

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO DISTRIBUTED RESOURCE COALITION

JT1.1-01

Ref: 2-DRC-6(a), (b)

Ref: 2-DRC-7(d)

Ref: 2-DRC-8(g), (h)

Preamble: Elexicon states that it has not formally evaluated managed EV charging or compared unmanaged and managed charging scenarios.

QUESTION: HAS ELEXICON CONSIDERED WHETHER MANAGED CHARGING COULD DEFER OR REDUCE ANY PROPOSED CAPACITY INVESTMENTS, AND IF NOT, WHY WAS THAT ANALYSIS NOT UNDERTAKEN BEFORE SELECTING THE PROPOSED INVESTMENT PLAN?

RESPONSE:

While Elexicon has not formally evaluated managed charging scenarios or quantified potential load reductions specifically for its service territory, Elexicon's Peak Load Forecast incorporates an average coincident electric vehicle ("EV") demand assumption of approximately 1.2 kW per light-duty vehicle, derived from a 2024 study on EV charging grid impacts produced for Natural Resources Canada¹. This demand assumption is significantly lower than the nameplate rating as it reflects diverse charging patterns, driven in part by time-of-use ("TOU") rates, and recognizes that EV charging demand is not fully coincident with system peak demand. Accordingly, the forecast already captures the expectation that a significant portion of EV charging occurs outside system peak periods.

In addition, Elexicon considered managed EV charging as part of the Non-Wires Solution ("NWS") feasibility assessment completed for the identified capacity need at Bradshaw Municipal Station

¹ Natural Resources Canada, "Electric Vehicle Charging Infrastructure for Canada," [[Electric Vehicle Charging Infrastructure for Canada - Natural Resources Canada](#)], February 2024.

1 (“MS”). As noted in Exhibit 10, Tab 1, Schedule 1, Attachment 1, pp. 11, managed EV charging was
2 screened out during the feasibility determination stage because of current adoption levels,
3 geographic distribution within the constrained region, and the degree of reliable controllability is still
4 quite uncertain. In addition, a significant portion of EV charging is expected to occur during overnight
5 periods, which may not consistently coincide with system peak demand. As a result, managed EV
6 charging was not considered capable of providing the scale, timing, and certainty of peak demand
7 reduction required to address the identified capacity needs.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO DISTRIBUTED RESOURCE COALITION

JT1.1-2

Ref: 2-DRC-6(i), (j)

Preamble: Elexicon notes that nine EVSE connection requests have been deferred due to capacity constraints.

QUESTION: CAN ELEXICON PROVIDE MORE DETAIL ON THE LOCATION, CUSTOMER CLASS, REQUESTED LOAD, DURATION OF DEFERRAL, AND WHETHER EACH REQUEST WAS ULTIMATELY CONNECTED, PARTIALLY CONNECTED, OR REMAINS DEFERRED?

RESPONSE:

Table 1 below lists the nine EVSE connections which were deferred due to capacity constraints, with their location, customer class, requested load, date of deferral and the current status.

Table 1: Deferred EVSE Connections Requests

Customer	Customer Class	Service Area	Load Requested (kW)	Date Application Received	Current Status
1	Commercial	Whitby	9,700	04-Jun-2024	Deferred
2	Commercial	Ajax	3,760	27-Dec-2025	Deferred
3	Commercial	Whitby	965	14-May-2025	Deferred
4	Commercial	Pickering	5,000	22-Jul-2025	Deferred
5	Commercial	Whitby	773	17-Oct-2025	Deferred
6	Commercial	Whitby	400	08-Jan-2026	Deferred
7	Commercial	Belleville	500	06-Mar-2026	Deferred
8	Commercial	Pickering	1,000	06-Mar-2026	Deferred
9	Commercial	Whitby	800	06-Mar-2026	Deferred

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO DISTRIBUTED RESOURCE COALITION

JT1.1-03

Ref: 2-DRC-6(n), (o), (p), (q);

Ref: 1-DRC-2(b), (d)

Preamble: Elexicon recognizes barriers for multi-unit and rental residential buildings but does not have specific programs for those customers.

QUESTION: ARE ANY PROPOSED SYSTEM INVESTMENTS TARGETED TO AREAS WITH HIGHER CONCENTRATIONS OF MURBS OR RENTAL HOUSING, AND HOW WILL/DOES ELEXICON ASSESS WHETHER THOSE INVESTMENTS IMPROVE EQUITABLE ACCESS TO EV CHARGING IN ELEXICON'S SERVICE TERRITORY?

RESPONSE:

Elexicon does not specifically target distribution system investments to areas with higher concentrations of multi-unit residential buildings ("MURBs") or rental housing. Investments are identified through Elexicon's asset management and customer connection processes and are based on factors such as asset condition, reliability requirements, load growth, system capacity needs, and customer-driven connection requests.

To the extent that MURBs or rental developments contribute to increased electricity demand, including EV charging load, the associated capacity requirements may contribute to the need for distribution system investments. While these investments may benefit customers residing in MURBs or rental housing, they are not selected or prioritized based on housing type. Elexicon does not assess distribution system investments based on their impact on equitable access to EV charging. Rather, investments are planned to maintain reliability, address asset condition, and provide sufficient capacity to accommodate customer load growth and connection requests across its service territory.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO DISTRIBUTED RESOURCE COALITION

JT1.4

Ref: 2-DRC-7(f), (h), (i), (j)

Ref : 2-DRC-8(a), (b), (e), (f), (h)

Preamble: Elexicon states that DER and EV capability readiness will be assessed during the rate period as part of its ADMS/DERMs investment program.

QUESTION: WHICH SPECIFIC ADMS/DERMS CAPABILITIES ARE EXPECTED TO BE UPDATED/OPERATIONAL IN EACH YEAR FROM 2029 TO 2031, INCLUDING DER REGISTRATION, TELEMETRY AGGREGATION, DISPATCH COORDINATION, AUTOMATED INTERCONNECTION, AND DYNAMIC HOSTING CAPACITY?

RESPONSE:

Table 1 below provides the specific ADMS/DERMS capabilities that are expected to be updated/operational within the 2029 – 2031 period.

Table 1: AMDS & DERMS Capabilities (2029 to 2031)

Functionality	Primary System	Potential Timeline for Operational Implementation
DER Registration	DERMS	2029 - 2031
Telemetry Aggregation	DERMS	2029 – 2031
Dispatch Coordination	DERMS with ADMS Integration	Post 2031 – next rate period
Automated Interconnection	DERMS/Interconnection Platform	Post 2031 – next rate period
Dynamic Hosting Capacity	ADMS with DERMS Support	Post 2031 – next rate period

With respect to the DER Registration and Telemetry Aggregation functionality, the timing of each implementation depends on several factors, including vendor product roadmaps, software release

1 schedules, licensing availability, system upgrade requirements, integration dependencies, and
2 implementation priorities. As a result, although these capabilities may become available at various
3 points during the 2029–2031 period, Elexicon cannot confidently assign specific functionalities to a
4 particular year.

5 Elexicon has identified dispatch coordination, automated interconnection, and dynamic hosting
6 capacity as potential future capabilities that may be implemented beyond the current rate period;
7 however, these are contingent on various factors that are not yet known, including vendor product
8 development, licensing structures, integration requirements, data and system architecture needs,
9 regulatory developments, and emerging technologies. The ADMS/SCADA investments proposed in
10 this application are intended to establish the foundational infrastructure upon which future
11 capabilities may be assessed and, where justified, implemented.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO DISTRIBUTED RESOURCE COALITION

JT1.5

Ref: 1-DRC-2(f);

Ref: 2-DRC-6(a), (b); 2-DRC-7(d);

Ref: 2-DRC-8(g), (h), (i)

Preamble: Elexicon states that it has not undertaken its own analysis of EVs as grid-interactive resources and that proposed ADMS/DERMS investments are not intended to directly enable V2X.

QUESTION: WHAT EVIDENCE OR MILESTONES WOULD ELEXICON NEED BEFORE CONSIDERING V2X SUFFICIENTLY MATURE FOR PILOT TESTING OR SYSTEM PLANNING AND WILL THE PROPOSED ADMS/DERMS INVESTMENTS, OR ANY OTHER PROPOSED INVESTMENTS IN THE DSP, ACCOMMODATE FUTURE V2X FUNCTIONALITY WITHOUT ADDITIONAL/MATERIAL RETROFIT COSTS?

RESPONSE:

As stated in 2-DRC-8 response (g), Elexicon considers V2X technology to be emerging and not yet sufficiently mature to warrant pilot testing. Elexicon will continue to monitor industry developments and, as the technology becomes more established and proven, will reassess its suitability for potential pilots or inclusion in system planning including such considerations as:

- Regulatory: which includes the development of a clear framework that outlines requirements related to interconnection, market participation and compensation mechanisms and responsibilities.
- Customer and Market Readiness: a value proposition for customers must be clearly defined and communicated, along with responsibilities and expectations in regard to customer engagement levels.

- Grid and Economic Value: benefits of V2X to the local distribution system must be quantified and evaluated against the alternative solutions that could provide similar grid services, considering both operational and economic impacts.

While the proposed ADMS/DERMS investments are expected to improve Elexicon's ability to monitor and manage distributed energy resources, enabling V2X capability would likely require additional investments in technology, system integration, operational processes, and staff training. The extent of any additional investment or retrofit requirements would be assessed as part of a future evaluation of V2X readiness and deployment.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO DISTRIBUTED RESOURCE COALITION

JT1.6

Ref: 1-DRC-4(b), (c), (d);

Ref : 1-DRC-5(a), (b), (c), (e), (f)

Preamble: Elexicon indicates that there was no targeted outreach to EV or DER owners and industry associations and no formal survey on customer priorities for DERs, EVs, or battery storage.

Question(s): How did Elexicon determine customer needs and priorities for DER and EV integration without targeted engagement with EV drivers, DER customers, aggregators, or relevant industry associations?

RESPONSE:

Elexicon's understanding of customer needs related to DER and EV integration is informed by its normal course customer engagement activities, including contact center and Key Accounts interactions and connections-related processes. Through these interactions, Elexicon gains insight into customer interests, emerging trends, and potential future support requirements, and has identified a growing need for support related to EV integration and DERs, including battery storage, solar, and other technologies. For example, in June 2026, the contact centre received 12 inquiries related to peak demand considerations and panel upgrades associated with EV charger installation.

In addition to its current ongoing customer support activities through the Customer Experience and Connections processes, the Key Accounts team has also identified several enhancements to improve customer experience and support evolving customer needs and market trends. DERs and EVs are among a number of emerging customer needs and market trends that the team monitors and responds to as part of its broader customer engagement and coordination responsibilities. These enhancements include increased coordination with municipalities and internal departments to

1 support customer projects and improve the overall customer experience. Please refer to Exhibit 1,
2 Tab 7, Schedule 2, Section 3.4, Table 3 and the response to 1-DRC-05 for further details.
3
4 In addition to normal course customer engagement, Elexicon undertook a two-phased customer
5 engagement study with INNOVATIVE Research Group, using random sampling approaches (in Phase
6 I) and open participation to all customers in its customer base (in Phase II), including EV drivers and
7 DER owners. In addition to including questions in various areas such as investment priorities and
8 trade-offs, among other areas, both surveys allowed customers to provide further feedback through
9 open comment boxes. Elexicon expects that the feedback provided by customers reflects their needs
10 and preferences including their preferences as EV drivers and DER owners/customers, as applicable.¹

¹ For the results of the Phase 1 online surveys please see Appendix 5-7 of Exhibit 1, Tab 7, Schedule 1, Appendix A. For copies of the Phase 2 online surveys please see Appendix 10-13 of Exhibit 1, Tab 7, Schedule 1, Appendix A.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VECC

JT_1.2-1

Ref: 3-STAFF-94

EE_3-SEC 68(1), Additional Growth Tab

Preamble: STAFF-94 states:

“The forecast number of households is used to derive annual household growth rates in Whitby and each community within the Veridian rate zone for the purpose of developing Residential growth rates.”

