RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1-CCC-1

Ref: Exhibit 1, Tab 5, Schedule 2, Attachment 1-2, pp. 14-15

Question(s):

a) A large number of letters of comment opposing Alectra's proposed rate increase were filed on the record. Please explain how these letters from Alectra's customers reconcile with Alectra's customer engagement results in the table on p. 15 of Exhibit 1, Tab 5, Schedule 2, Attachment 1-2.

b) Please explain why Innovative Research Group provided survey respondents with three options in support of the plan and only one option that opposes the plan.

c) Please confirm that the majority of residential customers either responded that they "don't like the proposed increase" or opposed the bill increase.

RESPONSE:

Responses prepared by Innovative Research Group:

a) While every customer's individual viewpoint is valid and should be treated with respect, letters submitted to the hearing are not the result of a systematic sampling of customers. Alectra has over 1 million customers. Based on the social permission measure in the engagement, there are likely over 90,000 customers who oppose this rate increase. The letters of opposition likely come from those customers.

b) Please see the response to interrogatory 1-SEC-09.

c) We would not group those two categories together as that distorts the meaning of "I don't like the proposed bill increase, but I think it's necessary to maintain the grid to a reasonable standard and prepare for the future".

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1-CCC-2

Ref: Exhibit 1, Tab 6, Schedule 2, Attachment 1-3, pp. 15-16, 20, 27-28

Question(s):

a) Please advise whether Clearspring was aware, at the time that it was preparing its evidence with respect to the revenue escalation formula, that Alectra intended to propose a Price Cap approach to incentive ratemaking.

b) Please further explain the statement "the reason for not including a G Factor or IPD term for capital is that we understand the Company is proposing to escalate capital revenue using a Capital Factor, which already implicitly includes a G Factor and IPD…" As part of the response, please confirm that the Capital Factor already directly captures the cost escalation associated with forecast inflation.

c) In the context that the Capital Factor implicitly captures forecast inflationary pressure on capital expenditures, please provide Clearspring's view on the application of the OEB's inflation factor in a Price Cap IR formula (i.e., inflation will be applied to rates which reflect cost recovery for both capital and OM&A). As part of the response, please discuss whether an additional term in the CPCI formula designed to ensure that the OEB's inflation factor applies only to the OM&A portion of rates is beneficial to avoid the potential for double counting inflation applicable to capital.

d) Please provide all of the values used in the "% labour in OM&A" calculation (i.e., salaries + wages, pension + benefits, total OM&A and OM&A outside services).

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e) Please provide all of the values required to perform the same calculation for % labour in capital expenditures.

RESPONSE:

Response prepared by Clearspring

a) Yes, Clearspring was aware. The theoretical and mathematical escalation parameters shown in Section 4 of the Clearspring Report are relevant under a price cap construct. Please also see Clearspring's response to 1-SEC-21 (e).

b) It is Clearspring's understanding that Alectra examined the capital projects the Company needs to undertake and calculated the plant additions to meet those needs. In that examination, both anticipated growth and inflation factored into those stated needs. In regard to cost escalation associated with forecasted inflation, the Company used a 2% asset price inflation assumption. Based on Clearspring's knowledge, this has been the standard approach in Custom IR applications. However, assuming only 2% asset price growth is, historically speaking, a low value. The historical inflation rates over the last two decades of Handy-Whitman indexes for the electric distribution industry in the United States have been around 6%. These historical inflation rates will continue to put considerable upward pressure on the rate base of all electric distributors for the foreseeable future.

c) It is Clearspring's understanding that there was a 2% "Inflation back-off" on the increase for the full revenue requirement found in *Table 1-11-4: RGF* in the Company's application. The OM&A IPD is only applied to OM&A revenue escalation. We do not see the need for an added term. Please see part (b) of this response for our view on the inadequacy of the asset price assumption of 2% and the ability of the Board's Inflation Price Index to properly account for asset price inflation.

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d) Please see the Clearspring working papers. The Excel file “Dataset Alectra.xls”, workbook “IPD OM&A”, columns C and D, will contain this information.

e) Clearspring does not have the information available for this calculation. A similar calculation for capital would not be appropriate. Capital asset price inflation is best calculated using the Handy-Whitman Indexes specific to electric distribution. These would imply a far higher IPD on capital. Clearspring estimates that a capital IPD would be around 4% and would have low sensitivity to projected asset price inflation rates during the custom IR years given the embedded nature of historically high asset price inflation within an electric distributor’s rate base.

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RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1-CCC-3

Ref: Exhibit 1, Tab 6, Schedule 4, pp. 1-2, 10-11, 13-14
Exhibit 1, Tab 9, Schedule 1, pp. 3-4

Question(s):

a) Please confirm that the annual sustained productivity-related savings discussed in Exhibit 1, Tab 6, Schedule 4, p. 10 ($23.2M) are incremental to the annual sustained merger-related savings described at Exhibit 1, Tab 9, Schedule 1, p. 4 of $44.3M.

b) Please further discuss the decision to "finalize the synergy forecast based on Q1 2021 results…" in the context of the savings shown in Table-1-9-1. More specifically, please explain how the post-2020 savings in Table-1-9-1 were derived.

c) Please explain, and provide a detailed calculation, for the $23.2M of annual sustained savings during the CIR term (2027-2031). As part of the response, please advise whether incremental capital costs were incurred to achieve the savings. If so, please discuss how those costs were reflected in the savings calculation.

d) Please advise whether the $23.2M of annual sustained savings is a revenue requirement figure. If not, please provide the revenue requirement figure associated with the annual sustained savings.

e) For each of the initiatives listed in Table 1-6-34, please provide the annual sustained savings amount that continues into the CIR term (2027-2031).

f) Where applicable, for each of the initiatives listed in Table 1-6-34, please provide the capital cost incurred to achieve the savings.

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g) Please provide, with specific references to the evidence, where the $23.2 of annual sustained savings is reflected as an offset to the revenue requirement for the CIR term. In the circumstance that these savings are applied as offsets to specific capital and operational forecast budgets proposed for the CIR term, please provide the proposed budgets by program (both with and without the application of the sustained savings).

h) While the descriptions of the various initiatives are helpful (Exhibit 1, Tab 6, Schedule 4, pp. 11-23), please provide detailed calculations supporting the cost savings shown in Table 1-6-34 (i.e., the baseline period costs, any adjustments made to the baseline costs, and the reported period costs). With respect to the baseline period costs, please show the derivation of those costs.

RESPONSE:

a) Alectra Utilities confirms that the annual sustained productivity-related savings discussed in Exhibit 1, Tab 6, Schedule 4, p. 10 ($23.2M) are incremental to the annual sustained merger-related savings described at Exhibit 1, Tab 9, Schedule 1, p. 4 of $44.3MM.

b) By the end of 2020, most integration initiatives and projects were substantially complete. The organization consequently transitioned to a unified operational approach with an emphasis on continuous cost performance improvement through post-consolidation productivity and efficiency initiatives.

The post-2020 savings in Table 1-9-1 reflect Alectra's forecast of ongoing, sustained merger savings developed after 2020. Labour synergies, the largest component, were derived through headcount tracking against the merger business case and expected timing to achieve the remaining planned workforce reductions. These remaining roles are primarily focused within Customer Service and are contingent upon the schedule of the Guelph CIS integration. The forecast for these positions has been revised to accurately reflect the timeline available at the time of this application. The remaining operating and

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capital synergies reflect forecasted savings that have been quantified and are sustained into the future, based on both realized and projected savings.

c) Please refer to 1-SEC-12, 1-SEC-12_Attach 1_Framework Initiatives.xlsx for the savings for the Framework Initiatives updated with 2025 actuals during the forecast period including a detailed explanation of the methodology used to calculate the savings. The $23.2MM of sustained savings, is a subset of the total 2026 savings of $26.6MM; the delta represents savings that do not persist in the forecast period.

Incremental capital costs were incurred on capital projects as required to achieve the planned outcomes of the projects which included but not limited to the financial benefits claimed as productivity savings. Please see table 1 below for the capital costs and associated investment drivers for the projects. The capital costs are not reflected in the savings as reported savings in the evidence are gross savings.

d) The $23.2MM of annual sustained savings is not a revenue requirement figure. As described in Ex. 1-6-4, page 8, the benefits achieved through the Framework Initiatives consist of achieved or expected cost reductions (which result in reductions to OM&A and/or capital expenditures that would otherwise be required), avoided costs (which represent OM&A and/or capital expenditures that would have otherwise been required to deliver Alectra's work programs), and efficiency benefits (such as productivity improvements that allow tasks to be completed more efficiently or effectively, allowing existing resources to absorb additional demands). All of these benefits are embedded in the historical and forecast expenditures presented in this application. The approximate revenue requirement associated with the expected cost reduction and avoided cost from the cumulative 2027-2031 productivity benefits can be estimated at $92.4MM ($87MM of OM&A cumulative expected reduction and cost avoidance benefits, plus 8% of the $67.9MM in Capital Expected reductions and avoided costs as per 1-SEC-12_Attach 1_Framework Initiatives.xlsx).

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e) Please see 1-SEC-12_Attach 1_Framework Initiatives.xlsx for the annual savings during the forecast period, updated with 2025 actuals. With the exception of MyAlectra portal and the Metering renewal technology which include incremental savings as described in 1-STAFF-29 (b), all other savings are sustained savings.

f) Alectra does not track project costs only related to productivity savings. Capital costs were incurred on capital projects as required to achieve the planned outcomes of the projects which include the financial productivity savings. Table 1 below lists the capital costs incurred up to 2026 for the projects that led to Framework Initiative productivity benefits as well as summarizing the investment drivers for the capital projects. Initiatives which did not incur capital costs show "-" in the table.

Table 1- Framework Initiative Enabling Capital Costs & Project Investment Drivers

Initiative	Capital Costs $MM	Capital Investment Needs and Drivers
Locates	-	
ERP Continuous Improvement	9.2 (2022-2026)	Mitigate the risk of software failure, disruption to business processes, non-compliance with regulatory requirements, cyber security exposure and compatibility issues with third party applications and systems (Exhibit 2A, Tab 1, Schedule 1, Appendix B09 – Information Technology Systems, Page 354)
Business Optimization - ServiceNow Expansion	0.7 (2021-2023)	Enhance the IT asset management system, employee IT support system, and support the management and optimization of software licenses.
Central Consolidation (Kennedy Operations Center)	123.8 (2019-2024)	Mitigate asset risks and deficiencies at the Sandalwood and Mavis facilities, and meet Alectra's long-term operational requirements (Exhibit 2, Tab 1, Sch 1, Appendix B07 - Facilities Management, page 291)
Metering Renewal Technology	39.2 (2023-2026)	Comply with mandated service obligations and respond to customer service requests, in addition to mitigating asset failure risk (Exhibit 2A, Tab 1, Schedule 1 Appendix B06- Network Metering p.210).

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Initiative	Capital Costs $MM	Capital Investment Needs and Drivers
Customer Service Strategy-CX Project	20.6 (2021-2025)	Improve customer experience by providing a personalized customer-centric product, with relevant easy to use touchpoints, that offers consistent quality, and customer satisfaction in their ability to complete the task they set out to accomplish.(Exhibit 2A, Tab 1, Schedule 1 Appendix B14 - Enabling Resiliency_ V Customer service technologies p.650)
Human Capital Management(HCM) System	-	
Meter-to- Cash Annual Licenses Growth on Meter-to-Cash platforms	4.6 (2023-2026)	Remain in compliance with Oracle's licensing model for the next generation of CIS (CC&B) platform. (Exhibit 2A, Tab 1, Schedule 1, Appendix B09 – Information Technology Systems, Page 349)
Continuous Improvement Process	-	
Meter-to-Cash CIS CC&B Enhancements	5.0 (2023-2026)	Meet evolving business needs, improve process efficiencies, and elevate the customer experience through integration with customer-facing applications (Exhibit 2A, Tab 1, Schedule 1, Appendix B09 – Information Technology Systems, Page 347)
IVR Enhancements (Knowledge Management system, IVA, Agent assist)	0.1 (2022-2023)	Improve customer experience by enhancing efficiency and effectiveness of customer calls, responding to inquiries more quickly and accurately, improving first call resolution (FCR), reducing average handle time with customers, and improving the Alectra website to facilitate better self-serve options (Exhibit 4, Tab 2, Schedule 7).
Payroll Process Improvement	-	
C55 Alectra: Optimization of Business Practices	9.7 (2019-2026)	Develop a capital plan with maximum portfolio value, considering financial, resource and risk constraints. Improvements include integration of multiple enterprise systems responsible for planning, scheduling, execution, and tracking of both capital and operating projects. (Exhibit 2A, Tab 1, Schedule 1, Appendix B09 – Information Technology Systems, Page 356)

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Initiative	Capital Costs $MM	Capital Investment Needs and Drivers
Customer Care Webchat & Chatbot	0.9 (2025-2026)	Improve customer experience and meet the evolving needs and expectations of today's digitally empowered consumers. (Exhibit 2A, Tab 1, Schedule 1 Appendix B14 - Enabling Resiliency & Modernization _V Customer service technologies 5.3 Invetement Drivers & Needs p643,)
New Customer Connections Process (NCCP) Portal Enhancements	0.5 (2021-2026)	Improve customer experience, implement enhancements resulting from regulatory requirements, enable ESA processing efficiencies, and offer customer payment flexibility
ADP Upgrade to WFN	-	
Work Force Management / Mobile Dispatch	2.2 (2022-2026)	Support work program planning and execution by assisting resource managers with resource allocation, job scheduling, dispatch and reporting, providing real-time visibility into crew activities and the status of field work, digitizing the flow of information between the office and field, and allowing for automated and semi-automated updates of the GIS and other back-office systems. (Exhibit 2A, Tab 1, Schedule 1 Appendix B09 - Information Technology Systems p 350).
Business Intelligence and Analytics	0.4 (2022-2024)	Provide better insights of corporate information, support enhanced decision making, and enable self-serve reporting and dashboards
Microsoft Copilot	-	
Power BI Report Development Reports - Proactive Lifecycle Management	-	
Customer Connections Portal Replacement Project	0.5 (2024-2026)	Mitigate end-of-life system and vendor support risks, while introducing an integrated self-service appointment booking for customers, progress tracking for connection and upgrade requests, and integration to enterprise systems. (Exhibit 2A, Tab 1, Schedule 1 Appendix B14 - Enabling Resiliency & Modernization _V Customer service technologies 5.3 Investment Drivers & Needs p643,)
Guelph Integration process improvement - ERP implementation	-	

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Initiative	Capital Costs $MM	Capital Investment Needs and Drivers
Power BI Report Development Reports - Defective Equipment Tracking	-	

g) As noted in the response to question d) above, the productivity benefits are embedded in the historical and forecast expenditures presented in this application. It is not possible to present the forecast program costs without productivity benefits because the budgets were not prepared in this manner. Productivity benefits are inputs to and reflected in the budgets annually along with other key considerations (such as inflationary cost pressures and incremental work requirements) through the business planning process described in Exhibit 1, Tab 3, Schedule 1. In an effort to be helpful we have identified the program(s) associated with each Framework Initiative; please refer to 1-SEC-12_Attach 1_Framework Initiatives.xlsx column “O”.

h) Please refer to 1-SEC-12_Attach 1_Framework Initiatives.xlsx for the detailed explanation of the methodology used to calculate the savings and underlying calculations, and how they are reflected in forecast amounts over the 2027-2031 period.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1-CCC-4

Ref: Exhibit 1, Tab 9, Schedule 1, p. 5

Question(s):

a) Please provide the detailed calculation showing the conversion of the $44.3M of annual sustained merger-related savings to $40.7 million of revenue requirement.

b) Please provide, with specific references to the evidence, where the above noted $40.7 million is reflected as an offset to the revenue requirement for the CIR term. In the circumstance that these savings are applied as offsets to specific capital and operational forecast budgets proposed for the CIR term, please provide the proposed budgets by program (both with and without the application of the sustained savings).

RESPONSE:

a) Please refer to 1-AMPCO-13

b) Merger synergies were reported at the business unit level rather than by cost centre. Consequently, these synergies cannot be directly mapped to the JC programs. In the absence of such mapping, we have presented the information at the business unit level, which aligns with the historical reporting approach for synergies.

In the absence of the sustained synergies resulting from Alectra and Alectra-Guelph mergers, holding other factors in the application constant, the impacted program costs would be higher by the expected reduction amounts reflected in the table below.

Table 1 - Sustained Synergy Savings by Business Unit

$MM	**Annual Sustained (Capital)**			**Annual Sustained (Operating)**			**Annual Sustained Total**		
Business Unit	**Alectra**	**Alectra /Guelph**	**Total**	**Alectra**	**Alectra /Guelph**	**Total**	**Alectra**	**Alectra /Guelph**	**Total**
Administration	-	-	**-**	1.6	1.4	**3.0**	1.6	1.4	**3.0**
Business Transformation	-	-	**-**	(0.3)	-	**(0.3)**	(0.3)	-	**(0.3)**
Customer Service	0.3	-	**0.3**	8.1	0.6	**8.8**	8.4	0.6	**9.1**
Finance	-	-	**-**	5.9	0.6	**6.4**	5.9	0.6	**6.4**
Government & Corporate Relations	-	-	**-**	1.1	0.3	**1.4**	1.1	0.3	**1.4**
Information Technology	-	-	**-**	4.6	0.8	**5.4**	4.6	0.8	**5.4**
Internal Audit & Enterprise Risk Management	-	-	**-**	(0.2)	-	**(0.2)**	(0.2)	-	**(0.2)**
Legal	-	-	**-**	(1.0)	-	**(1.0)**	(1.0)	-	**(1.0)**
Network Operations - Control Room	-	-	**-**	4.5	-	**4.5**	4.5	-	**4.5**
Network Operations - Metering	-	-	**-**	1.0	0.4	**1.4**	1.0	0.4	**1.4**
Network Operations - Operations	2.0	-	**2.0**	4.1	0.1	**4.2**	6.1	0.1	**6.2**
Network Services	-	-	**-**	0.7	-	**0.7**	0.7	-	**0.7**
People and Safety	1.4	-	**1.4**	(2.3)	0.2	**(2.1)**	(0.9)	0.2	**(0.7)**
Regulatory	-	-	**-**	2.3	0.1	**2.4**	2.3	0.1	**2.4**
Supply Chain Management	2.8	-	**2.8**	3.0	0.1	**3.1**	5.8	0.1	**6.0**
Total	**6.5**	**-**	**6.5**	**33.1**	**4.7**	**37.8**	**39.6**	**4.7**	**44.3**

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1-CCC-5

Ref: Exhibit 1, Tab 9, Schedule 3, pp. 1-2

Question(s):

a) Please confirm that Tables 1-9-4, 1-9-5, and 1-9-6 are comparing the total forecast savings from both mergers (i.e., Alectra and Alectra/Guelph) to the total actual savings.

b) Please provide two additional versions of Tables 1-9-4, 1-9-5, and 1-9-6 that show a comparison of the forecast savings (MAADs proceeding) and the actual savings for each of: (i) the Alectra merger only; and (ii) the Alectra / Guelph merger only.

c) For each of the Alectra merger only, the Alectra / Guelph merger only and the total for both mergers, please provide a table showing:

    i. The forecast annual sustained savings set out in the relevant MAADs proceedings and the related revenue requirement amount.
    ii. The actual annual sustained savings accomplished and the related revenue requirement amount.

RESPONSE:

a) Confirmed. Tables 1-9-4, 1-9-5, and 1-9-6 display Alectra Utilities' net consolidation synergies over the deferred rebasing period, as compared to the forecasts provided in the MAADs applications for both mergers combined.

b) Tables 1- 6 below provide versions of Tables 1-9-4, 1-9-5, and 1-9-6 that show a comparison of the forecast savings (MAADs proceeding) and the actual savings for each of: (i) the Alectra merger only; and (ii) the Alectra / Guelph merger only.

Table 1 - Alectra - Total Net Synergies (MAADs vs. Actuals/Forecast) ($MM)

The Alectra Merger only

Alectra Merger	**MAADS Proceeding**	**Sustained**	**One-time**	**Total Sustained and One-time**	**Variance**
Gross OM&A Synergies	354.6	286.5	11.6	298.0	(56.5)
Gross Capital Synergies	167.6	57.1	124.4	181.5	13.9
Gross Total Synergies	**522.2**	**343.6**	**135.9**	**479.5**	**(42.6)**
OM&A Transition Costs	42.9	-	29.4	29.4	13.5
Capital Transition Costs	53.3	-	121.5	121.5	(68.1)
Gross Total Transition Costs	**96.3**	**-**	**150.9**	**150.9**	**(54.6)**
Net OM&A Synergies	311.6	286.5	(17.9)	268.6	(43.0)
Net Capital Synergies	114.3	57.1	2.9	60.0	(54.3)
Total Synergies	**425.9**	**343.6**	**(15.0)**	**328.6**	**(97.3)**

Table 2 - Guelph - Total Net Synergies (MAADs vs. Actuals/Forecast) ($MM)

The Guelph Merger only

	MAADS Proceeding	**Sustained**	**One-time**	**Total Sustained and One-time**	**Variance**
Gross OM&A Synergies	28.5	28.2	0.1	28.3	(0.2)
Gross Capital Synergies	3.8	-	3.1	3.1	(0.7)
Gross Total Synergies	**32.3**	**28.2**	**3.2**	**31.4**	**(0.9)**
OM&A Transition Costs	4.5	-	3.3	3.3	(1.2)
Capital Transition Costs	9.7	-	16.0	16.0	6.3
Gross Total Transition Costs	**14.3**	**-**	**19.3**	**19.3**	**5.0**
Net OM&A Synergies	23.9	28.2	(3.2)	25.0	1.0
Net Capital Synergies	(5.9)	-	(12.8)	(12.8)	(7.0)
Total Synergies	**18.0**	**28.2**	**(16.1)**	**12.1**	**(5.9)**

Table 3 - Alectra - Total Net Payroll Synergies (MAADs vs. Actuals/Forecast) ($MM)

The Alectra Merger only

Alectra Merger	MAADS Proceeding	Sustained	One-time	Total Sustained and One-time	Variance
Gross OM&A Synergies	318.8	194.9	-	194.9	(123.9)
Gross Capital Synergies	22.6	11.8	-	11.8	(10.8)
Gross Total Synergies	**341.5**	**206.7**	**-**	**206.7**	**(134.7)**
OM&A Transition Costs	34.6	-	19.5	19.5	(15.2)
Capital Transition Costs	-	-	-	-	-
Gross Total Transition Costs	**34.6**	**-**	**19.5**	**19.5**	**(15.2)**
Net OM&A Synergies	284.2	194.9	(19.5)	175.4	(108.8)
Net Capital Synergies	22.6	11.8	-	11.8	(10.8)
Total Synergies	**306.8**	**206.7**	**(19.5)**	**187.2**	**(119.6)**

Table 4 - Alectra - Total Net Payroll Synergies (MAADs vs. Actuals/Forecast) ($MM)

The Guelph Merger only

	MAADS Proceeding	Sustained	One-time	Total Sustained and One-time	Variance
Gross OM&A Synergies	21.2	22.5	-	22.5	1.3
Gross Capital Synergies	-	-	-	-	-
Gross Total Synergies	**21.2**	**22.5**	**-**	**22.5**	**1.3**
OM&A Transition Costs	3.7	-	2.5	2.5	(1.2)
Capital Transition Costs	-	-	-	-	-
Gross Total Transition Costs	**3.7**	**-**	**2.5**	**2.5**	**(1.2)**
Net OM&A Synergies	17.5	22.5	(2.5)	20.0	2.5
Net Capital Synergies	-	-	-	-	-
Total Synergies	**17.5**	**22.5**	**(2.5)**	**20.0**	**2.5**

Table 5 - Alectra - Total Net Non-Payroll Synergies (MAADs vs. Actuals/Forecast) ($MM)

The Alectra Merger only

Alectra Merger	**MAADS Proceeding**	**Sustained**	**One-time**	**Total Sustained and One-time**	**Variance**
Gross OM&A Synergies	35.7	91.5	11.6	103.1	67.4
Gross Capital Synergies	145.0	45.3	124.4	169.7	24.7
Gross Total Synergies	**180.7**	**136.9**	**135.9**	**272.8**	**92.1**
OM&A Transition Costs	8.3	-	9.9	9.9	1.7
Capital Transition Costs	53.3	-	121.5	121.5	68.1
Gross Total Transition Costs	**61.6**	**-**	**131.4**	**131.4**	**69.8**
Net OM&A Synergies	27.4	91.5	1.6	93.2	65.7
Net Capital Synergies	91.6	45.3	2.9	48.2	(43.4)
Total Synergies	**119.1**	**136.9**	**4.5**	**141.4**	**22.3**

Table 6 - Guelph - Total Net Non-Payroll Synergies (MAADs vs. Actuals/Forecast) ($MM)

The Guelph Merger only

	MAADS Proceeding	**Sustained**	**One-time**	**Total Sustained and One-time**	**Variance**
Gross OM&A Synergies	7.3	5.7	0.1	5.8	(1.5)
Gross Capital Synergies	3.8	-	3.1	3.1	(0.7)
Gross Total Synergies	**11.1**	**5.7**	**3.2**	**8.9**	**(2.2)**
OM&A Transition Costs	0.8	-	0.8	0.8	(0.0)
Capital Transition Costs	9.7	-	16.0	16.0	6.3
Gross Total Transition Costs	**10.5**	**-**	**16.8**	**16.8**	**6.2**
Net OM&A Synergies	6.5	5.7	(0.7)	5.0	(1.5)
Net Capital Synergies	(5.9)	-	(12.8)	(12.8)	(7.0)
Total Synergies	**0.6**	**5.7**	**(13.6)**	**(7.9)**	**(8.4)**

c) For each of the Alectra merger only, the Alectra / Guelph merger only, and the total for both mergers, Table 7 below provides the i) forecast annual sustained savings set out in the relevant MAADs proceedings and the related revenue requirement amount, and ii) the actual annual sustained savings accomplished and the related revenue requirement amount.

The revenue requirement related to each of the Alectra merger only and Alectra / Guelph merger portions of sustained savings were derived by applying the ratio of each portion of sustained savings against the total sustained savings, to the total revenue requirement. Similarly, the MAADs related revenue requirement was determined by applying the ratio of each portion of MAADs sustained savings to the derived portions of revenue requirement.

Table 7 - MAADS Forecast and Actual Savings and Revenue Requirement ($MM)

($MMs)	MAADs Forecast Annual Sustained Savings	Actual /Forecast Annual Sustained Savings	MAADs Related Revenue Requirement	Actual /Forecast Related Revenue Requirement
Alectra Merger - OM&A	42.5	33.1	39.1	30.4
Alectra Merger - Capital	8.0	6.5	7.4	6.0
Alectra/Guelph Merger - OM&A	4.2	4.7	3.9	4.3
Alectra/Guelph Merger - Capital	-	-	-	-
Total	**54.7**	**44.3**	**50.3**	**40.7**

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1-CCC-6

Ref: Exhibit 1, Tab 9, Schedule 5, pp. 1-3

Question(s):

a) Please provide a table, or tables, showing the following:

i. a detailed project list for the $137.5M of transition-related capital expenditures
ii. a breakout of these capital expenditures between the Alectra merger and the Alectra / Guelph merger
iii. a detailed project list of the "planned IT capital expenditures by legacy utility" with reference to the evidence where these cited capital expenditures can be found.

b) A detailed project list for the $50.3M of remaining net book value in opening 2027 rate base related to the transition-related capital expenditures broken out between the Alectra merger and the Alectra / Guelph merger.

c) A detailed project list showing the remaining net book value in opening 2029 rate base related to the transition-related capital investments broken out between the Alectra merger and the Alectra / Guelph merger

RESPONSE:

a) part i and ii - See attachment 1-SEC-16_Attach 1_Capital Transition Project Schedule.xlsx – tab "1-SEC-16"
part iii - Please refer to Alectra's response to 1-SEC-16

b) See attachment 1-SEC-16_Attach 1_Capital Transition Project Schedule.xlsx – tab “1-Staff-39 (IT)” and tab “1-Staff-41 (non-IT)”

c) See attachment 1-SEC-16_Attach 1_Capital Transition Project Schedule.xlsx – tab “1-Staff-39 (IT)” and tab “1-Staff-41 (non-IT)”

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1-CCC-7

Ref: Exhibit 1, Tab 9, Schedule 7, pp. 1-2

Preamble:

Alectra Utilities seeks approval to rebase the Guelph Rate Zone two years early. Alectra noted that the proposals in the Application reflect planning on an Alectra Utilities-wide basis. Alectra Utilities' business planning process is informed by coordinated inputs from the DSP (capital planning), workforce planning, OM&A, revenue forecasts, financial requirements, and tax obligations.

Question(s):

In the context that early rebasing for the Guelph Rate Zone is eventually not approved by the OEB, please advise whether Alectra has developed an alternative set of proposals to rebase the utility with the exception of the Guelph Rate Zone. If so, please provide that alternative set of proposals. If not, please explain why these alternative proposals were not developed.

RESPONSE:

Alectra Utilities has not developed an alternative set of proposals to rebase the utility without the Guelph Rate Zone. As identified in the preamble and pre-filed evidence, the proposals in the application reflect planning on an Alectra-wide basis, inclusive of Guelph. The OEB's 2016 MAADs Handbook states that a request for early rebasing must be in the best interest of customers and Alectra Utilities provided its rationale for the early rebasing of the Guelph Rate Zone in Exhibit 1, Tab 9, Schedule 7, pp. 1-2. Rebasing the Guelph Rate Zone as part of this Application promotes regulatory efficiency by avoiding the preparation, adjudication and expense of another rebasing application two years later.

Further, all of Alectra Utilities' predecessor utilities migrated to Alectra Utilities' Enterprise Resource Planning (ERP) system in 2019 (Brampton, Horizon Utilities, PowerStream and Enersource) and 2022 (Guelph). These legacy systems are no longer in place due to the complexities and costs to maintain five additional sets of general ledgers. As a result, tracking costs at a rate zone level to identify Guelph Rate Zone specific costs to exclude from the current rebasing application is not feasible. This is aligned with the OEB's decision in Alectra Utilities' MAADs application (EB-2016-0025, p.26) that states "The OEB does not require, nor encourage reporting on a "separate" utility basis."

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1-CCC-8

Ref: Exhibit 1, Tab 11, Schedule 1, pp. 1-2
Exhibit 1, Tab 11, Schedule 2, p. 14
Exhibit 4, Tab 1, Schedule 1, p. 1

Preamble:

Alectra stated that it has provided a five-year forecast of operating costs in Exhibit 4 which is used to inform Alectra Utilities' justification for its custom index for its OM&A expenditures. Together, the Clearspring Report and Alectra Utilities' OM&A evidence, provide the evidentiary record necessary to support Alectra Utilities' request for OM&A funding based on its proposed custom index.

Question(s):

a) Please further explain the statement that the five-year OM&A forecast (Exhibit 4) is used to "inform" Alectra's proposed custom index. As part of the response, please discuss whether the OM&A forecast in Exhibit 4 reflects Alectra's planned 5-year OM&A expenditures.

b) Please advise whether Alectra is seeking approval of the five-year OM&A cost forecast in Exhibit 4 or the 2027 test year OM&A proposal (shown in Table 1-11-4) as escalated by the proposed custom index.

c) Please provide a single table that shows the OM&A budget set out in Table 1-11-4 (which underpins the calculation of the RGF) and the OM&A budget in Appendix 2-JC (adjusted as necessary to remove the shareholder funded portion of the GRE&T Centre) for the 2027-2031 period. Please explain the difference between the two figures.

RESPONSE:

a) Alectra Utilities provided a 5-year forecast projection of OM&A for informational purposes and to provide context for the OM&A revenue growth needs over the period. The OM&A forecast in Exhibit 4 reflects Alectra's projection of OM&A costs over the rate term based on information that was collected during the business planning process. However, its rates are proposed to be established on the basis of escalating the 2027 test year by the proposed index. Over the course of the rate term, the utility will need to challenge itself every year to figure out how to manage its OM&A investment plans and deliver its outcomes within the overall funding available.

b) As identified in Exhibit 1, Tab 11, Schedule 2, OM&A funding for 2027 is established based on forecast costs. In 2028 to 2031, each year's OM&A funding is equal to the prior year's OM&A funding escalated by the proposed custom index (i.e., inflation, growth factor and IPD). This is shown in Line 15 of Table 1-11-4 in Exhibit 1, Tab 11, Schedule 2, p.14.

c) Please refer to Table 1 below. The difference between the OM&A funded through the rate framework and the OM&A per Appendix 2-JC is $20.2MM over the 2027-2031 period. In addition, as identified on p.2 of Exhibit 1, Tab 11, Schedule 1, Alectra has limited rate payer funding for the GRE&T Centre of approx. $2.8MM annually or $14.2MM as presented below.

