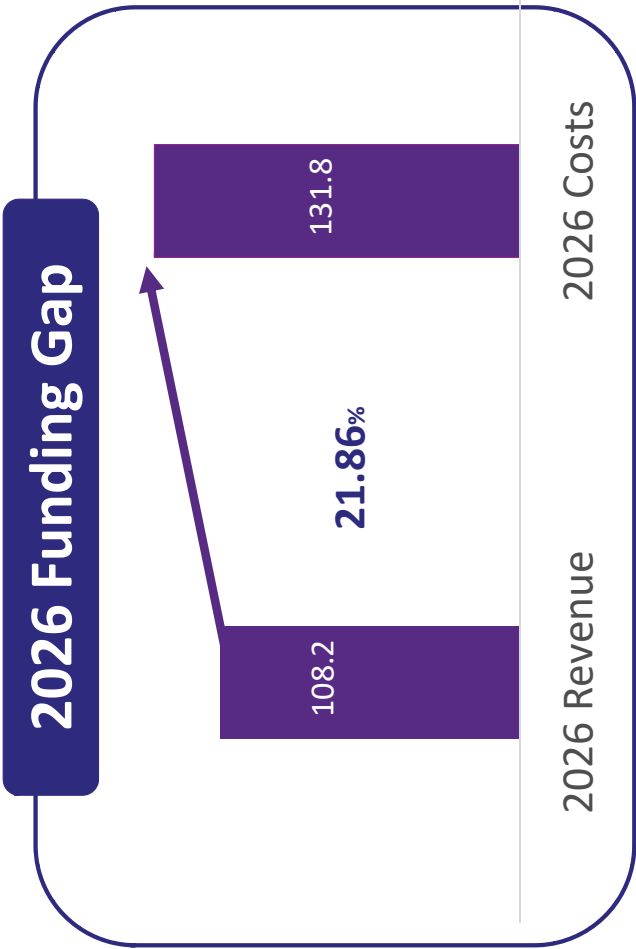
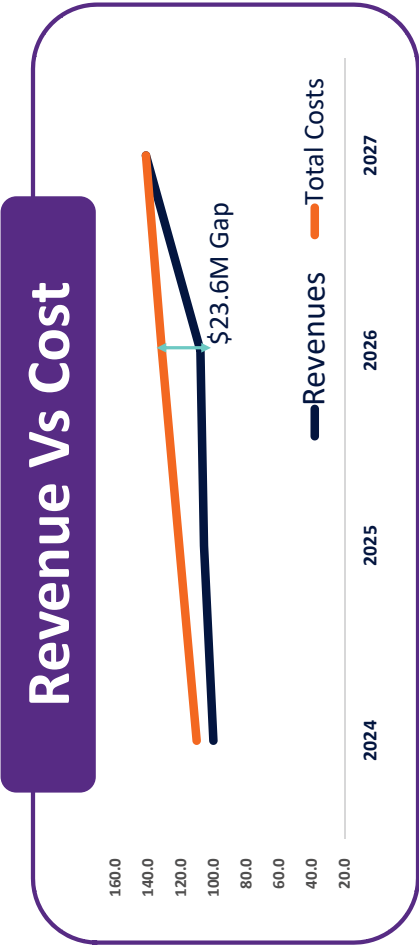
Scenarios	2027	2028	2029	2030	2031	Average /year
Distribution Rate Changes (including the “catch up”)						
“Catch Up”	22%					
Needs Based	35.1%	4.1%	7.3%	10.1%	9.5%	13.2%
Balanced Plan	22.6%	4.9%	4.2%	9.1%	7.2%	9.6%
Low Capital Plan	22.6%	4.8%	3.0%	7.2%	6.2%	8.7%

- Rate impacts show the **percentage change in Elexicon’s distribution rates** (not Total Bill).
 - Elexicon’s rates **represent about 30%** of the **Total Bill**.
- Bill impacts are partially mitigated by expected customer and load growth in 2027-2031 (more customers = spreading out costs over larger group)
- **“Catch up”** alone **contributes 4.4%** to average 5-year bill impact.



Explaining the “Catch-up”

- Elexicon’s rates are not aligned with it’s cost structures (i.e. revenue requirement).
- The “catch-up” is the difference between 2026 revenues and 2026 costs.
- This is the increase necessary to align rates with existing cost structures before we consider any incremental needs arising from the 2027-2031 plan.



	2024	2025	2026
Revenues	\$100.3M	\$106.0M	\$108.2M
Total Costs	\$110.5M	\$121.2M	\$131.8M
Funding Gap	(\$10.2M)	(\$15.1M)	(\$23.6M)

Highly Confidential Commercially sensitive

Balanced/Recommended Plan Detailed View

Highly Confidential Commercially Sensitive

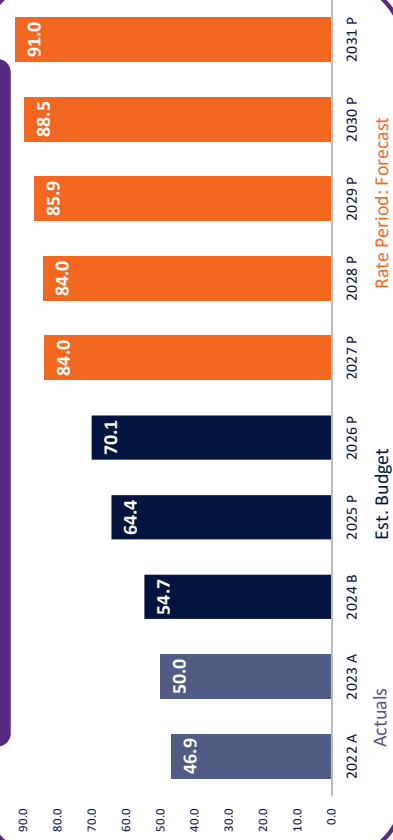
Updated on November 27, 2024

Balanced Plan - Summary

Capital (\$M)



OM&A (\$M)



Bill Impact

- Plan targets an average rate increase of about 10% per year.
- For residential customers, that means by 2031, distribution rates will have increased by an additional \$23.00 per month.

Mitigating Bill Impact

- Addressing some Deferral Accounts in 2026 rates – i.e. collecting money owed from customers before rebasing to lessen the jump in rates from 2026 to 2027.
- Deferring OM&A costs related to Dx NEXT and spreading them over a longer period.
- Deferring new positions to 2028 and after to reduce labour costs in 2027.
- Deferring \$1M in necessary, additional maintenance funding to 2028.

Overall Outcomes of Capital Plan



Meet Future Growth and Comply with Mandatory Obligations

- Upgrade of substation capacity & installation of new substations to accommodate new load.
- Timely connection of customers.
- Relocation of assets to support municipality, transit and third-party requests.
- Metering investment to comply with Measurement Canada.



Improves Reliability From Current Level

- Targeted asset specific renewal.
- Specific system reliability improvement projects on Worst Performing Feeders.
- Grid Modernization Enhancements.
- Increased Tree Trimming (OM&A).



Address Known Safety & Environmental Concerns

- Targeted asset specific renewal of assets with known safety concerns.
- Targeted renewal of substation assets with known safety & environmental concerns.
- Replacement of obsolete and non-standard assets.



Setting Up the Framework for the Grid of the Future

- Continued deployment of smart field devices.
- Targeted operational technology investments to support the communication background and functionality of the smart field devices.
- Upgrade of the Advanced Metering Infrastructure (AMI 2.0).