Question(s):

1.1 The forecast growth rate for Gravenhurst does not appear to have been included in the development of the Residential growth rate for the Veridian rate zone. Please confirm if this is the case and, if so, explain why.

1.2 Please confirm that for purposes of SEC-68 updated region/municipal forecasts were not included for Belleville, Port Hope and Gravenhurst.

1.3 STAFF-94 gives only one reference for the Ministry of Finance (MOF) forecast. However, SEC-68 appears to use a different MOF forecast than the original Application. Please reconcile and identify the basis for the different forecasts.

Response:

1.1 Confirmed. The Gravenhurst forecast growth rate has been incorporated in the weighted average growth rate in the revised load forecast filed in excel format as an attachment to JT 1.2-7.1.

1.2 Confirmed. The Region of Durham releases annual household forecasts so the customer count forecasts in the ‘Additional Growth Tab’ in 3-SEC-68 Attachment 1 reflect a more recent

1 forecast than was available when the prefilled load forecast was prepared. The Belleville, Port
2 Hope, and Gravenhurst household forecasts are based on longer-term municipal plans and
3 there have been no updated plans to-date since the prefilled load forecast was prepared.
4

5 1.3 The Ministry of Finance (“MOF”) reference provided in 3-Staff-94 is the MOF webpage for the
6 source of the data. This webpage includes a reference to only the latest data available. The
7 attached excel file JT_1.2-1.3(1)_MOF Census Divisions Population Forecasts provides the
8 population data file used for the prefilled load forecast and a second tab with the more recent
9 file used in the updated load forecast filed as 3-SEC-68 Attachment 1. Both tabs in the attached
10 excel file have been filtered for Durham Region and “Total Both Genders”, which are the
11 population data inputs used in Elexicon's load forecast models.

1 **TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VECC**

2
3 **JT1.2-2**

4 **Ref:**

5 **3-BOMA-3**

6 **3-STAFF-93(1)_Large Customer List**

7
8 **Preamble:** BOMA-3 states:

9 *"Yes, there is one data center included in the tables in reference #1.*

10 *All load is included in the Large Use rate class."*

11
12 **QUESTION:**

13 2.1 PLEASE CONFIRM THAT 2027 IS THE FIRST YEAR THIS CUSTOMER IS IN-SERVICE.

14
15 **RESPONSE:**

16 The anticipated in-service year for the project has been deferred to 2028 due to delays on the
17 customer's part.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VECC

JT1.2-3

Ref:

3-STAFF-93 a)

3-STAFF-93(1)_Large Customer List

Excel file 3.0-VECC-38_ Additional Large Loads

3-VECC-26

Preamble: Staff 93 a) includes the following table

Table 1: Large Load Projects and Associated Loads

	GS 50 to 2,999 kW		GS 3,000 to 4,999 kW		Large Use	
	Discrete Projects	Billed kW	Discrete Projects	Billed kW	Discrete Projects	Billed kW
2026	41	152,413	8	69,377	3	40,097
2027	48	374,875	10	179,417	5	161,323
2028	52	473,667	11	252,504	5	301,072
2029	53	522,094	11	295,509	5	367,565
2030	54	550,607	12	318,447	5	375,440
2031	54	563,525	13	342,285	5	375,440

VECC 38, part (a) includes the following table:

	2026	2027	2028	2029	2030	2031
Part a) i)	Committed					
Existing Customers	15	3	0	0	1	1
New Customers	28	6	1	1	1	0
Expected MW increase from Existing Customers	29.9	13.5	8.3	0.6	3.2	3.0
Expected MW of New Customers	44.5	33.7	20.2	5.1	2.9	0.6
Part a) ii)	Non-Committed					
Existing Customers	4	0	1	0	0	0
New Customers	6	2	2	0	0	0
Expected MW increase from Existing Customers	13.6	4.2	2.0	-	-	-
Expected MW of New Customers	10.2	11.9	5.3	2.6	0.4	1.0
Total Customers	53.0	11.0	4.0	1.0	2.0	1.0
Total MW	98.2	63.3	35.7	8.3	6.4	4.6

VECC 26, part (b) contains the following table which reconciles with VECC 38, part (a):

Table 1: Number and Anticipated Load for Existing Customers with Connection Requests

	2026	2027	2028	2029	2030	2031
Anticipated MW	43.6	17.7	10.3	0.6	3.2	3.0
Customers	19	3	1	0	1	1

1 **Question(s):**

2 3.1 The total number of discrete projects reported in Staff 93, part (a), Table 1 (i.e., 72) matches
3 that in accompanying excel file (3-STAFF-93(1)_Large Customer List) for 2031. However, in the
4 earlier years the values don't match. For example, in Table 1 the total number of discrete projects
5 for 2026 is 52 while in the excel file the total number anticipated in 2025 and 2026 is 49. Similar
6 issues exist for 2027, 2028 and 2030. Please reconcile.

7 3.2 The total number of customers reported in VECC-38, Part (a) does not match the number of
8 new projects in Staff 93 (a), Table 1 for the years 2026 and 2027. Please reconcile and revise the
9 responses as required.

10 The total number of customers reported in VECC-38, Part (a) does not match the cumulative
11 number of customers shown in 3-STAFF-93(1)_Large Customer List for the years 2026, 2027, 2028
12 and 2030 (i.e., based on the number of anticipated customers in each year). Please reconcile and
13 revise the responses as required.

14 3.3 With respect to VECC-38, part (a) and VECC 26, part (b), are the existing customers just those
15 existing prior to 2025 or does it include new customers that first energized in 2025 per Staff 93? If
16 new 2025 customers are included – please redo the tables so that they are classified as “new”
17

18 **RESPONSE:**

19 3.1 The Large Customer additions calculation is based on each customer's annual anticipated loads.
20 For many projects the customer anticipates loads to increase over multiple years and the billed
21 demand forecast accounts for those loads being added over time rather than entirely in the
22 Anticipated Energization Year.
23

24 In the updated customer list used for 3-SEC-68 Attachment 1, the Anticipated Energization Year
25 changed for some customers, however, the annual schedule of load additions was not fully
26 updated for all customers.
27

28 JT4.7 Attachment 1 provides a summary of the large customer list filed in response to 3-Staff-93
29 and provides the annual anticipated loads with calculations to reach annual billed demands. This

1 attachment also maps these calculations to 3-VECC-38 and the Known New Customers tab of the
2 load forecast. Relative to the original 3-Staff-93 large customer list, the attached Excel file JT_1.2-
3 3.1(1)_Revised Large Customer List provides an update to the annual schedules of anticipated
4 load additions for customers whose Anticipated Energization Year changed, so that the timing of
5 load additions is aligned with the revised energization assumptions. These revisions have also
6 been incorporated into the revised load forecast model filed in Excel as JT1.2-7.1 Attachment 1.

7
8 3.2 See the response to 3.1.

9
10 3.3 In VECC-38 & VECC-26, customers that connected in 2025 are counted as New customers. JT4.7
11 Attachment 1 includes the tabs provided in 3-VECC-38 with links to the large customer load and
12 customer count calculations as provided in 3-Staff-93 Attachment 1. Updated versions of these
13 tabs are provided in JT1.2-3.1 Attachment 1.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VECC

JT1.2-4

Ref:

3-PP-21

3-STAFF-93(1)_Large Customer List

**Excel File EE_3-SEC 68 (1), New Known Customer &
Customer Count Tabs**

Preamble: PP21 states:

“Billed kW of large load connections are forecast based on the anticipated peak load of the customer, the anticipated connection year, a connection likelihood percentage, an average monthly billed to peak anticipated demand ratio, and timing adjustments. The connection likelihood percentage of 50%, 80%, or 100% is assigned based on assessment of the maturity of the connection process. The monthly billed to peak anticipated demand ratio of 70% is applied to recognize that customers do not always reach their maximum anticipated demands and do not reach their actual annual peak in each month. The connection timing adjustment is applied such that 25% of anticipated load does not materialize in the anticipated year, accounting for connection delays and delays in a customer reaching their maximum demand. Finally, a half-year adjustment is made such that customers are assumed to connect, on average, half way through the year. The same likelihood adjustment, connection timing adjustment, and half-year rule are applied to forecast customer counts.” (Emphasis Added)

SEC 68 (1), New Known Customer Tab sets out the forecast for the cumulative new known customers by rate zone and by customer class (GS 50-2,999, GS 3,000-4,999 and Large Use).

In the SEC 68 (1), Customer Counts Tab the cumulative known customers for each customer class in each rate zone can be calculated as the difference between total customer forecast and the initial

customer forecast. For example, for VRZ GS 50-2,999 it would be the difference between column R and column

Question(s):

4.1 Please explain why the forecast of cumulative new known customers in the New Known Customer Tab differs from that calculated based on the values in the Customer Count Tab. For example:

- WRZ GS 50-2,999 (differ in the years 2027-2031)
- WRZ GS 3,000-4,999 (differ in the years 2027-2031)
- VRZ GS 50-2,999 (differ in all years 2026-2031)
- VRZ GS 3,000-4,999 (differ slightly in 2027 & 2028)

4.2 Provide a revised excel version of Staff 93, Attachment 1 that: i) includes a column identifying those customers that are “new” (i.e. no load prior to 2025) versus those that are “existing” (i.e., included in 2024 year-end customer count), ii) maintains columns A-E and O, and ii) includes columns showing for each of the customer applications their contribution to the incremental customer count in each of the years 2026-2031 after the likelihood adjustment, connection timing excel file that for each customer and year shows how the methodology as set out in PP-21 is used to calculate the incremental contribution).

4.2.1 Please confirm that the overall totals for each year reconcile with the (updated) responses to VECC-26, VECC-38 and SEC-68.

4.3 With respect to the incremental customer counts provided in the preceding question:

i. For those “new” customers first added in 2025, is their contribution to the incremental customer count in the years 2026-2031 equal to 0.5 and, if not, why not?

ii. For “new” customers first energizing in 2026 or later:

a. Is the incremental customer count contribution in the first year equal to $(0.5 \text{ (i.e., 1/2 year rule)} * \text{connection likelihood} * 0.75 \text{ (i.e., timing adjustment)})$? If not, why not and how is it calculated?

b. Is the incremental customer count contribution in all of the following years equal to $(1 * \text{connection likelihood})$? If not, why not and how is it calculated?

1

2 **RESPONSE:**

3 4.1 In the load forecast model filed as Attachment 1 to 3-SEC-68, the figures in the New Known
4 Customers tab are cumulative and include a half-year adjustment to customer counts in the first
5 year. The figures in the Customer Count tab are annual customer count additions before the half-
6 year adjustment is made. The Total Customers formulas in the Customer Count tab included the
7 half-year adjustment for customers added in that year and the sum of annual customer count
8 additions from prior years. This has been revised in the updated load forecast (JT1.2-7.1
9 Attachment 1) so the counts included in the Customer Count tab are the same as the figures in
10 the New Known Customers. The formulas for Total Customers and monthly customer additions
11 have been adjusted accordingly.