1 **Table 1 – OM&A Comparison**

	2027	2028	2029	2030	2031	5-Yr
Table 1-11-4	**$352.4**	**$367.1**	**$382.4**	**$398.4**	**$415.0**	**$1,915.3**
App. 2-JC	$355.0	$371.9	$389.5	$404.0	$415.1	**$1,935.5**
Difference	**($2.6)**	**($4.8)**	**($7.1)**	**($5.6)**	**($0.1)**	**($20.2)**
GRE&T Centre Reduction	**($2.6)**	**($2.2)**	**($3.0)**	**($3.1)**	**($3.3)**	**($14.2)**

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1-CCC-9

Ref: Exhibit 1, Tab 11, Schedule 2, pp. 4

Question(s):

Please provide Chart 1-11-1 in table format and provide all of the calculations used to derive the base RR and net distribution revenue under Price Cap IR.

RESPONSE:

Please refer to Table 1 below, which illustrates the calculations used to build Chart 1-11-1. Base revenue requirement (Custom Price Cap Revenue) for all years from 2027 to 2031 is equal to the distribution revenue forecast based on Alectra Utilities' proposed rate framework in this application, as summarized in Attachments 6-1 through 6-5 of Exhibit 6 (i.e. Revenue Requirement Workforms). Distribution revenue under Price Cap for 2027 is equal to the forecast base revenue requirement for 2027. For each year from 2028 through 2031, distribution revenue is equal to the prior year's distribution revenue initially escalated for billing determinant growth, followed by the Price Cap IR formula of I – X escalation. Finally, an adjustment is made to account for the transformer allowance to yield Distribution Revenue under Price Cap.

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Table 1 – Custom Price Cap Revenue vs Price Cap Revenue

Component	Description	2027	2028	2029	2030	2031	2027-2031
I	Inflation Factor		2.00%	2.00%	2.00%	2.00%	
X	Stretch Factor		0.15%	0.15%	0.15%	0.15%	
BD Growth	Revenue Growth from Billing Determinants		0.57%	0.63%	0.67%	0.61%	
RR	**Custom Price Cap Revenue Requirement**	**$810.3**	**$863.3**	**$907.2**	**$964.9**	**$1,025.0**	**$4,570.7**
	Prior Year Base Distribution Revenue		**$810.3**	**$830.2**	**$851.1**	**$872.8**	
	1. Escalate by Growth in Billing Determinants		$815.0	$835.4	$856.8	$878.1	
	2. Escalated by PCI (I - X)		$830.0	$850.9	$872.7	$894.4	
	3. Add: Transformer Allowance		$0.2	$0.2	$0.2	$0.2	
	Price Cap Revenue Requirement	**$810.3**	**$830.2**	**$851.1**	**$872.8**	**$894.5**	**$4,258.9**
							($312)

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RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1-CCC-10

Ref: Exhibit 1, Tab 11, Schedule 2, p. 14

Question(s):

a) Please confirm, or correct, the table below, which shows Alectra's proposed capital-related revenue requirement for the CIR term derived on a cost of service basis.

Line		2027	2028	2029	2030	2031
1	Average Net Fixed Assets	4,130.3	4,389.5	4,701.5	5,075.9	5,460.6
2	Working Capital Allowance	305.0	319.6	331.4	346.1	361.2
3	Rate Base	4,435.3	4,709.2	5,032.9	5,422.0	5,821.8
4	Return on Debt	111.0	122.0	130.8	141.3	156.3
5	Return on Equity	159.7	169.5	181.2	195.2	209.6
6	Depreciation	195.6	199.4	214.1	230.8	242.2
7	PILs Taxes	22.4	37.6	29.0	31.8	37.0
8	**Total Capital Related Revenue Requirement**	**488.7**	**528.5**	**555.1**	**599.0**	**645.1**

b) With respect to the forecast capital expenditures (and associated in-service additions) that underpin the CRRR amounts, please advise whether those forecasts reflect expected inflation during the CIR term. If so, please provide the inflation rate that was applied (and if different inflation rates were applied to various capital programs, please provided the weighted-average inflation rate). If different inflation rates were applied to labour and materials, please provide the weighted-average inflation rates applied to each of those cost categories.

c) Please explain the adjustment in Line 9 in Table 1-11-4 ("less incremental working capital related revenue requirement") and provide the calculation used in the derivation of this adjustment.

RESPONSE:

a) Alectra Utilities confirms that the table referenced in part a of this interrogatory is derived on a cost-of-service basis and aligns with Alectra Utilities' forecast capital-related revenue requirement over the rate term as provided in Table 1-11-4 of Exhibit 1, Tab 11, Schedule 2 (Line 9 - subject to potential rounding variances).

b) The overall inflation assumption for the 2025 - 2031 capital portfolio is 1.9% - 2.0%.

c) The purpose of the adjustment is to reduce rates for ratepayers by funding the capital-related revenue requirement of Working Capital Allowance on the basis of I-X, as opposed to funding this item on a forecast basis. Table 1 below illustrates the calculations used to derive the adjustment in Line 9 in Table 1-11-4 ("less incremental working capital related revenue requirement").

Table 1 - Line 9 (Table 1-11-4) Adjustment Calculations

		2027	2028	2029	2030	2031
Working Capital Allowance Forecast		$305.0	$319.6	$331.4	$346.1	$361.2
Working Capital Allowance escalated by Inflation	2%	$305.0	$311.1	$317.3	$323.7	$330.1
Cost of Capital		6.10%	6.19%	6.20%	6.21%	6.28%
Cumulative Change in Working Capital on Forecasted Basis	A = (Current Year WCA less 2027 WCA) * Current Year Cost of Capital Rate		-$0.9	-$1.6	-$2.6	-$3.5
Adjust for Inflation	B = Inflationary Amount * Current Year Cost of Capital Rate		$0.4	$0.4	$0.4	$0.4
"Less Incremential Working Capital-related RR" line	***A + B***		**-$0.5**	**-$1.3**	**-$2.2**	**-$3.1**

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 2-CCC-11

Ref: Appendix 2-AA
Exhibit 2B, Tab 1, Schedule 1, p. 1
Exhibit 2B, Tab 3, Schedule 1, pp. 6-8

Question(s):

a) Please provide a revised version of Appendix 2-AA that provides a more detailed view of the capital plan at the capital project / segment level instead of the project group level (and extends the historical period to 2019). For example, for the customer connections project group, please provide separate lines for each of residential and small commercial layouts, ICI services, new subdivisions, etc. In addition, please provide the capital contributions at the same level of granularity (i.e., by project/segment instead of project group). Please also include 2025 year-end actuals.

b) Please provide a revised version of Appendix 2-AA in the same format as requested in part (a) but on an in-service addition basis.

c) To the extent that any capital program segments have moved from one program to another, please provide an additional revised version of Appendix 2-AA that shows the relevant program segment budgets recast without the movement.

d) Please confirm that Alectra applies the half-year rule in the determination of rate base during the CIR term.

e) Please confirm that Alectra calculates depreciation expense based on a monthly forecast of when assets are expected to enter service over the CIR term. As part of the response, please confirm that this approach is applied to all assets (not a specific subset of Alectra's assets).

f) With respect to forecasting monthly depreciation expense, please provide an explanation of the methodology applied. As part of the response, please discuss whether these monthly forecasts are based on historical actuals, and whether there are different treatments applied to major capital projects (i.e., a new station) relative to ongoing capital programs (i.e., pole replacement).

g) For each year during the 2017-2031 period (or a later year if information to 2017 is not available), please provide the total monthly in-service additions (e.g., January total for each year, February total for each year, etc.) that were used in the determination of depreciation expense.

h) Please explain why Alectra applies different approaches to forecasting rate base and depreciation expense.

RESPONSE:

a) Alectra Utilities provides the table in excel workbook 2-CCC-11_attach 1_2-AA by segment.xlsx with 2-AA presented by Segment along with further breakdown of programs and segments by contributions.

b) Alectra Utilities provides the table as excel attachment named 2-CCC-11-b_Attach 2 App 2-AA In-Service.xlsx.

c) Alectra Utilities confirms that there were no instances where entire capital program segments were transferred between programs over the scope of this DSP. As a result, there are no material impacts associated with such movements, and a revised version of Appendix 2-AA reflecting such movements is not applicable.

d) Alectra has determined the rate base by adding the average of the opening and closing balances for net fixed assets each year plus a working capital allowance, in accordance with the OEB's Chapter 2 Filing Requirements.

e) Confirmed. Alectra calculates depreciation expense based on the month that assets are forecasted to be put into service. This approach is applied to all assets.

f) For forecasting purposes, Alectra calculates depreciation based on the projected timing of in-service additions. The timing of these in-service additions is based on the type of capital investment.

For all discrete projects, in-service additions are forecasted based on the projected timing of when assets are put into service, using the most current project schedules. Where projects are phased, in-service additions are forecasted in the year each phase is expected to be built.

For example, *Project 152758 Build Richmond Hill TS#3* is a discrete project which is forecasted to be put in-service in December 2030. Total additions for this project are added in December 2030, therefore the depreciation expense is calculated to commence in the same period.

For ongoing capital programs, in-service additions for each year are forecasted using historical trends to estimate the portion of annual expenditures that will be placed in-service each year. These programs consist of many smaller projects that are projected to go into service throughout the year, therefore, the annual forecasted in-service additions for each program are spread equally across each month.

For example, for the Transformer Renewal Program, based on historical trends, 90% of the capital expenditures are expected to go into service in the year these expenditures are incurred, and the remaining 10% is expected to be placed into service the following year. Once the projected additions are calculated for each year, these balances are then allocated equally across each month. Depreciation expense begins based on the month these additions are projected to go into service.

g) Please see the response to 2B-SEC-66 (a) for monthly additions from 2020 to 2031. Monthly additions prior to 2020 are not readily available, as the data was stored in five different legacy ERP systems and not aligned to the Alectra asset component structure.

h) Alectra forecasts depreciation expense based on the month when additions are expected to be placed into service, which is the same methodology applied for actuals, consistent with IFRS guidelines (IAS 16.55, IAS 38.97). These calculations are also used for internal reporting, measuring and monitoring financial results, performing variance analysis, and supporting decision-making. This methodology aims to project depreciation expense as accurately as possible for budgeting, forecasting, and comparisons to actuals.

Alectra calculates the rate base by adding the average of the opening and closing balances for net fixed assets each year, along with a working capital allowance, in accordance with the methodology described in Chapter 2 of the OEB's Filing Requirements. This calculation is consistent with the rate base calculations performed in prior years, and approved legacy rate base calculations of each predecessor legacy utility in their last rebasing application.

2-CCC-11

Attachment 1
2AA By Segment

Please see live Excel

2-CCC-11

Attachment 2
2AA In Service

Please see live Excel

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 2-CCC-12

Ref:

Exhibit 2A, Tab 1, Schedule 1, Appendix B06, pp. 217, 227-228, 251-255, 260-269

Exhibit 2B, Tab 3, Schedule 1, pp. 8-9

Appendix 2-AA

Question(s):

a) Please provide a revised version of Table B06-4 that adds a row showing the number of wholesale meters replaced or planned to be replaced each year of the 2020-2031 period.

b) Please provide a revised version of Table B06-11 that adds a row showing the number of new meters installed or planned to be installed (by type - single phase or polyphase) each year of the 2020-2031 period.

c) Please provide a revised version of Table B06-12 that adds a row showing the number of failed meters replaced or planned to be replaced each year of the 2020-2031 period. As part of the response, please explain any significant variances in the unit costs of failed meter replacement and elaborate on the statement that the "capital expenditures related to meter failures do not intuitively align with the number of failures experienced in that year."

d) Please provide the average cost per meter for an AMI 1.0 meter and an AMI 2.0 meter (which supports the statement that the AMI 2.0 meters are 26% less expensive).

e) Please provide further details with respect to the negotiated "inflation-sharing mechanism" with Itron.

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f) Please advise whether Alectra's contracts with either Itron and / or the selected service vendor include provisions related to cost responsibility for AMI 2.0 meters that fail prematurely. If yes, please provide explain those provisions. If not, please explain why not.

g) Please further discuss how the AMI 2.0 meters have been integrated with the AMI 1.0 Head End system. As part of the response, please explain why the Company needs to move to an AMI 2.0 Head End system.

h) Please provide the number of AMI 2.0 meters installed in Phase 2 (Small Scale Deployments) and the average unit cost per installation.

i) Please explain the difference between the total amounts shown in Table B06-18 and Appendix 2AA. Please also confirm that Table B06-18 reflects the 5.5-year mass deployment recommendation.

j) Please explain how Alectra calculated that an "additional 43,000 AMI 1.0 meters would fail between 2027-2031 under the seven-year replacement schedule compared to the five-year alternative."

k) Please advise whether Alectra has discussed with Measurement Canada the potential for dispensation from re-verification and resealing obligations based on the seven-year deployment alternative.

l) Please provide the percentage of meters that will be fully depreciated at the time of removal in each of the mass deployment scenarios (3-year, 5-year, 5.5-year and 7-year).

m) Please add the recommended 5.5-year deployment to Table B06-22 and provide the detailed calculations underpinning the table. As part of the response, please provide the assumptions made with respect to inflationary cost increases, the number of reactive meter failures and dispensation exemptions.

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n) Please advise whether the options set out in Table B06-22 reflects the financial implications of removing more (or less) AMI 1.0 meters from service before the end of their financial useful lives. If not, please include that impact as part of the options analysis (including for the 5.5-year option).

o) Please provide the detailed calculation supporting the AMI 1.0 Metering Accelerated Depreciation shown in Table 2-3-6.

p) Please provide excerpts from previous OEB decisions where the OEB has approved accelerated depreciation associated with meter replacements.

RESPONSE:

a) Table B06-4 has been updated below to include the numbers of wholesale meter installations and primary metering units that occurred between 2020 and 2025 and the forecasted numbers of installations between 2026 and 2031. 2025 has been updated with actual expenditures.

Table 1: Amended Table B06-4 Wholesale Metering Expenditures ($MM)

	Historical Spending					Bridge		Forecast Spending				
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Wholesale Metering ($MM)	2.5	1.1	1.1	2.0	1.4	2.1	1.1	2.6	2.6	2.6	2.8	2.9
Wholesale Meter Replacements	10	17	0	41	33	6	22	13	24	7	25	19
Primary Metering Unit Replacements	2	5	8	14	7	4	3	6	6	6	6	6

Meter replacement costs are only a portion of this budget, which also includes the equipment and labour related to broader wholesale installations including instrumentation and primary metering units. In addition, costs related to wholesale activities can vary significantly due to the complexity of the work and whether the activity is part of a larger substation project.

b) Table B06-11 has been updated below to include the numbers of single phase and polyphase meter installations completed through to 2025 and forecasted to be completed under the Network Metering program.

Table 2: Amended Table B06-11 New Connections Expenditures ($MM)

	Historical Spending					Bridge		Forecast Spending				
Year	2020	2021	2022	2023	2024	2025 Act	2026	2027	2028	2029	2030	2031
New Connections and Upgrades ($MM)	7.0	6.1	6.1	4.9	3.8	2.7	3.9	3.7	3.8	3.8	3.9	4.0
Single Phase Meter Installations	3,380	4,675	4,852	4,472	5,455	5,567	5,028	5,272	5,522	5,831	5,985	6,139
Polyphase Meter Installations	392	542	665	682	772	985	744	814	886	977	1,025	1,073
Total Meter Installations	3,772	5,217	5,517	5,154	6,227	6,552	5,772	6,086	6,408	6,808	7,010	7,212

The Network Metering program accounts only for a portion of Alectra Utilities’ meter installations for new customer connections and upgrades. Additional installations are completed by Network Operations.

Costs related to new connections may vary due to i) the complexity of the polyphase meter installation and ii) whether an AMI 1.0 or an AMI 2.0 meter was installed. Beginning in 2025, costs related to the re-deployment of a fully depreciated AMI 1.0 meter were expensed to Network Metering’s OM&A budget.

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c) Alectra Utilities has updated Table B06-12 below to include the numbers of meter failures recorded through to 2025 and forecasted between 2026 and 2031 as follows:

Table 3: Amended Table B06-12 Meter Failures Expenditures ($MM)

	Historical Spending					Bridge		Forecast Spending				
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Meter Failures ($MM)	5.8	3.7	4.1	3.8	2.3	2.3	5.0	5.5	4.8	3.7	2.5	0.8
Number of Meter Failures	4,202	6,340	6,756	8,595	11,074	13,806	23,619	28,441	24,827	19,591	12,354	3,959

The capital expenditures related to the volume of meter failures may not intuitively align with the number of failures experienced in a year for the following reasons:

i) While meters are the primary driver in this cost centre, it also includes costs related to the replacement of all failed retail metering infrastructure and equipment such as gate keepers, cabinets, instrumentation, etc.;

ii) Inventory constraints as a result of the global pandemic created scenarios where failed meters were assessed at the premise, replaced if the technician determined that the meter could be potentially repaired in Alectra Utilities' meter lab, or left in its failed state until a replacement meter was available. In these scenarios, the second "truck roll" increased failure costs;

iii) Alectra Utilities discontinued the procurement of AMI 1.0 in 2022 to avoid increasing its accelerated depreciation expense related to the end-of-life AMI 1.0 network. Instead, Alectra Utilities began installing AMI 2.0 meters in selected high-risk areas, re-stocking the removed functioning AMI 1.0 meters into inventory to service new connections, undertaking associated compliance activities, and addressing failures within the AMI 1.0 networks. Where the AMI 1.0 meter is fully depreciated, the costs of its installation at a new premise is captured in Network Metering's OM&A costs; and,

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iv) Where the location of a failed AMI 1.0 meter is sufficiently close to the AMI 2.0 network, the failed meter is replaced with an AMI 2.0 meter. AMI 2.0 meters are less expensive, on average, than the AMI 1.0 meters.

d) The weighted average cost for all types of AMI 1.0 meters was [redacted] per meter based on Alectra Utilities' most recent procurement orders, as compared to a weighted average of [redacted] for AMI 2.0 meters.

e) Alectra Utilities and Itron Canada Inc. negotiated the AMI 2.0 contract in 2021 and 2022, during uncertain market conditions. A fixed pricing schedule was negotiated over a twenty-year period, subject to annual adjustments capped against an inflation index. The calculation methodology allows for periods of low and high sector inflation by assessing the inflation index over the contract term, such that annual adjustment to the pricing schedule may be positive or negative. In this way, both parties share the impact of inflation, and Alectra Utilities may "earn back" price increases paid in high inflation periods as deflation occurs.

f) Alectra Utilities' contract with Itron Canada Inc. contains broad warranties that meter and network equipment will conform to the specifications, be free from defects and comply with all legal requirements.

Specific warranties include: Meter and Network Equipment warranty; Meter Safety Failure Warranty; Major Meter and Network Equipment Failure; AMI Solution Performance; Firmware Update Failure; and, a guaranteed support period for products and services.

Alectra Utilities is in the process of negotiating its mass deployment vendor contract and intends to establish warranties for work related to the installation of meters.

g) Three of Alectra Utilities' AMI 1.0 Head End systems are not compatible with the Itron AMI 2.0 technology.

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The fourth AMI 1.0 Head End system is the Itron UtilityIQ AMI Head End. This AMI system was established in 2006 by Alectra Utilities' legacy utility Guelph Hydro. It was originally scaled and configured to perform interrogation of Guelph's approximately 55,000 meters. The AMI 1.0 Head End is governed by the legacy Guelph Utilities contract which has typical AMI 1.0 service levels, does not include testing or disaster recovery systems, and is priced at high per-meter costs aligned to its originally anticipated meter volumes.

Alectra Utilities began installing Itron AMI 2.0 meters in 2023 as AMI 1.0 meters became challenging to procure as a result of supply chain constraints and product obsolescence. The Itron AMI 2.0 meters are compatible with the existing Itron AMI 1.0 UtilityIQ HeadEnd and are being interrogated daily.

Transitioning to the AMI 2.0 Head End system as compared to utilizing the legacy UtilityIQ AMI 1.0 Head End enables benefits for Alectra Utilities including:

- lower Head End per meter costs based on Alectra Utilities' negotiated volume-based AMI 2.0 pricing model;
- the inclusion of additional database instances to support testing and disaster recovery;
- enhanced AMI 2.0 service level protections and warranties;
- new and enhanced cyber security features;
- Standards-based integration and interfaces to simplify IT/OT integration;
- resolves meter volume limitations of the Guelph AMI 1.0 UtilityIQ Head End; and,
- supports future integration of AMI 2.0 functionality to achieve business value including the automation of Remote Disconnect and Reconnect functionality and "last gasp" outage detection.

h) Alectra Utilities planned to install approximately 95,000 meters during the small scale deployment period of 2023 to 2026 at an average cost of [redacted] per meter, inclusive of equipment and labour expenditures. Alectra Utilities is ahead of plan, and will likely install approximately 140,000 AMI 2.0 meters through to the end of 2026.

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i) Table B06-18 sets out the net Total Network Metering capital expenditures including customer contributions received. Alectra Utilities can confirm that this table reflects the recommended 5.5-year mass deployment alternative.

Appendix 2AA displays the gross cost of Network Metering with the contributions noted separately.

j) Alectra Utilities estimated the volume of AMI 1.0 failures under each alternative based upon incrementing failure rates as the remaining AMI 1.0 meter population ages and its ability to deploy AMI 2.0 in areas of greatest failure risk.

Table 4: Forecasted Meter Failures by Deployment Alternative

		5-year Mass Deployment Alternative			7-year Mass Deployment Alternative			
	AMI 1.0 Meter Age (years)	AMI 1.0 population	Average Forecasted Failure Rate	Forecasted Meter Failures	AMI 1.0 population	Average Forecasted Failure Rate	Forecasted Meter Failures	Variance in Failures
Year 1	18 to 20+	989,941	2.9%	28,441	999,893	2.9%	28,696	255
Year 2	19 to 20+	747,775	3.3%	24,827	871,808	3.3%	28,863	4,035
Year 3	20 to 20+	520,131	3.8%	19,591	731,668	3.8%	28,019	8,427
Year 4	over 20	278,423	4.4%	12,354	582,591	4.5%	26,189	13,835
Year 5	over 20	77,198	5.1%	3,959	405,818	5.1%	20,780	16,821
Total Over DSP Period				**89,173**			**132,546**	**43,374**

In the 5-year mass deployment alternative, AMI 2.0 volumes are expected to be sufficient to replace all AMI 1.0 meters in two mesh networks. The two networks being prioritized are experiencing the highest failure rates. One of these AMI 1.0 networks had a rolling 12-month failure rate in excess of 7% as of December 2025.

In the 7-year mass deployment alternative, Alectra Utilities will have insufficient AMI 2.0 meter volumes to collapse both of the aforementioned networks. In this scenario, AMI 1.0 failures are estimated to peak at 30,000 failures in 2028, and the last AMI 1.0 network would have meters reaching 23 to 27 years of age.

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k) In early 2025, Alectra discussed with Measurement Canada the potential for dispensation from AMI 1.0 meter re-verification requirements. Measurement Canada advised that dispensation may be considered when there is reasonable certainty that meters will be replaced within a timeframe that does not put consumers at risk of inaccurate measurement. In general, Measurement Canada advised that for meters with expiring seals that are scheduled for replacement beyond a three-year time frame, it would be increasingly difficult to justify that consumers would not be at risk, and therefore requests for dispensation would likely not be approved.

Furthermore, dispensation requests are made for groups of homogeneous meters. The meters are situated throughout the AMI network, not necessarily in contained geographic locations. In practical terms, all AMI 1.0 meters within the network must be replaced within the 3-year time frame to expect Measurement Canada to approve a request for dispensation.

Based on this discussion, Alectra Utilities determined that if it were to implement the 7-year mass deployment alternative, it would be unlikely to receive dispensation from re-verification and resealing obligations for the majority of its AMI 1.0 meters.

This is because, to qualify for dispensation for expiring AMI 1.0 meter seals, Alectra Utilities would need to have confidence that 100% of those meters would be replaced within a three-year time frame.

However, due to the potential for rapidly increasing meter failure rates across all areas as the AMI 1.0 population ages, Alectra Utilities is unlikely to follow a sequential and coordinated replacement schedule with sufficient certainty. Moreover, under the 7-year alternative Alectra Utilities would not expect to collapse its second AMI 1.0 network prior to 2030.

Therefore, under the 7-year mass implementation scenario with mass deployment continuing through to 2033, Alectra Utilities assumes that it would not qualify for significant

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dispensation by Measurement Canada, and would be required to continue its re-verification and resealing compliance programs for the majority of its AMI 1.0 meters through to 2030.

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l) Please see the following table that presents the percentage of meters that will be fully depreciated at the time of removal under each of the mass deployment scenarios:

Table 5: Depreciated Meters by Deployment Alternative

Mass Deployment Alternative	**% of Total Meters (NBV = 0)**
3 year	78%
5 year	81%
5.5 year	82%
7 year	84%

m) Please see the table below which adds the recommended 5.5-year mass deployment alternative to B06-22. This plan shifts 50,000 meters to be completed in 2032. As the deployment will be substantially complete, it has been assumed that the benefits for reduced failures and dispensation will continue to be realized consistent with the 5-year deployment.

The table has also been revised to include the assumption of quantities reflected in each mass deployment scenario. The average inflation assumption for 2026 – 2031 is consistent with the Alectra Utilities capital portfolio at 2%.

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Table 6: Amended Table B06-22 Mass Deployment Alternatives

Capital Expenditures ($MM)	DSP: 2027 to 2031	DSP: 2032 to 2036	Total Project and Project Dependent Costs	Assumed Meter Quantities between 2027 and 2031
3-Year Mass Deployment Alternative				
AMI Renewal	257.4	0.0	257.4	950,000
AMI 1.0 Reactive Meter Failures	14.7	0.0	14.7	74,944
AMI 1.0 Meter Reverifications and resealing, beyond dispensation exemptions	5.5	0.0	5.5	9,488
Total 3-Year Deployment	**277.6**	**-**	**277.6**	
Accelerated Depreciation	*36.6*	*0.0*	*36.6*	
Total including Accelerated Depreciation	*314.2*	*0.0*	*314.2*	
5-Year Mass Deployment Alternative				
AMI Renewal	261.9	0.0	261.9	950,000
AMI 1.0 Reactive Meter Failures	23.6	0.0	23.6	89,173
AMI 1.0 Meter Reverifications and resealing, beyond dispensation exemptions	5.5	0.0	5.5	9,488
Total 5-Year Deployment	**291.0**	**-**	**291.0**	
Accelerated Depreciation	*25.6*	*0.0*	*25.6*	
Total including Accelerated Depreciation	*316.6*	*0.0*	*316.6*	
5.5 Year Mass Deployment Alternative				
AMI Renewal	247.6	14.3	261.9	900,000
AMI 1.0 Reactive Meter Failures	23.6	0.0	23.6	89,173
AMI 1.0 Meter Reverifications and resealing, beyond dispensation exemptions	5.5	0.0	5.5	9,488
Total 5.5-Year Deployment	**276.7**	**14.3**	**291.0**	
Accelerated Depreciation	*25.2*	*0.0*	*25.2*	
Total including Accelerated Depreciation	*301.9*	*14.3*	*316.2*	
7 Year Mass Deployment Alternative				
AMI Renewal	193.2	69.5	262.7	650,000
AMI 1.0 Reactive Meter Failures	35.5	6.2	41.7	132,546
AMI 1.0 Meter Reverifications and resealing, beyond dispensation exemptions	19.2	2.9	22.1	32,680
Total 7-Year Deployment	**247.9**	**78.6**	**326.5**	
Accelerated Depreciation	*15.7*	*0.0*	*15.7*	
Total including Accelerated Depreciation	*263.6*	*78.6*	*342.2*	

n) Table B06-22 did not include the impact from accelerating depreciation and has been included above for all scenarios.

o) Alectra has calculated the accelerated depreciation as the difference between the depreciation calculated using the adjusted (shortened) useful life of the AMI 1.0 meters and the depreciation calculated using the original useful life. Alectra has used financial models that align the remaining useful lives of the existing AMI 1.0 assets with the planned replacements of those meters with AMI 2.0 meters.

The following table shows the results of these calculations based on the asset components for each year.

Table 7: Accelerated Depreciation Calculations

	Accelerated Depreciation	Standard Depreciation	Difference
AMI 1.0 Meters Single Phase-Commercial	1,591,788	1,009,491	582,297
AMI 1.0 Meters Single Phase-Residential	6,699,506	3,825,429	2,874,078
AMI 1.0 Polyphase	7,013,933	1,861,485	5,152,447
Total 2027	**15,305,227**	**6,696,405**	**8,608,821**
AMI 1.0 Meters Single Phase-Commercial	1,591,788	1,009,491	582,297
AMI 1.0 Meters Single Phase-Residential	5,787,079	3,563,806	2,223,273
AMI 1.0 Polyphase	6,648,207	1,860,873	4,787,334
Total 2028	**14,027,074**	**6,434,170**	**7,592,903**
AMI 1.0 Meters Single Phase-Commercial	1,591,788	1,009,491	582,297
AMI 1.0 Meters Single Phase-Residential	5,490,448	3,267,175	2,223,273
AMI 1.0 Polyphase	3,461,082	1,856,868	1,604,214
Total 2029	**10,543,318**	**6,133,534**	**4,409,784**
AMI 1.0 Meters Single Phase-Commercial	1,561,791	979,495	582,297
AMI 1.0 Meters Single Phase-Residential	4,215,561	2,919,381	1,296,180
AMI 1.0 Polyphase	2,664,695	1,805,468	859,227
Total 2030	**8,442,046**	**5,704,343**	**2,737,703**
AMI 1.0 Meters Single Phase-Commercial	1,414,680	887,978	526,702
AMI 1.0 Meters Single Phase-Residential	3,241,449	2,671,803	569,647
AMI 1.0 Polyphase	2,470,447	1,710,766	759,680
Total 2031	**7,126,576**	**5,270,547**	**1,856,029**
AMI 1.0 Meters Single Phase-Commercial	7,751,834	4,895,946	2,855,888
AMI 1.0 Meters Single Phase-Residential	25,434,044	16,247,594	9,186,450
AMI 1.0 Polyphase	22,258,362	9,095,461	13,162,902
Total 2027-2031	**55,444,240**	**30,239,000**	**25,205,241**

The following example illustrates the calculations used to determine the accelerated depreciation amounts. In this example, the meters were originally purchased in 2020, with an original useful life of 15 years. Since these AMI 1.0 meters are scheduled to be replaced in 2028, their remaining useful life is shortened by 6 years.

Meters Installed	Jan 2020	
Meters Initial Cost	$10,000	
Original Useful Life	15 years	
Scheduled Replacement	Dec 2028	
NBV as of Jan 1, 2027 (a)	5,333,33	
	Current Annual Depreciation	**Accelerated Annual Depreciation**
Remaining UL as of Jan 1, 2027(b)	8 Years	2 Years
Depreciation per year (a)/(b)	666.67	2,666.67
Annual Incremental Depreciation		2,000.00

p) Alectra Utilities is aware of the following excerpts from previous OEB decisions where approval has been provided for accelerated depreciation expense related to meter replacements are provided in the chart below. This list may not be exhaustive.

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Table 8: Excerpts from OEB Decisions related to Accelerated Depreciation Expense

OEB Guideline/Decision	**Relevant Excerpt(s)**
OEB Guideline G-2011-0001 - Smart Meter Funding and Cost Recovery - Final Disposition (Dec 15, 2011), p. 14	"In addition, a smart meter incremental revenue requirement rate rider ("SMIRR") is established to recover the prospective annualized incremental revenue requirement for the approved smart meters, until the distributor's next cost of service application. The SMIRR continues until the effective date of the distributor's next cost of service rate order, at which time assets and costs are incorporated into the rate base and revenue requirement and recovered on a going forward basis through base rates."
Halton Hills Hydro Inc. - *EB-2011-0271* (Interim Rate Order, Jul 4, 2012), p. 6	"Rate Rider for Recovery of Stranded Meter Assets - effective July 1, 2012 - April 30, 2016" * Shows a Rate Rider for Recovery of Stranded Meter Assets with a multi-year fixed effective period
Hydro One Networks Inc. - *EB-2007-0681* (Decision, Dec 18, 2008), p. 101	"The parties agree that the Applicant's treatment of stranded meter costs is appropriate. In the Applicant's 2006 Distribution Rate Application, a comprehensive depreciation study prepared by Foster Associates was filed dealing with all of Hydro One's assets (Exhibit C1, Tab 7). Intervenors did not cross examine on the study and no witness testified about the study. As a result, on page 24 of its Decision in EB-2005-0378 the Board accepted the costs flowing from the study. As it relates to stranded meters, the depreciation study stated: "It is the opinion of Foster Associates that a responsible and appropriate treatment of the embedded base of

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	conventional meters (i.e., Account 1860) is amortization over a period of 5 years. The recommended amortization period is consistent with the Provincial initiative to replace all conventional meters by 2010.”