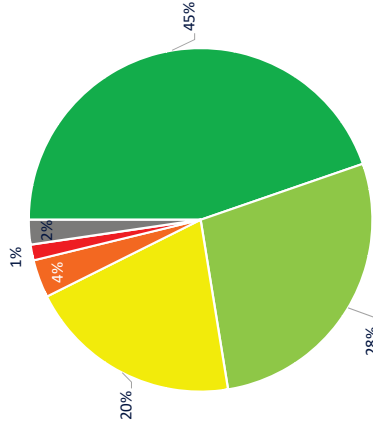


Enabling Backbone Infrastructure to Allow Elexicon to Efficiently Serve its Customers

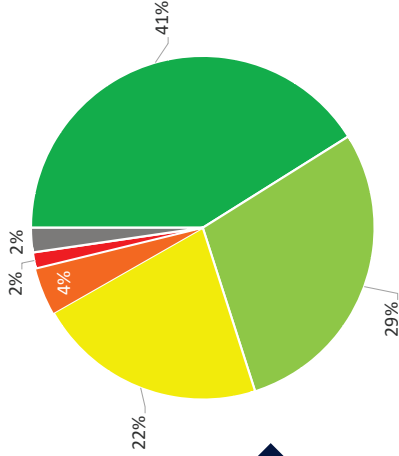
- Steps taken to address cyber security.
- Dx Next: Replacing end-of life and unsupported systems.. Bring new systems together to enhance productivity.
- Upgrading an ageing fleet and addressing facilities constraints.

Plan Outcomes – Health Index (HI) Demographics 2024 vs 2031

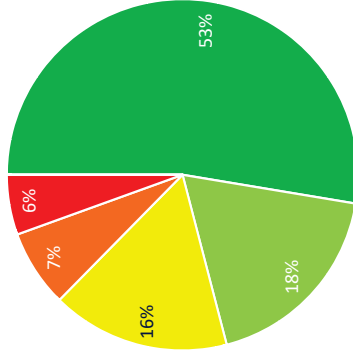
System Wide – 2024 Asset HI



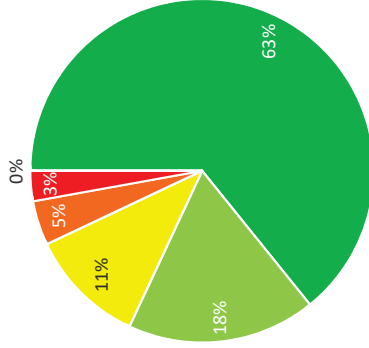
System Wide - 2031 Asset HI



Station Assets - 2024 Asset HI



Station Assets - 2031 Asset HI



Key Outcomes

Overall, the System Wide HI demographics will **remain similar** at the end of 2031 compared to 2024.

Station assets in 2031 will see an asset health and reliability improvement: Assets in poor and very poor **reduced from 13% in 2024 to 8%.**

Elexicon's investment plan **targets** its most **critical assets**, with a focus on assets that are having the **greatest impact on reliability:**
UG Cables, OH Sleeves, and Switches, Substation Equipment



Alignment of Recommended Plan w/ Corporate Strategy

The recommended investment plan will ensure we have the resources necessary to deliver on our draft corporate strategy

Strategic Focus Areas

Serve Our
Customers and
Communities

Invest in Our People

Stabilize the
Business

Enable Growth and
Electrification

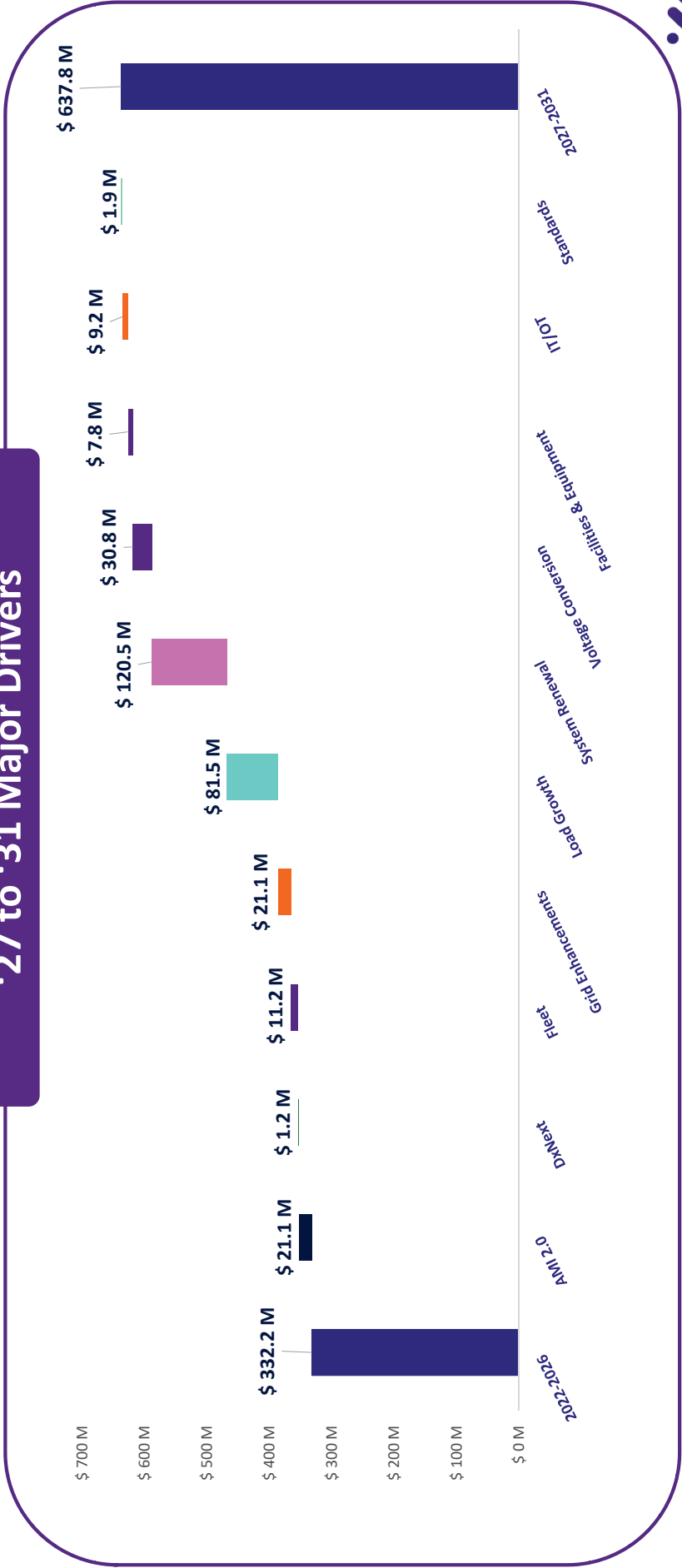
Recommended Plan

- Enable **efficient growth** through modernization of our **systems and processes** (e.g. Dx Next).
- Foundational investments in **grid modernization** and establishment of grid modernization team to **leverage and develop new capabilities**.
- **Incremental headcount** to ensure **sufficient** resources to deliver on plan.
- **Alignment of revenues and costs** through successful completion of rebasing application.
- Targeted investments in **aging infrastructure** to restore reliability **performance** and address **risk**.
- Support **community growth** (e.g. new connections and investments in capacity).

Recommended Plan – Drivers of Capital Spend

Increase in capital spending primarily driven by investments to address projected load growth and aging infrastructure