12

13 Revisions to the customer counts included in the New Known Customers tab was not fully
14 reflected in the Customer Count tab for the VRZ GS 50-2,999 kW, WRZ GS 50-2,999 kW, and WRZ
15 GS 3,000-4,999 kW classes in 3-SEC-68. The VRZ GS 50-2,999 kW class was understated by 3.3
16 customers and there was a 0.5 count reallocation from the WRZ GS 3,000-4,999 kW class to the
17 WRZ GS 50-2,999 kW class. This has been corrected in the updated load forecast model. A
18 summary of all adjustments reflected in the updated load forecast model is provided in the
19 written response to JT1.2-7.1.

20

21 4.2 The requested information is provided in Excel files JT4.7 Attachment 1 & JT1.2-3.1 Attachment
22 1.

23

24 4.3 i. No, the customer is included as a full customer in subsequent years in the load forecast model
25 filed as Attachment 1 to 3-SEC-68. In the updated load forecast model (JT1.2-7.1 Attachment 1),
26 this has been adjusted so customers that connected in 2025 have 0.5 incremental customer
27 counts in each year from 2026-2031.

28

29 ii. a) Yes.

1 b) No. The connection timing adjustment includes 75% in the first year and 25% in the
2 following year. The connection timing adjustment assumes that 75% of forecasted
3 connections occur in the first year and 25% occur in the following year. The application of
4 the half-year rule on the 25% portion of connections occurring in the following year reduces
5 the customer count. The customer count is 1 times the confidence adjustment in each
6 subsequent year. The connection timing adjustment is intended to reflect delays in project
7 in-service dates and recognizes potential in-service delays to the following year in which
8 the customer is not billed in each month of the following year.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VECC

JT1.2-5

Ref:

3-STAFF-93(1)_Large Customer List
Excel File EE_3-SEC 68 (1) New Known Customer & Customer Count Tabs

Question(s):

5.1 Provide a revised excel version of Staff 93, Attachment 1 that: i) includes a column identifying those customers that are “new” (i.e., no load prior to 2025) versus those that are “existing” (i.e., included in 2024 year-end customer count), ii) includes a column that for existing customers shows their customer classification as of 2024, iii) maintains columns A-E and O, and iv) includes columns showing for each of the customer applications their customer classification each of the years 2026-2031.

RESPONSE:

5.1 Please see the attached Excel file JT_1.2-5.1(1) Large Customer List Rate Classes.

- i. See column M.
- ii. See column L.
- iii. Columns A-E have been maintained.
- iv. See Columns O and P. Customer rate classes have been revised in Column P.

These revisions, reflecting corrections to customer rate classes to align with current customer classifications, have been incorporated into the revised load forecast model filed as JT1.2-3.1 Attachment 1.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VECC

JT_1.2-6

Ref:

Excel File EE_3-SEC 68 (1), VRZ GS<50 Tab

3-VECC-29

Preamble:

The VRZ GS<50 Tab in EE_3-SEC 68 (1) indicates that for the updated model the ON_FTEA variable is not statistically significant and was excluded from the final model used.

VECC-29 states that, for the VRZ GS<50 class, a time trend variable was tested in conjunction with the ON_FTEA variable and “not used because it has a counterintuitive negative coefficient and the p25 value is 16.5% and is thus not statistically significant”.

Question(s):

6.1 Was a version of the VRZ GS<50 model tested that included a time trend variable but did not include the ON_FTEA variable? If yes, what were the results? If not, please provide the results of such a model (i.e. coefficient values and statistical results).

Response:

6.1 Yes. A model with a time trend variable that did not include the ON_FTEAdj was tested and was not used because the time trend variable was not statistically significant. The time trend variable had a p-value of 30.6%, which is higher than the 5% threshold that is generally used to determine statistical significance. The results are provided in Table 1 below.

1

Table 1: Results of VRZ GS < 50 Model – with Time Trend Variable

Model 1: Prais-Winsten, using observations 2016:01-2025:12 (T = 120)				
Dependent variable: VRZ_GSlt50kWh_No_CDM_AL				
rho = 0.793441				
	coefficient	std. error	t-ratio	p-value
const	3,949,098	1,325,219	2.98	0.0035
HDD20	10,512	434	24.23	0.0000
CDD14	32,852	1,079	30.44	0.0000
COVID_AM	-2,564,308	578,908	-4.43	0.0000
Trend	-6,644	6,467	-1.03	0.3064
MonthDays	450,936	41,719	10.81	0.0000

Statistics based on the rho-differenced data			
Sum squared resid	3.52E+13	S.E. of regression	555,963
R-squared	0.9252	Adjusted R-squared	0.9219
F(5, 114)	344.91	P-value(F)	0.0000
rho	-0.1262	Durbin-Watson	2.2523

Statistics based on the original data			
Mean dependent var	22,855,713	S.D. dependent var	1,975,136

2

1 **TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VECC**

2

3 **JT_1.2-7**

4 **Ref:**

5 **Excel File EE_3-SEC 68 (1),**

6 **WRZ GS<50 Tab and**

7 **WRZ GS<50 Normalized Tab**

8

9 **Preamble:**

10 The WRZ GS<50 Tab includes the results for two different models using 2016-2025 data:

Model 14: Prais-Winsten, using observations 2016:01-2025:12 (T = 120)					Model 11: Prais-Winsten, using observations 2016:01-2025:12 (T = 120)				
Dependent variable: WRZ_GSlt50kWh_No_CDM_AL					Dependent variable: WRZ_GSlt50kWh_No_CDM_AL				
rho = 0.378775					rho = 0.383				
	coefficient	std. error	t-ratio	p-value		coefficient	std. error	t-ratio	p-value
const	172,055	775,967	0.22	0.8249	const	- 588,744	937,977	- 0.63	0.5315
HDD20	3,844	242	15.89	0.0000	HDD20	3,865	240	16.09	0.0000
CDD12	9,768	557	17.52	0.0000	CDD12	9,815	555	17.69	0.0000
MonthDays	157,574	25,102	6.28	0.0000	MonthDays	156,314	25,209	6.20	0.0000
Osh_FTEAdj (removed)					Osh_FTEAdj	3,510	2,416	1.45	0.1492
COVID_AM	- 989,852	165,256	- 5.99	0.0000	COVID_AM	- 925,125	167,678	- 5.52	0.0000
Fall	188,542	77,372	2.44	0.0164	Fall	184,936	76,703	2.41	0.0175
Statistics based on the rho-differenced data					Statistics based on the rho-differenced data				
Sum squared	8.00E+12	S.E. of regress	264,886		Sum squared	7.85E+12	S.E. of regress	263,652	
R-squared	0.8442	Adjusted R-squared	0.8374		R-squared	0.8470	Adjusted R-squared	0.8389	
F(5, 114)	119.85	P-value(F)	0.0000		F(6, 113)	100.46	P-value(F)	0.0000	
rho	0.0747	Durbin-Watson	1.8352		rho	0.0772	Durbin-Watson	1.8374	
Statistics based on the original data					Statistics based on the original data				
Mean dependent	7,128,677	S.D. dependent	656,239		Mean dependent	7,128,677	S.D. dependent	656,239	

The model used for purposes of the updated WRZ GS<50 forecast (WRZ GS<50 Normalized Tab) differs from either of these and appears to be based on 2015-2024 data as set out below:

Model 26: Prais-Winsten, using observations 2015:01-2024:12 (T = 120)				
Dependent variable: WRZ_GSlt50kWh_No_CDM_AL				
rho = 0.46494				
	coefficient	std. error	t-ratio	p-value
const	-2.79E+06	1,043,267	- 2.6702	0.01
HDD20	3,926	258	15.2284	3.78E-29
CDD12	10,177	600	16.9726	7.28E-33
MonthDays	159,112	26,072	6.1029	1.50E-08
Osh_FTEAdj	14,143	3,044	4.6465	9.20E-06
COVID_AM	- 797,503	201,147	- 3.9648	0.00
Fall	193,962	84,472	2.2962	0.02
Statistics based on the rho-differenced data				
Sum squared	9.36E+12	S.E. of regress	287819.6	
R-squared	0.843121	Adjusted R-squared	1	
F(6, 113)	92.3978	P-value(F)	0.0000	
rho	0.08	Durbin-Watson	1.8166	
Statistics based on the original data				
Mean dependent	7372805	S.D. dependent	707150.8	

1

2 **Question(s):**

3 7.1 Please confirm the basis for the WRZ GS<50 model used in SEC-68 and updated the load
4 forecast as necessary.

5

6 **Response:**

7 7.1 The basis for the WRZ GS<50 kW forecast in 3-SEC-68 is the model in the WRZ GS<50
8 Normalized Tab (labeled Model 26 above) but should be consistent with the model in tab WRZ
9 GS<50 Predicted (labeled Model 14 above). Please see the revised load forecast model attached as

1 to JT_1.2-7.1 which corrects this inconsistency by using the same WRZ GS<50 regression model in
2 both the WRZ GS<50 Predicted and WRZ GS<50 Normalized tabs. The regression model has been
3 revised for updated CDM values as noted in the response to JT 1.2-11.1.

4
5 In addition to the correction to the WRZ GS<50 kW model noted above, the excel file attached to JT
6 1.2-7.1 includes the following changes:

- 7 • JT 1.2-3.1: Volumes and customer counts in the “New Known Customer” tab have been
8 updated based on the revised large customer list loads in JT 1.2-3.1 Attachment 1. The
9 updates also reflect current customer rate classes.
- 10 • JT 1.2-1.1: The housing growth rate for Gravenhurst has been included in the weighted
11 average Veridian Residential growth rate calculation in the “Additional Growth” tab.
12 Monthly customer count calculations have been revised to maintain equivalency between
13 the average of monthly customer counts in a year and the annual customer counts
14 calculated with the historic geometric mean growth rate.
- 15 • JT 1.2-11.1: Historic CDM figures, including persistence of historic CDM, have been revised
16 in the ‘CDM’ tab according to the corrected LRAMVA workform filed as JT 1.2-11.1
17 Attachment 1. All regression models were rerun with the corrected historic CDM figures
18 that are included in the dependent variable of those models.
- 19 • In the load forecast, the *Known Additions* figures in the “Customer Count” tab have been
20 revised to equal the number of customers in the “New Known Customer” tab. These
21 figures are cumulative, while the figures provided as *Known Additions* in 3-SEC-68
22 Attachment 1 are incremental. As a result, the *Total Customers* calculations in the
23 “Customer Count” tab have been adjusted accordingly. *Total Customers* now equals the
24 sum of customer forecasts using geometric average growth rates and *Known Additions*. The
25 formula for *Total Customers* previously calculated a cumulative total of *Known Additions*
26 including counts from current and prior years. This change was made for clarity and
27 consistency in response to JT 4.7 and does not impact the forecast customer counts.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VECC

JT_1.2-8

Ref:

**Excel File EE_3-SEC 68 (1), the Normalized Tabs for the
Residential, Seasonal, GS<50, GS 50-2,999, GS 3,000-4,000
and Large Use customer classes in each of the two rate zones
Excel File EE_3-SEC 68 (1), EV Forecast Tab and Heating Tab
Excel File EE_3-SEC 68 (1), Normalized Annual Summary Tab**

Question(s):

8.1 Please confirm that for the Residential, Seasonal, GS<50, GS 50-2,999, GS 3,000-4,000 and Large Use customer classes in both Rate Zones the values for “Normal Predicted No CDM” in the Normalized Annual Summary Tab are based on the sum of: i) forecast model results for respective class, ii) the estimated cumulative annual load associated with EVs introduced to the service since January 2017 (per the EV Forecast Tab) and iii) the cumulative annual load associated with heating conversions in the service area since January 2019 (per the Heating Tab). If not, please explain why.