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 2-CCC-13

Ref: Exhibit 2A, Tab 1, Schedule 1, Appendix B07, pp. 297, 309-310

Question(s):

a) Please provide a table comparing the capital costs of the three options listed in section 7.4. Please provide the underlying calculation and explain any assumptions.

b) Please provide the following information with respect to the Kennedy Road South facility in a table:

i. In-Service Date
ii. Function
iii. Type of Project
iv. Building Sq. Ft. broken out between Administrative and Operational Functions
v. Location
vi. # of Acres
vii. FTEs working at facility
viii. Customers served by facility
ix. Total Capital Cost
x. Total Land Cost

c) With respect to the Kennedy Road South Facility, please provide a detailed table (i.e., line-by-line for each aspect of the total cost of the total building) showing both the original estimated cost and the final cost incurred.

d) For each of the cost increases experienced with respect to the Kennedy Road South Facility, as listed on pages 309-310, please provide the dollar value of the cost escalation relative to estimated.

RESPONSE:

a) The three options considered by Alectra were:
b)

- Option 1: Remain at Mavis Road and Sandalwood Parkway facilities on an 'as is' basis; continue to lease 3456 Mavis Road and use Alectra's substation yard at 7345 Bramalea Road for outside storage.

- Option 2: Redevelop the Mavis Road facility and remain at Sandalwood Parkway facility on an 'as is' basis.

- Option 3: Dispose of both Mavis Road and 175 Sandalwood Parkway facilities and relocate to a newly built Operations Centre.

Option 1 was eliminated as outlined in Exhibit 1, Tab 1, Schedule 1, section 7.4. The table below shows the initial assessment of options by Cresa. To reference the report prepared by Cresa please refer to 2A-SEC-53 (c). Please note that the options were updated and underlying assumptions described in 2A-SEC-53 (b).

Table 1 – Initial Assessment Options by Cresa

DESCRIPTION	OPTION 2	OPTION 3
Total Building Area	241,506 SF	155,000 SF (Original estimate)
Land Area	21.54 Acres	19.28 Acres
Proceeds from Sale(s)	$0	$40,000,000
Total Development Cost (Land & Building)	>$27,000,000	$82,769,694
Upfront Costs Less Sale Proceeds	>$27,000,000	$42,769.69
Total Occupancy Costs (20 Years)	$113,924,314	$93,406,972
PV Occupancy Costs	$67,666,129	$77,327,048
Average Annual Occupancy Cost	$5,696,216	$4,670,349

Alectra's final underlying assumptions, discount rate, and other considerations can be found in response to 2-SEC-53 (b).

Option 2 major considerations:

- The Preliminary Redevelopment Budget (2019) was based upon a preliminary site plan and was a Class "D" estimate only, that was subject to change. Additional testing, design and engineering was required for a more precise budget.

- No allowance carried for environmental remediation at Mavis Road

- Was deemed not to meet current and long-term operational needs

- Required relocation of operations to a temporary location which would increase operating costs and have an adverse impact on employees

- The rail line on the Mavis Road site reduced storage space and the efficiency of property and could not be removed

Option 3 major considerations:

- The Preliminary Proposal (2019) was based upon a preliminary programme and a Class "D" estimate only, that was subject to change. Additional testing, design and engineering was required for a more precise budget.

- Lower long-term annual operating costs due to building efficiencies

c)

Table 2 - 200 Kennedy Road South Building Summary

In-Service Date	December 2023	
Function	Interior fleet parking garage for Alectra critical fleet assets, warehouses, fleet shop, metering & substations shops, metering testing lab, office space for supporting groups. Exterior inventory storage yard and parking for employees and Alectra fleet assets.	
Type of Project	Design to Build	
Building SF (approx.)	Total building footprint between 2 floors	215,000 SF
Administrative Functions	Meeting/training rooms, server & IT rooms, lunchroom, washrooms, locker rooms, office space, etc.	83,000 SF
Operational Functions	Network Operations Warehousing Fleet Maintenance Shop Stations Sustainment Shop Meter Shop & Testing Lab Total	75,175 SF 33,900 SF 14,600 SF 2,495 SF 5,825 SF 131,995 SF

In-Service Date	December 2023
Location	200 Kennedy Road South, Brampton
Land Size (Acres)	19.238 Acres
FTEs at Facility	332 Employees (2025)
Customers Serviced	385,000 (Cities Mississauga & Brampton)
Total Capital Cost	$70.5 M
Total Land Cost	$53.3 M

d) Please see response to 2-AMPCO-45 a).

e) Please see response to 2-AMPCO-45 a).

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 2-CCC-14

Ref: Exhibit 2A, Tab 1, Schedule 1, Appendix B10, p. 406

Question(s):

For the residential and small commercial layout segment:

i. Please provide a table showing the 2020-2031 total gross expenditures, total capital contributions, total net expenditures, service connection volumes, and associated unit costs.

ii. Please provide the detailed spreadsheet(s) that support the 2027-2031 forecast on the basis of 2020-2023 volumes and historical unit cost pricing (plus EV related connections). Please show all assumptions that were applied.

iii. Please explain why 2020-2023 was selected as the appropriate historical period to use for estimating gross expenditures.

iv. Please advise which historical years were averaged to determine the 53% contribution level.

RESPONSE:

i. Please see Table 1 below showing the 2020-2031 total Gross Expenditures, Total Capital Contributions, Total Net Expenditures, Service Connection Volumes, and associated per unit costs:

Table 1 - Historical and Forecast – Residential and Small Commercial, Gross Costs, Contributions, Net and Volumes

LAYOUTS						
	YEAR	**QTY**	**TOTAL Gross $ MM**	**Per Unit Cost $**	**TOTAL Contributions $ MM**	**TOTAL Net $ MM**
HISTORICAL	2020	3039	$11.2	$3,687	-$5.0	$6.2
	2021	2768	$11.8	$4,266	-$5.9	$5.8
	2022	3321	$15.6	$4,687	-$7.1	$8.5
	2023	3468	$18.2	$5,253	-$8.8	$9.5
	2024	3325	$21.8	$6,561	-$9.2	$12.6
	2025 (Actual)	2521	$25.0	$9,926	-$10.7	$14.3
FORECAST	2026	3678	$15.9	$4,316	-$7.7	$8.2
	2027	4139	$18.1	$4,368	-$9.6	$8.4
	2028	4613	$20.4	$4,415	-$10.9	$9.5
	2029	5214	$22.9	$4,385	-$12.2	$10.7
	2030	5825	$25.9	$4,453	-$13.8	$12.1
	2031	5732	$26.1	$4,549	-$13.9	$12.2

NOTE: All dollar amounts are shown in $MM except the Average per unit cost. Minor variances may exist due to rounding.

ii. The 2020-2023 Volumes and Historical Costs are shown in Table 1 above. The Service Layout volumes with the EV volume breakdown for 2027-2031 is shown below in Table 2 below:

Table 2 - Forecasted Connection Volumes for Service Layouts (With and Without EV's)

Year	TOTAL QTY of All Other Connections (Layouts)	TOTAL QTY of EV Connections (Layouts)	TOTAL QTY of All Connections (Layouts)	Per unit cost	Total Gross $ MM	Total Contributions $ MM	Total Net $ MM
2027	2889	1250	4139	$4,368	$18.1	-$9.6	$8.4
2028	2889	1724	4613	$4,415	$20.4	-$10.9	$9.5
2029	2889	2325	5214	$4,385	$22.9	-$12.2	$10.7
2030	2889	2936	5825	$4,453	$25.9	-$13.8	$12.1
2031	2889	2843	5732	$4,549	$26.1	-$13.9	$12.2

NOTE: All dollar amounts are shown in $MM except the Average per unit cost. Minor variances may exist due to rounding.

Assumptions

Alectra Utilities has provided layout volumes in Table 1 and 2.

The following assumptions were used in calculating the forecast:

a. Average historical 2020-2023 service connection volumes and historical unit cost pricing were applied as the initial basis to determine the forecasted volumes and gross expenditures in Layouts.
b. The EV-related service upgrades are explained 1-DRC-02.
c. Layouts are forecasted to include 53% contributed capital after 2027.

iii. Starting 2020, Alectra had harmonized its Conditions of Service and related processes across its service territory, making the 2020-2023 period representative of current operating practices. Please refer to EB-2025-0252, Exhibit 2A, Tab1, Schedule 1, Page 406, lines 13-22.

iv. The average contribution level of 53% was based on historical data from 2020-2023 and appropriate adjustments for the removal of small commercial service credits, from 2027 onwards.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 2-CCC-15

Ref: Exhibit 2A, Tab 1, Schedule 1, Appendix B10, p. 406

Question(s):

For the new ICI services segment:

i. Please provide a table showing the 2020-2031 total gross expenditures, total capital contributions, total net expenditures, service connection volumes, and associated unit costs.

ii. Please further explain the remaining 2% of net costs for the forecast period. More specifically, please discuss why there would be payments for removed equipment and why Alectra would be responsible for funding any of the costs related to this program.

RESPONSE:

i. The table below summarizes the 2020-2031 Total Gross Expenditures, Total Capital Contributions, Total Net Expenditures, Service Connection Volumes and Associated Unit Costs:

Table 1 – 2020-2031 Total Gross Expenditures, Total Capital Contributions, Total Net Expenditures, Service Connection Volumes and Associated Unit Costs

ICI						
	YEAR	Service Connection Volumes	TOTAL Gross Expenditures ($) MM	AVG Gross Unit Cost	TOTAL Capital Contributions ($) MM	TOTAL Net Expenditures ($) MM
Historical	2020	165	$16.9	$102,591	-$12.5	$4.4
	2021	229	$19.3	$84,406	-$16.6	$2.7
	2022	259	$19.3	$74,338	-$16.1	$3.1
	2023	265	$29.2	$110,205	-$26.1	$3.1
	2024	297	$27.2	$91,441	-$25.2	$1.9
	2025 (Actual)	242	$39.1	$161,549	-$37.9	$1.1
Forecast	2026	292	$31.4	$107,557	-$28.1	$3.3
	2027	297	$32.3	$108,831	-$31.6	$0.8
	2028	303	$33.4	$110,306	-$32.6	$0.8
	2029	310	$34.1	$109,857	-$33.2	$0.8
	2030	319	$35.7	$111,821	-$34.8	$0.9
	2031	337	$38.7	$114,722	-$37.7	$0.9

NOTE: All dollar amounts are shown in $MM except the Average per unit cost. Minor variances may exist due to rounding.

ii. For ICI services, there may be instances where existing poles or other distribution assets located within the public right-of-way must be altered to accommodate a new or modified service connection. In some cases, the assets being replaced still have a remaining netbook value. In accordance with Alectra's standard connection practices, the customer is responsible for the costs associated with the removal and replacement of such assets, based upon the remaining netbook value and advancement of costs as determined by Alectra. As a result, a net portion of the costs may be covered by Alectra. These net costs are expected to represent approximately 2% of gross expenditure over the forecast period.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 2-CCC-16

Ref: Exhibit 2A, Tab 1, Schedule 1, Appendix B10, pp. 402, 406-408

Question(s):

a) With respect to the 2025 bridge year forecast connections set out in Table B10-6, please advise when that forecast was made.

b) Alectra states that it "expects connection and development to trend upwards across the utility's service territory from 2027 to 2031…". Please advise whether Alectra has seen decreases in housing starts (both subdivision and condo) in its service territory in 2025 relative to its forecasts for that year. If so, please explain if / how those lower housing starts are reflected in the Company's forecast for the 2026 bridge year and the forecast period.

c) Separately, for each of the specific components of the new subdivisions segment (i.e., residential subdivisions, high rise condominiums, new ICI subdivisions, developer relocation work for subdivisions, and damage/restoration), please provide tables showing the 2020-2031 total gross expenditures, total capital contributions, total net expenditures, connection volumes (lots, condominium buildings, etc.), and associated unit costs.

d) For the residential subdivision sub-component (separate from high rise condominiums):

   i. Please provide the detailed spreadsheet(s) that support the 2027-2031 forecast (gross expenditures and capital contributions). Please also show all assumptions that were applied.

ii. Please explain why the gross average unit cost for the 2022-2024 period was selected as the appropriate sample to determine the forecast gross costs.

iii. Please advise which years of the historical period were used to establish the capital contribution forecast.

e) For the high rise condominiums sub-component (separate from residential subdivisions):

i. Please provide the detailed spreadsheet(s) that support the 2027-2031 forecast (gross expenditures and capital contributions). Please also show all assumptions that were applied.

ii. Please explain why the gross average unit cost for the 2022-2024 period was selected as the appropriate sample to determine the forecast gross costs.

iii. Please advise which years of the historical period were used to establish the capital contribution forecast.

iv. Please provide a list of proposed developments (which are set in Appendix B13) that are considered part of the growth driving the high rise condominium connection program specifically. Please further explain the volume reduction applied to this program relative to the Appendix B13 forecast.

f) Alectra states that “a recent regulatory policy changed the revenue horizon in the economic model (DSC EB-2024-7 0092) from 25 to 40 years.” Please advise whether this change impacted the capital contributions for both the residential subdivisions and the high rise condominiums. Please also provide an estimate of impact of this policy change on the contributed capital percentage (i.e., difference between expected capital contributions based on the previous policy relative to the new policy).

g) Please confirm that the statement that the "forecasting approach is conservative, as it only accounts for the connections from identified developments" is with reference to the high rise condominium sub-program. If not, please explain.

h) For each of the new ICI subdivisions, developer driven relocation work for subdivisions and damage/restoration components of the subdivisions program, please provide a detailed explanation of the forecasting methodology applied and provide the underpinning spreadsheets that support the forecasts.

RESPONSE:

a) The forecast connections set out in EB-2025-0252, Exhibit 2A, Tab 1, Schedule 1, Appendix B10, Page 402, Table B10-6 was completed in 2024.

b) Alectra Utilities expects the connection and development activity to trend upwards across its service territory from 2027 to 2031. In 2025, the actual Gross expenditures ($49.9MM) for Subdivisions projects were close to the record spend incurred in 2024 ($53.2MM). Although the actual number of connections in 2025 were lower as compared to those provided in EB-2025-0252, Exhibit 2A, Tab 1, Schedule 1, Appendix B10, Page 402, Table B10-6, this was also accompanied by an increase in the actual gross average unit costs ($8,591) as compared to the average gross unit cost ($7,610) utilized in the forecast. In addition to this, Alectra Utilities expects continued growth in Subdivisions development across the utility's service territory based on Provincial initiatives, forecasted population and household growth as described in EB-2025-0252, Exhibit 2A, Tab 1, Schedule 1, Appendix B13, Page 481-547. In response to this, the reduction in connection volumes in 2025 have not been adjusted in the 2026 bridge year or the forecast period.

c) Please refer to 2-CCC-16_Attach 1 – Subdivisions Budget for 2020–2031 for the total gross expenditures, total capital contributions, and total net expenditures, presented separately for each specific component of the new subdivisions segment.

For connection volumes and associated unit costs for the period 2020–2031, please refer to the Table 1 below.

Table 1 - Connection Volumes and Associated Unit Costs

Year	Residential Lots		High Rise Condominium	
	Quantity	Unit Cost	Quantity	Unit Cost
2020	Not Available			
2021	5608	$ 4,652	1	$ 749,520
2022	5424	$ 6,810	37	$ 360,356
2023	4609	$ 8,642	38	$ 207,384
2024	5350	$ 7,380	10	$ 130,576
2025(Actual)	3505	$ 8,591	5	$ 728,855
2026	5231	$ 7,918	26	$ 242,176
2027	5283	$ 8,076	26	$ 247,019
2028	5336	$ 8,238	26	$ 251,960
2029	5389	$ 8,402	27	$ 256,999
2030	5443	$ 8,570	30	$ 262,139
2031	5498	$ 8,742	34	$ 267,382

d)

i. Alectra Utilities has provided the forecast for residential subdivisions from 2027-2031 as shown in Table 2 below. The following assumptions were used in calculating the Forecast:

The Historical Economic Evaluation Model (EEM) data from the 2022-2024 period was used to calculate the average annual volumes (5,128) and average gross unit cost ($7,610). Additionally, a 1% annual increase in the average annual volumes and a 2% annual inflation rate on the average gross unit costs were used. The contribution rate of 58% was determined by calculating the average annual contribution % from the historical expenditures.

Table 2 - Forecast Residential Subdivisions Gross Costs and Contributions

Forecast Residential Subdivisions Costs				
YEAR	**QTY**	**Gross Unit cost $**	**TOTAL Gross $MM**	**TOTAL Contribution $MM (58%)**
2027	5283	$8,076	$ 42.7	-$ 24.7
2028	5336	$8,238	$ 44.0	-$ 25.5
2029	5389	$8,402	$ 45.3	-$ 26.3
2030	5443	$8,570	$ 46.7	-$ 27.1
2031	5498	$8,742	$ 48.1	-$ 27.9

ii. The gross average unit cost from the EEM data for the 2022-2024 period was used as the basis for the forecast to ensure the accuracy of the analysis for future years, as these years represented the most current pricing available at the time of the forecast.

iii. The contribution rate of 58% was determined by calculating the average annual contribution % from the historical expenditures from 2022 to 2024.

e)

i. Alectra Utilities has provided the forecast for high-rise condominium subdivisions from 2027-2031 as shown in Table 3 below. The following assumptions were used in calculating the Forecast:

The Historical EEM data from the 2022-2024 period was used to calculate the average annual volumes (28 GS>50 connections) and average gross unit cost ($232,772). The forecast for the quantities is based on high-level site plan information derived from planned investments as noted in EB-2025-0252, Exhibit 2A, Tab 1, Schedule 1, Appendix B13, Page 497-547. Consistent with the Residential subdivision lots in part d) above, a 2% annual inflation rate on the average gross unit cost was also used. Similarly, the historical contribution rate of 58% that was determined by calculating the average annual contribution % from the historical expenditures from 2022 to 2024 was initially used. Following the amendments to the DSC that extended the connection and revenue horizons, Alectra Utilities compared sample calculations, based on representative high-rise condominium connection scenarios modeled under both the previous and amended DSC revenue and connection horizons, which showed an approximate 12% reduction to the historical capital contribution required. In light of this observation, Alectra Utilities adjusted the forecast contribution rate for high-rise condominium developments, which resulted in an overall contribution rate of 46%. The 46% contribution rate was applied to the forecast for determining the high-rise condominium development costs.

Table 3 - Forecast High Rise Condominium Gross Costs and Contributions

Forecast High Rise Condominium Development Costs				
YEAR	QTY	Gross Unit Cost $	TOTAL Gross $MM	TOTAL Contribution $MM (46%)
2027	26	$247,019	$6.4	-$3.0
2028	26	$251,960	$6.6	-$3.0
2029	27	$256,999	$6.9	-$3.2
2030	30	$262,139	$7.9	-$3.6
2031	34	$267,382	$9.1	-$4.2

ii. The Gross average unit cost from the EEM data for the 2022-2024 period was used as the basis for the forecast to ensure the accuracy of the analysis for future years, as these years represented the most current pricing available at the time of the forecast.

iii. The contribution rate of 46% was determined by calculating the average annual contribution % from the historical expenditures from 2022 to 2024 as well as factoring in the extended revenue horizon as per the DSC amendments.

iv. Alectra Utilities has provided a list of proposed developments based on expected growth areas listed under Appendix B13 as shown in Table 4 below.

Table 4 - Estimated High Rise Condo Connections between 2027-2031

Rate Zone	Project	Est Connections	2027	2028	2029	2030	2031	Est Condo Connections 2027-2031
ERZ	Brightwater	**4**	1					**1**
	Lakeview	**15**		1	3	3	3	**10**
	Rangeview	**15**		1	3	3	5	**12**
	Downtown	**6**	1					**1**
	Hwy10 & Eglinton	**5**	1		1	1		**3**
BRZ	Block 52	**24**	3	3	2	3	4	**15**
	Block 48	**6**	2	2	2			**6**
	Bramwest	**16**	2	2	1	1	1	**7**
	Downtown/Uptown	**8**		1		1	2	**4**
	Block 47	**10**	2		2	1	1	**6**
HRZ	Downtown, Lakeshore, Waterdown	**4**		2			1	**3**
	Rymal	**5**	2	2				**4**
GRZ	Downtown	**6**				2	2	**4**
PRZ	Yonge & Steeles	**16**						**0**
	Kylemore & Upper Markham	**6**		3		3		**6**
	Langstaff Gateway	**25**	3	3	4	5	6	**21**
	Block 27	**8**	2	2	3	1		**8**
	Hwy 48	**3**		1	1	1		**3**
	Angus Glen	**6**			3		3	**6**
	Block 41	**4**	2	2				**4**
	VMC	**24**	5	1	2	5	6	**19**
TOTAL		**216**	**26**	**26**	**27**	**30**	**34**	**143**

The total number of connections for the various projects listed in Table 4 above is estimated to be 216. Alectra Utilities anticipates around 143 connections to materialize during the forecast period between 2027-2031 which is approximately 66% of the total connections. Therefore, a volume reduction of 73 connections has been applied to this program to reflect that fact that it's unlikely all connections will occur within the forecast period.

f) Alectra believes that the change in connection and revenue horizon will reduce the overall amount of capital contributions based on the new policy. The expected contribution rate received by condo development projects was adjusted from 58% to 46%. For residential units, Alectra Utilities maintained the contribution rate at 58%. However, early indication is that even residential units will see reduced contributions, but to a lesser extent than condos.

g) Yes, the statement that the “forecasting approach is conservative, as it only accounts for the connections from identified developments.” as mentioned in EB-2025-0252, Exhibit 2A, Tab 1, Schedule 1, Appendix B10, Page 408, applies only to the forecast for the high rise condominium development costs.

h) Average historical actuals expressed as a percentage were used to forecast the total gross costs for ICI subdivisions, developer-driven relocation work for subdivisions and the Damage and Restoration components of the subdivision program. Table 5 below provides the percentages used to calculate the total gross costs for the 3 categories. Net values for ICI Subdivisions are based on 58% contributed capital. Damage and Restoration is 100% contributed by the developer.

Table 5 – Percentage splits used to determine Gross Expenditures for the 3 Categories (ICI Subdivisions, Capital Plant Relocations and Damage & Restoration

Category	% of the Total Gross$
ICI Subdivisions	**7.2%**
Cap Plant Relocation	**2.3%**
Damages & Restoration	**0.2%**

These three categories account for approximately 10% of the annual Subdivisions gross budget.

2-CCC-16

Attachment 1
Subdivisions Budget, Volume and Unit Costs

Please see live Excel

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 2-CCC-17

Ref: Exhibit 2A, Tab 1, Schedule 1, Appendix B10, pp. 400

Question(s):

a) Please add columns to Table B10-3 that provide the forecast in-service date for each VLP and the component of the customer connections project where the project funding is included.

b) For each VLP, please provide detailed spreadsheet(s), including all the assumptions made, that show how the cost estimates were developed. As part of the response, please show how the capital contribution for each VLP was forecast.

c) For each of the VLPs where there is no forecast capital contribution (e.g., Project 153236), please explain why the project does not attract contributed capital.

RESPONSE:

a) Columns have been added to Table B10-3 that provide the forecast in-service date for each VLP, as well as the dollar amount for customer connections portion of the project (gross – net).

1 **Table 1 - Forecast In-service Date for Each VLP**

Project Code	Project Name	Net 2027-2031 ($MM)	Gross 2027-2031 ($MM)	Expected In-service Date
151584	Customer Initiated Distribution System Project (West) McMaster Innovation Park - Dedicated Feeder- Business Park	5.9	8.8	2029
152335	HaLRT OMSF Expansion	5.7	11.6	2031
152482	Customer Initiated Distribution System Expansion Project - Trillium Health Partners	7.6	9.4	2028
152602	Customer Initiated Distribution System Expansion Project - GTAA Feeders	9.5	9.5	2028
152676	Lakeview Expansion	6.6	9.2	2030
153088	Customer Initiated Distribution System Expansion Project (East) DC5/DC6 Urbacon Date Centers	13.7	17.1	2029
153090	YNSE - TPSS System Expansion	0	41.4	2031
153092	HaLRT - TPSS 4 System Expansion	9.2	11.5	2029
153134	HaLRT TPSS 8 Expansion	3.1	14.5	2039
153229	Customer Initiated Distribution System Expansion Project - 2395 Speakman Drive	10.6	16.9	2028
153230	Customer Initiated Distribution System Expansion - Toronto Gore (Block 47)	15.3	15.3	2029
153231	Customer Initiated Distribution System Expansion (East South) - Angus Glen Developments	11.1	11.1	2028

Project Code	Project Name	Net 2027-2031 ($MM)	Gross 2027-2031 ($MM)	Expected In-service Date
153233	Customer Initiated Distribution System Expansion (East South) - Block 27	5.9	5.9	2028
153236	Customer Initiated Distribution System Expansion Project - Block 52 Mississauga Rd & Williams Pkwy	29.0	29.0	2028

b) Detailed spreadsheet estimates are not created for VLPs. The project estimates are based on high-level scopes, as simple as a location, and are based on representative similar past projects. The estimates are typically based on the distance to the closest source that has available capacity with the pole line configuration as a base. For the ICI customer-driven system expansion projects, capital contributions were based on preliminary economic evaluation model results (which factors in the customers' total load as well as the gross estimated cost to construct the project). For subdivision driven system expansions, it is assumed that there will be no customer capital contribution – see c) below for further explanation.

c) As noted in b), VLPs that are predominantly residential are forecasted to be entirely customer capital contributed. This is because the internal subdivision system expansion portion costs are typically higher than the forecasted revenue generated. The vast majority of subdivision system expansions result in some sort of cost split between the developer and the utility. Therefore, any further costs beyond the subdivision itself (i.e., the system expansion required to service the subdivision) are typically 100% contributed by the customer.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 2-CCC-18

Ref: Exhibit 2A, Tab 1, Schedule 1, Appendix B10, pp. 408-410

Question(s):

a) Separately, for each of the specific components of the customer initiated segment (i.e., known customer initiated expansion and relocation projects (both above and below $5M), unspecified customer initiated expansion and relocation projects, transit expansion projects, and customer initiated joint use projects), please provide tables showing the 2020-2031 total gross expenditures, total capital contributions, and total net expenditures.

b) Please provide a table listing all of the known customer initiated expansion projects that underpin the 2027-2031 forecast. As part of the table, please include the forecast in-service date and both the gross and net capital cost.

c) Please advise whether the capital contribution forecast for the known customer initiated expansion projects is entirely based on the result of the economic evaluation model run for each of these known projects.

d) For the unspecified expansion projects component of the customer initiated expansion and relocation projects segment:

i. Please provide the detailed spreadsheet(s) that support the 2027-2031 forecast (gross expenditures and capital contributions). Please also show all assumptions that were applied. As part of the response, please also discuss how Alectra determined the baseline for "unspecified expansion projects" (i.e., did it remove

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certain projects from the historical gross expenditures to reflect that it is separately forecasting known projects in the future)?

ii. Please explain why gross expenditures for the 2022-2024 period was selected as the appropriate sample to determine the forecast gross costs. Please also explain why 2024 is described as a forecast with respect to the unspecified projects.

iii. Please advise which years of the historical period were used to establish the capital contribution forecast.

e) For the unspecified relocation projects component of the customer initiated expansion and relocation projects segment:

i. Please provide the detailed spreadsheet(s) that support the 2027-2031 forecast (gross expenditures and capital contributions). Please also show all assumptions that were applied. As part of the response, please also discuss how Alectra determined the baseline for "unspecified expansion projects" (i.e., did it remove certain projects from the historical gross expenditures to reflect that it is separately forecasting known projects in the future)?

ii. Please advise which years of the historical period were used to establish the capital contribution forecast.

f) For the transit expansion projects component of the customer initiated segment:

i. Please confirm that only known projects are included as part of the 2027-2031 forecast budget.

ii. Please provide a table listing all of the known customer initiated transit expansion projects that underpin the 2027-2031 forecast. As part of the table, please include the forecast in-service date and both the gross and net capital cost.

RESPONSE:

a) Attached is an excel file named "2-*CCC-18_Attach 1_B10 Detailed Spending and Forecast*" file. This file contains the details for Gross, Net and Contributions for the Customer Initiated Projects for the 2027-2031 forecast.

b) The known customer-initiated expansion projects that underpin the 2027-2031 forecast are included in the excel file named "2-*CCC-18_Attach 1_B10 Detailed Spending and Forecast*", along with the in-service dates.

Please note that the attached project list was created in 2024. At that time, the project's start dates and expenditures were based on the information provided by the customers. Since then, some projects have been delayed into future years, resulting in significantly reduced actual spending for 2024 and 2025, shown in the attached table. These delayed projects are still active and are on target to start in 2026 or later, however the attached table does not include the spending required for these delayed projects in the future years. For example, Customer Initiated Distribution Expansion - East South - Project Rainbow Site 2 was scheduled to start in 2024 and the gross expenditures for 2024 and 2025 were estimated at $2,939,698 and $14,468,820 respectively, but the actual gross spending for these two years was only $476,352. As a result, it is estimated that the remaining balance of $16.9M will be spent in 2027 and 2028.

c) For the VLP projects, the contribution forecast is based on the results from the preliminary economic evaluation model, based on the initial information provided. In cases where the expansion is servicing predominately residential, the contribution forecast is assumed to be 100%. For all other system expansion projects, the contributions forecasts are based on historical data.

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d)

i. The attached "*2-CCC-18_Attach 1_B10 Detailed Spending and Forecast*" excel file provides the details on Gross, Net and Contributions for the Customer Initiated Projects. For the unspecified projects component and known projects below the VLP threshold, the average gross expenditures from 2022 to 2024 were used as a baseline to forecast future expenditures. There can be exceptions to this in a given year, where several known project costs exceed the average annual historical expenditures. The 2024 is described as a forecast with respect to the unspecified projects because the 2024 actuals were not available at the time when the forecast was being created.

Estimates for known specific VLP projects were created based on high level estimates for projects of similar past scopes and magnitudes and have discrete individual project budgets prepared, and individual business cases created.

ii. The gross expenditures for 2022 to 2024 best reflected the typical spending levels that are likely to continue in the future. In 2020 and 2021, the number of system expansions was significantly lower when compared with the latter years, likely due to the COVID 19 pandemic, as well as issues with supply chain. This is noticeable compared with the 2025 system expansion projects where the actual gross spending was even higher than the average from 2022 to 2024. In addition, prior to 2022, the overall budget and the corresponding business cases for Expansion Projects and Relocation Projects were combined into one business unit, which resulted in unclear individual results for both.

iii. As stated on Page 409, Schedule 1, Tab1, Exhibit 2A, 2022 to 2024 were used for forecasting.

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e)

i. Refer to the response above, part d) subsection i).

ii. Refer to the response above part d) subsection ii).

f)

i. Alectra confirms that only known Transit expansion projects are included as part of the 2027-2031 forecast budget.

ii. The known transit expansion projects that underpin the 2027-2031 forecast are included in the excel file named "2-*CCC-18_Attach 1_B10 Detailed Spending and Forecast*", along with the in-service dates.

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2-CCC-18

Attachment 1
B10 Detailed Spending and Forecast

Please see live Excel

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 2-CCC-19

Ref: Exhibit 2A, Tab 1, Schedule 1, Appendix B10, p. 410

Question(s):

For the transit connections segment of the customer connections program, please provide a table showing the 2020-2031 total gross expenditures, total capital contributions, and total net expenditures.

RESPONSE:

Table 1 shows the 2020-2031 total gross expenditures, total capital contributions, and total net expenditures for the transit connections segment of the customer connections program.

Table 1 - Transit Connection Expenditures

	Years	Transit Connections		
		Gross in $MM	Contributions in $MM	Net Expenditures in $MM
Historical Spending	2020A	0	0	**0**
	2021A	0	0	**0**
	2022A	0.2	0	**0.2**
	2023A	0.3	-0.1	**0.2**
	2024A	0.5	-0.8	**-0.3**
Bridge Years	2025A	4.3	-3.1	**1.2**
	2026	0.2	-0.2	**0**
Forecast Spending	2027	0.3	-0.3	**0**
	2028	0.3	-0.3	**0**
	2029	0.5	-0.5	**0**
	2030	0.4	-0.4	**0**
	2031	0.4	-0.4	**0**

All dollar amounts shown are in $MM. Minor variances may exist due to rounding.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 2-CCC-20

Ref: Exhibit 2A, Tab 1, Schedule 1, Appendix B11, pp. 427-432

Question(s):

a) For each of unspecified projects and known projects in the road authority segment, please provide tables showing the 2020-2031 total gross expenditures, total capital contributions, and total net expenditures.

b) For the unspecified projects component of the road authority segment:

i. Please provide the detailed spreadsheet(s) that support the 2027-2031 forecast (gross expenditures and capital contributions). Please also show all assumptions that were applied. As part of the response, please also discuss how Alectra determined the baseline for "unspecified road authority projects" (i.e., did it remove certain projects from the historical gross expenditures to reflect that it is separately forecasting known projects in the future)?

ii. Please discuss Alectra's approach to forecasting the probability that a road authority-related relocation project will also incur system enhancement-related costs.

iii. Please explain why gross expenditures for the 2020-2024 period was selected as the appropriate sample to determine the forecast gross costs.

iv. Please advise which years of the historical period were used to establish the capital contribution forecast of 35%.

c) Please confirm our understanding that there are 6 known road authority projects forecast for the 2027-2031 period (Table B11-6). For each of those known projects, please provide a table that shows the gross capital, capital contribution and net capital amounts. Please also provide the expected in-service date and whether the project is considered a relocation or a relocation with system enhancement.