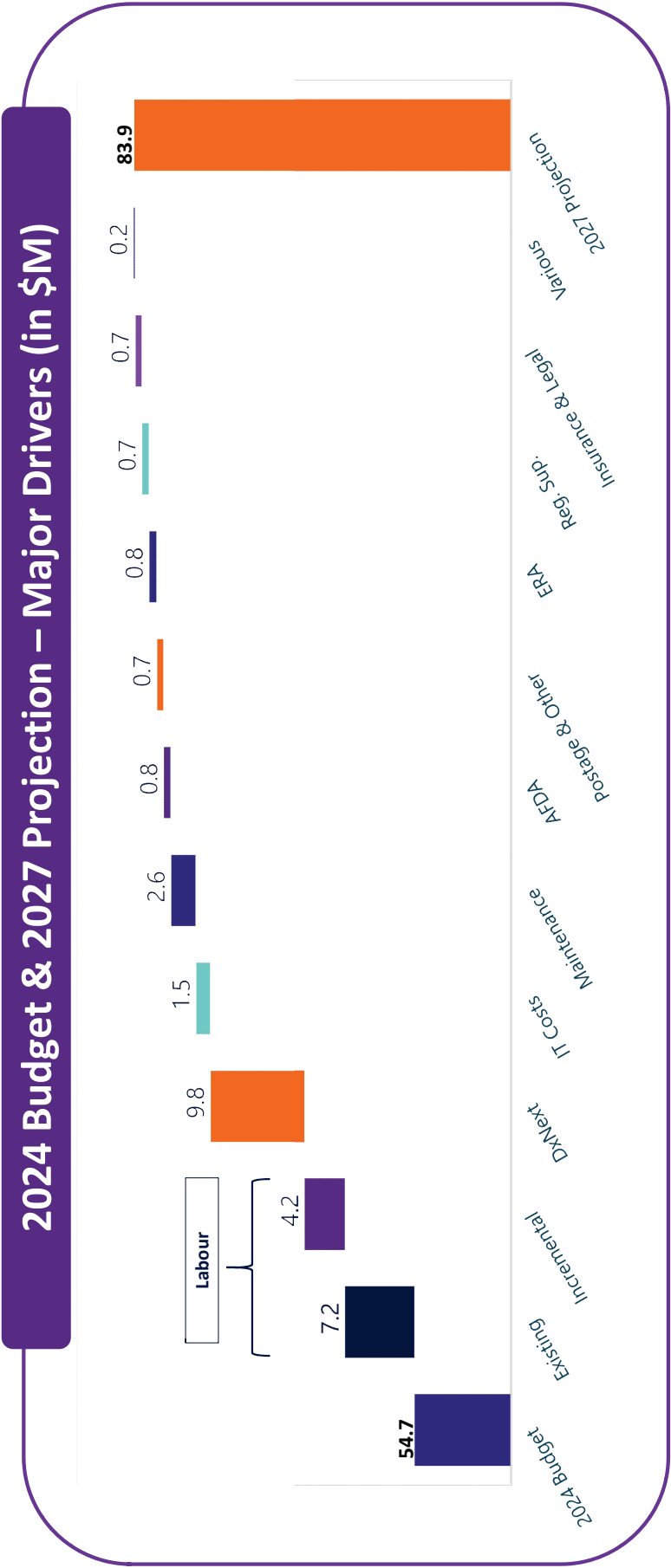
‘27 to ‘31 Major Drivers



Updated on November 27, 2024

Recommended Plan – Detailed OM&A Drivers

Growth in OM&A primarily driven by increased labour costs, incremental headcount requirements, maintenance spending and cloud computing (Dx NEXT).



- \$6.4 of DxNext spend in 2027 due to one-time, implementation costs for Phase 2.
- Rate Recovery proposal spreads the \$6.4M over 5 years to mitigate 2027 impact.
- Results in lower rates in 2027 and an OMA recovery of ~ \$78.8 M in 2027



Updated on November 27, 2024

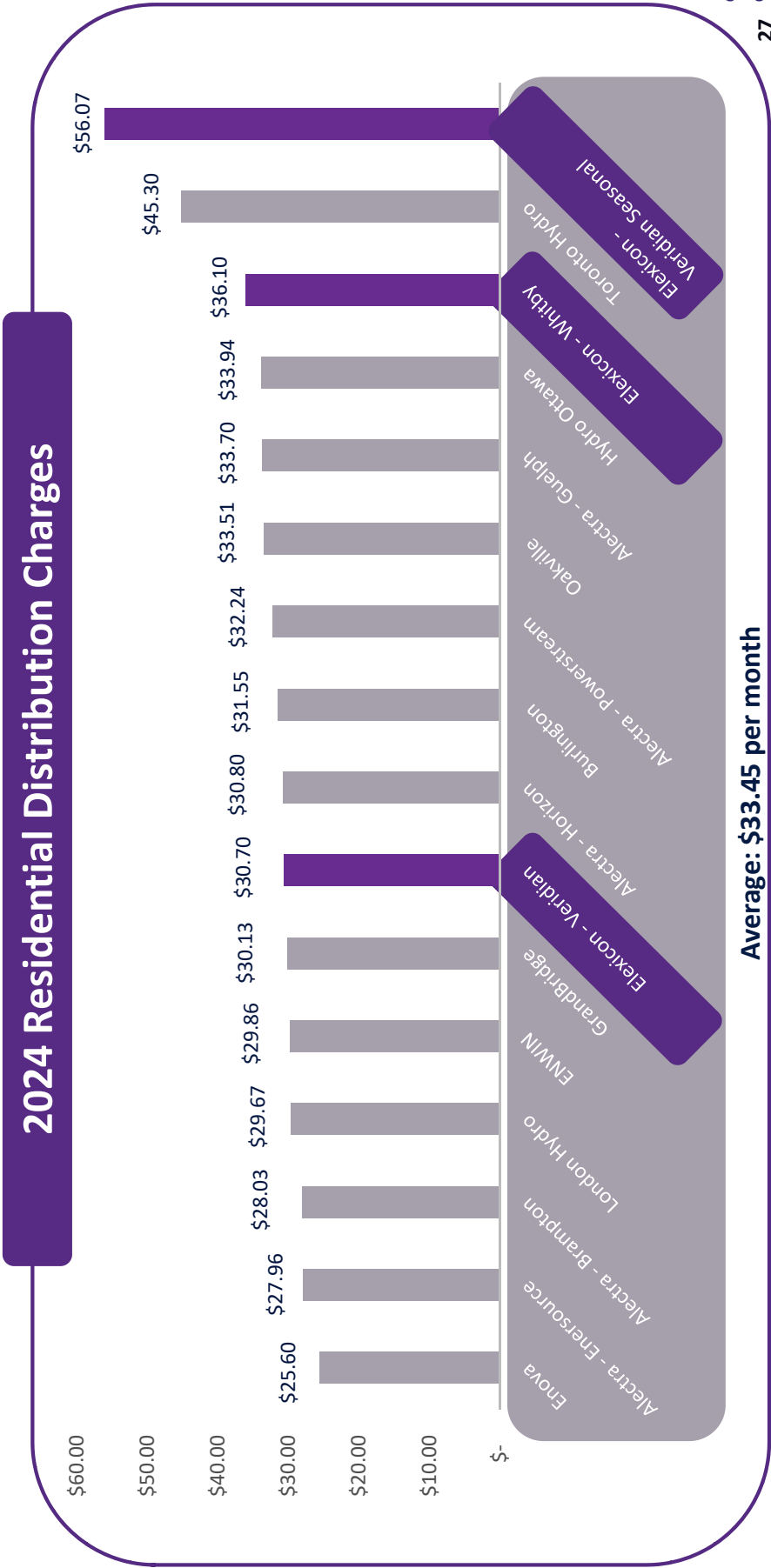
Appendix – Current Rates

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Updated on November 27, 2024

Peer Group Rate Comparison – Residential Customers

Current residential rates for former Veridian rate zone are lower than the peer group average. Former Whitby rates are higher than peer-group average.