8.2 Please also confirm that the historical customer class kWh data used to estimate the models includes the kWh associated with EV’s introduced to the rate zones and heating conversions in the rate zones up to 2025. If not, please explain why.

8.3 If the preceding two points are confirmed, doesn’t this mean that the resulting forecast for 2026-2031 have doubled counted the impact of: i) EVs introduced in the rate zones between 2017-2025 and ii) heating conversions made in the rate zones between 2019-2025? If not, please explain why. If yes, please adjust the forecasts for these customer classes in both rate zones accordingly.

Response:

8.1 Confirmed.

1

2 8.2 Not confirmed. EV and heating loads are subtracted from the sum of actual monthly kWh and
3 CDM for the purpose of regression modeling. This is described in Exhibit 3, Tab 1, Schedule 1,
4 Appendix A, page 3.

5 *To isolate the impact of electric vehicles (EVs) and electric heating, estimated EV and*
6 *electric heating loads are subtracted from “Actual No CDM”, which is denoted “Actual No*
7 *CDM AL” (additional loads) throughout the model. The weather normalized forecasts are*
8 *produced without the additional loads from electrification, and those loads are added back*
9 *to produce the normalized forecast. In the forecast years, cumulative EV and electric*
10 *heating loads are added to normal weather.*

11

12 8.3 EV and heating loads are not double counted because those loads are subtracted from the
13 volumes used to produce the models, as described in 8.2.

14

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VECC

JT_1.2-9

Ref:

3-PP-21

3-STAFF-93 (1)_Large Customer List

Preamble:

PP21 states:

“Billed kW of large load connections are forecast based on the anticipated peak load of the customer, the anticipated connection year, a connection likelihood percentage, an average monthly billed to peak anticipated demand ratio, and timing adjustments. The connection likelihood percentage of 50%, 80%, or 100% is assigned based on assessment of the maturity of the connection process. The monthly billed to peak anticipated demand ratio of 70% is applied to recognize that customers do not always reach their maximum anticipated demands and do not reach their actual annual peak in each month. The connection timing adjustment is applied such that 25% of anticipated load does not materialize in the anticipated year, accounting for connection delays and delays in a customer reaching their maximum demand. Finally, a half-year adjustment is made such that customers are assumed to connect, on average, half way through the year. The same likelihood adjustment, connection timing adjustment, and half-year rule are applied to forecast customer counts.”

Question(s):

9.1 With respect to the STAFF-93 (1)_Large Load List, based on the methodology set out in PP-21

one would expect that for all customer applications with an anticipated first year of 2026 or later:

- The billed load in the first year would equal the Anticipated Load (per column D) * the Confidence Factor (per column E) * 75% (timing adjustment) * 70%
- The billed load in the subsequent years would equal Anticipated Load (per column D) * the Confidence Factor (per column E) * 70%

1 For all the customer applications with an anticipated year of 2026 or later where this is not the
2 case, please explain why.

3 9.2 With respect to the STAFF-93 (1)_Large Load List, based on the methodology set out in PP-21
4 one would expect that for all customers with an anticipated first year of 2025 that the billed load in
5 each of the years 2026-2031 to be the same and equal to: i) the Anticipated Load (per column D) *
6 the Confidence Factor of 100% (per column E) * 70% less ii) the actual 2025 load. For all the
7 customer applications with an anticipated first year of 2025 where this is not the case, please
8 explain why.

9

10 **Response:**

11 9.1 There are many projects listed in Staff-93 Attachment 1 in which the customer anticipates load
12 additions over multiple years. The Anticipated Load includes the total load added throughout
13 the project and the Anticipated First Year is meant to reflect the first year that loads are added.
14 In preparing this response, Elexicon identified inconsistencies between the Anticipated First
15 Year and the first year in which annual loads are included. This has been corrected in JT_1.2-
16 3.1, Attachment 1. This attachment provides detailed calculations from each project's annual
17 anticipated load additions to the billed demands that are added to the load forecast. A few
18 projects have annual load additions that extend beyond 2031, so a portion of their total
19 Anticipated Loads are not added to the load forecast.

20 9.2 Customers with a 2025 Anticipated Year that connected in 2025 have had manual adjustments
21 made to account for actual billed demands to date in the load forecast filed as 3-SEC-68
22 Attachment 1. This reduction is made to the annual load additions that are used to calculate
23 billed demands such that the volumes added are only incremental to demands that have been
24 realized by the end of 2025. The "Anticipated Load" figures include loads for the full project
25 and have not been adjusted for actual 2025 demands.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VECC

JT_1.2-10

Ref:

3-VECC-38 (1), part (b)

3-STAFF-93 (1)_Large Customer List

Question(s):

10.1 In Staff-93 the sum of the anticipated loads (column D) for all 72 applications is 233,581 kW.

However, in VECC 38 the sum of the anticipated loads (excel row 7) is reported as 216,656 MW.

Please clarify whether the values reported in VECC-38 are in kW or MW and reconcile the differences in the totals.

10.2 In Staff-93 VECC calculates the sum of the anticipated loads (column D) with 80% confidence as 60,263. However, in VECC 38 the sum of the anticipated loads with 80% confidence (excel row 4) is 57,613. Please review and reconcile any differences in the totals.

10.3 In Staff-93 VECC calculates the sum of the anticipated loads (column D) with 50% confidence as 101,050. However, in VECC 38 the sum of the anticipated loads with 50% confidence (excel row 3) is 99,882. Please review and reconcile any differences in the totals.

10.4 In Staff-93 VECC calculates the sum of the anticipated loads (column D) connected in 2025 to be 46,027. However, in VECC 38 the sum of these anticipated loads (excel row 6) is 35,631. Please reconcile the differences in the totals.

10.5 In Staff-93 VECC calculates the sum of the anticipated loads (column D) not connected in 2025 but assigned 100% confidence to be 26,241. However, in VECC 38 the sum of these anticipated loads (excel row 5) is 23,530. Please reconcile the differences in the totals.

Response:

10.1 The differences between the sum of Anticipated Load values in 3-Staff-93 and the values in 3-VECC-38 are due to the load adjustment for customers that connected in 2025, as described in JT1.2-9.2, projects that extend beyond 2031, as described in JT1.2-9.1, and three projects

where the anticipated load differs from the sum of annual added loads. One customer's anticipated load exceeded the sum of annual added loads, one customer's anticipated load is greater than the sum of anticipated loads, and a load expansion in a year following the anticipated year was left out of the billed kW calculation. JT 4.7 Attachment 1 includes the sheets provided in 3-VECC-38 with cell references to sheets from 3-Staff-93. Corrected versions of the 3-VECC-38 sheets are included in JT 1.2- 3.1 Attachment 1. The values reported in 3-VECC-38 are MW.

The table below summarizes the differences between 3-Staff-93 and 3-VECC-38, and breaks out the differences for each confidence level sub-grouping that are addressed in the following sub-parts.

Table 1: Reconciliation of Anticipated Loads Between 3-Staff-93 and 3-VECC-38 (MW)

Undertaking Response	10.1	10.2	10.3	10.4	10.5
Sub-Grouping	Total	80%	50%	100% 2025	100% 2026-31
Sum of Loads in 3-Staff-93	233,581	60,263	101,050	46,027	26,241
Adjustments for load connected in 2025	-10,267			-10,267	
Anticipated Loads Extending after 2031	-2,668	-1,500	-1,168		
Differences between Anticipated Year and expected first year of annual loads				2,711	-2,711
Correction to Annual Load Addition	-1,250	-1,250			
Correction to "Anticipated Load"	-2,740	100		-2,840	
Sum of Loads in 3-VECC-38*	216,656	57,613	99,882	35,631	23,530

*Note: The "Sum of Loads in 3-VECC-38" row equals the sum of the loads in 3-Staff-93 plus all adjustments identified in the rows above.

10.2 The sum of anticipated loads with 80% confidence in 3-Staff-93 includes a project (Customer 69) with anticipated loads added in 2031 and 2032. The loads in 2032 are not included in 3-VECC-38. Additionally, in 3-Staff-93, Customer 15's anticipated load exceeded the sum of annual anticipated loads and Customer 7's load expansion after the anticipated year was erroneously left out of the billed kW calculation. This has been corrected in JT 1.2-3.1 Attachment 1, the revised large customer list, and in the updated load forecast filed as JT 1.2-7.1 Attachment 1. See Table 1 for a detailed reconciliation of these differences.

1

2 10.3 The sum of anticipated loads with 50% confidence in 3-Staff-93 includes a project (Customer
3 43) with anticipated loads added from 2028 to 2032. The loads in 2032 are not included in 3-
4 VECC-38. See Table 1 for a detailed reconciliation of these differences.

5

6 10.4 The sum of anticipated loads with a 2025 Anticipated Year in 3-Staff-93 includes full project
7 anticipated loads before adjustments to account for actual 2025 demands. As described in the
8 response to 10.1, 3-VECC-38 includes the loads after this adjustment. Additionally, there are
9 differences between the anticipated year and the first year of annual loads for the project. See
10 Table 1 for a detailed reconciliation of these differences.

11

12 10.5 The differences between 9-Staff-93 and 3-VECC-38 are due to differences between the
13 anticipated year and the first year of annual loads for the project. See Table 1 for a detailed
14 reconciliation of these differences.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VECC

JT_1.2-11

Ref:

Excel File EE_3-SEC 68 (1), CDM Tab

3-VECC-34

Excel file 3-VECC- 34(1)_Adjusted 2023 LRAMVA Workform.

Preamble:

VECC-34 states:

“A modified version of the LRAMVA workform is provided as Excel file 3-VECC-25 34(1)_Adjusted 2023 LRAMVA Workform. The values populated in the CDM Tab of the Load Forecast model are the actual and persisting CDM savings, as summarized at the bottom of each implementation year table in tab ‘5. 2015-2027 LRAM’.”

Question(s):

11.1 In the case of the Veridian Rate Zone, VECC has summed the annual persisting savings through to 2031 reported by program in VECC- 34(1)_Adjusted 2023 LRAMVA Workform, Tab 5 for each of the implementation years 2015 to 2021. VECC has also summed the persisting savings to 2031 reported in the CDM Tab across the various rate classes for implementation years 2015-2021. The totals from the two sources do not appear to match for the following Implementation Year/Savings Years:

- Implementation Year 2015 – All Savings Years 2015-2031
- Implementation Year 2016 – All Savings Years 2016-2031
- Implementation Year 2017 – All Savings Years 2017-2031
- Implementation Year 2018 – All Savings Years 2018-2031
- Implementation Year 2019 – All Saving Years 2019-2031
- Implementation Year 2020 – Saving Year 2020
- Implementation Year 2021 – Savings Years 2030 and 2031

Please reconcile.

11.2 In the case of the Whitby Rate Zone, VECC has summed the annual persisting savings through to 2031 reported by program in VECC- 34(1)_Adjusted 2023 LRAMVA Workform, Tab 5 for each of the implementation years 2015 to 2021. VECC has also summed the persisting savings to 2031 reported in the CDM Tab across the various rate classes reported in the CDM Tab for implementation years 2015-2021. The totals from the two sources do not appear to match for the following Implementation Year/Savings Years:

- Implementation Year 2016 – All Savings Years 2016-2030
- Implementation Year 2018 – Savings Year 2030
- Implementation Year 2019 – All Saving Years 2019-2031
- Implementation Year 2021 – Savings Year 2030

Please reconcile

Response:

11.1 Please refer to the attached Excel file JT 1.2-11.1(1)_Revised 2023 LRAMVA Workform. This file is a revised version of 3-VECC-34 Attachment 1 (LRAMVA workform) with adjustments to reconcile the annual totals with the sum of annual allocated kWh volumes:

- Adjustments to the 2016 Save on Energy Heating and Cooling Program in the Veridian rate zone were not allocated to rate classes. This has been revised in Tab '5. 2015-2027 LRAM' to allocate 100% to the VRZ Residential rate class, consistent with the allocations that were used for initial program (pre-adjustment).
- Adjustments to the Retrofit Program in the Veridian rate zone did not have kW savings in some years so kWh savings were not attributed to demand-billed classes. This has been revised by updating the allocation calculations in tab '3-a. VRZ Rate Class Alloc.' to be based on kWh for all classes.
- The Save on Energy Small Business Lighting Program in 2019 in the Whitby rate zone was not allocated to any rate class. This has been revised in Tab '5. 2015-2027 LRAM' to allocate 100% to the WRZ GS<50 kW rate class, consistent with the allocation in prior years.