RESPONSE:

a) Refer to the excel file titled "*2-CCC-20_Attach 1_B11 Detailed Spending and Forecast*" Tab a, for the details on unspecified projects and known projects in the road authority segments, including Gross, Net and Contributions for the Road Authority Projects.

b)

i. Refer to the excel file titled "*2-CCC-20_Attach 1_B11 Detailed Spending and Forecast*" Tab b for the details on the unspecified projects component of the Road Authority segment, including on Gross, Net and Contributions for the Road Authority Projects.

Please note that the attached project list was created in 2024. At that time, the project's start dates and expenditures were based on the information provided by the Road Authority or the customers driving the relocations. Since then, some projects have been delayed into future years, resulting in reduced actual spending for 2024 and 2025, shown in the attached table. These delayed projects are still active and are on target to start in 2026 or later, however the attached table does not include the spending required for these delayed projects in the future years. For example, Road Authority UG Relocation - Portage Pkwy was scheduled to start in 2025 and the gross expenditure for 2025 was estimated at $2,780,325, but the actual gross spending for the same year was only $42,960. As a result, it is estimated that the remaining balance of $2.7M will be spent in 2027.

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Aggregated average annual historical expenditures by region were used to forecast the expenditures for unspecified projects and known projects below the VLP threshold. Forecast adjustments for unspecified projects were made per region based on known projects.

ii. When designing any Road Authority projects, the Design and System Planning teams review the distribution system requirements, as well as other expansions that are required in the area, to identify opportunities for system enhancements that align with long-term planning and project coordination.

iii. As stated in Exhibit 2A, Tab 1, Schedule 1, the aggregated average annual historical expenditures by region were used to forecast the expenditures for unspecified projects and known projects below the VLP threshold. In some years, where several known project costs exceed the average annual historical expenditures, the unspecified project budgets were reduced to account for the additional known projects.

The gross expenditures for the 2020-2024 period were selected as the appropriate sample to determine the forecast gross costs because it best reflected the typical spending levels that are likely to continue in the future. It is noted that the 2025 Road Authority relocation projects had a higher gross spending than the average from 2020 to 2024.

iv. Alectra Utilities has used various projects from within the 2020 to 2024 historical period to calculate the 35% cost allocation for annual forecasting. Alectra utilities selected several projects that were representative of a typical Road Authority scope. There were no specific enhancements associated with these projects, and the cost sharing followed the PSWHA. The 35% contribution for the Road Authority projects results from Alectra paying 100% of the costs associated with the materials, as well as 50% of the costs associated with the labour and labour saving devices.

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c) Refer to the excel file "*2-CCC-20_Attach 1_B11 Detailed Spending and Forecast"* Tab c for the details on Gross, Net and Contributions for the Road Authority Projects.

Table B11-6 shows material Road Authority investments only, which include any projects with a net spend above $1MM for 2027-2031. The excel file shows seven (7) projects; project number 151648 is listed because it was previously a project with net spend above $1MM. The in-service date for each project is identified by the last year of spending indicated in the excel file. The projects listed are all considered road relocation projects. At the time of forecasting, detailed scopes and designs had not been completed for each project, because the road authority design is not advanced enough. If a system enhancement is identified, the appropriate portion is allocated to rate base, and the necessary budgets are adjusted for the year in which the capital spending will occur.

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2-CCC-20

Attachment 1
B11 Detailed Spending and Forecast

Please see live Excel

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 2-CCC-21

Ref: Exhibit 2A, Tab 1, Schedule 1, Appendix B11, p. 438

Question(s):

Please provide a revised version of Table B11-9 that shows gross capital, capital contributions and net capital amounts.

RESPONSE:

Please refer to Table 1 below that shows shows gross capital, capital contributions and net capital amounts.

Table 1 – Transit Projects Gross Capital, Capital Contributions, Net Capital

Year	$MM
2020 Gross Actual	28.1
2020 Contribution Actual	-27.6
2020 Net Actual	0.5
2021 Gross Actual	12.2
2021 Contribution Actual	-12.9
2021 Net Actual	-0.7
2022 Contribution Actual	-13.2
2022 Net Actual	0.1
2022 Gross Actual	13.3

Year	$MM
2023 Gross Actual	56.1
2023 Contribution Actual	-56.4
2023 Net Actual	-0.3
2024 Gross Actual	29.2
2024 Contribution Actual	-29.3
2024 Net Actual	-0.1
2025 Gross Actual	35.2
Contribution Actual	-35.0
2025 Net Actual	0.1
2025 Gross Plan	71.6
2025 Contribution Plan	-71.2
2025 Net Plan	0.4
2026 Gross Plan	45.1
2026 Contribution Plan	-43.0
2026 Net Plan	2.1
2027 Gross Plan	26.4
2027 Contribution Plan	-22.2
2027 Net Plan	4.2
2028 Gross Plan	15.1
2028 Contribution Plan	-11.0
2028 Net Plan	4.1
2029 Gross Plan	24.8

Year	$MM
2029 Contribution Plan	-24.8
2029 Net Plan	0.0
2030 Gross Plan	25.2
2030 Contribution Plan	-25.2
2030 Net Plan	0.0
2031 Gross Plan	25.7
2031 Contribution Plan	-25.7
2031 Net Plan	0.0

All dollar amounts shown are in $MM. Minor variances may exist due to rounding.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 2-CCC-22

Ref: Exhibit 2A, Tab 1, Schedule 1, Appendix B12, pp. 453, 469

Question(s):

a) Please advise whether the line capacity program reflects any contributed capital. If so, please provide a revised version of Table B12-1 that shows gross capital, capital contributions and net capital amounts.

b) If the line capacity program does not attract contributed capital, please explain why that would be the case for the greenfield expansion and downtown intensification segments.

c) Please provide a revised version of Table B12-5 that shows the in-service date for each of the line capacity projects and note whether the project is considered system expansion or system enhancement. Please also include an explanation for the treatment of each project as either a system expansion or system enhancement.

RESPONSE:

a) Yes, the Line Capacity program includes two projects with identified and specific customer connections for which capital contributions have been identified. Alectra Utilities has provided an expanded Table B12-1 (gross capital, capital contributions, and net capital) in Table 1 below.

b) Alectra Utilities notes that contributed capital is determined through the customer connection cost responsibility process in accordance with the Distribution System Code and applies where costs are directly attributable to a specific customer connection.

The Lines Capacity program in Appendix B12 is a System Service investment to provide feeder capacity from new or existing TSs and MSs into general areas of growth, relieve loading constraints, and maintain compliance with Alectra Utilities system planning criteria, while preserving safe and reliable service for existing and anticipated customers.

Accordingly, where Lines Capacity projects are driven by broader system needs (shared upstream feeder capacity and reliability benefits) and not a discrete customer-specific connection request, the lines capacity projects would not be expected to have capital contributions.

Greenfield expansion driven Lines Capacity projects provide feeder capacity from new or existing TS/MS supply points to growth areas with constrained or limited distribution infrastructure and increasing demand. Such projects are planned upstream distribution reinforcements that provide capacity with growing service areas and ensure system readiness to accommodate growth within required service levels. These are system enhancement projects and that are not driven by, or attributable to, a single connection request. However, if work is required to accommodate specific customer load connections, Alectra Utilities' practice is to attain capital contribution.

Intensification driven Lines Capacity projects reinforce feeders within existing urban centers to accommodate forecast demand increases associated with general area redevelopment and higher density, while maintaining safe and reliable service for existing customers in the area. The drivers of such investments include aggregated load growth and system constraints and not a single customer-specific connection. Similar to Greenfield Expansion projects, intensification driven Lines Capacity projects are system enhancement projects and are not driven by, or attributable to, a single connection request. However, if work is required to accommodate specific customer load connections, Alectra Utilities' practice is to attain capital contribution.

c) Refer to Table 1 and Table 2 below for the requested information.

1 **Table 1 - Lines Capacity Projects – Gross Cost, Capital Contribution, Net Costs, In-service Date and Project Type**

Operating Area	Station Capacity Projects		Lines Capacity Projects							
	Project ID	Project Name	Project ID	Project Name	In-service Date	Gross Cost ($MM)	Capital Contribution ($MM)	Net Cost ($MM)	Project Type	Rationale[1]
East (Alliston, Aurora, Beeton, Barrie, Bradford, Markham, Tottenham, Penetangu-ishene, Richmond Hill, Thornton and Vaughan)	101488	Build Markham TS #5	101489	Markham TS#5 Feeder Integration - Part 1	> 2031	17.4	0	17.4	Enhancement	See Table 2 #1
	101488		101490	Markham TS#5 Feeder Integration - Phase 2	> 2031	16.8	0	16.8	Enhancement	See Table 2 #2
	101542	New Barrie 20 MVA Substation	100461	New Barrie 20MVA Substation - 13.8kV Feeder Integration	> 2031	2	0	2	Enhancement	See Table 2 #3
	152909	New Alliston 2x20MVA MS	101571	New Alliston 2 x 20MVA Substation - 13.8kV Feeder Integration	2029	1	0	1	Enhancement	See Table 2 #4
	152762	Vaughan MTS#5-VMC	152763	VTS#5 Feeder Integration Part 1	> 2031	11.1	0	11.1	Enhancement	See Table 2 #5
	Expansion from existing stations		100904	Install Double-Circuits Pole Line on Major Mackenzie - Hwy 27 to Huntington Rd	2029	3.2	0	3.2	Enhancement	See Table 2 #6
			100917	Add one additional 27.6kV Circuit on 19th Ave from Bayview to Bathurst St	2030	2.4	0	2.4	Enhancement	See Table 2 #7
			100924	Install two additional 27.6kV circuits on Highway 7 from Jane St to Weston Rd	2028	2.2	0	2.2	Enhancement	See Table 2 #8

Operating Area	Station Capacity Projects		Lines Capacity Projects							
	Project ID	Project Name	Project ID	Project Name	In-service Date	Gross Cost ($MM)	Capital Contribution ($MM)	Net Cost ($MM)	Project Type	Rationale[1]
			152749	Rebuild pole line on 19th Ave into two circuits from McCowan Rd to Highway 48	2029	2	0	2	Enhancement	See Table 2 #9
			152757	Rebuild existing pole line on Keele St into wo circuits from Teston Rd to Kirby Rd	2029	1.2	0	1.2	Enhancement	See Table 2 #10
East (Alliston, Aurora, Beeton, Barrie, Bradford, Markham, Tottenham, Penetangu-ishene, Richmond Hill, Thornton and Vaughan)		Expansion from existing stations	102386	Rebuild 44kV pole line into two circuits on Tiffin St from Ferndale Ave to Miller Dr	2029	1.2	0	1.2	Enhancement	See Table 2 #11
			150007	Extend 153M10 to Transfer MS322	2027	2.4	0	2.4	Enhancement	See Table 2 #12
			103633	Install two 27.6kV Circuits on 16th Ave from Highway 404 to Woodbine Ave	2029	3.2	-1.3	1.9	Partial Enhancement	See Table 2 #13
			100281	Build Four 27.6kV Circuits on 19th Ave from Woodbine Ave to Warden Ave	2028	1.7	0	1.7	Enhancement	See Table 2 #14
			152751	Rebuild existing pole line on Nashville Rd into two circuits from Huntington Rd to Highway 50	2028	1.6	0	1.6	Enhancement	See Table 2 #15
			100913	Pole Line Installation Double-Circuits on Major Mack -	2028	1.5	0	1.5	Enhancement	See Table 2 #16

Operating Area	Station Capacity Projects		Lines Capacity Projects							
	Project ID	Project Name	Project ID	Project Name	In-service Date	Gross Cost ($MM)	Capital Contribution ($MM)	Net Cost ($MM)	Project Type	Rationale[1]
				Huntington Rd to Hwy 50						
			101487	Add one Additional 27.6kV Circuits on Major Mack Dr and 9th Line	2029	1.3	0	1.3	Enhancement	See Table 2 #17
Central North (Brampton)	152845	New Goreway 2 TS – Brampton	153068	New 4 Feeders Common Elements - Goreway TS 2	> 2031	15.2	0	15.2	Enhancement	See Table 2 #18
			152879	Feeder 1 Integration - Goreway TS 2	> 2031	7.1	0	7.1	Enhancement	See Table 2 #19
			152880	Feeder 2 Integration - Goreway TS 2	> 2031	3	0	3	Enhancement	See Table 2 #20
	152845	New Goreway 2 TS – Brampton	152881	Feeder 3 Integration - Goreway TS 2	> 2031	2.4	0	2.4	Enhancement	See Table 2 #21
			152882	Feeder 4 Integration - Goreway TS 2	> 2031	3.4	0	3.4	Enhancement	See Table 2 #22
			153073	3 Feeder Integration out of Goreway TS 2 - Along Castlemore Road	> 2031	3.3	0	3.3	Enhancement	See Table 2 #23
			153111	Feeder 2 integration 4xCircuits Duct bank - Goreway TS 2	> 2031	1.2	0	1.2	Enhancement	See Table 2 #24
	Expansion from existing station		151676	136M10 Feeder Extension Goreway TS to Highway 410	2029	8.4	0	8.4	Enhancement	See Table 2 #25
			150716	42M69 Feeder Extension - Williams	2029	8.9	0	8.9	Enhancement	See Table 2 #26

Operating Area	Station Capacity Projects		Lines Capacity Projects							
	Project ID	Project Name	Project ID	Project Name	In-service Date	Gross Cost ($MM)	Capital Contribution ($MM)	Net Cost ($MM)	Project Type	Rationale[1]
				Pkwy to Heart Lake/Sandalwood						
Central South (Mississauga)	150366	Webb MS New 20 MVA Substation - Mississauga	152890	Webb MS 20MVA Substation - Feeder Integration Plan (I)	2028	1.5	0	1.5	Enhancement	See Table 2 #27
	150366		152967	Webb MS 20MVA Substation - Feeder Integration Plan (II)	2029	1.3	0	1.3	Enhancement	See Table 2 #28
	152889	New Lakeview TS - South Mississauga	152893	Feeder Integration Plan (I) - 27.6kV Lakeview TS - South Mississauga	2031	7.6	0	7.6	Enhancement	See Table 2 #29
	Expansion from existing station		150369	New build – 44kV Feeder Extension York/Meadowpine, Mississauga	2031	2.1	0	2.1	Enhancement	See Table 2 #30
West (Hamilton and St.Catharines)	152850	New Station - Hamilton South-West (Station)	152865	New Station - Hamilton South-West (Egress)	2031	10.4	0	10.4	Enhancement	See Table 2 #31
	152493	New Station - Newton TS (Capacity)	152853	New Station - Newton TS (Feeder Consolidation)	2031	8	0	8	Enhancement	See Table 2 #32
	Expansion from existing station		152849	New Build - Carlton TS to Martindale Rd/Port, St. Catharines	2029	3	-1	2	Expansion	See Table 2 #33
			150368	New Build - Carlton TS to Linwell Rd/Lake St, St. Catharines	2030	2.1	0	2.1	Enhancement	See Table 2 #34

Operating Area	Station Capacity Projects		Lines Capacity Projects							
	Project ID	Project Name	Project ID	Project Name	In-service Date	Gross Cost ($MM)	Capital Contribution ($MM)	Net Cost ($MM)	Project Type	Rationale[1]
			152852	New Build - Nebo 3101X Extension, Hamilton	2028	2.4	0	2.4	Enhancement	See Table 2 #35
			152496	New Build - Waterdown 4th Feeder, Hamilton	2029	8.8	0	8.8	Enhancement	See Table 2 #36
			152854	St. Catharines Downtown - Feeder Consolidation	> 2031	15.3	0	15.3	Enhancement	See Table 2 #37
Southwest (Guelph and Rockwood	Expansion from existing station		152942	New Build - Guelph Downtown	2031	5.9	0	5.9	Enhancement	See Table 2 #38
			151238	New Build - Maltby Rd W (Crawley to Gordon), Guelph	2028	1.3	0	1.3	Enhancement	See Table 2 #39

[1] Please refer to Table 2 for details on the rationale for the project type classification.

1 **Table 2 - Lines Capacity Projects – Rationale by Project Type**

Item #	Rationale
1,2	The Markham and Richmond Hill North areas are experiencing sustained growth and existing supply stations- Richmond Hill TS #1, Richmond Hill TS #2, Markham TS #4 and Buttonville TS- and associated low-voltage feeders are operating at or near their capacity limits. Several feeders also experience low-voltage conditions during summer peak periods due to high loading and extended supply distances. The new Markham TS #5 was planned to provide capacity relief. These projects integrate four feeders from the new Markham TS #5 into Alectra's distribution system. They will provide approximately 80 MVA of incremental capacity to support planned developments, including the Markham Future Urban Area, the Markham Innovation Exchange, Highway 404 North, and the Richmond Hill North areas, beginning in 2030. These projects will relieve loading on the existing system and improve overall capacity and reliability in the Markham and Richmond Hill North service areas.
3	This investment includes new 13.8kV feeders required from the new municipal station (MS) to supply residential and non-residential developments in the Barrie South area. Existing stations -MS 305 and MS 308- are projected to reach their capacity limits by 2028 and 2032 respectively. The proposed new feeders provide necessary capacity relief.
4	This investment includes constructing 13.8kV feeders from a new MS to supply new residential units, as well as meeting N-1 contingency with neighboring stations. None of the existing 10 MVA substations in Alliston have the capacity to supply new developments. This investment allows Alectra Utilities to address system capacity needs driven by the new development. The 2 x 20 MVA configuration provides contingency backup on a second 20 MVA transformer given all other 13.8kV substations in Alliston are 10 MVA.
5	Significant intensification is planned within the Vaughan Metropolitan Centre area, with more than 90,000 condo units proposed to be built. The load is forecast to reach 240 MVA at full build-out. Existing stations and feeders do not have sufficient capacity to serve this growth. This investment integrates the supply from the proposed Vaughan MTS #5 into the Alectra distribution system to supply the upcoming load.
6	The existing feeders operate in a radial configuration. These feeders require an available backup supply to maintain service continuity and reliability.
7	This project is for increasing the supply capacity for intensification development in the area as well as adding ties between existing feeders.
8	This project will increase supply capacity to VMC by 40 MVA. This project will also enhance reliability and reduce risk of prolonged outages.
9	This project will accommodate anticipated organic load growth in the area and provide additional sectionalizing and backfeed capability to improve reliability.
10	To supply additional growth and provide feeder ties for block 27 in Vaughan.
11	The pole line rebuild provides switching capability and provides an alternate route to supply the Barrie South area from Midhurst TS.
12	This investment is a back-up capability lines project extending the 153M10 circuit and transfer for MS322 to enable load balancing.

Item #	Rationale
13	Alectra Utilities will receive capital contribution from the customer for the connection. Alectra Utilities will leverage this work to enhance the local distribution system by installing two additional feeders to enable feeder ties and improve operational flexibility and reliability.
14	The existing circuits are single phase and there is no capacity for organic growth and new customers.
15	The new feeder will provide additional capacity and tie to the existing feeder for reliability.
16	The new circuit will supply organic growth as well as provide tie capability to the existing feeder.
17	This project is to increase capacity to Markham East by extending a second feeder on Major Mack Dr from Hwy 48 to 9th Line. This project will form a new 27.6kV feeder loop in the Cornell area and also reduce the risk of customer outages that can arise as a result of the radial feeder configuration in that area.
18	Four new feeders will be constructed to supply the BramEAST development area, Queen Gore Development area and the Gore Road development (Block 47). 9 existing feeders from Goreway TS and 3 feeders from Bramalea TS will reach the planning limit by 2031. The new feeders will provide capacity relief to the overloaded feeders.
19	Four new feeders will be constructed to supply BramEAST development area, Queen Gore Development area and the Gore Road development area (Block 47). Nine existing feeders from Goreway TS and 3 feeders from Bramalea TS will reach the planning limit by 2031. The new feeders will provide the capacity relief to the overloaded feeders.
20	Four new feeders will be constructed to supply BramEAST development area, Queen Gore Development area and the Gore Road development (Block 47) area. 9 existing feeders from Goreway TS and 3 feeders from Bramalea TS will reach the planning limit by 2031. The new feeders will provide the capacity relief to the overloaded feeders.
21	Four new feeders will be constructed to supply BramEAST development area, Queen Gore Development area and the Gore Road development (Block 47) area. 9 existing feeders from Goreway TS and 3 feeders from Bramalea TS will reach the planning limit by 2031. The new feeders will provide capacity relief to the overloaded feeders.
22	Four new feeders will be constructed to supply BramEAST development area, Queen Gore Development area and the Gore Road development (Block 47) area. 9 existing feeders from Goreway TS and 3 feeders from Bramalea TS will reach the planning limit by 2031. The new feeders will provide capacity relief to the overloaded feeders.
23	Existing feeders supplied from Goreway TS and Bramalea TS are forecast to reach planning limits by 2031. Feeder Egress and three new feeders are required to serve new developments in the Block 47 area and provide capacity relief to the overloaded feeders.
24	Existing feeders from Goreway TS and Bramalea TS are forecast to reach planning limits by 2031. A four-circuit duct bank is required at Gore Road to enable feeder integration for the upcoming station and to serve new developments in the Block 47 area. The resulting new feeders will provide capacity relief to the overloaded feeders and support load growth.
25	The existing feeder 42M13 has reached its planning capacity in all previous 5 years. In 2023, the feeder operated at 531A which is approaching the thermal limit of 600A. This new feeder expansion will provide capacity relief to 42M13 as well as supply capacity to the new development area of block 48 in Brampton

Item #	Rationale
26	Existing feeder 136M8 has reached its planning capacity in the previous 5 years. In 2023, the feeder operated at 531A in 2023 approaching the thermal limit of 600A. This new feeder expansion will provide capacity relief to 136M9 as well as supply capacity to the new developments in Heart Lake Rd and Hwy 410.
27	The proposed 4 feeders will be serving the new loads (condo towers) and will provide relief to the existing feeders in the downtown core area. Feeder Integration Plan (I) covers F1, F2, F3, and F4, which will be supplied by the new Webb MS in Mississauga. The four feeders will be connected to existing overhead circuits from the existing station until load can be supplied from the new station. These four 13.8KV feeders will supply future load growth and two large developments planned for Mississauga.
28	The proposed 4 feeders will be serving the new loads (condo towers) and will provide relief to the existing feeders in the downtown core area. Feeder Integration Plan (II) covers F5, F6, F7, and F8. The feeders will be connected to the existing system until the new station is online. These four 13.8KV feeders will supply future load growth in the downtown area of Mississauga. The feeders will also provide backup to the other feeders in the area in contingency scenarios.
29	The proposed 4 feeders will supply the major development areas south of Mississauga, including Lakeview Village, wastewater treatments plants and the Dixie Mall development area. The existing feeders in this area are highly congested and cannot accommodate additional load. These feeders will be supplied from the existing station until the new station is completed, at which point the feeders will be transferred and reconfigured to be served from the new station.
30	This feeder extension is primarily driven by the need to provide backup of the 44kV supply to Meadowpine. There is no 44kV circuit on Meadowpine Blvd. 16MVA of connected load is on radial supply. An outage could be of substantial duration, leading to poor reliability and customer dissatisfaction.
31	New capacity is required to provide growth in the south-west side of Hamilton. Existing circuits are 300A rated, requiring upgrades to 600A industry standard. Limited ability for supply and backup is provided by the existing half-sized feeders, and the upgrade will provide benefits to both reliability and capacity. These feeders will be supplied from the existing station until the new station is completed, at which point the feeders will be transferred and reconfigured to be served from the new station.
32	The required capacity is currently limited by smaller feeder sizes. Existing circuits are 300A rated, requiring upgrades to 600A industry standard. 19 half-feeders will be consolidated to 8 full feeders. Limited ability for supply and backup is provided by the existing half-sized feeders, and the upgrade will provide benefits to both reliability and capacity.
33	Alectra will receive a capital contribution from the customer for the connection. Alectra Utilities will leverage this work to construct a new feeder to provide additional capacity to the west side of Port Dalhousie area from the station. This low-rise area is experiencing intensification, including higher density development, and requires incremental distribution capacity to accommodate growth.

Item #	Rationale
34	This project is to alleviate capacity issues in the North and Central sections of the city, primarily served by Carlton BY bus feeders. The project is coordinated with city road widening.
35	This project is to alleviate capacity issues in the South-East mountain area, primarily served by 3 Nebo feeders.
36	Existing circuits cannot back up Waterdown area in an outage. Upgrade will address back up reliability.
37	Existing circuits are 300A rated, requiring upgrades to 600A industry standard. Limited ability for supply and backup is provided by the existing half-sized feeders, and the upgrade will provide benefits to both reliability and capacity.
38	Existing feeders are over planning limits and require capacity for new growth. The City of Guelph is rebuilding the downtown core. The new builds are required to support downtown intensification and roadwork.
39	This feeder will service new growth in South-Guelph and provide contingency to radial loads.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 2-CCC-23

Ref: Exhibit 2A, Tab 1, Schedule 1, Appendix B12, p. 481

Question(s):

a) Please provide a revised version of Table B13-1 that shows gross capital, capital contributions and net capital for each segment of the stations capacity program.

RESPONSE:

a) Alectra Utilities provides the requested table in Table 1. Please note that 2025 values are provided on an actual basis.

Table 1 – Revised Version of Table B13-1

		Bridge Years		Forecasted Spending					
Investment Type ($MM)		**2025A**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**Total (2027-2031)**
New Transformer Stations (TS)	Gross	5.2	29.5	3.9	10.0	43.3	54.0	115.4	226.6
	Contributions	-4.8	-14.4	0.0	0.0	0.0	-1.9	-8.5	-10.4
	Net Expenditures	**0.4**	**15.1**	**3.9**	**10.0**	**43.3**	**52.1**	**106.9**	**216.2**
New Municipal Stations (MS)	Gross	1.4	8.2	3.0	0.0	0.0	2.9	3.9	9.8
	Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Net Expenditures	**1.4**	**8.2**	**3.0**	**0.0**	**0.0**	**2.9**	**3.9**	**9.8**
MS & TS Land Acquisition	Gross	0.0	5.2	15.7	14.1	12.7	0.0	0.0	42.5
	Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Net Expenditures	**0.0**	**5.2**	**15.7**	**14.1**	**12.7**	**0.0**	**0.0**	**42.5**
CCRA Payments to Hydro One	Gross	0.0	5.0	10.0	16.3	16.3	47.5	24.1	114.2
	Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Net Expenditures	**0.0**	**5.0**	**10.0**	**16.3**	**16.3**	**47.5**	**24.1**	**114.2**

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		Bridge Years		Forecasted Spending					
Investment Type ($MM)		**2025A**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**Total (2027-2031)**
Transmission Line Upgrades	Gross	0.8	5.0	5.0	0.0	0.0	0.0	0.0	5.0
	Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Net Expenditures	**0.8**	**5.0**	**5.0**	**0.0**	**0.0**	**0.0**	**0.0**	**5.0**
MS Expansions	Gross	0.5	0.0	1.6	1.6	2.8	6.9	0.0	12.9
	Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Net Expenditures	**0.5**	**0.0**	**1.6**	**1.6**	**2.8**	**6.9**	**0.0**	**12.9**
Total	Gross	7.9	52.9	39.2	42.0	75.1	111.3	143.4	411.0
	Contributions	-4.8	-14.4	0.0	0.0	0.0	-1.9	-8.5	-10.4
	Net Expenditures	**3.1**	**38.5**	**39.2**	**42.0**	**75.1**	**109.4**	**134.9**	**400.6**

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RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 2-CCC-24

Ref: Exhibit 2A, Tab 1, Schedule 1, Appendix B13, p. 482

Preamble:

Table B13-2 shows that data centres are forecast to increase system load by 425 MW between 2025 and 2031.

Question(s):

a) Please advise whether this load growth is entirely tied to a single new data centre or if it is multiple data centres driving this load growth. If multiple data centres, please provide a breakout of the load growth forecast for each data centre.

b) Please provide the total gross capital, capital contributions and net capital amounts that are forecast for each year of the 2027-2031 period directly associated with data centre load growth. Please ensure that all capital costs directly related to data centre load growth is included in the response (e.g., customer connection-related, lines capacity-related and station-capacity related costs, etc.) and provide a breakout of the capital amounts by program segment.

c) Please provide a detailed explanation of the calculation of the forecast capital contribution related to the data centre load growth. As part of the response, please provide the number of years of revenue that were included in the relevant economic evaluations.

d) Please discuss whether Bill 40 is expected to have any implications for the data centre-related load growth forecast set out in the application.

RESPONSE:

a) The forecast load growth from data centres is attributed to multiple data centre connections. Please refer to 2A-SEC-38 for a detailed breakdown of the forecast load by data center.

b) Alectra Utilities provides the requested forecast total gross capital, capital contributions, and net capital expenditures for each year of the 2027-2031 period directly associated with data centre-related load growth in table 1 below, with a breakout by program. Alectra Utilities notes that there is no gross capital directly attributable to lines capacity for the data centre-related load growth forecast over this period.

Table 1 - Forecast Total Gross Capital, Capital contributions, and Net Capital Expenditures 2027-2031 with Data Centre-related Load Growth

Program type		2027	2028	2029	2030	2031	Total 2027-2031
Customer Connections	Gross	17.6	14.8	6.2	0	0	38.6
	Contributions	-11.8	0	0	0	0	-11.8
	Net Expenditures	**5.8**	**14.8**	**6.2**	**0**	**0**	**26.8**
Stations Capacity	Gross	1.3	0	0	0	0	1.3
	Contributions	0	0	0	0	0	0
	Net Expenditures	**1.3**	**0**	**0**	**0**	**0**	**1.3**

The stations capacity project included above starts in 2025 and all the contributions are applied towards 2025 and 2026 expenditures.

c) For the distribution system expansion data centre projects, the Economic Evaluation Model (EEM) is based on the initial load ramp up schedule and project timelines provided by the customer. The gross cost input to the EEM is based on the best available (typically a high-level) cost estimate at the time of evaluation. The results of the EEM, including the forecast capital contribution, are used to forecast the budget. Alectra Utilities applies a 25-year revenue horizon for distribution data centre projects. However, in certain cases, the revenue horizon was reduced due to project-specific circumstances. Table 2 below summarizes the revenue horizon applied for recent or ongoing distribution data centre projects. For project 6 and 7 the capacity was available at the feeder/station and no expansion was required (i.e., the customer is responsible for the entire cost).

Table 2 - Data Centres Information

Project Name	Area	MW	Revenue Horizon
Project 1	Vaughan	100	**15 yrs**
Project 2	Markham	48	**25 yrs**
Project 3	Richmond Hill	40	**25 yrs**
Project 4, 5	Richmond Hill	80	**25 yrs**
Project 6	Vaughan	24	**Connection Only**
Project 7	Markham	8	**Connection Only**
Project 8	Brampton	22	**25 yrs**
Applicant 9, 10	Brampton	15	**25 yrs**
Applicant 11	Mississauga	40	**25 yrs**
Applicant 12	Mississauga	48	**25 yrs**

d) Bill 40 received Royal Assent on Dec 11, 2025. The data centre requests included in the application were all submitted prior to Bill 40 and are in various stages of design and construction.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 2-CCC-25

Ref: Exhibit 2A, Tab 1, Schedule 1, Appendix B13, pp. 492-493

Question(s):

a) Please add two new columns to Table B13-7 that show the most up to date actual population and household figures for each city.

b) Please advise whether the population and housing data reports used (as referenced below Table B13-7) continue to be the most recent reports available. If not, please provide links or the relevant excerpts from the more recent reports.

RESPONSE:

a) Please refer to Table 1 below, Table 1 shows revised Table B13-7 with two additional columns containing the updated actual population and household figures for each city.

b) Please refer to part a).