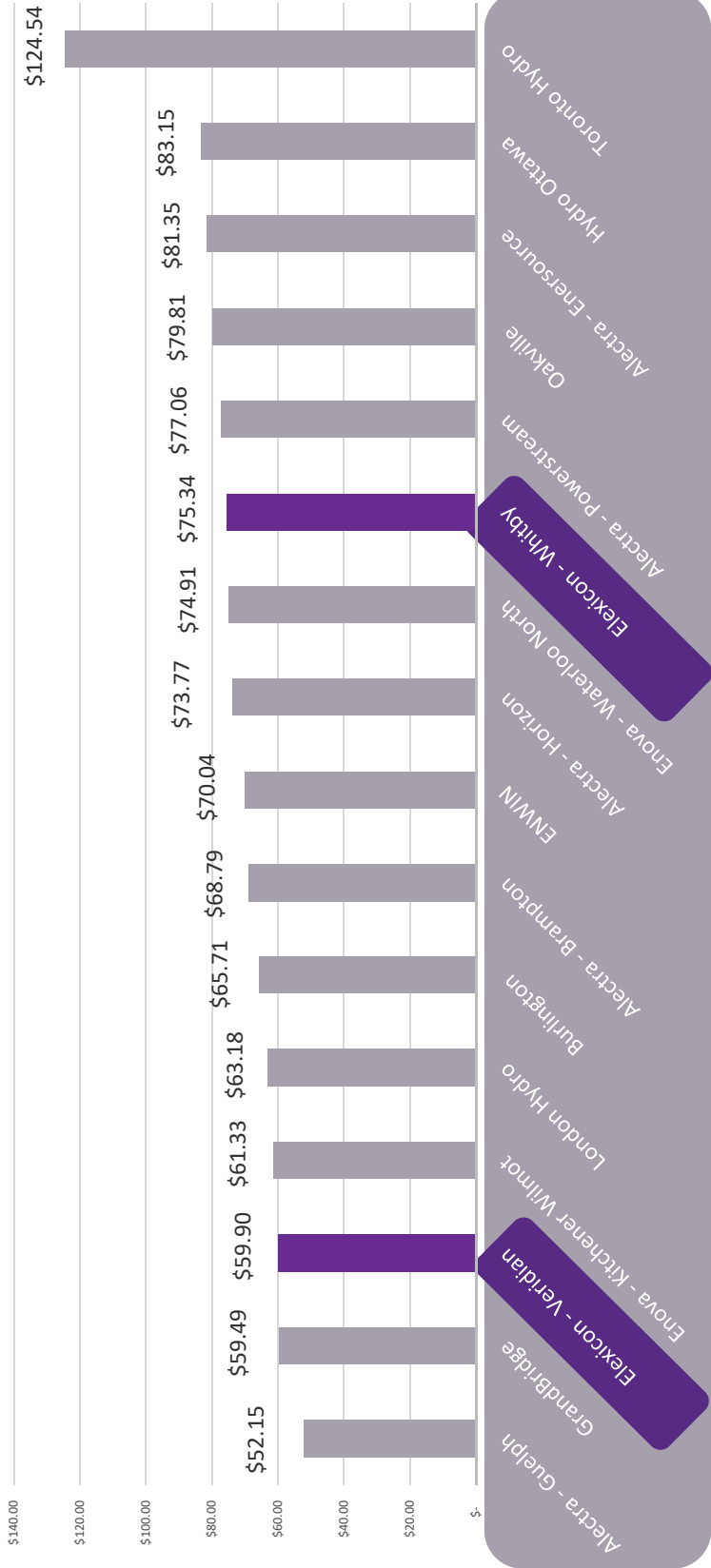


Updated on November 27, 2024

Peer Group Rate Comparison – Small Business Customers

Current distribution rates for small business customers in the former Veridian rate zone well below peer group average.
Former Whitby rates are slightly above peer group average.

2024 General Service < 50 kW Distribution Charges



Average: \$73.16 per month for a typical customer consuming 2,000 kWh/month

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO OEB STAFF

JT4.4

QUESTION:

PROVIDE A PROJECT-BY-PROJECT BREAKDOWN OF WHAT THE 9.32 MILLION IS IN RELATION TO SUBSTATION RENEWAL

RESPONSE:

Table 1 below provides the year-over-year in-service addition ("ISA") actual costs for the Substation Renewal program, combining the Veridian and Whitby costs. The higher level of Substation Renewal ISA costs in 2019 reflects the completion of several significant substation renewal projects and a greater volume of substation deficiencies that required corrective action compared to prior years.

Table 1: 2014 to 2019 Substation Renewal In-Service Costs

R1 Substation Renewal	2014	2015	2016	2017	2018	2019 (Elexicon)
Veridian & Whitby Spend (\$M)	3.21	2.22	4.25	4.17	3.13	9.32

Prior to 2019, annual Substation Renewal ISA costs within the former Veridian and Whitby service territories ranged from \$2.22 million to \$4.25 million annually, compared to \$9.32 million in 2019. The increased 2019 ISA spending reflects the cumulative effect of several larger substation renewal projects being completed during the year, together with ongoing renewal activities across the substation fleet.

Table 2 below provides the list of projects that make up the \$9.32M in relation to the substation renewal in-service costs for 2019. Major projects included the Dowty Substation rebuild, Gillespie Substation rebuild, Baldwin Substation rebuild, and Garden MS T1 gantry and circuit breaker remediation. In addition, many stations were also corrected for any substation deficiencies pertaining to inadequate fencing and ground grids.

1

Table 2: 2019 Substation Renewal Projects In-Service Costs

Project Breakdown of R1 Substation Renewal – 2019	Cost (\$)
Bayridges SS - F1 recloser	10,856
Bell SS- F2 Egress Cable Replacement	18,234
Bigelow SS Relay replacement	12,566
Bradshaw SS - Replace OLTC Filter System	10,426
Cavan South, 44kV/5kV insulator replacement	16,099
Crandell SS - Porcelain insulator, relay replacement	34,723
Defective Fault Indicator Replacement	5,717
Distribution Station Equipment -General	18,396
Dowty Substation Rebuild	2,264,788
Gillespie Substation Rebuild	1,455,979
Herchimer SS F2 & F3 Cable Replacement	33,394
Laidlaw SS - Battery Bank Replacement	128,393
Main SS- Replace HV Fusing	5,034
Maybley SS Relay replacement	17,280
Garden Substation - T1 Gantry and Circuit Breaker	456,323
Baldwin Substation - Baldwin Rebuild	1,817,176
Notion SS Relay replacement	135,455
Pineridge Ground Grid Upgrade	162,357
Reid SS Tapchanger	77,864
Sandy Beach SS - T2 Radiator Replacement	143,614
Shandex SS - Convert to OH Supply	128,552
Substation Battery	7,387
Substation Breakers	128,752
Substation Fence/grounding	1,974,482
Substation HVAC - install 5 heaters/AC units	28,741
Toronto Substation	225,954
Total	9,318,539

2

3 It should also be noted that ISA amounts reflect the year in which assets are placed into service
4 rather than when all project capital expenditures are incurred. As substation renewal projects
5 frequently span multiple years, a portion of the costs associated with projects placed into service in
6 2019 were incurred in prior years, including 2018. Accordingly, the increase in 2019 ISA spending is
7 not solely attributable to capital expenditures incurred during 2019 but also reflects the
8 completion and in-service placement of multi-year substation projects.

9

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO OEB STAFF

JT4.5

Question(s):

BREAK UP THE THREE ITEMS IN TABLE 1 OF 4-STAFF-105 INTO THREE DIFFERENT LINE ITEMS AND INDICATE THE OM&A GROUPS THAT THEY WOULD BE EMBEDDED WITHIN AND THE AMOUNTS FORECASTED FOR THOSE GROUPS

RESPONSE:

Elexicon wishes to clarify that the reference is to Attachment 1 of 4-Staff-105. Table 1 below provides a breakdown of the Legal, Audit and Bank charges. Legal costs are further summarized by OM&A program in Table 2. Please note the amounts shown in these tables exclude inflation of 2% to reconcile with the table provided in the 4-Staff-105 where inflation is shown separately.