The CDM tab has been revised in the revised load forecast model (JT1.2-7.1 Attachment 1), with regression models updated for each class. JT1.2-11.1 Attachment 1 includes a copy of the

- 1 CDM tab from the updated load forecast model with references to Tab '5. 2015-2027 LRAM'
- 2 demonstrating the total CDM savings allocated to rate classes aligns with the annual total
- 3 savings figures.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VECC

JT1.2-12

Ref: 3-VECC-71

Question(s):

12.1 At the time of the review how many metered customers were there in Elexicon's service area – outside of Gravenhurst?

RESPONSE:

Elexicon wishes to correct that the reference should be to 7-VECC-71.

12.1 At the time of the review there were 174,228 metered customers outside of Gravenhurst.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VECC

JT_1.2-13

Ref:

3-VECC-76

Preamble:

The response states:

“The 2027 monthly Network Units Billed is forecast by escalating the Veridian and Whitby volumes from the 2026 IRM application by forecast kWh growth from the Exhibit 3 load forecast. The sum of billed kW between the rate zones is escalated by 4.6% to forecast 2026 billed kW and by 4.0% to forecast 2027 billed kW. Within the RTSR model the monthly volumes are escalated on this basis, also shown in Table 1.”

monthly volumes are escalated on this basis, also shown in Table 1.”

Table 1: Forecast of 2027 Network Units Billed

Network Units	VRZ (2026 IRM)	VRZ (2026 IRM)	2025	2026	2027
Forecast MWh			3,747,675	3,918,947	4,074,560
Escalation %				4.6%	4.0%
IESO Network Billed kW	2,837,765	1,292,914	4,130,679	4,319,454	4,490,971
Hydro One Network Billed kW	2,527,998	547,526	3,075,523	3,216,077	3,343,781

And

“The 2027 monthly Line Connection and Transformation Connection Units Billed is forecast by escalating the Veridian and Whitby volumes from the 2026 IRM application by forecast kWh growth from the Exhibit 3 load forecast. The sum of billed kW between the rate zones is escalated by 4.6% to forecast 2026 billed kW and by 4.0% to forecast 2027 billed kW. Within the RTSR model the monthly volumes are escalated on this basis, also shown in Table 2.”

Table 2: Forecast of 2027 Line Connection and Transformation Connection Units Billed

Network Units	VRZ (2026 IRM)	VRZ (2026 IRM)	2025	2026	2027
Forecast MWh			3,747,675	3,918,947	4,074,560
Escalation %				4.6%	4.0%
IESO Line Connection Billed kW	1,059,767	1,371,487	2,431,254	2,542,364	2,643,316
Hydro One Line Connection Billed kW	2,015,711	550,727	2,566,438	2,683,726	2,790,291
IESO Transformation Billed kW	2,877,068	1,371,487	4,248,555	4,442,717	4,619,128
Hydro One Transformation Billed kW	2,571,959	550,727	3,122,686	3,265,394	3,395,057

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Question(s):

- 13.1 Please confirm that the third column in both Table 1 and Table 2 sets out the values for WRZ and not VRZ
- 13.2 Are the Veridian and Whitby volumes from the 2026 IRM Application values for 2025 or 2024? If for 2024, please revise Table 1 and Table 2 so as to add the escalation from 2024 to 2025.
- 13.3 Please provide the values used to calculate the growth rates used in the calculation and indicate whether they have been updated to reflect the load forecast per 3-SEC-68?

Response:

Ellexicon wishes to correct that the reference should be to 8-VECC-76.

13.1 Confirmed.

13.2 The values from the 2026 IRM Application are from 2024. Tables 1 and 2 below are the tables referenced in the question, updated to reflect escalation from 2024 to 2025. Tables 3 and 4 provide the corresponding calculations with the updated MWh values from Attachment 1 to 3-SEC-68.

Table 1: Forecast of 2027 Network Units Billed (3-VECC-76)

Network Units	VRZ	WRZ	2024	2025	2026	2027
	(2026 IRM)	(2026 IRM)				
Forecast MWh			3,649,852	3,747,675	3,918,947	4,074,560
Escalation %				2.7%	4.6%	4.0%
IESO Network Billed kW	2,837,765	1,292,914	4,130,679	4,241,389	4,435,224	4,611,338
Hydro One Network Billed kW	2,527,998	547,526	3,075,523	3,157,953	3,302,274	3,433,400

Table 2: Forecast of 2027 Line and Transformation Connection Units Billed (3-VECC-76)

Line and Transformation Connection Units	VRZ	WRZ	2024	2025	2026	2027
	(2026 IRM)	(2026 IRM)				
Forecast MWh			3,649,852	3,747,675	3,918,947	4,074,560
Escalation %				2.7%	4.6%	4.0%
IESO Line Connection Billed kW	1,059,767	1,371,487	2,431,254	2,496,416	2,610,505	2,714,162
Hydro One Line Connection Billed kW	2,015,711	550,727	2,566,438	2,635,223	2,755,655	2,865,077
IESO Transformation Billed kW	2,877,068	1,371,487	4,248,555	4,362,424	4,561,791	4,742,930
Hydro One Transformation Billed kW	2,571,959	550,727	3,122,686	3,206,380	3,352,914	3,486,051

Table 3: Forecast of 2027 Network Units Billed (3-SEC-68)

Network Units	VRZ	WRZ	2024	2025	2026	2027
	(2026 IRM)	(2026 IRM)				
Forecast MWh			3,504,986	3,566,143	3,709,866	3,927,224
Escalation %				1.7%	4.0%	5.9%
IESO Network Billed kW	2,837,765	1,292,914	4,130,679	4,202,753	4,372,132	4,628,292
Hydro One Network Billed kW	2,527,998	547,526	3,075,523	3,129,186	3,255,299	3,446,024

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Table 4: Forecast 2027 Line and Transformation Connection Units Billed (3-SEC-68)

Line and Transformation Connection Units	VRZ	WRZ	2024	2025	2026	2027
	(2026 IRM)	(2026 IRM)				
Forecast MWh			3,504,986	3,566,143	3,709,866	3,927,224
Escalation %				1.7%	4.0%	5.9%
IESO Line Connection Billed kW	1,059,767	1,371,487	2,431,254	2,473,676	2,573,370	2,724,141
Hydro One Line Connection Billed kW	2,015,711	550,727	2,566,438	2,611,219	2,716,456	2,875,611
IESO Transformation Billed kW	2,877,068	1,371,487	4,248,555	4,322,686	4,496,899	4,760,368
Hydro One Transformation Billed kW	2,571,959	550,727	3,122,686	3,177,172	3,305,218	3,498,869

13.3 The values used to calculate the Escalation % of the Forecast MWh are in row 2 of each table provided in JT 1.2-13.2. These values in Tables 1 and 2 are consistent with the load forecast files as Exhibit 3 Attachment 1, and those in Tables 3 and 4 are consistent with 3-SEC-68 Attachment 1. The growth rates used in 8-VECC-76 Attachment 1 are consistent with 3-SEC-68 Attachment 1.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VECC

JT1.2-14

Ref: 3-VECC 76, Attachment 1, Tab 4 and LV Charges Tab

Question(s):

14.1 Confirm that in the Updated RTSR WF (VECC 76, Attachment 1, LV Charges Tab) the LV Expense for 2027 is determined by: i) for each of the Veridian and Whitby Rate Zones calculating LV revenues based on 2026 LV charges and 2027 forecast billing quantities, ii) summing the results of the two calculations and iii) escalating this result by forecast increase in HONI' ST rates for 2023->2027 (per Tab 4)

14.1.1 The source of the forecast increases in HONI's ST rates is given as EB-2021-0110 Settlement Agreement, Attachment 1, Schedule 2.3 (see Tab 4). Should the reference actually be Attachment 2, Schedule 4.1?

14.1.2 Why not use the forecast increase from 2026 to 2027 from HON's Settlement Agreement in the LV Charges Tab calculation (as opposed to the average increase over the 2023 to 2027 period actually used in the Application)?

14.2 What was Elexicon's total actual LV expense (i.e., ST charges from HON) for 2025 broken down by charge type?

14.3 What is the increase in Elexicon's total retail volumes (MWh) as between 2025 actuals and the forecast for 2027?

RESPONSE:

Elexicon wishes to clarify that the reference is to 8-VECC-76.

14.1 Confirmed.

14.1.1 Yes, the attachment reference should be Attachment 2, Schedule 4.1.

1 14.1.2 As the forecast LV charge increases are applied each year from 2026 to 2031, an average of
2 charge increases over the 2022 to 2027 was selected to better reflect the longer-term trend of
3 LV charge increases rather than the increases of a single year from 2026 to 2027.

4
5 14.2 Elexicon's 2025 Sub-Transmission charges by charge type are provided below.

6 **Table 1: Sub-Transmission Charges by Charge Type**

Charge Type	Amount (\$)
Monthly Service Charge	\$ 346,198
Facility Charge- Connection to Low Voltage Distribution Station	\$ 225,783
Specific ST Lines	\$ 136,589
Facility Charge- Connection to Common ST Lines	\$ 4,428,061
Meter Service Charge	\$ 40,089
Sub-Total (before riders)	\$ 5,176,719
Rate Riders	-\$ 2,399,996
Total (including riders)	\$ 2,776,723

7
8 14.3 MWh volumes are forecast to increase by 361.080 MWh (10.1%) from 2025 to 2027.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CCC

JT1.3

QUESTION:

PROVIDE THE SAME INFORMATION THAT WAS PROVIDED WITH RESPECT TO THE INPUTS TO THE
PEAK DEMAND FORECAST FOR 2025 AS WAS PROVIDED FOR 2026 TO 2031 IN CCC-15,
ATTACHMENT 1

RESPONSE:

Elexicon interprets this request as seeking the inputs to the 2025 peak demand forecast in a format
consistent with the information provided in 2-CCC-15, Attachment 1 for the 2026–2031 forecast
period.

Please refer to the attached Excel file JT_1.3(1)_System & Region Peak Demand 2019-2031. This
includes updates to the original excel file 2-CCC-15(1)_System & Region Peak Demand 2019-2031, to
include the inputs to the peak demand forecast for 2025 for the system and all respective regions.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CCC

JT1.4

QUESTION:

PROVIDE THE ADDITIONAL EXPANSION PROJECTS THAT ARE NOT LISTED IN TABLE 5 OF 2-STAFF-52 AND ADVISE HOW \$33 MILLION OF ASSETS WILL BE PUT IN THAT DO NOT APPEAR TO BE CONNECTED TO KNOWN CUSTOMERS.