Table 1 - Population & Household Growth Forecast (2021-2041)

	Population							Households						
City	2021	2026	2031	2036	2041	% Increase Population	Most up to date actual	2021	2026	2031	2036	2041	% Increase Households	Most up to date actual
Brampton	691,382	751,542	807,875	848,897	889,920	28.72%	697,034 (2023)	247,826	264,478	280,723	295,336	309,950	25.07%	194,777 (2023)
Mississauga	763,300	792,340	818,100	849,680	883,290	15.72%	763,000 (2021)	249,514	262,450	279,850	298,940	317,840	27.38%	247,180 (2021)
Hamilton	584,000	618,000	652,000	692,500	733,000	25.51%	585,640 (2021)	222,540	240,320	258,100	276,635	295,170	32.64%	222,805 (2021)
York	973,024	1,078,997	1,207,649	1,234,573	1,333,680	37.07%	1,023,878 (2025)	311,657	351,392	394,004	436,977	478,958	53.68%	335,761 (Dec 31, 2025)
Guelph	147,000	157,500	168,000	177,000	186,000	26.53%	148,610 (2021)	57,500	62,850	68,200	72,950	77,700	35.13%	56,480 (2021)
Simcoe County	255,310	295,700	337,990	375,780	412,790	61.68%	276,421 (2022)	88,140	104,750	120,790	137,260	153,770	74.46%	90,496 (2023)
St. Catharines	137,886	142,993	148,099	155,982	163,865	18.84%	136,803 (2021)	59,549	62,274	64,999	68,734	72,469	21.70%	59,549 (2021)

Notes:	
1	**Brampton Population and Housing Data (2021-2041):** "City of Brampton 2024 Development Charges Background Study, September 9, 2024, Hemson Report"
2	**Mississauga Population and Housing Data (2021-2041):** "City of Mississauga Development Charges Background Study, August 4, 2022, Hemson Report"
3	**Hamilton Population and Housing Data (2021-2041): "**Development Charges Background Study, December 21, 2023, Watson Report**"**
	https://www.hamilton.ca/sites/default/files/2024-02/planning-2024-Development-Charges-Report-Final.pdf
4	**Guelph Population and Housing Data (2021-2041):** “2023 Development Charges Background Study, September 27, 2023, Watson Report"
	https://guelph.ca/wp-content/uploads/Guelph2023DCReport-Final.pdf
5	York population and housing data (2021-2041): https://www.arcgis.com/apps/dashboards/829c40bdc1d24f2fafd130e503e4e5d3
	Markham:
	2021-2031: “2022 Development Charges Study, City of Markham, March 2022, Hemson Report”
	2031-2041: “2022 YORK REGION OFFICIAL PLAN Office Consolidation | June 2024, York Region Report”
	Richmond Hill:
	2021-2031: “Development Charges Background Study, Town of Richmond Hill, March 26, 2019, Watson Report”
	2031-2041: “Development Charges Background Study, City of Richmond Hill, December 22, 2023, Watson Report”
	Vaughan:
	2021-2031: “Development Charges Background Study, City of Vaughan, June 21, 2022, Hemson Report”
	2031-2041: “2022 York Region Official Plan Office Consolidation | June 2024, York Region Report”
	Aurora:
	2024-2034: “Development Charges Background Study, Town of Aurora, January 23, 2024, Watson Report” https://www.aurora.ca/media/uvbfp3md/final-2024-dc-study.pdf
	2031-2041: “2022 York Region Official Plan Office Consolidation | June 2024, York Region Report”
6	**St. Catharines Population and Housing Data (2021-2041):**
	"Development Charges Background Study, City of St. Catharines, June 2, 2021, Watson Report”
7	Simcoe County population and housing data (2021-2041):

	Barrie:
	"City of Barrie Development Charges Background Study, October 10, 2023, Hemson Report"
	Penetanguishene, Bradford, and New Tecumseth:
	"Town of Penetanguishene Development Charges Background Study, June 14, 2024, Hemson Report"
	Bradford:
	"Development Charges Background Study Town of Bradford West Gwillimbury, May 2, 2025, Watson & Associates Economists Ltd."
	New Tecumseth:
	"Town of New Tecumseth Development Charges Background Study, July 2023, Hemson Report"
	Thornton:
	"Township of Essa Development Charges Background Study,, April 21, 2023, Hemson Report"
8	York Region- Numbers indicated are for the Alectra Utilities service territory, including Markham, Vaughan, Richmond Hill, and Aurora.
9	Simcoe County –Numbers indicated are for the Alectra Utilities service territory, including Barrie, Bradford, New Tecumseth, and Penetanguishene.

2-CCC-25

Attachment 1
Population and Household Growth

Population & Household Growth Forecast (2021-2041)															
	Population							Households							
City	2021	2026	2031	2036	2041	% Increase Population	Most up to date actual	2021	2026	2031	2036	2041	% Increase Households	Most up to date actual
Brampton	691,382	751,542	807,875	848,897	889,920	28.72%	697,034 (2023)	247,826	264,478	280,723	295,336	309,950	25.07%	194,777 (2023)
Mississauga	763,300	792,340	818,100	849,680	883,290	15.72%	763,000 (2021)	249,514	262,450	279,850	298,940	317,840	27.38%	247,180 (2021)
Hamilton	584,000	618,000	652,000	692,500	733,000	25.51%	585,640 (2021)	222,540	240,320	258,100	276,635	295,170	32.64%	222,805 (2021)
York	973,024	1,078,997	1,207,649	1,234,573	1,333,680	37.07%	1,023,878 (2025)	311,657	351,392	394,004	436,977	478,958	53.68%	335,761 (Dec 31, 2025)
Guelph	147,000	157,500	168,000	177,000	186,000	26.53%	148,610 (2021)	57,500	62,850	68,200	72,950	77,700	35.13%	56,480 (2021)
Simcoe County	255,310	295,700	337,990	375,780	412,790	61.68%	276,421 (2022)	88,140	104,750	120,790	137,260	153,770	74.46%	90,496 (2023)
St. Catharines	137,886	142,993	148,099	155,982	163,865	18.84%	136,803 (2021)	59,549	62,274	64,999	68,734	72,469	21.70%	59,549 (2021)

Notes:	
1	**Brampton Population and Housing Data (2021-2041):** "City of Brampton 2024 Development Charges Background Study, September 9, 2024, Hemson Report"
2	**Mississauga Population and Housing Data (2021-2041):** "City of Mississauga Development Charges Background Study, August 4, 2022, Hemson Report"
3	**Hamilton Population and Housing Data (2021-2041): "**Development Charges Background Study, December 21, 2023, Watson Report**"**
	https://www.hamilton.ca/sites/default/files/2024-02/planning-2024-Development-Charges-Report-Final.pdf
4	**Guelph Population and Housing Data (2021-2041):** “2023 Development Charges Background Study, September 27, 2023, Watson Report"
	https://guelph.ca/wp-content/uploads/Guelph2023DCReport-Final.pdf
5	York population and housing data (2021-2041): https://www.arcgis.com/apps/dashboards/829c40bdc1d24f2fafd130e503e4e5d3
	Markham:
	2021-2031: “2022 Development Charges Study, City of Markham, March 2022, Hemson Report”
	2031-2041: “2022 YORK REGION OFFICIAL PLAN Office Consolidation | June 2024, York Region Report”
	Richmond Hill:
	2021-2031: “Development Charges Background Study, Town of Richmond Hill, March 26, 2019, Watson Report”
	2031-2041: “Development Charges Background Study, City of Richmond Hill, December 22, 2023, Watson Report”
	Vaughan:
	2021-2031: “Development Charges Background Study, City of Vaughan, June 21, 2022, Hemson Report”
	2031-2041: “2022 York Region Official Plan Office Consolidation | June 2024, York Region Report”
	Aurora:
	2024-2034: “Development Charges Background Study, Town of Aurora, January 23, 2024, Watson Report” https://www.aurora.ca/media/uvbfp3md/final-2024-dc-study.pdf
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	Bradford:
	"Development Charges Background Study Town of Bradford West Gwillimbury, May 2, 2025, Watson & Associates Economists Ltd."
	New Tecumseth:
	"Town of New Tecumseth Development Charges Background Study, July 2023, Hemson Report"
	Thornton:
	"Township of Essa Development Charges Background Study,, April 21, 2023, Hemson Report"
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RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 2-CCC-26

Ref: Exhibit 2A, Tab 1, Schedule 1, Appendix B13, pp. 564-565, 568-569

Question(s):

a) Please confirm that the station capacity program is entirely forecast on the basis of known projects. If this is not correct, please explain.

b) Please provide a revised version of Table B13-32 that shows the in-service date for each of the station capacity projects and note whether the project is considered system expansion or system enhancement. Please also include an explanation for the treatment of each project as either system expansion or system enhancement.

RESPONSE:

a) Alectra Utilities wishes to clarify that Station Capacity projects are planned based on existing capacity conditions as well as known projects. The station capacity needs are identified through the load forecast, which incorporates known developments and projected growth in housing and Industrial, Commercial and Institutional development obtained through municipal plans, and other drivers such as electrification.

Alectra Utilities is obligated, pursuant to section 3.3.1 of the Distribution System Code, “to plan and build the distribution system for reasonable load growth”.

Please refer to *Exhibit 2A, Tab 1, Schedule A1, Appendix J Load Forecast and System Capacity* Assessment.

b) Refer to the table 1 below.

Table 1 - Revised version of Table B13-32

Project Code	Project Name	CAPEX ($MM)	In-service date	Expansion / Enhancement	In Part / In Full	Explanation
152758	Build Richmond Hill TS3	56.5	2030	Expansion	In part	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Page 504
152883	230kV UG Transmission Expansion in Brampton	53.3	2034	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Page 561 Section 3.3.1
152889	TS Station – 230/27.6kV Lakeview TS - South Mississauga	50.1	2032	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Section 3.2.2
152845	New Goreway TS - Brampton	50.1	2032	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Page 541 Section 3.2.2.2 (A)
152493	New Station - Newton TS (Capacity)	25.5	2031	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Section 3.2.3
151147	New Station - Campbell TS Metal Clad Expansion	25.5	2031	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Section 3.2.4
152850	New Station - Hamilton South-West (Station)	19.8	2033	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Section 3.2.3
152762	Build Vaughan MTS#5 for VMC	14.9	2033	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Page 509
152847	New Heritage TS - Brampton	13.3	2034	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Page 545 Section 3.2.2.2 (B)
101488	Build Markham TS #5	10	2027	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Page 502
102455	Melbourne MS322 - 2 x 10MVA - Bradford	9.2	2030	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Page 518 Section 3.2.1.2 (C)

Project Code	Project Name	CAPEX ($MM)	In-service date	Expansion / Enhancement	In Part / In Full	Explanation
152844	Land Purchase – 230/27.6kV Gateway TS - North Mississaugua	5.5	2029	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Section 3.2.2
152972	Land Purchase – 230/27.6kV - GTAA TS	5.4	2028	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Section 3.2.2
152859	Land Purchase - Brampton - New Heritage TS	5.3	2027	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Page 545 Section 3.2.2.2 (B)
152857	Land Purchase – 230/27.6kV Lakeview TS - South Mississauga	5.3	2027	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Section 3.2.2
152862	Purchase Land for Future Vaughan MTS#5	5.1	2027	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Page 509
152723	Pleasant TS - H29 H30 Reconductoring - Transmission	5	2027	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Page 562 Section 3.4.1
152860	Markham MTS#6 Land Purchase and Class EA	5	2028	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Page 509
152973	TS Station – 230/27.6kV GTAA TS	4.5	2033	Expansion t	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Section 3.2.2
152909	New Alliston 2x20MVA MS	4.5	2032	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Page 513 Section 3.2.1.2 (A)
152866	New Station - Hamilton South-West (Land)	3.6	2028	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Section 3.2.3
152864	New Station - Guelph North-West (Land)	3.3	2029	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Section 3.2.4
150366	Webb MS New 20MVA Substation	3	2030	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Section 3.2.2

Project Code	Project Name	CAPEX ($MM)	In-service date	Expansion / Enhancement	In Part / In Full	Explanation
152846	Build Markham TS #6	2.8	2034	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Page 509
152888	TS Station – 230/27.6kV Gateway TS - North Mississauga	2.8	2034	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Section 3.2.2
101542	New Barrie 20MVA Substation	2.3	2032	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Page 516 Section 3.2.1.2 (B)
102128	Aurora MS#6 Expansion	2.1	2029	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Page 512
152870	Land Purchase - New Barrie 20MVA Substation - Bryne Dr.	1.9	2029	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Page 516 Section 3.2.1.2 (B)
152934	Land Purchase - New Alliston 2x20MVA MS	1.9	2029	Enhancement	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Page 513 Section 3.2.1.2 (A)
152753	Install Capacitor Banks at VTS1E	1.5	2027	Enhancement	In full	This project will increase supply capacity by 15MW by increasing power factor via installing capacitor banks.
152484	Vaughan TS#6-Build Station	1.3	2027	Expansion	In full	See Exhibit 2A Tab1 Schedule 1 Appendix B13-Station Capacity Page 509

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 2-CCC-27

Ref: EB-2025-0055, Decision and Rate Order, December 16, 2025, p. 32
Exhibit 2B, Tab 3, Schedule 1, p. 5

Preamble:

Alectra noted that it implemented new useful lives based on an Alliance Consulting Group (Alliance) report on January 1, 2025. The change in useful lives is expected to result in a decrease of $16.6M and $21.2M for 2025 and 2026 and Alectra sought approval, in its 2026 IRM, for a new variance account ("Useful Lives Changes" variance account) to track the cumulative difference between the utility's net PP&E under its former and revised depreciation policies.

The OEB denied Alectra's request to establish the above noted variance account in its EB-2025-0055 Decision and Rate Order.

Question(s):

a) Please advise whether 2027 opening rate base as proposed in the current application was calculated based on the revised useful lives as implemented on January 1, 2025 (i.e., 2025 and 2026 depreciation reflected the updated useful lives).

b) Please provide a table showing 2027 opening rate base calculated based on each of the former and revised useful lives.

RESPONSE:

a) Yes, 2027 opening rate base as proposed in the current application was calculated based on the revised useful lives as implemented on January 1, 2025.

b) Please see the response to 2-Staff-153.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 2-CCC-28

Ref: Exhibit 2B, Tab 3, Schedule 1, p. 8
Exhibit 9, Tab 3, Schedule 25, pp. 1-3

Question(s):

a) Please confirm that the $6.4M of MIST Meter-related depreciation expense forms part of the $11.4M that Alectra is seeking to dispose of as part its disposition of Account 1557 (Meter Cost DA).

b) Please explain why the disposition of Account 1557 is causing an increase in depreciation expense (in the context that the disposition will be operationalized through a rate rider).

c) If the $6.4M of MIST Meter-related depreciation expense is related to the undepreciated asset cost as of 2027, please provide the calculation supporting the depreciation expense.

RESPONSE:

a) Alectra Utilities confirms that the $5.4M of the $6.4M of depreciation expense forms part of the $11.4M that Alectra is seeking to dispose of as part its disposition of Account 1557 (Meter Cost DA).

b) In accordance with the OEB's Accounting Procedures Handbook (APH) Guideline issued in March 2015, the accounting and disposition of Account 1557 should be guided by the OEB's established record-keeping and disposition requirements for smart meter costs. Please refer to Question 8 of the APH FAQ (2008) and the OEB's illustrative journal entries for smart meter accounting, where a distributor has received Board approval for the smart meter investment and the associated revenue requirement in a rate order. The illustrative entry demonstrates the transfer of amortization expense from the deferral account to the appropriate expense account.

c) The $6.4M depreciation expense is not related to undepreciated asset cost.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 2-CCC-29

Ref: Exhibit 2B, Tab 5, Schedule 1, pp. 1-2

Question(s):

a) With respect to 2018 Road Authority York Region Rapid Transit project, please provide a detailed table that shows the original project cost (including all the specific forecasts made) and the final project cost. Please also include the forecast capital contribution and the actual capital contribution. As part of the response, please include a comprehensive explanation of the cost overrun of $4.6 million experienced with respect to the project.

b) With respect to 2019 Road Authority York Region Rapid Transit project, please provide a detailed table that shows the original project cost (including all the specific forecasts made) and the final project cost. Please also include the forecast capital contribution and the actual capital contribution. As part of the response, please include a comprehensive explanation of the cost overrun of $12.1 million experienced with respect to the project.

RESPONSE:

a) and b) Please refer to 9-Staff-272 part a.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 2-CCC-30

Ref: EB-2025-0055, Decision and Rate Order, December 16, 2025, p. 32
Exhibit 2B, Tab 6, Schedule 2, p. 3
Exhibit 9, Tab 3, Schedule 11, pp. 1-2

Preamble:

Alectra noted that it implemented a revised Direct Labour Capitalization rate methodology effective January 1, 2025. The results of the study indicate an increase in labour capitalization and a corresponding decrease to OM&A costs in 2025 and 20256. Alectra sought approval for a new variance account ("Direct Labour Capitalization Changes" variance account) to capture the financial impacts from the change to the methodology.

The OEB denied Alectra's request to establish the above noted variance account in its EB-2025-0055 Decision and Rate Order.

Question(s):

a) Please advise whether 2027 opening rate base as proposed in the current application was calculated based on the revised direct labour capitalization rate (i.e., 2025 and 2026 in-service additions reflect the updated DLC rate).

b) Please provide a table showing 2027 opening rate base calculated based on each of the former and revised DLC rates.

RESPONSE:

a) Yes, 2027 opening rate base as proposed in the current application was calculated based on in-service additions for 2025 and 2026, that include the updated DLC rate. The new DLC rates were implemented effective January 1, 2025.

b) Please see the response to 2-Staff-153.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 3-CCC-31

Ref:
Exhibit 3, Tab 1, Schedule 2

Exhibit 2A, Tab 1, Schedule 1

Question(s):

Please provide a single table for the period 2019-2031 (or preferably, including additional historical years to the extent that they are available) that includes the following:

i. Actual Demand (MW)
ii. Actual Weather Normalized Demand (MW)
iii. Forecast Demand (MW) used for capital planning purposes (both prior capital planning forecasts and the current capital planning forecast)
iv. Actual / Forecast (MW) System Capacity

RESPONSE:

Refer to Table 1 below for the requested information.

Table 1 - Historical and Forecast Peak Demand

Category	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Actual System Demand (MW)	5,296	5,806	5,440	5,552	5,458	5,549	6,003						
Prior Capital Planning Demand Forecast (MW)[1]	5,995	6,128	6,288	6,436	6,550	6,657							
Current Capital Planning Demand Forecast (MW)						5,938	6,110	6,294	6,501	6,737	6,917	7,171	7,406
Weather Normalized Demand (MW)[2]	5,959	5,953	5,895	5,834	5,791	5,981	6,018	6,294	6,501	6,737	6,917	7,171	7,406
System Capacity (MW)	8,300	8,300	8,300	8,300	8,300	8,300	8,300	8,300	8,300	8,640	8,640	8,810	8,938

[1] *Prior Capital Planning forecast is 1 in 10 forecast for 2019-2024 as per EB-2019-0018, 2020 EDR Application, Exhibit 4, Tab 1, Schedule 1, Chapter 5.3.2.*

[2] *Weather normalized demand for 2019-2025 are derived from actual peak demand values adjusted for 1 in 10 weather and 2026-2031 is forecast for 1-in-10 weather as per Exhibit 2A, Tab 1, Schedule 1, Appendix J.*

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-32

Ref: Exhibit 4, Tab 1, Schedule 1, p. 4

Question(s):

Please provide a breakdown of operational costs for the 2017-2031 period as between internal labour costs and external/contract labour costs.

RESPONSE:

Please see response to 4-AMPCO-58.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-33

Ref: Exhibit 4, Tab 1, Schedule 2
Appendix 2-JC

Question(s):

a) Please provide a revised version of Appendix 2-JC that further disaggregates the programs into program segments (e.g., corporate services would separately show Regulatory, Legal, etc.) and shows 2025 year-end actuals.

b) To the extent that any work functions have moved from one operational program segment to another, please provide an additional revised version of Appendix 2-JC that shows, for the 2017-2031 period, the relevant program segment budgets recast without the movement. For example, it appears that the payroll function moved from the Finance segment to HR in 2022 (Exhibit 4, Tab 2, Schedule 4, p. 16). Please provide the finance segment over the entire historical and forecast periods inclusive of the payroll function (and a coincident removal of the payroll function cost from HR).

RESPONSE:

a) Please see 4-Staff-165_Attach-1_JC by Segment for a disaggregated view of the program costs by segment.

b) Appendix 2-JC has been populated in a manner that minimizes the impacts from organizational changes to the extent possible. Aside from the payroll function, where no separate business unit existed, all other organizational movements of business unit costs took place within the same JC Program. All business unit movements between segments in the same program have already been reflected in the analysis, to the extent that these movements could be tracked and reallocated accordingly.

The costs associated with the Payroll function cannot be disaggregated from the historical Finance costs, but can be disaggregated from Human Resource since the transfer in 2022. The payroll function was grouped with Human Resources based on the current functional rollup, however, the tables that follow provide a hypothetical view of the Program costs if the Payroll function was grouped with Finance.

Table 1 - Payroll Function grouped with Finance Segment

Program	Segment	2017	2018	2019	2020	2021	2022	2023	2024
Finance+Payroll and Treasury	Finance	10.8	11.2	12.2	12.7	11.8	12.1	12.6	12.9
	Treasury	6.1	7.6	8.0	10.2	10.0	10.2	10.7	11.2
	Total	**16.9**	**18.8**	**20.2**	**22.9**	**21.8**	**22.3**	**23.2**	**24.2**
Human Resources no Payroll	Business Transformation	4.6	3.9	2.8	2.0	2.2	3.1	3.4	3.8
	Health Safety Wellness & Environmental	3.3	2.3	2.7	2.4	2.4	3.2	3.1	2.9
	People Services, L&OD, Employee Communications	6.4	7.6	9.7	8.8	9.8	7.9	10.1	9.2
	Total	**14.3**	**13.8**	**15.1**	**13.3**	**14.4**	**14.2**	**16.6**	**15.8**

Program	Segment	2025	2026	2027	2028	2029	2030	2031
Finance+Payroll and Treasury	Finance	13.6	14.2	15.3	16.4	17.9	18.5	19.1
	Treasury	11.3	12.5	12.8	13.7	14.2	14.7	15.2
	Total	**24.8**	**26.7**	**28.1**	**30.1**	**32.1**	**33.2**	**34.3**
Human Resources no Payroll	Business Transformation	4.2	4.2	5.1	5.1	5.3	5.5	5.6
	Health Safety Wellness & Environmental	3.4	3.5	3.7	3.9	4.4	4.4	4.6
	People Services, L&OD, Employee Communications	11.2	10.3	11.1	11.7	12.3	12.8	13.1
	Total	**18.8**	**18.0**	**19.9**	**20.7**	**22.0**	**22.7**	**23.3**

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-34

Ref: Exhibit 4, Tab 1, Schedule 3, p. 4

Question(s):

a) Please provide an alternative view of Chart 4-1-2 that shows the 2027 baseline to the 2027 test year proposal broken out between only incremental labour costs and all other non-labour expenses.

b) Please explain whether / how the merger and productivity savings described in Exhibit 1, Tab 6, Schedule 4 and Exhibit 1, Tab 9, Schedule 3 are reflected in Chart 4-1-2.

RESPONSE:

With respect to Chart 4-1-2:

a) In response to 4-SEC-79 Part d) Alectra identified a correction for inflation that was used to populate this chart and provided updated values for the figures. The updated inflation values have been reflected in response to this IR. Please see below for an alternative view of Chart 4-1-2 with only Labour and Non-labour expenses.

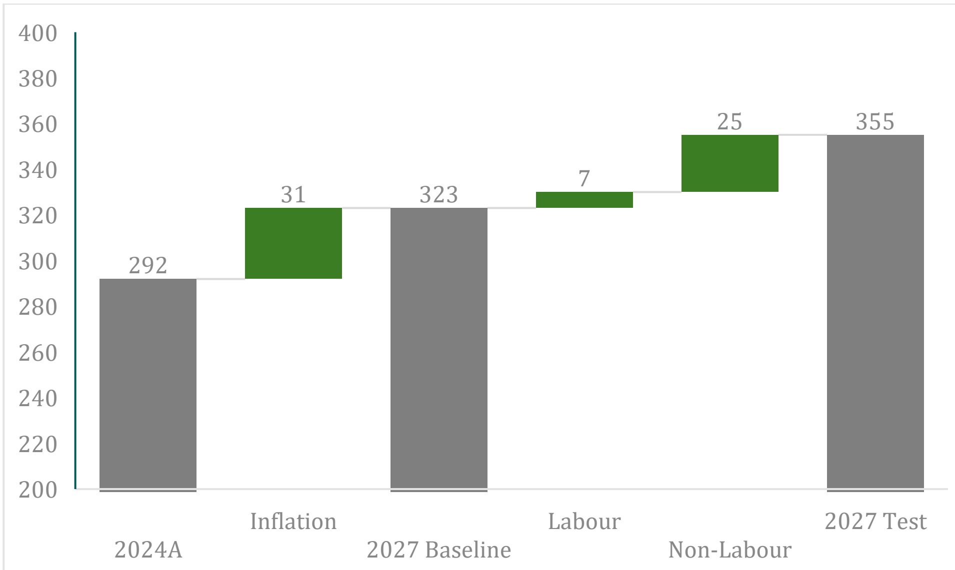

Chart 1 – Alternative Chart 4-1-2 with only Labour and Non-Labour Expenses

b) Please see response to 4-SEC-79 part a) for a description of how the merger synergies described in Exhibit 1, Tab 9, Schedule 1 are reflected in Chart 4-1-2.

Please see response to 4-SEC-79 part b) for a description of how the productivity savings described in Exhibit 1, Tab 6, Schedule 4 are reflected in Chart 4-1-2.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-35

Ref: Exhibit 4, Tab 1, Schedule 4, p. 2

Question(s):

a) Please provide Chart 4-1-5 in tabular format.

b) Please provide a revised version of Chart 4-1-5 that reflects only the FTEs that are involved in roles that are directly related to the implementation of the DSP and also provide the same information in tabular format.

RESPONSE:

a) The table provides the data in Chart 4-1-5.

Table 1 – Data of Chart 4-1-5 in Tabular Form

	2017	2018	2019	2020	2021	2022	2023	2024
Gross Capital Expenditure ($M)	$333	$344	$378	$350	$351	$343	$470	$469
FTE	1,411	1,405	1,514	1,422	1,465	1,446	1,439	1,463

	2025	2026	2027	2028	2029	2030	2031
Gross Capital Expenditure ($M)	$511	$516	$603	$688	$791	$849	$923
FTE	1,628	1,623	1,679	1,749	1,816	1,839	1,855

b) The chart and table provide a revised version of Chart 4-1-5 that reflects the FTE related to the implementation of the DSP.

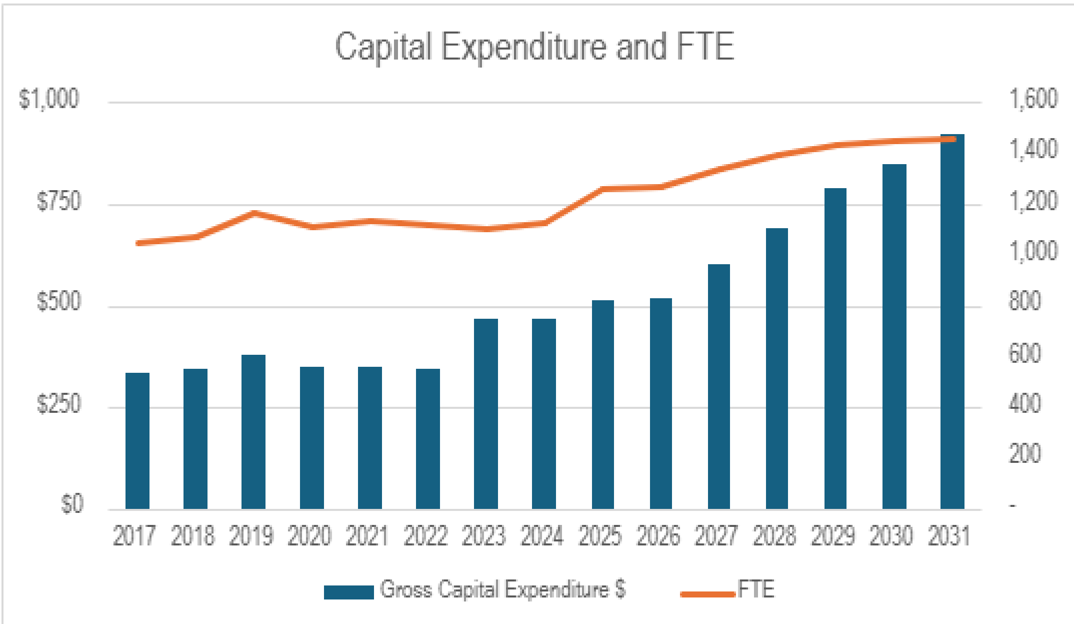

Chart 1 – Capital Expenditure and FTE

Table 2 – Reflects the FTE related to the implementation of the DSP

	2017	2018	2019	2020	2021	2022	2023	2024
Gross Capital Expenditure ($M)	$333	$344	$378	$350	$351	$343	$470	$469
FTE	1,053	1,072	1,172	1,114	1,139	1,117	1,106	1,127

	2025	2026	2027	2028	2029	2030	2031
Gross Capital Expenditure ($M)	$511	$516	$603	$688	$791	$849	$923
FTE	1,266	1,271	1,342	1,401	1,441	1,455	1,462

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-36

Ref: Exhibit 4, Tab 2, Schedule 1

Preamble:

It appears that the variance analysis completed for all of the OM&A program segments listed in Exhibit 4, Tab 2 provide variances for:

- 2017 to 2018
- 2018 to 2019
- 2020 to 2021
- 2021 to 2022
- 2022 to 2023
- 2023 to 2024
- 2024 to 2026
- 2026 to 2031

Question(s):

Please provide a variance analysis discussion for each program segment comparing 2025 actuals and the proposed 2027 test year.

RESPONSE:

Please see below for the 2025 Actuals to 2027 test year analysis for each program segment in Exhibit 4, Tab 2, Schedules 1-21:

Schedule 1 – Asset Management

Segment	2025 Actual	2027 Test	Variance
Asset Management	6.99	8.27	1.28
Grid Modernization	0.49	0.99	0.50

Asset Management 2025-2027 Variance Explanation:

From 2025 to 2027 the cost variance is primarily due to vacancies and resources to oversee the increased volume, scope and complexity of capital work. In addition to the execution of the 2027-2031 distribution system plan, resources are required to be retained for work related to Distribution Design, integrated regional planning with gas utilities, capacity allocation model, non-wires solution guidelines with benefit-cost analysis and engineering solutions related to climate risk and vulnerability assessment.

Grid Modernization 2025-2027 Variance Explanation:

From 2025 to 2027 cost increase is primarily due to labour resources, as the segment ramps up to deliver on various initiatives.

Schedule 2 – Distribution Design

Segment	2025 Actual	2027 Test	Variance
N/A	7.29	9.61	2.32

Distribution Design 2025-2027 Variance Explanation:

The increase in Distribution Design OM&A between 2025 actuals and the proposed 2027 test year primarily reflects normalization of staffing levels and the timing of design activities relative to capital execution, rather than a direct year-over-year change in aggregate capital expenditures.

Distribution Design resources are required in advance of construction, as design, coordination, and permitting activities typically occur one or more years prior to capital work being executed. As a result, staffing levels must be in place ahead of peak capital spending years to ensure work can be delivered efficiently and on schedule. Accordingly, the proposed 2027 staffing levels support design activities associated with capital work forecast to be executed in subsequent years.

In addition, 2025 actual OM&A and FTE levels were temporarily understated due to the timing of hiring, vacancies, and partial-year occupancy of positions. While the approved staffing plan for Distribution Design was approximately 153.5 FTEs, the 2025 actual average reflected approximately 136.3 FTEs, as several positions were filled partway through the year or later in the year and therefore not fully reflected in annualized actuals. By the end of 2025, staffing levels were aligned with the approved plan.

The combined effect of staffing normalization following vacancy backfill and the need to resource design activities in advance of capital execution results in an increase in Distribution Design OM&A from $7.29M in 2025 actuals to $9.61M in the proposed 2027 test year.

Schedule 3 – Corporate Services

Segment	2025 Actual	2027 Test	Variance
Government and Corporate Relations	3.11	3.70	0.59
Internal Audit	0.49	0.98	0.49
Legal	1.98	3.02	1.04
Regulatory	7.48	15.03	7.55
Strategy & Special Projects	0.90	1.05	0.15

Regulatory 2025-2027 Variance Explanation:

From 2025 to 2027 costs are expected to increase by $7.55MM primarily due to an increase in the OEB's cost assessment fees, the amortization of one-time rebasing application costs and an increase in direct labour costs. As identified in Exhibit 4, Tab 2, Schedule 3, the OEB revised its cost assessment model in 2016, resulting in an increase in cost assessment fees. The OEB established Account 1508 Other Regulatory Assets, Sub-Account OEB Cost Assessment Variance, to record the difference between OEB cost assessment fees built into rates and the actual assessment fees. In accordance with the OEB's guidance, Alectra Utilities recorded this difference in the variance account since 2016. Starting in 2027, Alectra Utilities has forecasted OEB cost assessment fees to fully capture the increase in assessment fees on a go forward basis. This represents an increase of approximately $3.6MM compared to the historical amounts built into rates. One-time costs related to the preparation of this application include consulting costs, legal fees and costs for third-party experts. The increase in direct labour costs is attributable to annual pay increases and the addition of two new positions as described in Exhibit 4, Tab 2, Schedule 3.