Table 1: Breakdown of Legal, Audit and Bank Charges

OM&A	2027 Test Year	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast
<i>Reporting Basis</i>	MIFRS (\$)	MIFRS (\$)	MIFRS (\$)	MIFRS (\$)	MIFRS (\$)
Legal	769,159	784,542	800,233	816,237	832,562
Audit	614,466	581,774	593,409	605,278	617,383
Bank Charges	189,186	192,970	196,829	200,766	204,781
Total	1,572,811	1,559,285	1,590,471	1,622,281	1,654,726

1

Table 2: Summary of Legal Costs by Program¹

Legal Costs by OM&A Program	2027 Test Year	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast
	MIFRS (\$)	MIFRS (\$)	MIFRS (\$)	MIFRS (\$)	MIFRS (\$)
System Planning and Design	55,000	56,100	57,222	58,366	59,534
Asset Planning & System Engineering	31,883	32,649	33,096	34,014	34,704
Design Services & Connections	23,117	23,451	24,126	24,353	24,830
Common Corporate	714,159	728,442	743,011	757,871	773,028
People & Culture	100,000	102,000	104,040	106,121	108,243
Finance	42,054	42,895	43,753	44,628	45,520
Regulatory Affairs	200,000	204,000	208,080	212,242	216,486
Stakeholder Relations	2,105	2,147	2,190	2,234	2,279
Legal and Corporate Secretariat	370,000	377,400	384,948	392,647	400,500
Total	769,159	784,542	800,233	816,237	832,562

2

¹ Table 1 of 4-CCC-56 displays aggregate costs for the internal Legal function, which include costs for external counsel as well as other third-party costs and inflation.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO OEB STAFF

JT_4.6

Question(s):

PROVIDE THREE SCENARIOS, ONE BEING A FULL SETTLEMENT, ONE BEING PARTIAL, AND ONE BEING A FULL ORAL HEARING, IN TERMS OF THE REGULATORY COSTS SET OUT IN APPENDIX 2-M OF 4-CCC-49

Response:

Elexicon interprets the reference as being to Appendix 2-M, filed as Attachment 1 in the response to 4-Staff-130, rather than to 4-CCC-49.

Since filing Appendix 2-M with 4-Staff-130, Elexicon has reviewed its incurred and expected costs associated with interrogatories, expert evidence, technical conference, undertakings, settlement conference and hearing processes, and has prepared a revised estimate of the forecasted rate costs based on more recent information and updated assumptions with respect to the level of effort that will be required for upcoming steps in the proceeding. Please see the attached Excel file JT_4.6(1)_Application Costs (Requested Scenarios), which shows scenarios requested by the undertaking.

The forecasted rate application costs are driven by several factors, including the length of time since Elexicon last rebased its rates, limited internal experience and capacity to support rate proceedings, the breadth and complexity of the issues in this proceeding, the extensive evidentiary requirements for Custom IR applications, and the volume and level of detail associated with discovery requests, including the management of confidentiality processes associated with requests for production of documents.

- 1 In light of these revised estimates, Elexicon is refiling Appendix 2-M with revised costs using the full
- 2 hearing estimate, as provided in the attached Excel file JT_4.6(2)_OEB App.2-M_Regulatory One-
- 3 Time Costs Schedule_Revised.

1 **TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SEC**

2
3 **JT4.7**

4
5 **Question(s):**

6
7 ADVISE HOW THE NUMBERS IN THE LOAD FORECAST AT 3-STAFF-93 SPECIFICALLY ARE
8 DETERMINED FOR THE ADDED LOAD FROM THE ORIGINAL CUSTOMER LIST PROBABILITIES THAT
9 ARE APPLIED TO GET TO WHAT HAS BEEN ADDED

10
11 **RESPONSE:**

12
13 JT4.7(1)_Large Customer List (Excel) provides detailed calculations demonstrating how the billed
14 demands provided in 3-Staff-93 are calculated based on the Anticipated Load values. The
15 “Anticipated Load” values include the total anticipated loads for each project but the calculation of
16 annual billed demands relies on an annual schedule of added loads. The process used to determine
17 the load forecast additions from the large load list is explained in 3-Staff-93, part c).

18
19 This attachment includes the following Tabs:

- 20 - **3-Staff-93-b Billed kW:** The information originally provided in 3-Staff-93, some additional
21 customer details (rate class, rate zone, new/existing status) to provide rate zone and rate
22 class sub-totals, the annual schedule of anticipated loads, calculations for the probability
23 adjustment, calculations for the billed load adjustment, calculations for the connection
24 timing adjustment, and calculations for the half-year rule and cumulative loads. The bottom
25 of this sheet provides sub-totals by rate class and rate zone, whether the customer is a new
26 or existing customer, whether the customer is considered committed or non-committed, by
27 the likelihood/confidence factor, and the calculation of the annual calculation of describe
28 projects. The Half-Year Rule and cumulative amounts represent the load additions

1 incorporated into the load forecast model, and correspond to the values provided in 3-VECC-
2 38.

3 - **3-Staff-93-b Counts:** This tab follows the same structure as the Billed kW sheet with
4 anticipated loads replaced with anticipated customer counts. This tab includes the same
5 adjustment calculations, except the billed load adjustment.

6 - **'3-VECC-38 a) Committed_Non-Com', '3-VECC-38 Part b) Billed MW', & '3-VECC-38 Part b)
7 kWh':** The tabs from Attachment 1 to 3-VECC-38 are included with direct links to '3-Staff-93-
8 b Billed kW' and '3-Staff-93-b Counts' to demonstrate the alignment between 3-Staff-93 and
9 3-VECC-38.

10 - **New Known Customers:** The 'New Known Customers' tab from the load forecast model (3-
11 SEC-68 Attachment 1) is included with references to the input tabs to demonstrate the
12 alignment between 3-Staff-93 and the load forecast model.

13

14 Please note that Elexicon identified revisions to inputs in 3-Staff-93 and the load forecast model,
15 which are reflected in a revised version of JT4.7(1) filed as Excel Attachments JT1.2-3.1(1) and JT1.2-
16 7.1(1), respectively. JT4.7(1) is retained to illustrate the methodology used to determine the load
17 forecast additions reflected in 3-Staff-93 that are included in the Excel file 3-SEC-68 Attachment 1.
18 The revised Excel Attachments reflect the revised inputs and resulting calculations using the same
19 methodology.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SEC

JT4.8

Question(s):

PROVIDE AN UPDATED VERSION TO 1-SEC-11 THAT INCLUDES THE IMPACTS REFLECTED IN THE BILL IMPACTS IN 9-STAFF-181, ATTACHMENT 1, AND INCLUDE A TABLE THAT SHOWS THE FIVE-YEAR TOTAL BILL IMPACTS

RESPONSE:

Table 1 below provides 2027 sub-total A bill impacts excluding CRRR Catch-Up (\$9.54 million) with rate rider updates that are included in 9-Staff-181 Attachment 1, and the difference between this scenario and the updated bill impacts provided in 9-Staff-181 Attachment 1.

Table 1: 2027 Bill Impacts of CRRR Catch-Up

Rate Zone	Rate Class	Sub-Total A Bill Impact				CRRR Catch-Up Impact	
		9-Staff-181		Excluding CRRR Catch-Up		Difference	
		\$	%	\$	%	\$	%
Veridian	Residential	10.38	29.0%	7.28	20.3%	3.10	8.6%
	GS <50 kW	18.25	25.7%	12.65	17.8%	5.60	7.9%
	GS 50 - 2,999 kW	255.53	25.3%	176.11	17.5%	79.42	7.9%
	GS 3,000 - 4,999 kW	4,935.48	24.0%	3,409.08	16.6%	1,526.40	7.4%
	Large Use >5MW	13,129.28	24.0%	9,279.04	17.0%	3,850.24	7.0%
	Street Light	(968.58)	-5.4%	(2,189.81)	-12.1%	1,221.23	6.7%
	Sentinel	1.87	18.7%	1.05	10.5%	0.82	8.2%
	USL	4.84	24.2%	3.15	15.7%	1.70	8.5%
Whitby	Seasonal Residential	16.19	24.9%	10.63	16.3%	5.56	8.5%
	Residential	6.42	16.3%	3.32	8.4%	3.10	7.9%
	GS <50 kW	7.21	8.7%	1.61	1.9%	5.60	6.7%
	GS 50 - 2,999 kW	66.95	5.6%	(12.47)	-1.0%	79.42	6.6%
	GS 3,000 - 4,999 kW	3,745.65	17.2%	2,219.25	10.2%	1,526.40	7.0%
	Street Light	(36,365.28)	-68.8%	(37,717.85)	-71.3%	1,352.57	2.6%
	Sentinel	2.12	22.0%	1.30	13.5%	0.82	8.5%
	USL	(5.80)	-19.5%	(7.50)	-25.2%	1.70	5.7%

1 Table 2 below provides average 2027-2031 sub-total A bill impacts excluding CRRR Catch-Up (\$9.54
2 million) in each year.