RESPONSE:

The placeholder of \$32.85M of system expansion projects identified in Table 5 of interrogatory response to 2-CCC-22(f) represents additional customer-driven system expansion projects that were not individually identified in Table 5 due to the evolving nature of customer connection requests. At the time of filing, this amount was related to forecasted projects that were in pre-consultation or early planning stages which have since evolved.

Table 1 below summarizes an additional \$23.56M in system expansion projects included within the placeholder amount that are expected to be placed in service in 2027. Most of these projects are currently in the detailed design phase and are scheduled to advance to construction during Q4 2026 and into 2027. The remaining placeholder balance of \$9.29M is currently a forecasted value based on anticipated system expansion projects that are currently in the pre-consultation or early planning stages with customers, and as such project details and cost estimates have not yet been determined.

1 **Table 1: Additional Expansion Projects Forecasted to be Placed into Service in 2027**

Customer	District	Est. Connection Year	Load (MW)	Total Cost Estimate	Description	Project Status
1	Ajax	2027	2.1	\$0.72M	Mixed residential high-rise development requires 2.1MW by 2027, requiring ~1.1km of feeder expansion from the 27.6kV system due to capacity constraints on the 44kV System.	OTC in Progress
2	Whitby	2027	0.7	\$0.56M	Industrial customer requires 0.7MW by 2027, requiring ~0.5km pole line expansion from the 44kV system to connect the customer.	Detailed Design
3	Ajax	2027	1.9	\$0.36M	Residential subdivision development requires capacity by 2027, requiring ~1km of feeder expansion from the 27.6kV system to supply approximately 628 residential units.	Detailed Design
4	Whitby	2027	0.75	\$1.81M	Residential subdivision requires capacity for 250 units by 2027, requiring ~1km of expansion from nearby 13.8kV feeder due to capacity constraints on the existing feeder in the area	Detailed Design
5	Ajax	2027	4.3	\$4.28M	Residential high-rise development requires 4.3MW by 2027, with an ultimate demand of 14MW, triggering approximately 1km of 27.6kV feeder expansion due to capacity constraints on the 44kV system	Awaiting Construction
6	Ajax	2027	1.53	\$1.41M	Residential subdivision requires capacity for 510 units by 2027, requiring ~1km pole line expansion from the 27.6kV system in Pickering	Detailed Design

Customer	District	Est. Connection Year	Load (MW)	Total Cost Estimate	Description	Project Status
7	Whitby	2027	15	\$9.95M	Construction of three new feeder expansions, including overhead pole lines and distribution circuits, from Winchester West MS to serve the North Brooklin residential development in Whitby, enabling capacity for connection of approximately 5,000 new homes.	Detailed Design
8	Ajax	2027	NA	\$0.79M	Four new feeders are planned to be added to the existing 27.6 kV distribution system in Pickering to support residential growth within the Seaton Development Area. These feeders will connect to the existing 27.6 kV network, providing the capacity required to accommodate and serve new residential subdivisions and future customer connections.	Detailed Design
9	Ajax	2027	5	\$0.39M	Existing industrial customer requires 5MW by 2027, requiring ~0.4km pole line expansion to connect to the 27.6kV system in Pickering.	Detailed Design
10	Whitby	2027	0.75	\$0.35M	New industrial customer requires 0.75MW by 2027, requiring ~0.5km underground primary distribution feeder expansion to connect the customer to the existing grid	Detailed Design
11	Whitby	2027	1	\$0.12M	New mixed used residential development requires 1MW by 2027, requiring expansion from the 44 kV system	Detailed Design

Customer	District	Est. Connection Year	Load (MW)	Total Cost Estimate	Description	Project Status
12	Ajax	2027	1.5	\$0.19M	Industrial customer requires 1.5 MW by 2027 in Ajax. System upgrades are required to enable the connection of the customer to the existing 44kV system	OTC in Progress
13	Gravenhurst	2027	0.15	\$0.26M	Commercial customer requires 0.15 MW by 2027. The existing single phase pole line is planned to be rebuild to a three-phase line to meet customer load requirements	Detailed Design
14	Whitby	2027	0.64	\$0.12M	Commercial customer requires 0.64 MW by 2027, requiring system upgrades on the existing 13.8kV system in area.	Detailed Design
15	Whitby	2027	0.3	\$0.29M	Commercial customer has requested 0.3MW of capacity by 2027. To connect the load, ~0.15km of underground feeder expansion is required from the existing 13.8kV feeder in the area.	Detailed Design
16	Belleville	2027	0.96	\$0.01M	Commercial customer requires 0.96 MW of capacity by 2027, necessitating approximately 0.3 km of feeder expansion from a nearby three-phase distribution line.	Detailed Design
17	Ajax	2027	2.5	\$1.12M	Long-term care facility requires 2.5 MW of capacity by 2027. The existing distribution lines in the area are at capacity and an expansion of ~0.5km from an alternate feeder is required to connect the customer.	Detailed Design

Customer	District	Est. Connection Year	Load (MW)	Total Cost Estimate	Description	Project Status
18	Belleville	2027	0.35	\$0.58M	Commercial facility requires 0.35MW of capacity by 2027, requiring ~0.3km of expansion from the existing 13.8kV distribution lines in the area.	OTC in progress
19	Whitby	2027	3	\$0.25M	Two large commercial customers on adjacent sites require a combined capacity of 3 MW by 2027. To accommodate this load demand, approximately 1 km of feeder expansion from the 44 kV distribution system is required. This expansion will provide the necessary electrical capacity and system connectivity to support the customers' service requirements.	OTC in progress

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CCC

JT1.5

QUESTION:

CONFIRM WHETHER THE CABLE LISTED IN EXHIBIT 1, TAB 5, SCHEDULE 2 WOULD FALL INTO THE WIRE AND CABLE CATEGORY IN TABLE 1 OR ONE OF THE OTHER CABLES LISTED IN TABLE 2.

RESPONSE:

Elexicon understands that the scope of this undertaking is limited to the Church Substation Cable Replacement Project listed in Exhibit 1 – Tab 5 – Schedule 2. The Church SS Cable Replacement project, identified within 2-CCC-19 Attachment 1, had a variance description of “the variance is primarily attributable to higher-than-estimated material costs, particularly underground cable, relative to the estimate prepared in 2019 and construction executed in 2023”.

It is confirmed that the underground cable associated with this project would fall into Table 2 of the Impacts of Inflationary Pressure in Exhibit 1 – Tab 5 – Schedule 2 – Page 2 (Station Equipment Increases). Additionally, it should be noted that this project was estimated in 2019 prior to the significant price increases that followed as captured Table 2, which contributed to the variance between the estimate in 2019 and actual construction costs in 2023.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CCC

JT1.6

QUESTION:

PROVIDE A MORE DETAILED RATIONALE, INCLUDING ANY INTERNAL DOCUMENTATION, FOR THE PROJECTS WHERE THE EXPLANATION IS VARIANCE ATTRIBUTABLE TO LABOUR AND MATERIAL COSTS EXCEEDING THE ORIGINAL ESTIMATE.

RESPONSE:

Please see the attached Excel file, JT_1.6(1) - Project Variance Descriptions, for a more detailed explanation for projects where the variance is attributable to labour and material costs exceeding the original estimate.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CCC

JT1.7

QUESTION:

PROVIDE THE BREAKOUT OF THE TEN TRANSFORMERS THAT ARE BEING ASSESSED TO BE REPLACED BY 2031 AND WHAT THEIR CONDITION IS AS BETWEEN FAIR, GOOD, OR VERY GOOD.

RESPONSE:

Table 1 below lists the 10 transformers included in the 2027–2031 investment plan that are currently assessed to be in fair or better condition.

Table 1: Transformers in Fair or Better Condition in the Substation Renewal 2027-2031 Plan

Project	Asset ID	Service Age	HI Category
Fairport MS	FAIRPORT-T1	51	Fair
	FAIRPORT-T2	51	Fair
Edgehill MS	EDGEHILL-M.S.5-T1	64	Good
	EDGEHILL-M.S.13-T2	33	Fair
Garden MS	GARDEN-T1	34	Good
Crandell MS	CRANDELL-T1	58	Fair
Riverside MS	RIVERSIDE-M.S.4	61	Fair
Uxbridge East MS	UXBRIDGE EAST-T1	61	Fair
Town Centre MS	TOWN CENTRE-T1	53	Fair
	TOWN CENTRE-T2	35	Fair

Replacement of these transformers is primarily driven by broader substation rebuild requirements, where most other station assets are at or near end-of-life, in poor or very poor condition, or present safety, operational, or configuration constraints (see Elexicon’s response to IR 2-Staff-55 part f, and the program evidence in Exhibit 2B – Tab 4 – Schedule 3 – Appendix E for additional details).

In addition to being replaced as part of full substation rebuilds, transformers assessed to be in fair condition are also considered for replacement where the asset criticality and consequence-of-

1 failure considerations indicate that continued operation presents an increasing risk to reliable
2 service, as noted in the ACA Report (Exhibit 2B, Tab 3, Schedule 2, Appendix B, p. 71). Substation
3 transformer failures can result in the distribution system operating under contingency conditions
4 for an extended period while repairs are completed or a replacement unit is procured and installed.
5 Given the long procurement timelines associated with power transformers, this contingency state
6 may persist for a considerable duration.

7
8 During this period, neighboring substations may be required to serve significantly more customers
9 than normal, reducing overall system resilience and operational flexibility. Should an additional
10 failure occur while the system is operating in this contingency state, the ability to maintain service
11 to all customers may be compromised, potentially resulting in rotating outages or a sustained
12 outage until the service is restored. Accordingly, Elexicon's Substation Renewal asset replacement
13 strategy considers the replacement of these critical assets before they reach poor condition, and
14 present a highly elevated risk of reactive failure.

15
16 In the case of Edgehill T1, although the transformer is assessed to be in good condition, the
17 transformer is 64 years old, exceeding its typical useful life by 19 years. Due to its age and critical
18 importance in the system, continued operation of this asset presents an elevated risk of failure that
19 needs to be mitigated to preserve safety and reliability. In addition, Edgehill T1 utilizes a pothead
20 cable termination, a legacy design that has been associated with catastrophic failures modes.
21 Elexicon experienced such a failure at another substation in 2025, where the event resulted in the
22 projection of metal shrapnel and insulating oil throughout the substation. Replacement of the
23 transformer and associated pothead termination will eliminate this risk and improve overall
24 substation safety and reliability.

25
26 In the case of Garden T1, the replacement rationale extends beyond just transformer T1 itself and
27 reflects the condition and operational risks associated with the broader substation. The
28 substation's switchgear lineup is in poor condition, and the bus tie breaker is out of service, limiting
29 operational flexibility and reducing the substation's ability to manage contingency events. As a

1 result, a failure of Garden T1 would present an increased risk of customer outages, as the
2 substation's ability to reconfigure to maintain service during equipment failures is constrained.
3 Given the overall condition of key substation assets and the operational limitations associated with
4 the existing configuration, a substation rebuild, which includes the transformer, is the prudent and
5 necessary solution to mitigate the elevated reliability and safety risks posed these critical assets.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CCC

JT1.8

QUESTION:

ADVISE OF THE DIFFERENCE IN UNIT COST BETWEEN CABLE INJECTION AND CABLE REPLACEMENT

RESPONSE:

Table 1 below provides the forecasted per metre unit cost associated with cable injection and cable replacement investments over the 2027 to 2031 period.

Table 1: Forecasted Annual Unit Costs for Cable Injection and Cable Replacement per Metre

	2027	2028	2029	2030	2031
Cable Replacement (\$/M)	N/A ¹	\$541	\$577	\$620	\$642
Cable Injection (\$/M)	\$120	\$128	\$137	\$147	\$152

¹ Elexicon has not planned any cable replacement projects in 2027 as part of the Balanced investment plan. As a result, no representative unit cost is included.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CCC

JT1.9

Ref: 4-CCC-41, Attachment 1

QUESTION:

EXPLAIN WHAT DAMAGE PREVENTION AND INSPECTION ACTIVITY IS.