Legal 2025-2027 Variance Explanation:

It is anticipated that the significant increase in operational work contemplated by this rebasing application will result in a need for an increase in legal advice both internal and external. Direct labour costs will increase as a result of the hiring of (a) a senior legal counsel to provide internal legal advice, (b) an executive assistant to provide administrative and managerial assistance to the new senior legal counsel and other existing internal legal counsel and (c) a real estate law clerk to deal with real estate matters such negotiating and registering easements, license agreements and other real property agreements. External legal costs will also increase on an ongoing basis to deal with the increase in legal advice required to deal with the increase in electrical work

Internal Audit 2025-2027 Variance Explanation:

There is a $300k increase in consulting costs which is primarily attributable to artificial intelligence (AI) related audits specifically 1) an AI Readiness and 2) an AI Strategy Assessment. These audits were requested by the Audit, Finance and Risk Management Committee of the Board of Directors, due to the anticipated increase in AI usage, required internal controls and governance AI frameworks within the organization, the strategic advantages of adopting AI technology and to ensure that the use of AI is in line with Alectra's strategic direction.

The Internal Audit department will be hiring additional audit resources that will focus on data and analytics, as well as internally conducting IT related audits for Internal Audit. The costs of hiring specialist IT auditors will allow Internal Audit to conduct some IT audits internally and partially offset the cost of some IT/Cyber audit consulting costs.

Government and Corporate Relations 2025-2027 Variance Explanation:

The main reason for the variance is labour costs, with the addition of one incremental FTE for a Manager of Government and Industry Relations role in 2026. This role is required because of department structural changes (the repurposing of a Director role to focus solely on communications which previously also oversaw government relations) and increased workload for the government and industry relations team.

Additionally, more government relations consulting support is needed to manage the growing number and complexity of government and agency policy consultations, information requests and submission requirements.

Strategy, ERM & Sustainability 2025-2027 Variance Explanation:

The variance between 2025 to 2027 is attributed to a $0.15MM cost increase due to increased advertising/communications and additional industry memberships.

Schedule 4 – Finance and Treasury

Segment	2025 Actual	2027 Test	Variance
Finance	12.61	14.16	1.55
Treasury	11.26	12.80	1.54

Finance 2025-2027 Variance Explanation:

From 2025 to 2027 costs are expected to increase by $1.55MM primarily due to an increase in direct labour and an increase in consulting related expenditures. The increase in direct labour is attributable to annual pay increases, the addition of four new positions as described in Exhibit 4, Tab 2, Schedule 4 (one in 2026, three in 2027), and the filling of one vacancy. The FTE increases in 2027 are partially offset by the reduction of four temporary positions in 2027 which are included in 2025 actuals (principally to support the rebasing application). The increase in consulting is to support end-to-end Accounting process improvements related to managing increasing volumes of work orders, invoices, and financial transactions.

Treasury 2025-2027 Variance Explanation:

From 2025 to 2027 costs are expected to increase by $1.54MM primarily due to an increase in insurance premiums, increased bank charges, and an increase in direct labour costs primarily due to higher salaries partially offset by lower consulting due to the completion of the treasury management system implementation.

Schedule 5 – Supply Chain Services

Segment	2025 Actual	2027 Test	Variance
N/A	12.41	11.85	(0.56)

Supply Chain Services 2025-2027 Variance Explanation:

The variance between 2025 and 2027 is primarily driven by a significant reduction in expected material write-offs, partially offset by salary increases over two years and the addition of one headcount.

Schedule 6 – Human Resources

Segment	2025 Actual	2027 Test	Variance
Human Resources	12.20	12.28	0.08
Health Safety & Environmental	3.36	3.69	0.33
Business Transformation	4.16	5.05	0.89

Human Resources 2025-2027 Variance Explanation:

From 2025 to 2027 costs are expected to increase by $0.08M primarily driven by increased labour costs ($1.00M) which is attributable to inflationary increases and the addition of 1.5 FTE to provide support to business operations; and an increase in non-labour ($0.39M). The non-labour increase is primarily related to increased consulting, legal fees and recruitment costs. The increases are partially offset by a reduction in severance of $1.30M.

Health & Safety and Environment 2025-2027 Variance Explanation:

From 2025 to 2027 costs are expected to increase by $0.33M primarily due to increased labour ($0.15M) and non-labour ($0.19M).

Business Transformation 2025-2027 Variance Explanation:

From 2025 to 2027 costs are expected to increase by $0.89M primarily driven by an increase in consulting ($0.46M) and an increase in labour costs ($0.39M). The consulting increase is primarily driven by external support for the identification and implementation of Continuous Improvement opportunities to drive further productivity and external expertise to conduct maturity assessments and improvements to the BT functions. The labour increase is driven by the addition of two FTEs in project management and change management required to support the planned projects in 2027.

Schedule 7 – Customer Service

Segment	2025 Actual	2027 Test	Variance
Billing	18.32	19.27	0.95
Collections & Payments	15.81	16.98	1.17
Customer Care	14.73	16.41	1.68
Customer Connections and Key Accounts	1.98	2.57	0.59
Customer Excellence	3.22	4.26	1.04

Billing 2025-2027 Variance Explanation:

From 2025 to 2027, Billing costs are expected to increase by $0.95 million driven by a $3.6 million increase as a result of fixed costs for the City of Hamilton water billing services (formerly excluded from Revenue Requirement per legacy Horizon) absorbed in OM&A, and $0.4 million increase in labour costs due primarily to wage inflation. These increases are partially offset by a $2 million reduction in postage and printing costs from higher e-bill penetration rates and a $1.1 million decrease in outside service provider costs from lower water meter reading costs.

Collections and Payments 2025-2027 Variance Explanation:

From 2025 to 2027, Collection & Payment costs are expected to increase by $1.2 million, led by a $0.8 million increase as a result of a fixed costs for the City of Hamilton water billing services (formerly excluded from Revenue Requirement per legacy Horizon) absorbed in OM&A, a $1.1 million increase in LEAP funding as expected LEAP disbursements move from the regulatory variance account to OM&A, and a $0.34 million increase in labour costs due primarily to wage inflation. This is partially offset by a $0.7 million decrease in credit losses from lower arrears to 2025 actuals and a $0.3 million decrease in outside service provider costs from lower field collection costs.

Customer Care 2025-2027 Variance Explanation:

From 2025 to 2027 Customer Care costs are expected to increase by $1.7 million, led by a $1.2 million increase in labour costs from backfilling of vacancies in 2026 compared to 2025 actual, and a $1.5 million increase as a result of a fixed costs for the City of Hamilton water billing services (formerly excluded from Revenue Requirement per legacy Horizon) absorbed in OM&A. These increases are partially offset by a $1.1 million reduction in third-party contact center costs compared to 2025 actuals where additional third-party agents were brought on to offset internal agent vacancies.

Customer Connections and Key Accounts 2025-2027 Variance Explanation:

From 2025 to 2027, Customer Connections and Key Account costs are expected to increase by $0.6 million driven by a $0.4 million increase in labour costs and $0.2 million increase in outside service costs to support Customer Connections.

Customer Service Excellence 2025-2027 Variance Explanation:

From 2025 to 2027. Customer Excellence costs are expected to increase by $1.0 Million, driven by a $1.2 million increase in labour costs from lower project capitalization from the completion of the Guelph CC&B integration project, and a $0.2 million increase as a result of a fixed costs for the City of Hamilton water billing services (formerly excluded from Revenue Requirement per legacy Horizon) absorbed in OM&A. These increases are partially offset by a $0.3 million decrease in outside service costs from lower contractor costs with the completion of the Guelph CC&B integration project.

Schedule 8 – Digital and Innovation

Segment	2025 Actual	2027 Test	Variance
Product Management	18.65	21.55	2.90
IT Operations	14.56	18.71	4.15
D&I Business	6.38	9.00	2.62
Cyber	3.21	5.92	2.71
GRE&T Centre	2.88	3.16	0.28

Product Management 2025-2027 Variance Explanation:

- Licensing costs are expected to increase by approximately $2.0MM principally attributable to a new Oracle CC&B application license agreement, increased costs related to the MyAlectra customer portal, and licensing from the Workforce Management project. Consulting costs are expected to increase by approximately $0.5MM mainly driven by the commencement of a revised Customer Information

System (CIS) managed services agreement and increased costs to support operational technology applications.

IT Operations 2025-2027 Variance Explanation:

- From 2027, incremental costs reflect the addition of a Disaster Recovery & Business Continuity Specialist and new management positions including Manager, Engineering and Operations, and Product Manager, Enterprise Systems.
- Network, storage, and computation licensing costs were underspent by approximately $0.40MM in 2025 primarily due to technology retirement. Increases to the plan from 2027 include a $0.30MM increase associated with the Windows operating system upgrade, and a further $0.25MM increase related to Microsoft Enterprise and Copilot licensing.
- Beginning in 2026, IVA module and AI tuning license costs are expected to increase by $0.20MM annually, along with an additional $0.20MM increase in IVR licensing to support customer growth and higher call volumes.
- SaaS costs are expected to increase by approximately $0.50MM beginning in 2026, driven by enhancements to Alectra's backup and recovery capabilities, and cyber readiness services
- Consulting costs were reduced in 2025 by $0.40MM due to reduced spending on disaster recovery planning and staff augmentation, with these costs expected to be incurred in 2026 and 2027.

D&I Business 2025-2027 Variance Explanation:

- Increased licensing costs of $1.2MM are attributed to ServiceNow Automation, Knowledge Management, Copperleaf C55, DER license to support DSO, and Dayforce HCM licensing.
- Increased system integration and data management licensing costs of $0.88M through Alectra's Enterprise Data Management platform in support of WFM, INM, Enterprise GenAI Chatbot, and BizTalk Replacement projects.

Cyber Security 2025-2027 Variance Explanation:

- Increased costs of $0.7MM are attributed to the implementation and licensing of Alectra's Enterprise Information Protection initiative.
- Increased costs of $0.60MM are attributed to the implementation and licensing of Alectra's Identify and Access Management initiative.
- Increased cost of $0.4MM are attributed to Alectra's SECaaS service and Cyber Security device upgrades.
- Increase cost of $0.3MM attributable to the refreshment of Alectra's Cyber Security Roadmap.

GRE&T Centre 2025-2027 Variance Explanation:

- There are no material variances related to the GRE&T Centre during this period.

Schedule 9 – System Control

Segment	2025 Actual	2027 Test	Variance
N/A	12.37	15.08	2.71

The variance between the 2025 actuals and 2027 test year budget for the System Control Program is driven by the need to increase the number of System Control Operators. The need for additional System Control Operators is detailed in Exhibit 4, Tab 2, Schedule 9 starting on page 7.

Schedule 10 – Stations

Segment	2025 Actual	2027 Test	Variance
N/A	12.05	13.96	1.91

The variance between 2025 Actuals and 2027 Test year budget is primarily due to an increase in labour costs of $1.8 million between the 2025 actual and the 2027 test year. The increase is primarily driven by the addition of new headcount to meet the increased demand for capital and maintenance activity during the forecast period, as described in Exhibit 4, Tab 2, Schedule 10.

Schedule 11 – Records and Mapping Services

Segment	2025 Actual	2027 Test	Variance
N/A	5.16	5.35	0.19

The variance between the 2025 actuals and 2027 test year budget for the Records and Mapping Services Program is driven by the addition of two FTEs in 2027.

Schedule 12 – Cable Locates

Segment	2025 Actual	2027 Test	Variance
N/A	0.47	8.67	8.20

The variance between 2025 actuals and 2027 test year are due to the disposition of the GOCA Variance Account. The gross cable locates program actual in 2025 is $8.42M and the variance from gross to gross is $0.25M or 2.9%. This variance is due to inflationary increases in cable locate service provider costs and Ontario One Call fee increases.

Schedule 13 – Network Metering

Segment	2025 Actual	2027 Test	Variance
N/A	12.45	14.89	2.44

Network Metering 2025-2027 Variance Explanation:

Network Metering's 2027 costs are expected to increase by $2.4MM as compared to 2025 actual. This is primarily due to:

- An increase in outside service provider costs of $1.2MM with one time project costs as Alectra Utilities implements its customer communications and education strategy for the mass deployment of AMI 2.0 meters ($0.6MM), undertakes auditing of its new AMI 1.0 Head End system ($0.4MM), provides for the cost of a letter of credit from its AMI 2.0 vendor ($0.1MM) and provides training on new processes and procedures related to its AMI Renewal project outcomes ($0.1MM);

- An increase in IST licenses and maintenance of $0.7MM due to the planned implementation of Alectra Utilities AMI 2.0 head end system, temporarily resulting in incremental head end expenditures; and,
- An increase in direct labour costs of $0.5MM due to the addition of 1.8 FTE and inflationary increases.

Schedule 14 – Program Delivery

Segment	2025 Actual	2027 Test	Variance
N/A	1.10	1.64	0.54

Program Delivery costs are expected to increase by $0.54M between 2025 and 2027 primarily due to increases in FTE count to meet the forecast increase in capital expenditures. Please refer to Exhibit 4, Tab 3, Schedule 3, Page 31 for more details.

Schedule 15 – Vegetation Management

Segment	2025 Actual	2027 Test	Variance
Vegetation Planned Cut Cycle	6.42	6.81	0.39
Reactive Vegetation Calls	0.27	0.24	(0.03)

Vegetation Management Cut Cycle 2025-2027 Variance Explanation:

The increase of $0.39M from 2025 Actual ($6.42M) to the 2027 Test Year ($6.81M) is primarily driven by a combination of contractor rate increases, inflationary pressures, and adjustments to maintain planned cut cycle coverage and productivity across the system partially offset by expected lower administrative/supervisory costs to support this program in 2027 compared to 2025.

Reactive Tree Trimming 2025-2027 Variance Explanation:

The $0.03M decrease from 2025 Actual ($0.27M) to the 2027 Test Year ($0.24M) is minor and reflects normal year-over-year variation. Test year Reactive Tree Trimming levels are expected to return to typical levels compared to 2025 which saw high levels of adverse weather-related outages and an ice storm that increased reactive trimming levels.

Schedule 16 – Overhead Inspections and Maintenance

Segment	2025 Actual	2027 Test	Variance
Asset Inspection	3.00	2.41	(0.59)
Disconnects/Reconnects	8.78	9.23	0.45
Preventative Maintenance	2.58	2.55	(0.03)
System Reactive Repairs and Trouble Calls	14.26	16.53	2.27

Asset Inspection costs were higher than previously forecast in 2025 due to increased inspection requirements due to missing legacy utility records to confirm compliance with the Canadian Environmental Protection Act's PCB Regulations. The forecast variance of ($0.59M) between 2025 and 2027 is due to that requirement being satisfied in 2025 and a return to the previously forecast program requirements.

Disconnects/Reconnects is forecast to have a variance of $0.45M between 2025 and 2027. This is primarily attributable to inflationary labour cost increases.

Preventative Maintenance has a forecast variance of ($0.03M) between 2025 and 2027. This variance is immaterial and primarily related to minor fluctuations in asset maintenance schedules.

System Reactive Repairs and Trouble Calls is forecast to have a variance of approximately $2.27M between 2025 and 2027. This is primarily attributable to increases in staff compliment and inflationary labour increases in this segment. Funding in this segment supports Alectra Utilities trouble response, including responding to more frequent storm events (please see reference Exhibit 2A Tab 1 Schedule 1 Appendix G), responding to outage and power quality events, and repairing corrective actions and other deficiencies. Please see IR response 4-AMPCO-67 for historical corrective action and trouble call volumes.

Schedule 17 – Underground Inspections and Maintenance

Segment	2025 Actual	2027 Test	Variance
Asset Inspection	2.26	2.75	0.49
Preventative Maintenance	0.34	0.43	0.09
System Reactive Repairs and Trouble Calls	28.29	25.18	(3.11)

The forecast variance of $0.49M between 2025 and 2027 in Asset inspections are primarily due to increases in service provider fees and annual variance in asset quantities requiring inspection.

The Preventative Maintenance segment has a forecast variance of $0.09M between 2025-2027 primarily due to increases in service provider fees and labour rates for administrative costs. Costs were lower than expected in 2025 primarily due to deferral of previously forecast staff increases resulting in lower allocated administrative costs.

System Reactive Repairs and Trouble Calls has a forecast variance of ($3.11M) between 2025 and 2027. This is primarily due to higher than anticipated costs in 2025 primarily due to direct labour and third-party contractor charges arising from higher than anticipated repair costs. Alectra Utilities experienced 14% higher cable and cable accessory related failures in 2025 than 2024 (524 outages caused by primary/secondary cable and accessories in 2025, versus 459 in 2024).

Schedule 18 – Facilities

Segment	2025 Actual	2027 Test	Variance
N/A	16.07	13.58	(2.49)

Facilities Management 2025-2027 Variance Explanation:

- The reduction in Facilities between 2025 and the 2027 test year is mainly due to a one-time expense the removal of all the underground fuel tanks at Alectra Utilities' Facilities. Alectra Utilities also forecasted lower repairs and maintenance costs from switching to a more predictive maintenance (PdM) method and testing of assets. The predictive method is intended to provide a better forecast of equipment health that will allow Alectra Utilities to make smaller repairs prior to complete asset failures which require more costly repairs.

Schedule 19 – Fleet Asset Management

Segment	2025 Actual	2027 Test	Variance
N/A	13.31	12.48	(0.83)

Fleet Asset Management 2025-2027 Variance Explanation:

A large portion of this reduction is due to forecasted 407 ETR reductions by $0.46 from 2025-2026/2027. Also, Repairs and Maintenance are expected to decrease from 2025-2026/2027 by $0.80. The combination of these two-line items are the major contributors to the 2025-2027 variance.

Schedule 20 – Property Taxes

Segment	2025 Actual	2027 Test	Variance
N/A	5.28	6.94	1.66

Property Taxes 2025-2027 Variance Explanation:

Property Taxes are forecast to increase by approximately $1.66MM from 2025 to 2027 due to the commencement of a new Ontario property tax assessment cycle. Alectra Utilities has assumed that a Current Value Assessment (CVA) update will occur and be phased in over the 2026 – 2029 period. This assessment cycle captures increases in property tax assessments over the elongated 2016 – 2025 period. Approximately $0.84MM of the change relates to the Kennedy Road Operations Centre generated by the significant increase in the estimated 2026 CVA of $110MM in comparison to its 2016 CVA of $28MM. All other properties were estimated to have a 50% increase in the CVA from 2016 to 2026, which results in the remaining $0.82MM increase in property tax expense from 2025 to 2027.

Schedule 21 – Allocations and Recoveries

Segment	2025 Actual	2027 Test	Variance
Shared Service Allocation	6.90	6.87	(0.03)
Fleet Recoveries	(13.69)	(13.09)	0.60
Material Recoveries	(10.14)	(9.32)	0.82
Other Recoveries	(1.08)	(8.46)	(7.38)

Shared Service Allocations 2025-2027 Variance Explanation:
There is no material variance over this period.

Fleet Recoveries 2025-2027 Variance Explanation:

Fleet Recoveries are forecast to decrease by $0.6MM in 2025 to 2027. 2026 decreases due to lower forecasted fleet repairs and maintenance expenditures. The increase in 2027 is principally due to inflationary increases.

Material Recoveries 2025-2027 Variance Explanation:

Material Recoveries are forecast to decrease by approximately $0.8MM from 2025 to 2027 principally due to higher than expected utilization of direct materials to support Supply Chain, Overhead Inspections and Maintenance, and Underground Inspections and Maintenance programs in 2025.

Other Recoveries 2025-2027 Variance Explanation:

Other Recoveries are forecast to increase by approximately $7.4MM from 2025 to 2027, principally attributable to the 2027 vacancy provision, partially offset by a credit for the over recovery of burden pool costs to AUC OM&A programs in 2025.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-37

Ref: Exhibit 4, Tab 2, Schedule 1, pp. 11, 21, 25, 29

Question(s):

a) Please provide a more detailed version of Table 4-2-3 that shows the various cost components for each of the asset management and grid modernization segments of the asset management program. For example, to the extent that these cost components are relevant to the program, please show line items for labour / wages, third-party contractors, licensing fees, etc. Please add to the list any other cost components that are relevant to the specific segments.

b) Please provide a table that shows the costs of the asset management segment between 2017-2031 by function (i.e., system planning, asset sustainment, and CIP).

c) Please further explain the methodology applied to forecast costs for the asset management program in the test period (including a discussion of the test year forecasting methodology and the 2028-2031 forecasting methodology if those methodologies are different).

d) Please further explain the statement that the “CIP function will start reporting on In-Service Capital moving away from Capital Expenditure…”. As part of the response, please explain how the Company is currently tracking in-service additions in the context of its monthly approach to the determination of depreciation expense.

e) Please provide a table that shows the costs of the grid modernization segment between 2017-2031 by function (i.e., technology enablement, grid analytics, etc.). Please also further explain the methodology applied to forecast costs in the test year.

RESPONSE:

a) Please see Table 1 for cost components for each of the asset management and grid modernization segments of the asset management program into the following categories:

   a. Consulting
   b. Labour Costs
   c. Other

   There are no licensing fees.

Table 1 – OM&A Costs by component

					Historical				
Segment	**Cost Driver**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
All Segments		**5.52**	**4.56**	**5.96**	**5.22**	**4.61**	**4.90**	**5.30**	**6.45**
Asset Management		**5.52**	**4.56**	**5.96**	**5.22**	**4.61**	**4.90**	**5.30**	**6.44**
Asset Management	Consulting	0.34	0.40	0.71	0.26	0.07	0.41	0.44	0.02
Asset Management	Direct Labour Costs	4.18	3.93	5.00	4.85	4.43	4.22	4.56	6.03
Asset Management	Other	1.00	0.23	0.25	0.11	0.11	0.27	0.30	0.39
Grid Modernization		**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.01**
Grid Modernization	Direct Labour Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grid Modernization	Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01

		Bridge		Test	Forecast			
Segment	**Cost Driver**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
All Segments		**7.48**	**9.63**	**9.26**	**10.52**	**11.09**	**11.49**	**11.89**
Asset Management		**6.98**	**8.71**	**8.27**	**8.83**	**9.11**	**9.43**	**9.77**
Asset Management	Consulting	0.18	0.36	0.41	0.42	0.58	0.64	0.70
Asset Management	Direct Labour Costs	6.48	7.88	7.34	7.85	7.97	8.22	8.49
Asset Management	Other	0.32	0.47	0.52	0.56	0.56	0.57	0.58
Grid Modernization		**0.49**	**0.92**	**0.99**	**1.69**	**1.99**	**2.05**	**2.12**
Grid Modernization	Direct Labour Costs	0.48	0.90	0.94	1.62	1.90	1.96	2.02
Grid Modernization	Other	0.01	0.02	0.05	0.07	0.09	0.09	0.10

b) Please see Table 2 for costs of the asset management segment between 2017-2031 by function.

Table 2 – OM&A Costs by Segment

Program Costs ($MM)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Asset Sustainment & Standards	3.09	2.54	2.53	2.17	2.23	2.50	2.99	3.06	3.34	3.66	3.65	3.77	3.96	4.09	4.21
System Planning & Electrification	1.28	0.90	1.88	1.56	0.85	0.95	0.84	1.12	1.11	1.68	1.63	1.76	1.83	1.88	1.94
Capital Investment Planning	1.15	1.12	1.55	1.49	1.54	1.44	1.47	2.27	2.53	3.38	2.99	3.31	3.31	3.46	3.62
Total	5.52	4.56	5.96	5.22	4.61	4.90	5.30	6.44	6.98	8.71	8.27	8.83	9.11	9.43	9.77

c) Forecast is based on resources and annual cost escalation. Refer to response provided to 4-SEC-80 for detailed explanation on mandatory initiatives by Ontario Energy Board (OEB) requiring additional staff and Exhibit 4-2-1-Section 4.1 Cost Drivers.

d) Refer to response provided in 2-CCC-11-f) for details related to in-service and monthly approach to the determination of depreciation expense.

e) Please see Table 3 for costs of the grid modernization segment between 2017-2031 by function.

Table 3 – Grid Modernization segment costs by function

Program Costs ($MM)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Grid Analytics & Data Modernization	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00
Grid Modernization Technology	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00
Grid Modernization	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.43	0.92	0.99	1.69	1.99	2.05	2.12
Total	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.49	0.92	0.99	1.69	1.99	2.05	2.12

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-38

Ref: Exhibit 4, Tab 2, Schedule 2, p. 8

Question(s):

a) Please provide a more detailed version of Table 4-2-8 that shows the various cost components for the distribution design program. For example, to the extent that these cost components are relevant to the program, please show line items for labour / wages, third-party contractors, licensing fees, etc. Please add to the list any other cost components that are relevant to the program.

b) Please provide a table that shows the costs of the distribution design program for the 2017-2031 period broken out by function (i.e., customer initiated work, distribution support services and asset management driven work).

c) Please further explain the methodology applied to forecast costs for the distribution design program in the test period (including a discussion of the test year forecasting methodology and the 2028-2031 forecasting methodology if those methodologies are different).

RESPONSE:

a) **Table 1 – Distribution Design Cost Components**

	2017	2018	2019	2020	2021	2022	2023	2024
Total	**3.91**	**3.93**	**5.99**	**6.58**	**6.27**	**6.88**	**7.30**	**7.09**
Direct Labour Costs	3.35	2.69	4.53	4.69	4.64	5.04	5.34	5.37
ESA fees	0.05	0.42	0.44	0.47	0.47	0.48	0.49	0.50
Pole attachment	0.34	0.27	0.57	1.21	0.78	0.79	0.83	0.67
Other	0.22	0.55	0.45	0.21	0.38	0.57	0.64	0.55
		2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Total		**7.29**	**8.60**	**9.61**	**10.61**	**11.41**	**12.07**	**12.58**
Direct Labour Costs		5.08	6.53	7.52	8.43	9.16	9.66	10.02
ESA fees		0.51	0.51	0.53	0.54	0.55	0.56	0.57
Pole attachment		0.79	0.78	0.79	0.81	0.83	0.84	0.86
Other		0.91	0.78	0.77	0.83	0.87	1.01	1.13

b) Table 2 – Distribution Design Costs by Function

	2017	2018	2019	2020	2021	2022	2023	2024
Total	**3.91**	**3.93**	**5.99**	**6.58**	**6.27**	**6.88**	**7.30**	**7.09**
Customer Initiated Work	2.46	1.73	3.10	2.51	2.71	3.22	3.44	3.28
Distribution Support Services	1.00	1.39	2.14	3.05	2.72	2.82	3.16	3.05
Asset Management Driven Work	0.45	0.80	0.75	1.02	0.84	0.85	0.70	0.75
		2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Total		**7.29**	**8.60**	**9.61**	**10.61**	**11.41**	**12.07**	**12.58**
Customer Initiated Work		3.11	3.51	4.05	4.40	4.66	4.84	5.00
Distribution Support Services		3.37	3.68	3.71	3.81	3.91	4.13	4.33
Asset Management Driven Work		0.81	1.41	1.85	2.39	2.84	3.10	3.25

c) <u>Test Year Forecasting Methodology</u>

For both the test year and the test period, Distribution Design program costs were forecasted based on projected workloads, their associated direct labour costs, and non-labour actuals expenditures.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-39

Ref:

Exhibit 4, Tab 2, Schedule 3, pp. 4, 17

Question(s):

a) Please provide a more detailed version of Table 4-2-12 that shows the various cost components for each of the specific segments (i.e., regulatory, legal, etc.) of the corporate services program. For example, to the extent that these cost components are relevant to the program, please show line items for labour / wages, third-party contractors, licensing fees, etc. Please add to the list any other cost components that are relevant to the specific segment.

b) Please explain the methodology applied to forecast costs in the test period for the corporate services program (including a discussion of the test year forecasting methodology and the 2028-2031 forecasting methodology if those methodologies are different).

RESPONSE:

a) The detailed breakdown of cost components for the Corporate Services segments are provided below.

Table 1 - Corporate Services Program Expenditures by Segment ($MM)

Corporate Services Program Costs ($MM) - Historic Period Segment	Cost Driver	2017	2018	2019	2020	2021	2022	2023	2024
All Segments		**12.09**	**12.92**	**14.15**	**14.96**	**13.99**	**14.25**	**13.57**	**13.51**
Regulatory		**6.82**	**6.96**	**8.05**	**6.87**	**6.80**	**7.19**	**7.25**	**7.32**
Regulatory	Consulting	0.19	0.29	0.14	0.04	0.10	0.19	0.16	0.15
Regulatory	Direct Labour Costs	2.81	2.67	3.37	3.52	3.32	3.43	3.46	3.83
Regulatory	OEB costs	3.11	3.05	3.18	3.29	3.19	3.24	3.36	3.05
Regulatory	Other	0.71	0.95	1.36	0.02	0.19	0.33	0.27	0.29
Legal		**1.28**	**1.23**	**1.51**	**2.68**	**1.95**	**2.26**	**2.01**	**1.75**
Legal	Direct Labour Costs	0.90	0.94	1.25	1.49	1.41	1.51	1.43	1.11
Legal	Legal Fees	0.34	0.23	0.20	1.14	0.51	0.69	0.54	0.61
Legal	Other	0.04	0.06	0.06	0.05	0.03	0.06	0.04	0.03
Internal Audit		**0.72**	**0.93**	**0.87**	**0.83**	**0.73**	**0.33**	**0.39**	**0.52**
Internal Audit	Consulting	0.10	0.11	0.13	0.04	0.00	0.00	0.02	0.00
Internal Audit	Direct Labour Costs	0.61	0.78	0.72	0.77	0.72	0.32	0.36	0.50
Internal Audit	Other	0.01	0.04	0.02	0.02	0.01	0.01	0.01	0.02
Govt & Corp Relations		**2.63**	**2.49**	**2.34**	**3.23**	**3.04**	**3.35**	**3.11**	**3.03**
Govt & Corp Relations	Advertising	0.52	0.31	0.55	1.10	1.08	1.14	0.70	0.70
Govt & Corp Relations	Consulting	0.41	0.21	0.20	0.16	0.17	0.14	0.18	0.09
Govt & Corp Relations	Direct Labour Costs	1.38	1.61	1.30	1.73	1.54	1.67	1.82	1.86
Govt & Corp Relations	Subscriptions & memberships	0.12	0.00	0.09	0.05	0.11	0.18	0.18	0.13
Govt & Corp Relations	Other	0.20	0.36	0.20	0.19	0.14	0.22	0.23	0.25
Strategy, ERM & Sustainability		**0.64**	**1.31**	**1.38**	**1.35**	**1.48**	**1.11**	**0.82**	**0.89**
Strategy, ERM & Sustainability	Consulting	0.12	0.24	0.27	0.30	0.35	0.29	0.03	0.00
Strategy, ERM & Sustainability	Direct Labour Costs	0.44	1.03	1.01	1.00	1.09	0.71	0.72	0.77
Strategy, ERM & Sustainability	Subscriptions & memberships	0.01	0.00	0.04	0.04	0.03	0.07	0.05	0.09
Strategy, ERM & Sustainability	Other	0.07	0.04	0.06	0.01	0.01	0.04	0.02	0.03

Program Costs ($MM) - Bridge and Forecast Period								
Segment	**Cost Driver**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
All Segments		**13.96**	**16.78**	**23.78**	**24.33**	**25.20**	**25.82**	**26.45**
Regulatory		**7.48**	**8.56**	**15.03**	**15.34**	**15.67**	**16.00**	**16.34**
Regulatory	Consulting	0.12	0.32	1.70	1.58	1.60	1.62	1.64
Regulatory	Direct Labour Costs	4.10	4.44	4.80	5.13	5.31	5.48	5.66
Regulatory	OEB costs	3.23	3.51	7.06	7.19	7.31	7.45	7.58
Regulatory	Other	0.03	0.29	1.47	1.44	1.45	1.45	1.46
Legal		**1.98**	**2.76**	**3.02**	**2.89**	**2.97**	**3.06**	**3.14**
Legal	Direct Labour Costs	1.20	1.84	1.92	1.98	2.04	2.10	2.17
Legal	Legal Fees	0.73	0.85	1.04	0.85	0.87	0.88	0.90
Legal	Other	0.05	0.07	0.06	0.06	0.06	0.08	0.07
Internal Audit		**0.49**	**0.87**	**0.98**	**1.19**	**1.49**	**1.54**	**1.59**
Internal Audit	Consulting	0.00	0.30	0.30	0.30	0.30	0.30	0.30
Internal Audit	Direct Labour Costs	0.46	0.53	0.64	0.84	1.13	1.17	1.22
Internal Audit	Other	0.03	0.04	0.04	0.05	0.06	0.07	0.07
Govt & Corp Relations		**3.11**	**3.56**	**3.70**	**3.83**	**3.94**	**4.06**	**4.18**
Govt & Corp Relations	Advertising	0.63	0.68	0.69	0.70	0.72	0.73	0.75
Govt & Corp Relations	Consulting	0.07	0.19	0.20	0.20	0.20	0.21	0.21
Govt & Corp Relations	Direct Labour Costs	2.02	2.27	2.38	2.48	2.58	2.67	2.76
Govt & Corp Relations	Subscriptions & memberships	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Govt & Corp Relations	Other	0.24	0.27	0.28	0.30	0.29	0.30	0.31
Strategy, ERM & Sustainability		**0.90**	**1.03**	**1.05**	**1.09**	**1.12**	**1.16**	**1.20**
Strategy, ERM & Sustainability	Consulting	0.01	0.03	0.03	0.03	0.03	0.03	0.03
Strategy, ERM & Sustainability	Direct Labour Costs	0.78	0.78	0.81	0.84	0.87	0.90	0.94
Strategy, ERM & Sustainability	Subscriptions & memberships	0.08	0.12	0.12	0.12	0.12	0.13	0.13
Strategy, ERM & Sustainability	Other	0.03	0.10	0.09	0.10	0.10	0.10	0.10

b) As identified in section 4.1 Cost Drivers of Exhibit 4, Tab 2, Schedule 3, p. 5, the forecast costs are driven by the OEB's annual cost assessment fees, the addition of 5 positions and one-time costs related to the preparation of this rebasing application.