3 **Table 2: 5-Year Average Bill Impacts of CRRR Catch-Up**

Rate Zone	Rate Class	Sub-Total A Bill Impact				CRRR Catch-Up Impact	
		9-Staff-181		Excluding CRRR Catch-Up		Difference	
		\$	%	\$	%	\$	%
Veridian	Residential	5.34	11.8%	4.70	10.6%	0.64	1.2%
	GS <50 kW	10.57	11.8%	10.30	11.5%	0.27	0.2%
	GS 50 - 2,999 kW	139.24	11.1%	124.22	10.1%	15.02	1.0%
	GS 3,000 - 4,999 kW	1,540.07	6.6%	1,309.66	5.7%	230.41	0.9%
	Large Use >5MW	4,170.73	6.7%	3,309.42	5.4%	861.31	1.2%
	Street Light	834.11	4.2%	898.17	4.5%	-64.06	-0.3%
	Sentinel	1.38	11.1%	1.44	11.5%	-0.06	-0.4%
	USL	2.78	11.1%	2.90	11.5%	-0.12	-0.4%
	Seasonal Residential	11.40	13.4%	9.64	11.7%	1.75	1.7%
Whitby	Residential	4.60	9.6%	3.95	8.5%	0.64	1.2%
	GS <50 kW	8.10	8.3%	7.82	8.0%	0.27	0.2%
	GS 50 - 2,999 kW	99.29	7.2%	84.27	6.2%	15.02	1.0%
	GS 3,000 - 4,999 kW	1,253.03	5.2%	1,022.62	4.3%	230.41	0.9%
	Street Light	(5,746.84)	-14.5%	(5,677.45)	-14.3%	-69.39	-0.2%
	Sentinel	1.45	11.8%	1.51	12.2%	-0.06	-0.4%
	USL	0.81	2.6%	0.92	2.9%	-0.12	-0.4%

4

5

1 Table 3 below provides total 5-year 2027-2031 sub-total A bill impacts excluding CRRR Catch-Up
2 (\$9.54 million) in each year.

3 **Table 3: 5-Year Bill Impacts of CRRR Catch-Up**

Rate Zone	Rate Class	Sub-Total A Bill Impact				CRRR Catch-Up Impact	
		9-Staff-181		Excluding CRRR & OM&A Catch-Up		Difference	
		\$	%	\$	%	\$	%
Veridian	Residential	26.71	74.5%	23.49	65.5%	3.22	9.0%
	GS <50 kW	52.85	74.4%	51.49	72.5%	1.36	1.9%
	GS 50 - 2,999 kW	696.18	69.0%	621.08	61.6%	75.09	7.4%
	GS 3,000 - 4,999 kW	7,700.34	37.5%	6,548.30	31.9%	1,152.04	5.6%
	Large Use >5MW	20,853.64	38.1%	16,547.08	30.3%	4,306.56	7.9%
	Street Light	4,170.56	23.0%	4,490.84	24.8%	-320.28	-1.8%
	Sentinel	6.91	69.1%	7.21	72.2%	-0.30	-3.1%
	USL	13.90	69.5%	14.49	72.4%	-0.59	-2.9%
	Seasonal Residential	56.98	87.5%	48.21	74.0%	8.77	13.5%
Whitby	Residential	22.98	58.3%	19.76	50.1%	3.22	8.2%
	GS <50 kW	40.48	48.8%	39.12	47.1%	1.36	1.6%
	GS 50 - 2,999 kW	496.46	41.6%	421.36	35.3%	75.09	6.3%
	GS 3,000 - 4,999 kW	6,265.13	28.8%	5,113.09	23.5%	1,152.04	5.3%
	Street Light	(28,734.18)	-54.3%	(28,387.23)	-53.7%	-346.94	-0.7%
	Sentinel	7.23	74.9%	7.53	78.1%	-0.30	-3.2%
	USL	4.03	13.5%	4.62	15.5%	-0.59	-2.0%

4

5

1 Table 4 below provides 2027 sub-total A bill impacts excluding CRRR and OM&A Catch-Up (\$23.98
2 million).

3 **Table 4: 2027 Bill Impacts of CRRR & OM&A Catch-Up**

Rate Zone	Rate Class	Sub-Total A Bill Impact				CRRR & OM&A Catch-Up Impact	
		9-Staff-181		Excluding CRRR & OM&A Catch-Up		Difference	
		\$	%	\$	%	\$	%
Veridian	Residential	10.38	29.0%	2.60	7.2%	7.78	21.7%
	GS <50 kW	18.25	25.7%	3.77	5.3%	14.48	20.4%
	GS 50 - 2,999 kW	255.53	25.3%	55.92	5.5%	199.61	19.8%
	GS 3,000 - 4,999 kW	4,935.48	24.0%	1,098.28	5.3%	3,837.20	18.7%
	Large Use >5MW	13,129.28	24.0%	2,836.28	5.2%	10,293.00	18.8%
	Street Light	(968.58)	-5.4%	(2,189.81)	-12.1%	1,221.23	6.7%
	Sentinel	1.87	18.7%	1.05	10.5%	0.82	8.2%
	USL	4.84	24.2%	3.15	15.7%	1.70	8.5%
	Seasonal Residential	16.19	24.9%	(2.54)	-3.9%	18.73	28.8%
Whitby	Residential	6.42	16.3%	(1.36)	-3.5%	7.78	19.7%
	GS <50 kW	7.21	8.7%	(7.27)	-8.8%	14.48	17.4%
	GS 50 - 2,999 kW	66.95	5.6%	(132.66)	-11.1%	199.61	16.7%
	GS 3,000 - 4,999 kW	3,745.65	17.2%	(91.55)	-0.4%	3,837.20	17.6%
	Street Light	(36,365.28)	-68.8%	(37,717.85)	-71.3%	1,352.57	2.6%
	Sentinel	2.12	22.0%	1.30	13.5%	0.82	8.5%
	USL	(5.80)	-19.5%	(7.50)	-25.2%	1.70	5.7%

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5

1 Table 5 below provides average 2027-2031 sub-total A bill impacts excluding CRRR and OM&A
2 Catch-Up (\$23.98 million) in each year.

3

4 **Table 5: 5-Year Average Bill Impacts of CRRR & OM&A Catch-Up**

Rate Zone	Rate Class	Sub-Total A Bill Impact				CRRR & OM&A Catch-Up Impact	
		9-Staff-181		Excluding CRRR & OM&A Catch-Up		Difference	
		\$	%	\$	%	\$	%
Veridian	Residential	5.34	11.8%	3.82	8.9%	1.53	2.9%
	GS <50 kW	10.57	11.8%	8.55	9.9%	2.02	1.9%
	GS 50 - 2,999 kW	139.24	11.1%	101.50	8.5%	37.74	2.6%
	GS 3,000 - 4,999 kW	1,540.07	6.6%	961.18	4.3%	578.89	2.3%
	Large Use >5MW	4,170.73	6.7%	2,361.04	4.0%	1,809.69	2.7%
	Street Light	834.11	4.2%	1,043.65	5.2%	-209.54	-1.0%
	Sentinel	1.38	11.1%	1.55	12.2%	-0.17	-1.1%
	USL	2.78	11.1%	3.12	12.2%	-0.34	-1.1%
	Seasonal Residential	11.40	13.4%	6.57	8.5%	4.83	4.9%
Whitby	Residential	4.60	9.6%	3.07	6.8%	1.53	2.8%
	GS <50 kW	8.10	8.3%	6.08	6.4%	2.02	1.8%
	GS 50 - 2,999 kW	99.29	7.2%	61.56	4.7%	37.74	2.5%
	GS 3,000 - 4,999 kW	1,253.03	5.2%	674.14	2.9%	578.89	2.3%
	Street Light	(5,746.84)	-14.5%	(5,517.88)	-13.7%	-228.96	-0.8%
	Sentinel	1.45	11.8%	1.62	12.9%	-0.17	-1.1%
	USL	0.81	2.6%	1.15	3.6%	-0.34	-1.0%

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6

- 1 Table 6 below provides total 5-year 2027-2031 sub-total A bill impacts excluding CRRR and OM&A
2 Catch-Up (\$23.98 million) in each year.