RESPONSE:

The Damage Prevention and Inspection budget line item represents the administrative and technical activities necessary to support the Elexicon's inspection and maintenance program. These activities, which are performed by non-field staff, include the review and analysis of inspection reports, assessment of inspection findings, identification of future inspection requirements, maintenance of the inspection records, and coordination of program activities. This work supports the effective planning, prioritization, and management of inspections, helping ensure the ongoing monitoring and maintenance of distribution system assets.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CCC

JT1.10

Ref: 4-CCC-41 Attachment 1 Maintenance Dx System (excel)

Question(s):

Provide a normalized 2025 that is comparable to the future period and provide an explanation as to what was done.

RESPONSE:

Please refer to Attachment JT_1.10(1)_Maintenance Dx System Normalized Costs, which includes the normalized costs for 2025 expenditures included in the referenced Excel attachment previously filed in response to 4-CCC-41. To normalize annual expenditures, the cumulative pole testing cost of \$1,022,885, reported as a 2025 actual due to the recognition in OM&A of historical pole testing costs that had previously been capitalized, were redistributed and averaged across the 2020–2024 period to better reflect the expenditures incurred in each year. Elexicon did not perform any pole testing activities in 2025 due to budgetary constraints; accordingly, no pole testing expenditures are reflected in 2025 following normalization.

In addition, the Historical Costs Write-Off of \$698,623 related to capital projects that did not materialize was removed to ensure that 2025 actual expenditures more accurately reflect ongoing distribution maintenance program segment costs. As a result, the normalized 2025 maintenance expenditure of \$3.01M is more representative of ongoing annual maintenance activities and provides a more meaningful basis for comparison to the forecast expenditures for 2026–2031.

Furthermore, Elexicon notes that it's necessary to consider its operating conditions when attempting to compare 2025 and 2026 OM&A expenditures to future years. Elexicon has been managing challenging operational circumstances which have driven the need for investment above levels of funding in rates driving significant financial constraints and under-earning for the organization. These

1 funding constraints have impacted the level of spending in historical and bridge years. Several
2 maintenance and inspection programs, including pole testing, insulator washing, single-phase pad-
3 mounted transformer inspections, and solid blade switch maintenance programs were unfunded or
4 underfunded in 2025. As a result, the actual costs reported for these programs reflect the reduced
5 scope of work relative to program requirements and the level of work that Elexicon was able to
6 execute during the year within the available funding envelope. Consequently, OM&A expenditures
7 increase in the early forecast period to address maintenance backlog from prior years, expand the
8 scope of certain maintenance programs such as insulator washing, and add labour resources to
9 support enhancements to existing maintenance activities, including overhead distribution system
10 patrols.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CCC

JT1.11

Question(s):

PROVIDE THE HISTORICAL ACTUALS FOR THE PERIOD OF 2020 TO 2025 FOR THE EQUIVALENT OF TABLE 4 IN EXHIBIT 4, TAB 1, SCHEDULE 4

RESPONSE:

Ellexicon interprets this undertaking as requesting the historical planned positions and actual FTE levels for the period 2020–2025 for the equivalent of Table 4 in the response to 10-CCC-71(g) and Table 6 in the response to 10-CCC-71(h).

As described in Exhibit 10 - Tab 2 - Schedule 1, p 1, lines 6 - 8, the information below relates solely to the SCC component of the Control Centre segment and does not include the Emergency Management or Asset Records functions.

Accordingly, Table 1 below presents the planned SCC internal and external staffing positions for the period 2020–2025 (as of Dec 31st for each year), representing the historical information that corresponds to Table 4 of the response to 10-CCC-71(g). Table 2 provides actual FTE levels for the positions included in Table 1 for the historical period. The FTE values in Table 2 represent the calendarization of the positions and may differ from the number of positions shown in Table 1, as FTEs reflect the portion of the year each position was filled based on full-time annual hours. For example, a full-time position filled for six months of the year would be reflected as 0.5 FTE.

1

Table 1: SCC Internal and External Staffing Planned Positions (2020 to 2025)

Year	Apprentice	Qualified Operator	Sr. System Operator	Dispatcher	Supervisor	Trainer	Training Coordinator (Contractor)	P&P Coordinator (Contractor)	Analyst	Student	Qualified Operators (Contractor)
2020	1	7	1	0	1	0	0	0	0	0	0
2021	1	9	1	0	1	0	0	0	0	0	0
2022	1	9	1	0	1	1	0	0	0	0	0
2023	2	8	1	0	1	1	0	0	0	1	1
2024	6	4	1	0	1	1	0	0	1	1	1
2025	7	3	1	0	2	1	0	0	1	1	3

2

3

Table 2: SCC Internal Staffing Actual FTEs (2020-2025)

Year	Apprentice	Qualified Operator	Sr. System Operator	Dispatcher	Supervisor	Trainer	Analyst	Student
2020	0.8	5.9	1	0	1	0	0	0
2021	0.0	7.8	1	0	1	0	0	0
2022	0.6	7.1	1	0	1	1	0	0
2023	1	5.2	0.6	0	0.1	0.7	0	0.2
2024	4.8	3.9	1	0	0.9	0.6	0.2	0.6
2025	5.4	1.6	0.9	0	1.6	0.6	0.9	0.2

4

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CCC

JT1.12

QUESTION:

ADVISE WHAT IS DRIVING THE DIFFERENCE BETWEEN THE PROPOSAL OF \$30 MILLION AND THE ESTIMATED COST ABOUT THREE MONTHS AGO OF \$22 MILLION FOR OPTION C

RESPONSE:

The approximately \$22M estimate for Option C was a preliminary, high-level figure prepared by Operations to support initial decision-making, prior to Finance review. Throughout this process, the underlying staffing plan and implementation approach under Option C remained unchanged, including paced hiring to achieve a total complement of 15 Qualified Operators by 2031 and a reduction in contractor resources to one contractor position by 2031. Ellexicon's Executive Leadership Team (ELT) approved Option C with the understanding that the preliminary cost would be refined as assumptions were validated and costing was further developed. The ELT was kept informed of material updates throughout the process.

The approximately \$8M increase that resulted in the updated cost of approximately \$30M is primarily attributable to the refinement of labour costs and the inclusion of additional compensation-related costs that were not fully reflected in the preliminary estimate.

The costs for the other options in the table were prepared using the same preliminary costing assumptions. These refinements did not alter the staffing plan or implementation approach approved by the ELT. The increase is attributable to the following factors:

- Replacement of preliminary costs based on planning-level labour assumptions developed by Operations, with updated costs that reflect Finance-validated budgeted salary rates: \$2.93M
- Addition of Labour burden costs (69% of labour costs in 2027 and 2028, 68% of labour costs in 2029 to 2031): \$4.57M

- 1 • Addition of Market Compensation Adjustment of \$30,000 for Qualified Operators, Sr. System
2 Operators and Apprentice Operators, consistent with the response to 10-SEC-103(a):
3 \$1.89M
- 4 • Partially offset by lower contractor rates resulting from refined cost assumptions relative to
5 those used in the preliminary cost: (\$1.48M)
- 6
- 7 Collectively, these refinements increased the cost of Option C by approximately \$8M, resulting in the
8 updated cost of approximately \$30M.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SEC

JT1.13

QUESTION:

PRODUCE THE ASSOCIATED PRIORITIZATION RESULTS FOR EACH OF THE PROJECTS THAT HAVE BEEN PUBLISHED THUS FAR FOR THE 2027 PERIOD AND THE CORRESPONDING MATH ON HOW THOSE SCORES WERE DERIVED.

RESPONSE:

Please refer to the excel file attachment JT_1.13(1) Project Prioritization Results for the project prioritization results and the associated project prioritization variable scores for the projects that have been published thus far for the 2027 period. Please refer to the Prioritization Process provided within interrogatory response 2B-SEC-46 Attachment 1 – Prioritization Process for the methodology used to create a project criticality score.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SEC

JT1.14

Question(s):

ADVISE WHETHER A SECOND EMERGENCY MANAGEMENT SPECIALIST POSITION IS BEING ADDED IN 2026

RESPONSE:

No, a second Emergency Management Specialist position is not being added in 2026. The 2026 plan reflects one Emergency Management Specialist position for the System Control Centre. This position is a vacancy from 2024. The position was filled and vacated in 2024 and since then the related work has been completed by a third-party contractor until the vacancy can be filled.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SEC

JT1.15

QUESTION:

PROVIDE ANY INFORMATION REGARDING THE NUMBER OF QUALIFIED OPERATORS, APPRENTICES, AND DISPATCHERS THAT TORONTO HYDRO AND ALECTRA HAVE IN THEIR CONTROL CENTRE

RESPONSE:

Elexicon understands this undertaking request to be for publicly available information regarding the number of Qualified Operators, apprentices, and dispatchers in the control centres of Toronto Hydro and Alectra.

In response to 4-CCC-71(i), Elexicon referenced an internal review of the resourcing requirements in the System Control Centre function within the Control Centre OM&A segment, including consideration of staffing approaches used by comparator utilities.

Toronto Hydro's evidence describes dispatchers as a separate function that supports control room operations through communications intake, event triage, stakeholder communications, resource coordination, and crew dispatch. During major events, dispatchers may be assigned specific responsibilities to manage increased call volumes and coordinate field resources. (Toronto Hydro, EB-2023-0195, Exhibit 4 - Tab 2 - Schedule 5, Sections 3.1 and 3.1.1).

Elexicon also reviewed Alectra Utilities' evidence regarding System Control staffing. Alectra identified the number of field crews supported as a key driver of operator requirements and developed its System Control resource forecast based on the resources required to execute its capital investment portfolio while maintaining 24/7/365 control room operations. Alectra's 2031 System Control Resource Forecast identifies 136 field crews, 77 operators required, and a total operator

1 complement of 80, equivalent to approximately 1.7 to 1.8 crews per operator.¹ While Elexicon did
2 not rely on Alectra's staffing levels as a benchmark, Alectra's evidence corroborates that operator
3 requirements increase as the field crew complement grows.
4
5 Elexicon's planning assumption that a fully Qualified Operator can safely and efficiently support two
6 to three crews is within a comparable range and reflects Elexicon's operational circumstances,
7 planned work program, and System Control Centre operating model.
8
9 Alectra's evidence also indicates that System Control Operators complete a four-year apprenticeship
10 program. (Alectra Utilities, EB-2025-0252, Exhibit 4 - Tab 2 - Schedule 9, p.7–9).

¹ EB-2025-0252, Alectra Utilities Corporation, 2027 Rebasing Application, Exhibit 4-Tab 2-Schedule 9, page 9, Chart 4-2-8.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SEC

JT1.16

QUESTION:

PROVIDE THE OEB'S TARGETS BASED ON THE RELIABILITY PERFORMANCE TARGETS FOR EACH YEAR THROUGH 2031 AND THE CALCULATIONS

RESPONSE:

The Ontario Energy Board (OEB) reliability performance targets are established in accordance with its October 3, 2025, letter¹. For 2027 rates, the OEB has derived baselines using 2020–2024 data and applied annual improvement factors. For Elexicon, these improvement targets are set at 0.25% for both SAIFI and SAIDI.