Prior to 2027, OEB cost assessment fees in the Regulatory Affairs segment reflected the OEB assessment costs embedded in rates. The difference between OEB cost assessment fees built into rates and the actual assessment fees based on the OEB's revised 2016 cost assessment model were recorded in Account 1508, Other Regulatory Assets. Starting in 2027, Alectra Utilities has forecasted the OEB cost assessment fees to fully capture the assessment fees, representing an increase of approximately $3.6MM compared to the historical amounts. With respect to the addition of 5 positions, 3 positions have been included in 2027, 1 in 2028 and 1 in 2029. One-time rebasing application costs includes consulting costs, legal fees and costs for third-party expert reports. These costs are amortized evenly over the 2027-2031 period with approximately $1.8MM included each year. Costs for the 2028-2031 reflect inflationary increases.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-40

Ref: Exhibit 4, Tab 2, Schedule 4, pp. 5, 7, 9, 11

Question(s):

a) Please provide a more detailed version of Table 4-2-20 that shows the various cost components of the specific segments (i.e., finance and treasury) of the finance and treasury program. For example, to the extent that these cost components are relevant to the program, please show line items for labour / wages, third-party contractors, licensing fees, etc. Please add to the list any other cost components that are relevant to the specific segment.

b) With respect to Tables 4-2-21 and 4-2-23, please confirm the statement that "FTE with productivity represents the headcount in Alectra Utilities' financial plan" means that those are the FTEs forecast for the 2027-2031 period. In addition, with respect to the historical period, please advise whether the FTE w/ productivity line reflects Alectra's actual FTEs.

c) With respect to the forecasts of total invoices and works orders over the 2027-2031 period, please explain the methodology used to derive those forecasts.

d) Please provide a detailed description of the types of Alectra's insurance coverage.

RESPONSE:

a) The detailed breakdown of cost components for the Finance and Treasury segments are provided in Table 1 below.

Table 1 - Detailed View of Finance and Treasury Segments Program Costs ($MM)

		Historical							
Segment	**Cost Driver**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Finance		**10.80**	**11.19**	**12.22**	**12.69**	**11.81**	**10.45**	**11.13**	**11.62**
	Direct Labour Costs	9.28	10.07	10.94	11.40	10.53	9.63	10.28	10.80
	Audit Fees	0.53	0.74	0.69	0.51	0.60	0.52	0.59	0.57
	Other	0.99	0.38	0.59	0.78	0.68	0.30	0.26	0.25
Treasury		**6.05**	**7.63**	**7.95**	**10.19**	**9.98**	**10.21**	**10.68**	**11.24**
	Insurance	3.90	4.06	4.16	4.48	4.58	5.05	5.78	5.96
	Bank Charges	1.26	1.69	1.85	3.62	3.31	2.87	2.30	2.47
	Direct Labour Costs	0.69	1.34	1.40	1.54	1.57	1.59	1.59	1.87
	Other	0.20	0.54	0.54	0.55	0.52	0.70	1.01	0.94

			Bridge	Test		Forecast		
Segment	**Cost Driver**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Finance		**12.61**	**13.13**	**14.16**	**15.21**	**16.69**	**17.24**	**17.79**
	Direct Labour Costs	11.53	12.03	12.84	13.80	15.23	16.05	16.50
	Audit Fees	0.57	0.59	0.60	0.61	0.62	0.64	0.65
	Other	0.51	0.51	0.72	0.80	0.84	0.55	0.64
Treasury		**11.26**	**12.46**	**12.80**	**13.73**	**14.19**	**14.68**	**15.19**
	Insurance	5.94	6.62	6.93	7.27	7.62	7.98	8.37
	Bank Charges	2.51	2.84	2.86	3.47	3.50	3.53	3.56
	Direct Labour Costs	1.90	2.05	2.23	2.19	2.26	2.33	2.40
	Other	0.91	0.95	0.78	0.80	0.81	0.84	0.86

b) Confirmed that the FTE with productivity is what has been forecast for the 2027-2031 period. The FTE in the historical period reflects the actual FTEs supporting this function.

c) Alectra Utilities used the historical volume of invoices and work orders processed to forecast the projections for 2025 – 2031 period. Historically between 2021 – 2024, Alectra processed an annual average of 46 capital related invoices per $1M of gross capital expenditures and 152 OM&A related invoices per $1M of non-labour OM&A expenditures. Similarly, historically between 2021 – 2024, Alectra processed an average of 13 capital-related work orders per $1M of gross capital expenditures.
These historical ratios were used to project the number of invoices and work orders based on the OM&A non-labour and capital investment plan for the 2025 – 2031 period.

d) Alectra Utilities currently has the following insurance coverage:

- **General Liability** – Coverage for electricity distribution operations arising from Alectra's negligence. This includes the following coverage:
  - Premises and Operations
  - Products and completed Operations
  - Employers / Contingent Employers Liability
  - Bodily injury Liability
  - Personal Injury & Advertising Liability
  - Property Damage Liability
  - Tenant's Legal Liability
  - Environmental Impairment
  - Errors & Omissions / Professional Liability
  - Non-Owned Automobile
  - Legal Expense (Conflict of Interest and Occupational Health & Safety)

- **Property and Equipment Breakdown Insurance** – Coverage for damage and losses to physical assets (buildings, contents, distribution stations. Includes the following coverage:
  - Property Terrorism and Sabotage

- **Fleet Vehicle Insurance** – Coverage against physical damage or bodily injury and third-party liability in a vehicle accident.

- **Crime** – Provides coverage for losses due to criminal acts and social engineering related to scams and fraud. Includes coverage for the following:
  - Employee theft
  - Premises
  - In transit
  - Forgery
  - Computer fraud
  - Funds transfer
  - Money order and counterfeit currency fraud

  - Credit card fraud
  - Client coverage
  - Expense coverage
  - Social engineering

- **Privacy, Cyber and Network Security** – Provides coverage for privacy and data breaches. Includes coverage for the following:
  - Privacy and security
  - Media liability
  - Payment card Industry
  - Failure to supply
  - Breach response services
  - Business interruption loss
  - Data asset restoration
  - Cyber extortion

- **Directors and Officers Liability** – Protects Alectra's D&O's from lawsuits based on performance of duties.

- **Employment Practices Liability** – Coverage for defense costs and damages for employment related claims.

- **Fiduciary Liability** – Coverage for exposures arising from administration and management of employee benefit plans.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-41

Ref: Exhibit 4, Tab 2, Schedule 5, pp. 3, 10-17

Question(s):

a) Please provide a more detailed version of Table 4-2-29 that shows the various cost components for the supply chain services program. For example, to the extent that these cost components are relevant to the program, please show line items for labour / wages, third-party contractors, licensing fees, etc. Please add to the list any other cost components that are relevant to the program.

b) Please provide a table that shows the costs of the supply chain services for the 2017-2031 period by function (i.e., procurement, inventory planning & logistics, and commodity management).

c) Please further explain the methodology applied to forecast costs in the test period for the supply chain services program (including a discussion of the test year forecasting methodology and the 2028-2031 forecasting methodology if those methodologies are different).

d) With respect to the standardization initiative, please provide any available analysis regarding the impact on procurement costs.

e) Please add a column to Table-4-2-30 that shows the $/unit for the key commodities listed in the table.

f) Please provide a table, similar to Table 4-2-30, that shows the 2027-2031 forecast materials issued, the total value for those materials and the $/unit.

g) Please provide the historical and forecast cost of 3PL services for the 2017-2031 period.

RESPONSE:

a) **Table 1 – Detailed Supply Chain Services Program Expenditures ($MM)**

Supply Chain Services								
Program Costs ($millions) – Historic Period								
Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Direct Labour Costs	5.89	6.30	7.06	7.21	7.10	7.46	8.47	7.77
Direct Material Costs	1.11	1.25	1.03	0.94	1.02	1.25	1.59	1.7
Environmental Expenses	0.65	0.44	0.46	0.40	0.52	0.30	0.30	0.34
Inventory Write off	(0.70)	0.08	(0.14)	0.74	0.21	0.62	0.87	0.95
3PL Services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.79	0.80	0.81	0.44	0.35	0.50	(0.01)	0.03
Total	**7.74**	**8.87**	**9.22**	**9.73**	**9.20**	**10.13**	**11.22**	**10.80**
Program Costs ($millions) – Bridge and Forecast Period								
Year	**2025A**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	
Direct Labour Costs	8.06	8.32	8.72	9.46	10.12	10.44	10.77	
Direct Material Costs	2.09	1.35	1.38	1.41	1.44	1.46	1.49	
Environmental Expenses	0.43	0.42	0.43	0.43	0.44	0.45	0.46	
Inventory Write off	1.42	0.52	0.52	0.53	0.54	0.55	0.56	
3PL Services	0.15	0.28	0.23	0.26	0.44	0.63	0.76	
Other	0.26	0.55	0.58	0.58	0.60	0.63	0.64	
Total	**12.41**	**11.44**	**11.85**	**12.67**	**13.58**	**14.16**	**14.68**	

b) **Table 2 – Supply Chain Services Program Expenditures by Function ($MM)**

Supply Chain Services								
Program Costs ($millions) – Historic Period								
Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Commodity	0.49	0.68	0.63	0.78	0.86	0.94	1.01	0.93
Logistic Inventory	4.69	5.88	6.45	7.07	6.43	7.12	7.85	7.40
Procurement	2.56	2.32	2.13	1.87	1.91	2.07	2.37	2.47
Total	**7.74**	**8.87**	**9.22**	**9.73**	**9.20**	**10.13**	**11.22**	**10.80**
Program Costs ($millions) – Bridge and Forecast Period								
Year	**2025A**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	
Commodity	1.02	1.05	1.09	1.12	1.16	1.19	1.23	
Logistic Inventory	8.48	7.67	7.85	8.09	8.48	8.89	9.25	
Procurement	2.92	2.72	2.91	3.46	3.95	4.07	4.20	
Total	**12.41**	**11.44**	**11.85**	**12.67**	**13.58**	**14.16**	**14.68**	

c) Forecast costs for the Supply Chain Services program for the test year and test period were developed based on historical spending and an assessment of expected operational needs, as outlined in Section 4.1 (Cost Drivers). Historical data was used to establish a baseline, which was adjusted for forecast changes in activity levels and inflation. These adjustments include incremental third-party logistics (3PL) costs to address yard space constraints and increased material volumes, starting in 2026 and continuing through 2031.

d) Alectra Utilities has not completed an analysis on reductions in procurement costs related to the standardization initiative. The primary benefits of standardization have been realized in improved inventory management, reduced operational complexity and enhanced supply chain resilience, rather than in measurable unit cost reductions.

e) **Table 3 – 2024 Values of Key Commodities and Unit Cost Averages***

Commodity Type	Materials Issued in 2024 (Qty)	Total Value in 2024 ($)	$/unit
Insulators	28,553	$ 2,691,498	$ 94
Metering	221,038	$ 5,255,567	$ 24
Misc	1,259,733	$ 15,550,972	$ 12
Switches &Fuses	40,521	$ 13,786,856	$ 340
Switchgear	153	$ 9,330,771	$ 60,985
Transformer	2,150	$ 29,296,594	$ 13,626
Wire/Cable (in meters)	890,082	$ 14,847,272	$ 17
Wood Poles	1,603	$ 3,958,317	$ 2,469
Concrete Poles	987	$ 4,225,185	$ 4,281
Total		$ 98,943,032	

*Each commodity group includes a large number of individual SKUs with varying specifications and unit costs. Accordingly, average $/unit values were calculated by dividing the total value of materials issued by the total number of units issued in 2024, to provide a high-level indicative measure for reference purposes.

f) **Table 4 – 2031 Projected Values of Key Commodities and Unit Cost Averages****

Commodity Type	Projected Materials by 2031 (Qty)	Projected Value in 2031 ($)	Expected Average Price/Unit with Inflation
Insulators	58534	$ 6,325,534	$ 108
Metering	601551	$ 16,397,369	$ 27
Misc	2544661	$ 36,012,904	$ 14
Switches & Fuses	81852	$ 31,927,568	$ 390
Switchgear	269	$ 18,826,927	$ 69,916
Transformer	3311	$ 51,843,969	$ 15,658
Wire/Cable	1958180	$ 37,447,134	$ 19
Wood Poles	3767	$ 10,664,185	$ 2,831
Concrete Poles	1530	$ 7,508,041	$ 4,908
Total		**$ 216,953,629**	

**The $/unit values were calculated as outlined in response to 4-CCC-41-e. Please note that the projected 2031 values reflect inflationary increases as outlined in the capital expenditure plan and do not account for broader market fluctuations, tariff impacts, or changes in commodity pricing.

g) See response to part (a) Table 1.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-42

Ref: Exhibit 4, Tab 2, Schedule 6, pp. 10-11, 13, 18-20

Question(s):

a) Please provide a more detailed version of Table 4-2-35 that shows the various cost components of the specific segments (i.e., human resources, health & safety, business transformation) of the human resources program. For example, to the extent that these cost components are relevant to the program, please show line items for labour / wages, third-party contractors, licensing fees, etc. Please add to the list any other cost components that are relevant to the program.

b) Please further explain the methodology applied to forecast costs of the human resources program in the test period (including a discussion of the test year forecasting methodology and the 2028-2031 forecasting methodology if those methodologies are different).

c) For each year during the period 2017-2031, please provide a table showing:

   i. Number of projects supported by the business transformation team
   ii. Cost of projects supported by the business transformation team
   iii. Number of FTEs assigned to the business transformation team

RESPONSE:

a) Table 1 provides a more detailed version of Table 4-2-35 and shows cost components of the specific segments that are relevant to the program and has been updated with 2025 actuals.

Table 1 - Human Resource segment cost components

Human Resources ($MM)	2017	2018	2019	2020	2021	2022	2023	2024
Human Resources	**6.37**	**7.61**	**9.65**	**8.83**	**9.80**	**9.51**	**11.56**	**10.43**
Labour Costs	4.25	5.21	6.20	6.47	6.55	7.11	7.57	7.64
Severance	0.07	0.27	1.13	0.47	0.96	0.01	1.36	0.56
Consulting	0.17	0.17	0.58	0.56	0.87	0.73	0.67	0.47
Other	1.88	1.95	1.74	1.32	1.41	1.66	1.96	1.76
Health & Safety and Environment	**3.30**	**2.32**	**2.70**	**2.38**	**2.39**	**3.19**	**3.07**	**2.90**
Labour Costs	2.13	2.01	1.90	2.01	2.03	2.24	1.83	2.04
Consulting	0.08	0.08	0.09	0.05	0.09	0.20	0.29	0.17
Training and Development	0.62	0.13	0.41	0.20	0.12	0.51	0.70	0.44
Other	0.47	0.10	0.30	0.12	0.15	0.26	0.25	0.24
Business Transformation	**4.62**	**3.90**	**2.78**	**2.04**	**2.19**	**3.12**	**3.43**	**3.81**
Labour Costs	4.33	3.34	2.72	1.94	2.11	2.83	2.95	3.46
Consulting	0.18	0.42	-0.01	0.02	0.03	0.08	0.35	0.13

Human Resources ($MM)	2025	2026	2027	2028	2029	2030	2031
Human Resources	**12.20**	**11.40**	**12.28**	**12.91**	**13.55**	**14.07**	**14.41**
Labour Costs	8.49	8.97	9.49	10.04	10.70	11.08	11.45
Severance	1.32	-	-	-	-	-	-
Consulting	0.65	0.67	0.77	0.83	0.75	0.86	0.77
Other	1.74	1.76	2.02	2.04	2.10	2.13	2.19
Health & Safety and Environment	**3.36**	**3.48**	**3.69**	**3.93**	**4.39**	**4.43**	**4.56**
Labour Costs	2.20	2.15	2.35	2.58	2.91	3.02	3.13
Consulting	0.20	0.28	0.21	0.26	0.33	0.27	0.21
Training and Development	0.75	0.72	0.74	0.76	0.78	0.79	0.81
Other	0.21	0.32	0.40	0.34	0.38	0.35	0.41
Business Transformation	**4.16**	**4.19**	**5.05**	**5.05**	**5.31**	**5.47**	**5.64**
Labour Costs	3.68	3.93	4.07	4.38	4.83	4.99	5.15
Consulting	0.15	-	0.72	0.40	0.20	0.20	0.20

b) The same methodology was used to forecast costs of the human resources program in the test period and 2028-2031. For labour forecasting, the Human Resources program resource requirements and the associated methodology is described in Exhibit 4, Tab 3, Schedule 3 page 24-26. The non-labour forecast costs are based on historical information and review of expected program deliverables as well as inflation increases. The cost drivers and variances are detailed in Exhibit 4, Tab 2, Schedule 6.

c) Table 2 includes the number and cost of projects supported by the business transformation team and the number of FTEs in the business transformation team.

Table 2 - Number of projects, cost of projects and number of FTEs assigned to the business transformation team

Year	2017 Actual	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Actuals
Projects	44	39	55	52	65	62	49	31
Project costs (MM)	$26.6	$43.4	$34.6	$28.7	$29.9	$55.3	$67.9	$29.2
FTE	21.5	12.8	11.6	12.3	15.5	14.2	15.1	18.4
Year	**2025 Planned**	**2026 Forecast**	**2027 Forecast**	**2028 Forecast**	**2029 Forecast**	**2030 Forecast**	**2031 Forecast**	
Projects	58	50	56	62	58	42	47	
Project costs (MM)	$38.5	$40.9	$88.1	$121.6	$116.2	$98.5	$90.6	
FTE	20.4	19.3	19.5	20.5	22.0	22.0	22.0	

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-43

Ref: Exhibit 4, Tab 2, Schedule 7, pp. 7-9, 11, 13-14, 20

Question(s):

a) Please provide a more detailed version of Table 4-2-41 that shows the various cost components for each segment (i.e., billing, collections & payment, etc.) of the customer service program. For example, to the extent that these cost components are relevant to the program, please show line items for labour / wages, third-party contractors, licensing fees, bad debt, postage, etc. Please add to the list any other cost components that are relevant to the program.

b) Please reconcile the internal call centre FTEs shown in Table 4-2-43 to the internal agents shown in Table 4-2-48.

c) Please explain the basis for the assumption that EV owners will contact the utility at least once during the first year of ownership.

d) Please explain why, starting in 2026, Row 1 does not equal the prior years' Row 7 (Total w/ Electrification) in Table 4-2-44.

e) Please explain the negative growth shown in the collection line in Table 4-2-44 in certain years.

f) Please explain the reduction in electrification related call volume in 2031 relative to 2030.

g) Please provide Alectra's experience to date with the use webchat, chatbots, and smart forms, which appear to have been implemented in 2025.

h) Please explain why the number of 2025 interactions for webchat and chatbots is set to zero in Table 4-2-45.

i) Please explain the basis for the determination of the number of internal agents relative to third-party agents in Table 4-2-48. Please also advise whether the agent count in Table 4-2-48 are FTE figures or headcount. If headcount, please provide the relevant FTE figures.

j) Please provide the average cost per FTE of an internal vs. third-party agent.

k) Please explain why Alectra appears to have elected for a largely internally staffed call centre as opposed to a contracting approach to call centre services.

l) Please provide the total call hours on a monthly basis for each year during the 2017-2024 period.

RESPONSE:

a) Please see attached Tables 1-5 below for a breakdown of Customer Service segments by cost category:

1 **Table 1 - Detailed Billing Segment OM&A Expenditures ($Millions)**

Billing Segment								
Program Costs ($millions) – Historic Period								
Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Labour	4.43	5.47	6.99	5.77	6.33	6.34	6.85	7.02
Water Billing OM&A Credit	(1.88)	(2.36)	(1.98)	(2.85)	(3.10)	(3.16)	(3.24)	(3.38)
Outside Service Provider (Meter Reading & Admin Support)	2.10	2.26	3.17	2.92	2.82	3.13	3.19	3.34
Postage & Delivery	8.08	9.88	11.49	10.99	10.38	10.28	10.13	10.07
Other	0.49	0.55	0.21	0.23	0.21	0.15	0.09	0.37
Total	**13.21**	**15.79**	**19.88**	**17.06**	**16.64**	**16.74**	**17.01**	**17.41**
Program Costs ($millions) – Bridge and Forecast Period								
Year	**2025A**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	
Labour	7.16	8.62	7.53	7.80	8.04	8.44	8.86	
Water Billing OM&A Credit	(3.63)	-	-	-	-	-	-	
Outside Service Provider (Meter Reading & Admin Support)	3.29	2.21	2.07	2.16	0.54	0.55	0.57	
Postage & Delivery	11.34	10.94	9.35	9.19	8.87	8.74	8.81	
Other	0.16	0.32	0.31	0.39	0.22	0.23	0.23	
Total	**18.32**	**22.10**	**19.27**	**19.53**	**17.68**	**17.96**	**18.46**	

1 **Table 2 - Detailed Collections Segment OM&A Expenditures ($Millions)**

Collections Segment								
Program Costs ($millions) – Historic Period								
Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Labour	3.06	4.07	4.22	3.36	3.11	3.32	3.85	4.28
Water Billing OM&A Credit	(0.26)	(0.31)	(0.44)	(0.67)	(0.68)	(0.69)	(0.72)	(0.74)
Outside Service Provider (Field Collections, Back office and Collection Agencies)	1.17	0.98	1.60	1.62	2.05	1.95	2.70	3.27
Credit losses	4.26	3.85	6.99	27.41	19.45	12.21	5.92	6.37
LEAP	0.14	0.57	0.68	0.64	0.69	0.68	0.68	0.68
Other	0.20	0.30	0.11	0.05	0.05	0.03	0.05	0.07
Total	**8.57**	**9.45**	**13.16**	**32.40**	**24.66**	**17.50**	**12.47**	**13.93**
Program Costs ($millions) – Bridge and Forecast Period								
Year	**2025A**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	
Labour	4.12	4.73	4.46	4.77	5.23	5.42	5.75	
Water Billing OM&A Credit	(0.82)	-	-	-	-	-	-	
Outside Service Provider (Field Collections, Back office and Collection Agencies)	3.19	2.55	2.86	2.82	2.42	2.41	2.40	
Credit losses	8.47	6.34	7.79	8.42	8.57	8.36	8.17	
LEAP	0.68	0.68	1.82	1.87	1.91	1.96	2.01	
Other	0.18	0.05	0.05	0.05	0.05	0.05	0.06	
Total	**15.81**	**14.35**	**16.98**	**17.93**	**18.18**	**18.21**	**18.39**	

Table 3 - Detailed Customer Care Segment OM&A Expenditures ($Millions)

Customer Care								
Program Costs ($millions) – Historic Period								
Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Labour	7.59	6.61	7.09	6.62	7.58	8.31	8.34	8.41
Water Billing OM&A Credit	(0.72)	(0.85)	(0.80)	(1.15)	(1.22)	(1.26)	(1.33)	(1.39)
Outside Service Provider (Contact Center and Outage Management Comms. Support)	2.05	3.58	4.25	4.24	4.10	4.24	5.62	6.01
Consulting and Professional Services	0.14	0.09	0.27	0.05	0.10	0.40	0.49	0.76
Other	0.26	0.18	0.14	0.06	0.13	0.19	0.26	0.15
Total	**9.32**	**9.62**	**10.95**	**9.83**	**10.68**	**11.87**	**13.39**	**13.94**
Program Costs ($millions) – Bridge and Forecast Period								
Year	**2025A**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	
Labour	8.61	9.49	9.79	10.38	12.39	13.55	14.91	
Water Billing OM&A Credit	(1.49)	-	-	-	-	-	-	
Outside Service Provider (Contact Center and Outage Management Comms.	6.88	5.27	5.83	5.89	6.05	6.35	6.19	
Consulting and Professional Services	0.58	1.08	0.57	0.66	0.48	0.64	0.52	
Other	0.16	0.21	0.21	0.22	0.22	0.22	0.23	
Total	**14.73**	**16.05**	**16.41**	**17.14**	**19.14**	**20.77**	**21.85**	

Table 4 - Detailed Customer Connections and Key Accounts Segment OM&A Expenditures ($Millions)

Customer Connections and Key Accounts								
Program Costs ($millions) – Historic Period								
Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Labour	0.44	1.13	1.14	1.32	1.44	1.69	1.48	1.49
Outside Service Provider Costs	-	0.01	0.21	(0.13)	0.24	0.09	0.12	0.11
Other	0.03	0.09	0.02	0.03	0.10	0.09	0.10	0.07
Total	**0.47**	**1.23**	**1.37**	**1.23**	**1.78**	**1.87**	**1.70**	**1.67**
Program Costs ($millions) – Bridge and Forecast Period								
Year	**2025A**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	
Labour	1.88	2.28	2.32	2.43	2.70	2.91	3.08	
Outside Service Provider Costs	0.03	0.12	0.18	0.21	0.25	0.25	0.26	
Other	0.07	0.07	0.07	0.08	0.08	0.08	0.08	
Total	**1.98**	**2.48**	**2.57**	**2.71**	**3.02**	**3.25**	**3.41**	

Table 5 - Detailed Customer Excellence Segment OM&A Expenditures ($Millions)

Customer Excellence								
Program Costs ($millions) – Historic Period								
Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Labour	0.66	0.66	1.52	1.17	1.56	1.53	1.54	2.55
Water Billing OM&A Credit	(0.10)	(0.12)	(0.10)	(0.20)	(0.15)	(0.15)	(0.16)	(0.16)
Outside Service Provider	-	-	0.59	0.49	0.05	-	-	0.01
Other	0.01	0.13	0.03	0.01	0.00	0.04	0.31	0.01
Total	**0.57**	**0.66**	**2.04**	**1.47**	**1.46**	**1.42**	**1.69**	**2.41**
Program Costs ($millions) – Bridge and Forecast Period								
Year	**2025A**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	
Labour	3.08	4.05	4.23	4.90	5.60	5.97	6.18	
Water Billing OM&A Credit	(0.18)	-	-	-	-	-	-	
Outside Service Provider	0.31	-	-	-	0.28	0.29	0.29	
Other	0.01	0.03	0.03	0.03	0.03	0.04	0.04	
Total	**3.22**	**4.08**	**4.26**	**4.93**	**5.91**	**6.30**	**6.51**	

b) Table 4-2-43 provides the total number of FTEs in the Customer Care – Call Centre segment, while Table 4-2-48 only includes call centre agents. The difference between the two tables reflects internal support and leadership roles within the segment, including specialists, supervisors, managers, and director-level positions.

c) As stated in Exhibit 4 Tab 2 Schedule 7 Page 12, Alectra Utilities forecasts that new EV owners will contact the utility at least once in the year they purchase an EV to inquire about rate options and/or to understand how home charging impacts their electricity bill. This assumption is informed by a 2023-2024 JD Power Insights study which shows that EV owners are more likely to interact with their utility digitally (67% versus 34% for non-EV owners) and also more likely to call their utility (21% versus 12% for non-EV owners).

d) In Table 4-2-44, row 1 refers to the total of the previous year's call volumes excluding electrification specific growth. A revised version of Table 4-2-44 is provided below (Table 6) for further clarity. Line F from the prior year is equal to Line A for the next year.

1 **Table 6 - Total Customer Inquiries Before Digital Transformation (2025-2021)**

		2023	2024	2025	2026	2027	2028	2029	2030	2031
1. Total Call Volumes from Previous Year	A	527,916	606,388	636,233	666,912	667,726	697,837	724,192	754,516	807,438
Customer Growth	B	3,505	2,020	5,042	3,835	3,768	3,684	3,807	3,731	3,726
Collections Growth	C	64,207	72,645	12,706	(16,799)	11,953	7,304	10,124	31,637	(5,360)
Moves Growth	D	11,455	3,677	6,569	7,108	7,712	8,390	9,152	10,009	10,977
Billing Growth	E	(695)	(48,497)	6,362	6,669	6,677	6,978	7,242	7,545	8,074
Total Before Electrification	F = A+B+C+D+E	606,388	636,233	666,912	667,726	697,837	724,192	754,516	807,438	824,855
Electrification	G			15,124	27,346	40,951	55,379	73,029	91,151	79,970
Total With Electrification	H = F+G	606,388	636,233	682,036	695,072	738,788	779,571	827,545	898,589	904,825
2. E-mail	I	130,922	124,178	136,347	153,817	147,828	154,379	161,013	168,702	177,107
Total Customer Inquiries (Before shift to digital)	J = H+I	737,310	760,411	818,384	848,889	886,616	933,950	988,558	1,067,292	1,081,932

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e) The call forecast in Table 4-2-44 assumes that collections-related calls will grow in line with customer arrears, averaging 5.75% over the 2027-2031 period, with year-to-year variability reflecting changes in arrears. Based on 2024 collections call trends, adjustments were made to the 2025 and 2026 forecasts to reflect higher expected volumes in 2025, followed by lower volumes in 2026 as collections and severance activities stabilize. For the 2027–2031 period, as shown in Table 7, collections call growth is projected to track arrears, increasing gradually through 2031 and then declining as the benefits of the Collections Enhancement project materialize.

Table 7 - Change in Arrears and Collection Calls

	2025	2026	2027	2028	2029	2030	2031
Arrears > 30 days ($Millions)	388	389	415	431	453	523	511
Change in Arrears (%)	-7%	0%	7%	4%	5%	15%	-2%
Increase / Decrease in Collection Calls	12,706	-16,799	11,953	7,304	10,124	31,637	-5,360
Change in Collection Calls (%)	7%	-9%	7%	4%	5%	15%	-2%

f) As shown in Table 8 below, the reduction in electrification calls reflects the forecast new EV sales within Alectra's territory which shows a peak in 2030 before slightly declining in 2031. The EV vehicle sales assumptions are described in Exhibit 2A Tab 1 Schedule 1, Appendix J, Page 69.

Table 8 - Assumptions for Calls Related to Electrification and EV's

	2025	2026	2027	2028	2029	2030	2031
New BEV and PHEV Vehicles	18,905	34,182	51,189	69,224	91,286	113,939	99,962
Calls Due to Electrification	15,124	27,346	40,951	55,379	73,029	91,151	79,970

g) In Q4 2025, Alectra implemented a general chatbot linked to its website and an IVA outage chatbot on the outage call line. In 2025, the general chatbot successfully completed 9,247 interactions and the outage chatbot, 7,338 interactions. The webchat project is on track for a March 2026 launch. The automated moves project was delayed from April 2025 to October 2025 due to competing priorities, and the deployment of necessary organizational change management and training. Despite the delay, 15,087 online move-in forms were processed in the year. See also 4-SEC-77.

h) The number of interactions for chatbot and webchat were set to zero in 2025 as the projects were scheduled to be delivered in late 2025 with full capability planned for mid-2026.

i) Table 4-2-48 reflects the total agent requirements necessary to support the Contact Center based on the forecast of call volumes, average handle times, and service level targets. Internal agents refer to Alectra employees are expressed as FTE requirements within the Customer Care segment. Third Party agents are provided under contract by an outside service provider and are reflected in the Customer Care Segment's Outside Service Provider budget; they are not included in Alectra's FTE headcount.

Accordingly, the agent figures in Table 4-2-48 are expressed on an FTE basis. As shown in Table 9 below, the relative % of internal/external agents is relatively unchanged until 2029 when the share of internal agents increases from 49% to 58% of the total agent requirements. See also part k) for a rationale on the increased percentage share of internal agents starting in 2029.

Table 9 - % Internal and % Third-Party Contact Center Agents

	2024	2025	2026	2027	2028	2029	2030	2031
Internal Agents (FTE Within Alectra's Headcount)	29	59	59	58	60	69	73	78
Third Party Agents (Not Within Alectra's Headcount)	52	61	58	64	62	59	62	57
Total Agent Requirements	81	120	117	122	122	128	135	135
% Internal Agents	36%	49%	50%	48%	49%	54%	54%	58%
% External Agents	64%	51%	50%	52%	51%	46%	46%	42%

j) In 2025, third-party agents average $79,627 annually, while internal CSR/Sr. CSR roles average $107,518 including burden costs.

k) As noted in Table 9 above, third-party agents currently provide approximately 51% of total agent capacity, declining to 42% by 2031. This shift aligns with Alectra's digital-first strategy, which is intended to expand customer self-service options for routine transactions while strengthening internal capacity to manage increasingly complex inquiries, including net metering, rate options, billing and collections, and EV-related matters.