3 **Table 6: Total 5-Year Bill Impacts of CRRR & OM&A Catch-Up**

Rate Zone	Rate Class	Sub-Total A Bill Impact				CRRR & OM&A Catch-Up Impact	
		9-Staff-181		Excluding CRRR & OM&A Catch-Up		Difference	
		\$	%	\$	%	\$	%
Veridian	Residential	26.71	74.5%	19.08	53.2%	7.63	21.3%
	GS <50 kW	52.85	74.4%	42.77	60.2%	10.08	14.2%
	GS 50 - 2,999 kW	696.18	69.0%	507.49	50.3%	188.68	18.7%
	GS 3,000 - 4,999 kW	7,700.34	37.5%	4,805.90	23.4%	2,894.44	14.1%
	Large Use >5MW	20,853.64	38.1%	11,805.18	21.6%	9,048.46	16.5%
	Street Light	4,170.56	23.0%	5,218.25	28.8%	-1,047.69	-5.8%
	Sentinel	6.91	69.1%	7.77	77.8%	-0.86	-8.6%
	USL	13.90	69.5%	15.62	78.1%	-1.72	-8.6%
	Seasonal Residential	56.98	87.5%	32.83	50.4%	24.15	37.1%
Whitby	Residential	22.98	58.3%	15.35	38.9%	7.63	19.3%
	GS <50 kW	40.48	48.8%	30.40	36.6%	10.08	12.1%
	GS 50 - 2,999 kW	496.46	41.6%	307.78	25.8%	188.68	15.8%
	GS 3,000 - 4,999 kW	6,265.13	28.8%	3,370.69	15.5%	2,894.44	13.3%
	Street Light	(28,734.18)	-54.3%	(27,589.38)	-52.2%	-1,144.79	-2.2%
	Sentinel	7.23	74.9%	8.09	83.8%	-0.86	-8.9%
	USL	4.03	13.5%	5.75	19.3%	-1.72	-5.8%

4

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SEC

JT4.9

QUESTION:

REVISE RESPONSE TO 1-SEC-22 TO INCLUDE ANY KNOWN ANTICIPATED STATIONS BEYOND THE RATE TERM THAT MIGHT BE AT RISK FOR ADVANCEMENT IF LOAD GROWTH ACCELERATES.

RESPONSE:

As noted in Elexicon's interrogatory response to IR 1-SEC-22, Elexicon is not currently aware of any specific station projects beyond those included in the 2027-2031 investment plan that would definitively require advancement into the rate term.

There are, however, broader capacity constraints across portions of Elexicon's service territory, as discussed in Exhibit 2B, Tab 3, Schedule 2, pp. 49 to 71. At the Municipal Station ("MS") level, Elexicon's proposed investment plan results in 21 MSs with limited remaining capacity by 2031 (Exhibit 2B, Tab 3, Schedule 2, pp. 64). While these constraints are expected to be manageable through operational measures under the selected Elexicon peak load scenario, higher load growth could result in N-1 capacity limitations emerging earlier and to a greater extent than expected. In such circumstances, the need for additional station capacity, including new MS investments currently anticipated beyond the 2031 planning horizon, may be advanced into an earlier timeframe.

From a Transformer Station ("TS") perspective, regional planning activities are underway in several regions served by Elexicon, including GTA East, Peterborough to Kingston, and South Georgian Bay and Muskoka. While the GTA East TS project is the primary TS solution within the current planning horizon, the regional planning studies have identified additional medium- and long-term capacity constraints extending beyond 2031, particularly in the GTA East region. Under higher load growth scenarios, these longer-term constraints could materialize sooner than currently forecast, potentially advancing TS investments presently anticipated for the mid-to-late 2030s. Although specific station solutions have not yet been finalized through the regional planning process, accelerated demand growth could require early-stage development activities to commence during

- 1 the 2027-2031 rate term, which may include land acquisition, environmental assessments,
- 2 preliminary engineering, and other development work.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VECC

JT4.10

Question(s):

REVIEW THE CALCULATIONS FROM BOMA-5 AND CONFIRM WHETHER THEY ARE USING THE RIGHT COSTS, THE RIGHT WEIGHTINGS, AND DERIVATION OF THE WEIGHTINGS THROUGHOUT, AND PROVIDE A REVISED RESPONSE TO THE EXTENT ONE IS NECESSARY

RESPONSE:

Elexicon understands that this undertaking also requests that, if the CAM is revised as a result of this review, an updated version of 7-BOMA-5, Comparison of CAM Results, be provided reflecting any resulting impacts.

Elexicon has reviewed the revised response to 7-BOMA-5 and confirms there is a discrepancy in the Collections Department balance. For clarity, Table 1 below provides details of the calculations of the account groupings using the amounts reported in the Cost Allocation Model, Tab I3 TB Data, as most recently filed in Attachment 6 to 1-Staff-1.

1 **Table 1: Calculation of the Account Groupings for the Billing and Collecting Weighting Factor**

Billing and Collecting Account Grouping	Cost (\$)	Details*	Calculation
Canada Post	\$1,934,738	Within 3515 Customer Billing	\$1,934,738
Key Accounts	\$352,209	5405 Supervision	\$189,771
		5410 Community Relations - Sundry	+\$767,478
		less amounts unrelated to Key Accounts	-\$605,040
		Total	\$352,209
Customer Service Expenses	\$3,324,512	5305 Supervision	\$176,175
		5340 Miscellaneous Customer Accounts Expenses	+\$3,148,337
		Total	\$3,324,512
Billing Department	\$3,928,639	5315 Customer Billing	\$6,894,510
		less Canada Post	-\$1,734,738
		less Meter Reading tracked in 5315	-\$1,031,133
		Total	\$3,928,639
Collections Department	\$1,632,941	5320 Collecting	\$1,652,405

2 *Canada Post, Key Accounts and Meter Reading amounts are consistent with forecast activity-based cost tracking
3

4 The revised tables from 7-BOMA-5 are provided below. There are no changes to Tables 2 and 3. In
5 Table 4 the collections amount has been revised from \$1,632,941 to \$1,652,405, consistent with the
6 balance in USOA 5320 Collecting in 2027. The Collections cost per customer has been revised in Table
7 5, which results in an increase in the overall weighting factor for the GS 50-2,999 kW, GS 3,000 to
8 4,999 kW, and Large Use rate classes from 5.09 to 5.08. Additionally, the weighted Billing cost per
9 customer for the GS 50-2,999 kW, GS 3,000 to 4,999 kW, and Large Use rate classes was entered for
10 all classes. This has been corrected in the table, however, the calculations to derive the weighting
11 factors in 5-BOMA-7 used the correct amounts so this correction to Table 5 does not impact the
12 overall weighting factors. Changes are bolded in Tables 4 and 5.

13

14 A comparison of 7-BOMA-5 and the revised weighting factors are summarized in the attached Excel
15 file JT_4.10(1)_CAM Result Comparison - Updated B&C Factors. The changes are minor as the largest

1 impact is a \$338 reduction to the revenues allocated to the GS 50 to 2,999 kW rate class and most
2 rate classes are not impacted.

3

4

Table 2: Weighting Factors for Billing and Collecting Expense Group

Rate Class	Relative Cost (Weight) per Customer				
	Canada Post	Billing	Collections	Customer Service	Key Accounts
Residential	1	1	1	1	
Seasonal Res.	1	1	1	1	
GS < 50	1	1	1	1.2	
GS 50-2,999	1	1.2	1	1.2	1
GS 3,000-4,999	1	1.2	1	1.2	1
Large Use	1	1.2	1	1.2	1
Street Lighting	1	1		1	
Sentinel Lighting	1	1		1	
USL	1	1		1	

5

Note: Table 2 presents the same relative costs as Exhibit 7 - Tab 1 - Schedule 1, Table 2.