As noted in the OEB letter, for rebasing applications beyond 2027, the OEB will update historical trends and benchmarking results using the most recent data (e.g., 2028 rates will be based on 2021–2025 data). Accordingly, Elexicon can determine performance targets for 2027 and 2028 using this prescribed methodology in Tables 1 through 4 below but cannot establish targets for subsequent years until the relevant historical averages are available.

As noted in the OEB letter, “As outlined in the January 2025 letter, distributors can propose alternative targets aligned with their proposed investment plans in their rebasing application.” Elexicon has adopted this approach, as described in Exhibit 2B - Tab 2 - Schedule 2 - Section 1.2 - pages 7–11.

¹ Ontario Energy Board Letter, “Reliability Performance Targets for Electricity Distributors”, (October 3, 2025)

Table 1: SAIDI 2027 Performance Target

Performance Measure	5-Year Average (2020-2024)	Target (2027)
SAIDI (Excluding MED and LOS)	1.47	1.46

Table 2: SAIDI 2028 Performance Target

Performance Measure	5-Year Average (2021-2025)	Target (2028)
SAIDI (Excluding MED and LOS)	1.60	1.59

Table 3: SAIFI 2027 Performance Target

Performance Measure	5-Year Average (2020-2024)	Target (2027)
SAIFI (Excluding MED and LOS)	1.09	1.08

Table 4: SAIFI 2028 Performance Target

Performance Measure	5-Year Average (2021-2025)	Target (2027)
SAIFI (Excluding MED and LOS)	1.16	1.15

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SEC

JT1.17

QUESTION:

CLARIFY THE IMPACT OF THE PROBABILITY ASSESSMENT AND THE HEALTH INDEX ON SYSTEM
SERVICE PROJECTS IN CASES WHERE AN ASSET IS NOT BEING REPLACED.

RESPONSE:

For projects that do not involve asset replacements, such as certain System Service initiatives,
Elexicon assigns a Health Index (HI) of 85% (Very Good) to a project, which corresponds to a
Probability Score of 0.15.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SEC

JT1.18

QUESTION:

PRODUCE THE 2026 LIST OF PROJECTS WITH THEIR CRITICALITY SCORES AND THE INPUTS TO THOSE CRITICALITY SCORES, AND ADVISE WHICH PROJECTS ARE IN AND WHICH ARE OUT OF THE 2026 PROGRAM.

RESPONSE:

Please see Excel file attachment JT_1.18(1) 2026 Project List for the 2026 list of projects with the associated criticality scores and the inputs to those criticality scores along with information on which projects are in or out of the 2026 program. Please refer to the Prioritization Process provided within interrogatory response 2B-SEC-46 (Attachment 1 – Prioritization Process) for the methodology used to create a project criticality score.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VECC

JT1.19

QUESTION:

PROVIDE LINKS TO THE MUNICIPAL PLANNING DOCUMENTS THAT ARE USED IN THE PEAK LOAD
FORECAST AND COMPARE THE SOURCES IN THE PEAK LOAD FORECAST AND THE REVENUE
FORECAST TO CONFIRM WHETHER OR NOT THEY ARE THE SAME

RESPONSE:

Table 1 provides the sources and comparison of the municipal planning documents used in the
Peak Load Forecast and the Revenue Load Forecast.

1 **Table 1: Peak Load Forecast vs. Revenue Load Forecast Sources for Customer Growth**

Area	Peak Load Forecast (Exhibit 2B, Tab 3, Schedule 1)	Revenue Load Forecast (Exhibit 3, Tab 1, Schedule 1)	Comparison
Durham Region	Envision Durham (2024): https://www.durham.ca/media/00sign4c/approved-durham-rop-2024.pdf	Monitoring of Growth Trends (2024): https://pub-durhamregion.escribemeetings.com/filestream.ashx?DocumentId=5623 Update included in Ellexicon’s interrogatory response to 3-SEC-68, Monitoring of Growth Trends (2025): https://www.durham.ca/media/bd0pidpt/2025-info-93-monitoring-of-growth-trends.pdf	The Peak Load Forecast and the Revenue Load Forecast utilize different municipal planning reports. Envision Durham provides long-term population, housing, and employment forecasts used to support the Peak Load Forecast, while the Monitoring of Growth Trends report monitors historical growth trends and provides a shorter-term outlook suitable for the Revenue Load Forecast. Both reports are produced by Durham Region and are appropriate for the intended use of each forecast.
Belleville	Population, Housing, and Employment Growth Forecast Update – City of Belleville (2022): https://www.belleville.ca/media/10cd421a/city-of-belleville-2022-growth-forecast-update-final-report-december-21.pdf	Official Plan (2021): https://opencouncil.ca/wp-content/uploads/2024/10/City-of-Belleville-OP-BL-2021-180-As-Amended-Oct-1-2025.pdf Asset Management Plan (2024): https://opencouncil.ca/wp-content/uploads/2024/10/City-of-Belleville-AM-Plan-2024.pdf	The Peak Load Forecast and the Revenue Load Forecast utilize different municipal planning reports. Growth projections are shared amongst all reports. The Peak Load Forecast and the Revenue Load Forecast each utilize different and

		content/uploads/2024/08/Belleville-Asset-Management-Plan-Current-Levels-of-Service-June-2024.pdf	appropriate long-term population and housing growth scenarios that are relevant to each forecast.
Port Hope	Amendment No. 2 to the Official Plan for Northumberland County (2025): https://joinin.northumberland.ca/16424/widgets/222688/documents/169406	Official Plan Review (2017): https://www.porthope.ca/en/business-and-development/resources/Official%20Plan/Official%20Plan%202017%20(9).pdf	The Peak Load Forecast and the Revenue Load Forecast utilize different municipal planning reports. The Revenue Load Forecast utilizes the Port Hope Official Plan, whereas the Peak Load Forecast utilizes the Amendment to the Northumberland County Official Plan.
Gravenhurst	Growth Strategy – District of Muskoka (2024): https://muskoka.civicweb.net/document/42481/	Growth Strategy – District of Muskoka (2024): https://muskoka.civicweb.net/document/42481/	The Peak Load Forecast and Revenue Load Forecast rely on the District of Muskoka Growth Strategy.

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TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VECC

JT1.20

QUESTION:

PROVIDE THE METRICS FOR THE HISTORICAL PERIOD BY DISTRICT

RESPONSE:

Please refer to Tables 1 through 5 below for the SAIDI, SAIFI and FESI7 results by district from 2020 to 2025. Note that Elexicon reports and sets targets at the system level, which includes the entire Elexicon service territory and customer base. The system-level SAIDI and SAIFI values, weighted by district, are presented in Tables 2 and 4 below.

Table 1 —Elexicon SAIDI by District

Districts	2020	2021	2022	2023	2024	2025
Ajax-Pickering	0.78	1.12	1.36	1.14	1.85	1.56
Belleville	0.70	1.26	2.50	1.65	0.89	1.94
Brock	1.25	2.93	3.38	3.39	0.90	2.35
Clarington	3.09	0.42	0.84	0.75	0.93	2.53
Gravenhurst	5.42	5.45	10.12	7.43	5.41	12.97
Whitby	1.19	0.71	0.95	0.81	1.77	0.97

Table 2 —Elexicon System Cumulative SAIDI Weighted by District

Districts	2020	2021	2022	2023	2024	2025
Ajax	0.331	0.475	0.575	0.483	0.788	0.669
Belleville	0.074	0.132	0.260	0.170	0.091	0.198
Brock	0.049	0.117	0.133	0.131	0.034	0.089
Clarington	0.396	0.054	0.107	0.095	0.116	0.313
Gravenhurst	0.205	0.205	0.377	0.275	0.200	0.482
Whitby	0.315	0.188	0.257	0.220	0.480	0.263

Table 3 — Elexicon SAIFI by District

Districts	2020	2021	2022	2023	2024	2025
Ajax-Pickering	0.81	0.98	1.40	1.09	0.98	1.50
Belleville	1.01	1.57	1.14	1.22	1.27	1.49
Brock	0.40	0.73	1.49	0.82	0.46	1.38
Clarington	1.45	1.43	0.64	1.07	0.95	1.23
Gravenhurst	1.62	1.13	1.82	1.64	3.66	2.36
Whitby	1.14	1.06	1.00	0.56	1.26	1.73

Table 4 — Elexicon System SAIFI Weighted by District

Districts	2020	2021	2022	2023	2024	2025
Ajax	0.331	0.475	0.575	0.483	0.788	0.669
Belleville	0.074	0.132	0.260	0.170	0.091	0.198
Brock	0.049	0.117	0.133	0.131	0.034	0.089
Clarington	0.396	0.054	0.107	0.095	0.116	0.313
Gravenhurst	0.205	0.205	0.377	0.275	0.200	0.482
Whitby	0.315	0.188	0.257	0.220	0.480	0.263

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Table 5 — FES17 by districts

Districts	2020	2021	2022	2023	2024	2025
Ajax	0.331	0.475	0.575	0.483	0.788	0.669
Belleville	0.074	0.132	0.260	0.170	0.091	0.198
Brock	0.049	0.117	0.133	0.131	0.034	0.089
Clarington	0.396	0.054	0.107	0.095	0.116	0.313
Gravenhurst	0.205	0.205	0.377	0.275	0.200	0.482
Whitby	0.315	0.188	0.257	0.220	0.480	0.263

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TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO BOMA

JT1.21

QUESTION:

PROVIDE THE NUMBERS USED TO GENERATE THE WINTER PEAK NUMBERS IN FIGURE 9 IN EXHIBIT 2B, TAB 3, SCHEDULE 1

RESPONSE:

Please see Table 1 below for the Winter System Peak Load Forecast, as per Figure 9 in Exhibit 2B, Tab 3, Schedule 1.

Table 1: System Peak Load Forecast Winter 2024-2031

Peak Load (MW)	2024	2025	2026	2027	2028	2029	2030	2031
System Level - Winter	590	704	752	795	839	883	929	970

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO BOMA

JT1.22

QUESTION:

PROVIDE A SUMMARY INCLUDING THE SUBCATEGORIES IN SECTION 4.1, 4.2, 4.3, 4.4, AND ADVISE WHICH LOAD FORECAST DRIVES IT.

RESPONSE:

Please refer to Table 1, below, which outlines the load forecast that drives each specific investment program, where applicable.

1 **Table 1: Specific Load Forecast Driver for each Investment Program**

Investment Category	Investment Program	Load Forecast Utilized
System Access	A1 Externally-Initiated Plant Relocation	N/A
	A2 Customer & Generation Connections	Revenue Load Forecast (Exhibit 3, Tab 1, Schedule 1)
	A3 System Expansion	Driven by customer-specific requests ¹
	A4 Metering and AMI 2.0	N/A
General Plant	P1 Facilities Management & Security	N/A
	P2 Fleet	
	P3 IT Systems	
	P4 Equipment	
	P5 OT Systems	
System Renewal	R1 Substation Renewal	N/A
	R2 Underground System Renewal	
	R3 Overhead System Renewal	
	R4 Reactive Capital	
System Service	S1 Substation Growth	Peak Load Forecast (Exhibit 2B, Tab 3, Schedule 1)
	S2 Grid Enhancements	Peak Load Forecast (Exhibit 2B, Tab 3, Schedule 1)
	S3 Voltage & System Conversion	Peak Load Forecast (Exhibit 2B, Tab 3, Schedule 1)

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3 The capacity investments that form part of the System Service investment category address

4 existing capacity constraints; the sensitivity scenarios of the Peak Load Forecast, i.e., low, medium,

5 and high, have no implications on Elexicon's capacity investments in this category.

¹ The customer requests are also an input to the Revenue Load Forecast (Exhibit 3, Tab 1, Schedule 1).