6

7

Table 3: Weighted Customer Counts by Cost Category and Rate Class

Rate Class	Customer Count (2027 Forecast)	Weighted Customer Count (Cust Count x Relative Cost per Customer*)				
		Canada Post	Billing	Collections	Customer Service	Key Accounts
Residential	169,458	169,458	169,458	169,458	169,458	-
Seasonal Res.	1,546	1,546	1,546	1,546	1,546	-
GS < 50	12,170	12,170	12,170	12,170	14,604	-
GS 50-2,999	1,516	1,516	1,819	1,516	1,819	1,516
GS 3,000-4,999	13	13	16	13	16	13
Large Use	6	6	7	6	7	6
Street Lighting	10	10	10	-	10	-
Sentinel Lighting	26	26	26	-	26	-
USL	921	921	921	-	921	-
Total	185,666	185,666	185,973	184,709	188,407	1,535

*Relative Cost per Customer is provided in Table 2.

1 **Table 4: Revised OM&A Cost Categories for Billing and Collecting Weighting Factor**

	Canada Post	Billing	Collections	Customer Service	Key Accounts
USoA	(Direct)	5315 (excluding Canada Post)	5320	5305 and 5340	
Total Cost (2027 Forecast)	\$1,934,738	\$3,928,639	\$1,652,405	\$3,324,512	\$352,209

2 Note: Bold amounts indicate revision compared to 7-BOMA-5

3 **Table 5: Revised Derivation of Proposed Billing and Collections Weighting Factors**

Weighted Cost per Customer (\$/Cust) [(Total Cost /Total Weighted Customer Count) x Relative Cost per Customer]*						Weighting Factor***
	Canada Post	Billing	Collections	Customer Service	Key Accounts	Proposed
Cost per Weighted Customer**	10.42	17.65	8.95	17.56	229.45	1.00
Residential	10.42	17.65	8.95	17.56		1.00
Seasonal Res.	10.42	17.65	8.95	17.56		1.00
GS < 50	10.42	21.12	8.95	21.17		1.06
GS 50-2,999	10.42	21.12	8.95	21.17	229.45	5.08
GS 3,000-4,999	10.42	21.12	8.95	21.17	229.45	5.08
Large Use	10.42	21.12	8.95	21.17	229.45	5.08
Street Lighting	10.42	17.65		17.56		0.85
Sentinel Lighting	10.42	17.65		17.56		0.85
USL	10.42	17.65		17.56		0.85

*Total Cost is provided in Table 4, Relative Cost per Customer is provided in Table 2 and Total Weighted Customer Count is calculated in Table 3.

**Cost per Weighted Customer = Total Cost as provided in Table 3 divided by Total Weighted Customer Count as calculated in Table 3

***The Residential weighting factor is set at 1.0. The weighting factors for all other rate classes are calculated by dividing the Weighted Cost per Customer for each rate class by the Residential Weighted Cost per Customer.

4 ****Bold amounts indicate revision compared to 7-BOMA-5

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VECC

JT4.11

Question(s):

RECALCULATE WHAT THE 2026 WEIGHTED RATES WOULD BE BASED ON THE NEW FORECAST
BILLING DETERMINANTS FROM EXHIBIT 7, TAB 1, SCHEDULE 1

RESPONSE:

The 2026 fixed and variable rates weighted by the updated billing determinants (3-SEC-68) are
provided in Tables 1 and 2 below.

Table 1: Derivation of Weighted Average Existing Fixed Charges

Rate Class	Veridian Rate Zone		Whitby Rate Zone		Weighted Average 2026 Fixed Charge (\$/month)
	Forecast 2027 Customer Count	2026 Fixed Charge (\$/month)	Forecast 2027 Customer Count	2026 Fixed Charge (\$/month)	
Residential	122,282	32.79	47,177	38.56	34.40
GS <50 kW	9,633	21.26	2,538	32.41	23.59
GS 50 - 2,999 kW	1,104	135.84	412	246.85	166.00
GS 3,000 - 4,999 kW	8	7,137.67	6	246.85	4,340.68
Large Use >5MW	6	10,722.24			10,722.24
Street Light	33,884	0.89	11,891	2.17	1.22
Sentinel	222	5.71	38	7.05	5.91
USL	789	8.68	371	11.99	9.74
Seasonal Residential	1,546	59.89			59.89

1 **Table 2: Derivation of Weighted Average Existing Variable Charges**

Rate Class	Veridian Rate Zone		Whitby Rate Zone		Weighted Average 2026 Variable Charge (\$/kW or \$/kWh))	kW/kWh
	Forecast 2027 Variable Charge Determinant (kW/kWh)	2026 Variable Charge (\$/kW or \$/kWh)	Forecast 2027 Variable Charge Determinant (kW/kWh)	2026 Variable Charge (\$/kW or \$/kWh))		
Residential	1,069,640,327		418,598,267			kWh
GS <50 kW	265,162,520	0.0214	94,275,360	0.024	0.0221	kWh
GS 50 - 2,999 kW	2,472,003	4.1908	901,368	4.9301	4.3883	kW
GS 3,000 - 4,999 kW	351,397	2.6549	204,371	4.9301	3.4916	kW
Large Use >5MW	699,953	3.7393			3.7393	kW
Street Light	33,230	4.7202	10,314	8.3048	5.5693	kW
Sentinel	569	17.2626	85	18.9807	17.4863	kW
USL	4,588,885	0.0213	1,890,889	0.0383	0.0263	kWh
Seasonal Residential	13,098,094					kWh

2
3 The prefiled weighted rates as per Exhibit 7 - Tab 1 - Schedule 1, page 9 and the distribution
4 revenues calculated with weighted 2026 rates are also provided for reference.

5
6 **Table 3: Weighted Average Charge Comparison**

Rate Class	Exhibit 7, Tab 1, Schedule 1 (& 1-Staff-1 Attachment 7)			Weighted rates with 3-SEC-68 Billing Determinants		
	Fixed Charge	Variable Charge		Fixed Charge	Variable Charge	
Residential	\$34.40			\$34.40		
GS <50 kW	\$23.60	\$0.0220	/kWh	\$23.59	\$0.0221	/kWh
GS 50 - 2,999 kW	\$165.94	\$4.3833	/kW	\$166.00	\$4.3883	/kW
GS 3,000 - 4,999 kW	\$4,758.36	\$3.4614	/kW	\$4,340.68	\$3.4916	/kW
Large Use >5MW	\$10,722.24	\$3.7393	/kW	\$10,722.24	\$3.7393	/kW
Street Light	\$1.27	\$5.5669	/kW	\$1.22	\$5.5693	/kW
Sentinel	\$5.94	\$17.5056	/kW	\$5.91	\$17.4863	/kW
USL	\$9.85	\$0.0265	/kWh	\$9.74	\$0.0263	/kWh
Seasonal Residential	\$59.89			\$59.89		
Distribution Revenue: 2026 Rates & 2027 billing determinants	\$106,000,603			\$105,943,927		

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO BOMA

JT4.12

Question(s):

PROVIDE A TABLE SEPARATING THE DRIVERS OF THE REVENUE LOAD FORECAST IN A MANNER THAT ALIGNS WITH EXHIBIT 3, AND IF THE CAM IS REVISED, PROVIDE AN UPDATED VERSION OF EE-7-BOMA-5, COMPARISON OF CAM RESULTS, REFLECTING THE RESULTING IMPACTS

RESPONSE:

Elexicon has interpreted this undertaking as requesting a table separating the drivers of the revenue load forecast in a manner that aligns with Exhibit 3 and has responded on that basis. No further response has been provided, as, based on the Day 4 Transcript (p. 102 line 6-p. 103 line 10), Elexicon understands that the comparison of CAM results was intended to be related to JT4.10. Accordingly, Elexicon has responded to this element in the response to JT4.10.

A summary of the drivers of forecast MWh growth aligned with the load forecast filed as 3-SEC-68 Attachment 1 (the updated Exhibit 3 load forecast) is provided in the attached Excel file JT_4.12(1)_Revenue Load Forecast Drivers. The attachment separates total MWh load into base load, organic & economic growth, incremental heating load, incremental EV load, large customer additions, and net CDM.