This approach is informed by experience with higher turnover among third-party agents, which has contributed to increased call transfers, reduced call quality, and lower customer satisfaction. Accordingly, routine inquiries are primarily assigned to third-party agents, while more complex matters are handled by internal staff. Through the forecast period, Alectra expects continued growth in digital self-service to reduce routine inquiry volumes and lessen reliance on third-party agents relative to internal resources.

l) Please see Table 10 below for Total Call Hours by Month. Please also see 4.0-VECC-52 for an update to Exhibit 4 Tab 2 Schedule 7, page 45, Table 4-2-55: Historical and Forecast Call Volumes, Service Level, AHT and Total Call Hours.

1 **Table 10 - Total Call Hours by Month (Millions of Hours)**

	2017	2018	2019	2020	2021	2022	2023	2024
January	0.55	0.40	0.47	0.53	0.45	0.42	0.46	0.55
February	0.48	0.33	0.36	0.42	0.41	0.38	0.38	0.47
March	0.50	0.39	0.50	0.43	0.46	0.47	0.48	0.48
April	0.42	0.41	0.55	0.37	0.41	0.41	0.43	0.73
May	0.50	0.48	0.48	0.37	0.42	0.45	0.59	0.83
June	0.52	0.55	0.44	0.38	0.45	0.45	0.61	0.67
July	0.51	0.51	0.58	0.43	0.45	0.42	0.60	0.68
August	0.55	0.53	0.58	0.47	0.44	0.49	0.61	0.60
September	0.47	0.47	0.55	0.49	0.40	0.44	0.52	0.57
October	0.49	0.54	0.61	0.56	0.42	0.47	0.69	0.68
November	0.43	0.44	0.50	0.50	0.46	0.52	0.49	0.63
December	0.31	0.37	0.39	0.39	0.34	0.34	0.33	0.61
Total	**5.72**	**5.41**	**6.00**	**5.35**	**5.10**	**5.26**	**6.20**	**7.48**
% Change		**-5%**	**11%**	**-11%**	**-5%**	**3%**	**18%**	**21%**

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-44

Ref: Exhibit 4, Tab 2, Schedule 7, pp. 21-22

Question(s):

For each year during the 2021-2031 period, please provide the total number of bills and the total cost broken out between e-billing and paper bills.

RESPONSE:

Table 1 - Total Bills, Cost for e-Bills and Paper Bills

	Total Bills	Cost For e-Bill ($)	Cost For Paper Bill ($)	Total ($)
2021	13,447,326	216,192	10,161,907	10,378,099
2022	13,478,174	254,863	10,003,190	10,258,053
2023	13,574,461	284,834	9,801,347	10,086,182
2024	13,783,989	317,101	9,698,969	10,016,069
2025	13,841,268	370,949	10,957,289	11,328,238
2026	13,974,273	410,103	10,477,533	10,887,636
2027	14,109,939	464,739	8,863,982	9,328,721
2028	14,392,138	494,609	8,668,160	9,162,769
2029	14,679,980	529,945	8,318,338	8,848,283
2030	14,973,580	558,510	8,154,051	8,712,562
2031	15,273,052	579,860	8,199,554	8,779,415

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-45

Ref: Exhibit 4, Tab 2, Schedule 7, p. 29

Question(s):

Please explain why the fixed costs related to City of Hamilton water billing ($3.6M) are being recovered (as suggested by the statement that the water billing exit is applying cost pressure) in the customer service program after discontinuation of this service in Q4 2025.

RESPONSE:

Historically, the regulatory treatment of the City of Hamilton water billing contract differed from that of the other municipalities. Under Legacy Horizon Utilities, the costs associated with providing water billing services to the City of Hamilton were excluded from the revenue requirement for rate-setting purposes, and the related municipal revenues were also excluded from the Other Revenue offset. As a result, no portion of the Hamilton water billing costs was reflected in Horizon's OM&A programs or recovered through electricity rates.

In contrast, for the Guelph, Markham, and Vaughan contracts under legacy Guelph and PowerStream, all water billing costs were included in the revenue requirement, and all related municipal revenues were included as an offset. Accordingly, 100 per cent of water billing costs in these service areas were reflected in OM&A, with a corresponding reduction in revenue requirement through Other Revenue.

While both regulatory treatments were revenue-neutral to electricity customers, they result in different OM&A impacts following the discontinuation of water billing services. Following the discontinuation of water billing services for Hamilton in Q4 2025, certain fixed costs that supported both electricity and water billing activities, such as fixed labour, postage, and third-party support, will remain within the Customer Service function. Because these costs were previously excluded from rates under the legacy Horizon treatment, they must now be absorbed within the Customer Service OM&A and recovered through electricity rates. Accordingly, the OM&A impact associated with the Hamilton exit reflects the inclusion of remaining fixed costs in the electricity revenue requirement.

For the other municipalities, these fixed costs were already reflected in OM&A. As water billing services are discontinued, the associated variable costs are eliminated, but the corresponding municipal revenues also cease. As a result, the exit of water billing in these areas does not create the same incremental OM&A impact.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-46

Ref: Exhibit 4, Tab 2, Schedule 7, pp. 38-39

Question(s):

a) Please further explain the statement that "[a]lthough bad debt in 2024 returned to more historical levels of $6.4MM, declines in the Allowance for Doubtful Account (AFDA) balance continue to offset high write off rates."

b) Please explain how bad debt expense shown in Table 4-2-53 was forecast for the 2027-2031 period. Please also provide the detailed spreadsheets supporting the bad debt calculation in each year of the forecast period.

c) Please explain the relationship between the "net write offs" and "bad debt" rows.

d) In the context that there is a decline in arrears between 2023 and 2025 (even with increasing distribution and energy revenues), please explain the basis for the forecast increase in arrears starting in the 2027 test year.

e) Please explain why Alectra uses arrears > 30 days as the relevant metric to calculate arrears as a percentage of revenues. Please advise whether Alectra also considers other ageing categories (e.g., arrears > 60 days, > 90 days, etc).

RESPONSE:

a) While bad debt expense in 2024 ($6.4 million) returned to historical levels, the underlying sub-components of bad debt were highly volatile. Specifically, both gross and net write offs remained at historically high levels ($14.8 million and $11.3 million respectively), but were offset by favourable changes in the Allowance for Doubtful Accounts (-$2.3 million) as a result of Alectra's Get Back on Track collections campaigns, lower billed revenue (-$2.3 million) and lower unbilled revenue (-$1 million).

b) The bad debt expense forecast starts with historical data for billed revenue and customer arrears, which are disaggregated into residential, commercial (< 50 kW) and commercial (> 50 kW) active and final arrears. These arrears are categorized further according to their AR aging (1-30 days in arrears, 31-60 days in arrears, 61-90 days in arrears, 90+ days). A further categorization is made to 90+ day accounts to identify watch-list, high-risk accounts for active customers with arrears greater than $500 and who have not made a payment in the last 90 days.

Once the customer arrears data is segmented, a roll forward forecast is prepared for each arrears bucket, assuming an average 4.4% growth rate. Productivity savings for the Collections Enhancement project have been included in the 2029, 2030 and 2031 arrears levels. Customer arrears levels are then used as inputs to forecast the change in Allowance for Doubtful Accounts (AFDA).

The AFDA forecast for billed revenue and customer arrears applies the appropriate accounting provision rate to drive the change in Allowance for Doubtful Accounts (AFDA) forecasts for billed revenue and customer arrears. Provision rates are based on historical accounting write off rates for each arrears category. AFDA for unbilled is forecast based on the number of unbilled customers multiplied by the average $ per bill for each customer class and the 31# day unbilled category used a 0.1% growth rate.

<u>Write offs</u> are forecast as a separate line item and trend finalized account AR using a 1.62% growth rate. Recovery rates of 15% applied to gross write offs to calculate net write offs.

<u>Guelph - Separate</u> forecasts have been prepared for Guelph based on historical actuals, as Guelph is currently on a legacy CIS system until mid-2026.

Miscellaneous AR is also forecast based on management estimates and based on historical actuals.

The detailed components of the annual bad debt expense forecast are shown in Table 1. The supporting calculations are provided in 4-CCC-46_Attach1_bad debt forecast.xlsx

Table 1 - Bad Debt Expense Forecast

Description	2025B	2025A	2026	2027	2028	2029	2030	2031
Gross Write-offs and Write-downs	12,361,645	13,334,920	7,146,741	7,610,345	8,390,361	8,332,663	7,998,760	7,680,704
Non Electricity AR (MAR)	583,129	29,973	121,718	117,525	119,879	120,079	120,079	120,479
Guelph	459,310	268,373	473,775	488,695	511,151	535,478	560,907	587,543
Change in AFDA (High-risk customers)	(4,856,615)	(395,112)	(290,081)	399,164	90,485	45,238	49,417	53,983
Change in AFDA (Billed)	379,055	(815,566)	(91,091)	260,369	493,150	704,972	746,238	790,261
Change in AFDA (Unbilled)	11,275	41,789	46,958	48,347	70,441	75,972	79,252	82,842
Recoveries	(1,854,247)	(3,994,568)	(1,072,011)	(1,141,552)	(1,258,554)	(1,249,899)	(1,199,814)	(1,152,106)
Total	**7,083,553**	**8,469,808**	**6,336,010**	**7,782,893**	**8,416,914**	**8,564,503**	**8,354,840**	**8,163,707**

c) Net write-offs are gross write-offs minus any recoveries from written-off accounts collected by third-party collection agencies. As described in a), net write-offs are a component of bad debt expense.

d) The primary reasons for the $1.4 million increase in 2027 bad debt expense is a $0.46 million increase in write offs due to sustained levels of bankruptcies, high account turnover and finalization of accounts, a $0.65 million increase in AFDA balances due to increasing high-risk and watchlist residential customer arrears, and a $0.35 million increase in AFDA balances from higher billed revenue.

e) Alectra uses > 30 days as a Key Performance Indicator for arrears as it excludes volatility from payments received within 1 month of a bill due date, characterized by customers who are late payers but still exhibit good paying history. The > 30 days metric captures aging categories older than 30 days, enabling a more stable trend analysis against revenues and payments. Other aging metrics are also used to measure arrears at different aging: generally, older arrears' AR categories have higher provision rates in the calculation of AFDA balances. Special attention is paid to arrears > 90 days and they are considered high-risk. A further distinction is made to > 90 day accounts if they have balances greater than $500 and have not made a payment in the last 90 days. These high-risk accounts carry the highest provision rate in the AFDA calculation.

4-CCC-46

Attachment 1
Bad Debt Forecast

Please see live Excel

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-47

Ref: Exhibit 4, Tab 2, Schedule 7, pp. 13, 50-52

Question(s):

a) Please confirm that the calls / emails associated with customer connections are incremental / separate from those managed under the customer care segment.

b) Please explain the relationship between the customer inquiries related to electrification shown in Table 4-2-44 and the customer inquires (42,000 customer calls and 62,7500 emails) listed at Exhibit 4, Tab 2, Schedule 7, p. 50.

c) Please explain the basis for the service upgrade forecast that increases from 13,000 in 2025 to 95,000 in 2031.

d) Please provide a table that shows the following for the 2017-2031 period:

   i. Number of service requests
   ii. Number of connection-related customer inquires
   iii. Number of FTEs in the customer connection segment
   iv. Total costs of the customer connection segment

RESPONSE:

a) Alectra confirms the calls and emails associated with the Customer Connections department are distinct and incremental relative to those handled by the Customer Care segment.

b) The electrification-related inquiries shown in Table 4-2-44 pertain to the Customer Care segment and do not include interactions handled by Customer Connections. When customers contact the Customer Care team regarding electrification, these inquiries typically generate additional follow-up with the Customer Connections department for new service or service upgrade applications.

c) The projected increase in Customer Connections department customer inquiries as shown in Table 1 includes "business-as-usual" connection inquiries. It also includes the impact of service upgrade requests from expected growth in EV adoption, as well as other drivers of electrification such as cold-climate heat pumps.

d) Alectra does not have historical data on service requests or connection-related inquiries prior to 2019. A harmonized customer connection process was implemented in June 2019, and before that time, systems, resources, and tracking mechanisms are not available for consolidation of comparable historical data. The available data after process harmonization is provided in Table 1, starting in 2020. This table includes staffing (FTEs) specific to Customer Connections and has estimated Departmental costs for Customer Connections at 65% based on the relative share of departmental FTE's to Key Account FTE's.

Table 1 - Number of Service Requests and Customer Connection Inquiries

	2017	2018	2019	2020	2021	2022	2023	2024
Number of Service Request Inquiries Related to Electrification	N/A	N/A	N/A	15,770	25,666	23,216	21,669	22,755
Number of Connection-Related Customer inquires	N/A	N/A	N/A	73,015	119,347	108,418	100,327	104,750
Number of FTEs	7	10	13.6	10.8	15	15	15	16
Cost of Customer Connections Segment ($ Million)	0.31	0.80	0.89	0.80	1.16	1.22	1.11	1.09

	2025	2026	2027	2028	2029	2030	2031	
Number of Service Request Inquiries Related to Electrification	22,427	26,571	42,099	58,069	78,295	98,880	95,770	
Number of Connection-Related Customer inquires	104,905	127,206	132,829	138,894	156,919	175,303	169,992	
Number of FTEs	14.4	14	14	14	15	16	17	
Cost of Customer Connections Segment ($ Million)	1.63	1.61	1.67	1.76	1.96	2.11	2.22	

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-48

Ref: Exhibit 4, Tab 2, Schedule 8, pp. 8-9, 13-14

Question(s):

a) Please provide a more detailed version of Table 4-2-63 that shows the various cost components for each segment (i.e., product management, IT operations, etc.) of the digital & innovation program. For example, to the extent that these cost components are relevant to the program, please show line items for labour / wages, third-party contractors, licensing fees, etc. Please add to the list any other cost components that are relevant to the program.

b) Please explain the methodology used to forecast the test period costs for each segment of the digital & innovation program (including a discussion of the test year forecasting methodology and the 2028-2031 forecasting methodology if those methodologies are different).

c) Please provide a single table that provides a breakdown between the software costs that were or will be capitalized and the software costs that were or will be expensed for each year during the 2017-2031 period.

RESPONSE:

a) Please refer to Table 1 and Table 2 below for a detailed version of Table 4-2-63 that shows the various cost components for each segment (i.e., product management, IT operations, etc.) of the Digital & Innovation program for the historical, bridge and future years:

Table 1 - OM&A Cost Components Broken Down by Segment 2017-2024 ($MM)

		Historical							
Segment	**Cost Driver**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
All Segments		**27.10**	**29.77**	**35.33**	**34.67**	**34.56**	**37.31**	**40.62**	**43.72**
Product Management		**11.89**	**13.98**	**14.71**	**14.80**	**15.01**	**16.17**	**16.40**	**15.98**
Product Management	Consulting	0.08	0.50	0.47	2.29	2.34	2.28	2.34	2.57
Product Management	Direct Labour Costs	5.28	4.33	4.45	5.39	5.00	5.31	5.44	5.93
Product Management	IST Licenses and Maintenance	5.52	7.53	8.73	6.38	7.26	7.96	8.00	6.73
Product Management	Other	1.01	1.62	1.06	0.74	0.41	0.62	0.62	0.75
IT Operations		**8.54**	**8.49**	**10.71**	**10.58**	**10.46**	**11.00**	**12.05**	**12.90**
IT Operations	Direct Labour Costs	2.80	2.48	3.57	2.46	2.74	3.19	3.54	3.98
IT Operations	IST Licenses and Maintenance	2.65	2.60	3.62	3.68	4.02	3.77	4.57	4.50
IT Operations	Phone/mobile costs	1.55	2.31	2.67	4.02	2.79	3.07	2.91	3.00
IT Operations	Software as a Service	0.93	0.30	0.08	0.08	0.38	0.48	0.51	0.58
IT Operations	Other	0.61	0.80	0.77	0.34	0.53	0.49	0.52	0.84
D&I Business		**2.38**	**2.38**	**3.18**	**4.04**	**4.77**	**4.97**	**6.51**	**8.46**
D&I Business	Consulting	0.00	0.11	0.14	0.41	0.55	0.46	0.90	1.20
D&I Business	Direct Labour Costs	1.25	1.62	1.92	2.05	2.26	2.27	2.60	4.00
D&I Business	IST Licenses and Maintenance	0.89	0.35	0.27	0.75	1.11	1.13	1.67	1.74
D&I Business	Software as a Service	0.00	0.24	0.77	0.77	0.80	0.95	1.14	1.26
D&I Business	Other	0.24	0.06	0.08	0.06	0.05	0.16	0.20	0.26
Cyber Security		**1.05**	**1.35**	**1.54**	**1.68**	**1.89**	**2.14**	**2.60**	**2.82**
Cyber Security	Consulting	-0.01	0.01	0.02	0.16	0.09	0.25	0.27	0.17
Cyber Security	Direct Labour Costs	0.23	0.32	0.56	0.55	0.62	0.61	0.84	0.94
Cyber Security	IST Licenses and Maintenance	0.77	0.39	0.20	0.27	0.39	0.57	0.76	0.93
Cyber Security	Software as a Service	0.00	0.60	0.74	0.67	0.79	0.70	0.71	0.74
Cyber Security	Other	0.06	0.03	0.02	0.03	0.00	0.01	0.02	0.04
GRE&T Centre		**3.25**	**3.58**	**5.19**	**3.57**	**2.42**	**3.03**	**3.06**	**3.57**
GRE&T Centre	Consulting	1.87	1.80	2.49	0.62	0.21	0.82	0.42	0.23
GRE&T Centre	Direct Labour Costs	0.46	0.78	1.46	1.80	1.21	1.50	1.85	2.68
GRE&T Centre	Other	0.92	1.00	1.24	1.15	1.00	0.71	0.79	0.66

Table 2 – OM&A Cost Components Broken Down by Segment 2025-2031 ($MM*)*

		Bridge		Test		Forecast		
Segment	**Cost Driver**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
All Segments		**45.69**	**52.40**	**58.34**	**60.21**	**64.35**	**68.83**	**70.91**
Product Management		**18.65**	**20.16**	**21.55**	**22.92**	**24.55**	**27.76**	**28.54**
Product Management	Consulting	2.82	2.70	3.30	3.78	3.27	5.11	3.43
Product Management	Direct Labour Costs	7.33	7.10	7.39	7.70	8.49	9.58	10.93
Product Management	IST Licenses and Maintenance	7.56	9.01	9.59	10.12	11.42	11.91	12.98
Product Management	Other	0.94	1.35	1.27	1.32	1.37	1.16	1.20
IT Operations		**14.56**	**17.21**	**18.71**	**19.95**	**20.84**	**21.43**	**22.01**
IT Operations	Direct Labour Costs	5.41	5.45	6.04	6.69	7.02	7.26	7.52
IT Operations	IST Licenses and Maintenance	3.87	4.65	5.15	5.56	5.19	5.30	5.39
IT Operations	Phone/mobile costs	2.91	3.65	3.97	4.07	4.88	5.03	5.19
IT Operations	Software as a Service	1.68	2.29	2.35	2.42	2.52	2.58	2.63
IT Operations	Other	0.69	1.17	1.20	1.21	1.23	1.26	1.28
D&I Business		**6.38**	**7.33**	**9.00**	**8.92**	**9.66**	**10.14**	**10.46**
D&I Business	Consulting	1.07	0.64	1.16	0.77	0.57	0.58	0.59
D&I Business	Direct Labour Costs	2.32	2.34	2.60	2.67	3.41	3.54	3.67
D&I Business	IST Licenses and Maintenance	0.91	1.41	1.55	1.58	1.61	1.82	1.85
D&I Business	Software as a Service	1.79	2.69	3.54	3.68	3.82	3.95	4.09
D&I Business	Other	0.29	0.25	0.15	0.22	0.25	0.25	0.26
Cyber Security		**3.21**	**4.61**	**5.92**	**5.61**	**5.74**	**5.79**	**6.04**
Cyber Security	Consulting	0.39	0.57	1.41	0.55	0.62	0.51	0.58
Cyber Security	Direct Labour Costs	1.03	1.00	1.17	1.58	1.87	1.94	2.01
Cyber Security	IST Licenses and Maintenance	0.75	1.46	1.43	1.50	1.23	1.25	1.31
Cyber Security	Software as a Service	1.01	1.56	1.86	1.93	1.97	2.03	2.08
Cyber Security	Other	0.03	0.02	0.05	0.05	0.05	0.06	0.06
GRE&T Centre		**2.88**	**3.09**	**3.16**	**2.82**	**3.56**	**3.71**	**3.86**
GRE&T Centre	Consulting	0.31	0.36	0.17	0.10	0.06	0.06	0.06
GRE&T Centre	Direct Labour Costs	2.28	2.96	3.12	3.08	3.29	3.43	3.57
GRE&T Centre	Other	0.29	-0.23	-0.13	-0.36	0.21	0.22	0.23

b) Alectra Utilities forecasts Digital & Innovation program costs using a program level approach aligned with Alectra Utilities' overall OM&A forecasting methodology.

For the 2027 Test Year, costs were developed on a bottom-up basis by program segment. Historical actual expenditures were used to establish a baseline level of cost and activity, which was adjusted for known and expected changes in scope, technology lifecycle needs, and planned initiatives.

As part of this process, Alectra Utilities utilizes the Copperleaf platform to support business case development for Digital & Innovation initiatives. Within this framework, expected costs, benefits, and risks are identified and quantified at the initiative level, and the resulting business cases inform the development and costing of initiatives included in the forecast.

Future costs associated with Digital & Innovation program initiatives are developed using multiple inputs, including vendor assisted estimates where available, information from third party advisory firms where applicable, and Alectra Utilities' historical cost experience for comparable systems, services, or activities. These inputs are used to develop planning level cost estimates that reflect the expected scope, timing, and scale of each initiative.

Labour related costs are forecast based on approved FTE requirements by role, including salaries, burdens, and inflationary adjustments, with workforce changes included where required to support identified program outcomes. Non-labour costs are forecast using vendor assisted estimates where available, or derived from historical levels based on expected utilization and contractual terms.

For the 2028 to 2031 period, the 2027 Test Year forecast is carried forward and adjusted for inflation and the phasing of planned initiatives. There is no change in forecasting methodology between the Test Year and the future years.

c) Please refer to Table 3 below, which provides a breakdown of software costs capitalized and expensed for each year over the 2017–2031 period. Capitalized software costs relate solely to initiatives identified in 2-1-1 Appendix B-09 and exclude software costs associated with initiatives presented elsewhere in Alectra's rate application. Both capital and OM&A software costs reflect expenditures within the Digital and Innovation program only, including software licensing, enhancements, and implementation costs.

Table 3 – Capitalized Software Costs 2017-2031($MM)

Total Digital and Innovation software ($MM)								
Nature of cost	**2017 Actual**	**2018 Actual**	**2019 Actual**	**2020 Actual**	**2021 Actual**	**2022 Actual**	**2023 Actual**	**2024 Actual**
Capital	2.70	2.15	5.62	6.82	8.95	14.08	11.39	9.96
OM&A/ Expensed	-	-	-	15.55	17.49	18.47	20.12	20.15
Total software	**2.70**	**2.15**	**5.62**	**22.37**	**26.43**	**32.55**	**31.51**	**30.10**
Nature of cost	**2025 Actual**	**2026 Net**	**2027 Net**	**2028 Net**	**2029 Net**	**2030 Net**	**2031 Net**	**total 2017-2031**
Capital	9.68	8.36	12.41	23.79	21.10	4.08	5.60	146.69
OM&A/ Expensed	22.17	27.67	31.49	32.78	33.90	36.67	36.50	312.94
Total software	**31.85**	**36.03**	**43.90**	**56.57**	**55.01**	**40.75**	**42.10**	**459.64**

Note 1: Capital software excludes capital Cyber Security related software costs as Cyber Security was not broken into categories of hardware and software in 2A-1-1 Appendix B-09.

Note 2: OM&A data at a detailed break-down of hardware and software was not developed until 2020, therefore Alectra Utilities is only able to provide the requested detail required from 2020 onward.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-49

Ref: Exhibit 4, Tab 2, Schedule 8, pp. 37-39
Appendix 2-JC

Question(s):

a) Please advise whether Appendix 2-JC reflects the total operating cost of the GRE&T centre or the amount that is sought for recovery in rates. If it is the former, please provide a table showing the relevant amount sought for recovery in rates for the 2027-2031 period.

b) For each year of the 2027-2031 period, please provide an estimate of the annual support costs (e.g., HR support, IT burden, facility allocations, etc.) that the GRE&T Centre attracts. Please explain any assumptions made to derive the estimate.

RESPONSE:

a) Appendix 2-JC reflects the total operating cost of the GRE&T Centre.

The amounts sought for recovery in rates over the 2027-2031 period are provided in the table below. These amounts are derived from the costs that were included in rates for legacy PowerStream, as identified in Exhibit 4, Tab 2, Schedule 8, pp. 37-38.

Table 1 – GRE&T Centre costs for recovery

2027	2028	2029	2030	2031
$0.56M	$0.58M	$0.59M	$0.60M	$0.61M

b) The GRE&T Centre is a segment within Alectra Utilities' Digital & Innovation division which is part of the regulated entity. As a result, similar to other Alectra Utilities segments, there are no annual support costs that are allocated to the GRE&T Centre.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-50

Ref: Exhibit 4, Tab 2, Schedule 9, pp. 7-11

Question(s):

a) Please provide a more detailed version of Table 4-2-74 that shows the various cost components for the system control program. For example, to the extent that these cost components are relevant to the program, please show line items for labour / wages, third-party contractors, licensing fees, etc. Please add to the list any other cost components that are relevant to the program.

b) Please explain the methodology used to forecast the test period costs for the system control program (including a discussion of the test year forecasting methodology and the 2028-2031 forecasting methodology if those methodologies are different).

c) Please explain why Alectra waited until the 2024-2026 period to stabilize system control resources in the context of the high turnover rate experienced in 2021 following the merger.

d) Please confirm that costs associated with the DWMP project are not reflected in the system control program budget. If DWMP project costs are reflected elsewhere in the capital or operational budgets, please provide the amount for the 2027-2031 period and the specific program budget(s) where these costs are contained.

e) Please expand Chart 4-2-8 to include the 2017-2024 period (or as much of the historical period for which the relevant information is available).

f) Please further explain the relationship between the total # of operators required and the total # of crews supported. As part of the response, please discuss why a decrease in total # of crews supported in 2026 relative to 2025 does not result in a decrease to the # of operators required.

g) Please provide a breakdown of the system control labour costs for the 2017-2031 period between regular time and overtime pay.

RESPONSE:

a) Table 4-CC-50 below provides a more detailed version of Table 4-2-72.

Table 1 - Detailed System Control Group Program Expenditures ($MM)

System Control								
				Historical				
Cost Driver	2017	2018	2019	2020	2021	2022	2023	2024
	13.33	**11.63**	**13.05**	**13.33**	**12.95**	**13.85**	**16.35**	**15.98**
Direct Labour Costs	10.77	11.39	12.68	13.04	12.69	13.51	16.03	15.62
Other	2.56	0.24	0.37	0.29	0.26	0.34	0.32	0.36
		Bridge		Test		Forecast		
Cost Driver		2025	2026	2027	2028	2029	2030	2031
		12.37	**13.37**	**15.08**	**16.02**	**16.51**	**17**	**17.55**
Direct Labour Costs		11.96	12.98	14.6	15.53	16.01	16.5	17.03
Other		0.41	0.39	0.48	0.49	0.5	0.5	0.52

The Other category in Table 1 above includes costs such as training and development, subscription and membership, mileage and parking, phone and mobile costs, consulting costs, and travel and accommodation costs.

b) The forecast for the System Control test period costs was driven by forecasting the Direct Labour costs for the test year. Direct Labour costs averaged 98% of the total program costs for the five years preceding the test year (i.e 2020 - 2024).

The methodology (which is the same for the 2027 Test Year and for 2028-2031) for determining the System Control resource forecast is provided in Exhibit 4, Tab 2, Schedule 9, Page 8 lines 9 through 27.

c) Alectra continuously balances System Control resource availability against resource demand. Prior to the 2024-2026 time period, the resource vs demand imbalance was managed through a number of short-term approaches. Reducing the number of System Control Operators on shift and increased overtime for existing System Control Operators were the primary approaches taken. Reducing the number of System Control Operators caused delays for the field crews and reduced their ability to execute their work resulting in decreased efficiency. Reduced staffing levels resulted in overworked staff leading to increased sick time and staff turnover. Increasing overtime was costly and also led to overworked staff resulting in increased sick time and staff turnover. These approaches are neither viable nor cost-effective over the long term. This, combined with the forecast increase in System Control resource demand associated with the expanded capital programs proposed for 2027–2031, resulted in the decision to increase System Control FTEs to stabilize resourcing levels.

d) The costs associated with the DWMP project are not reflected in the System Control Program budget. The DWMP project costs can be found in Exhibit 2A, Tab 1, Schedule 1, Appendix B14, Table B14-9.

e) Chart 1 below provides the data that is available.

Chart 1- System Control Resources

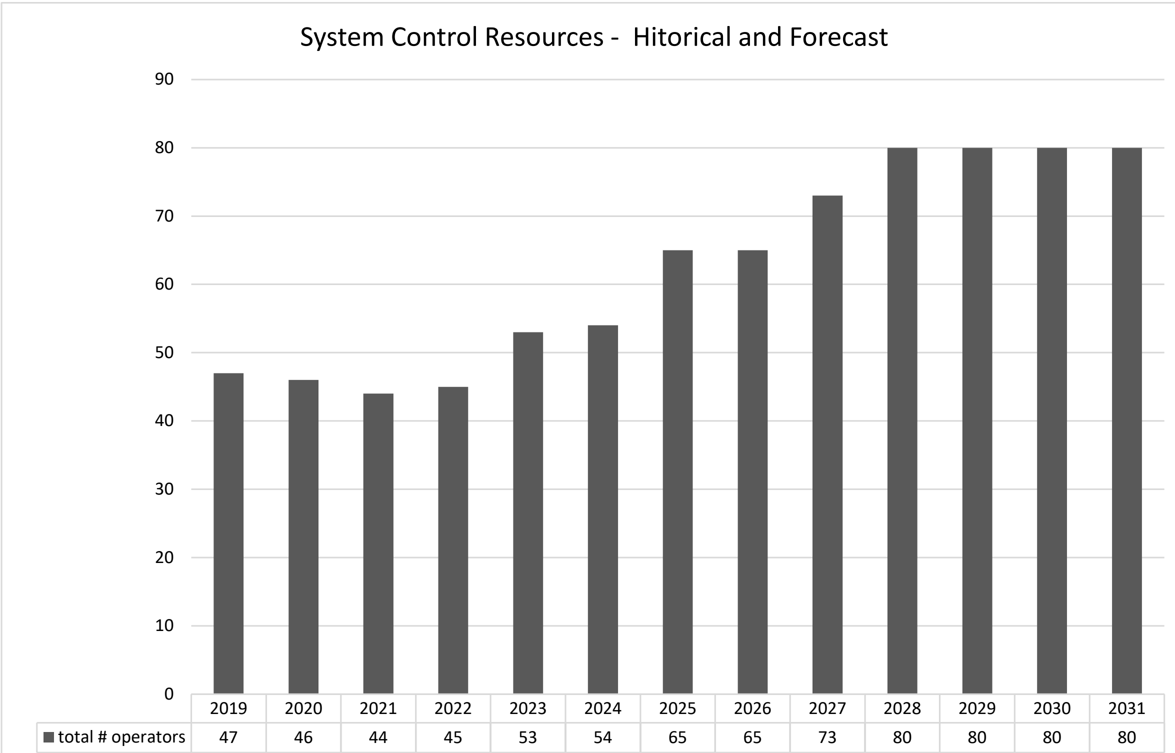

Chart 1 above provides the total number of operators for the years 2019 – 2031. Alectra did not track and cannot provide the historical actual number of crews supported by the operators (which would include both internal and external crews). The forecast of the number of crews supported by the number of operators required for 2026 to 2031 was estimated based on 2025 data.

f) System Control resources are proportional to the volume of internal and external crews being supported. The System Control resource requirements for 2025 through 2021 were determined by extrapolating the current ratio of crews to system control operators to the forecasted number of crews required.

The decrease in crews supported in 2026 did result in a small decrease in Total # of Operators Required (i.e. resource demand) as reflected in Chart 4-2-8, however; this did not translate into a reduction in FTEs because System Control staffing levels cannot be easily increased or decreased from year to year without creating material operational risk.

There is a shortage of qualified System Control Operators in Ontario recruitment is highly competitive, and a minimum four-year apprenticeship and qualification process is required before an operator can perform independently. As a result, any reduction in FTEs in response to a single, temporary decrease in supported crews would be imprudent and short-sighted, as it would erode institutional capability, jeopardize system reliability, and materially constrain the utility's ability to respond to future increases in demand or system contingencies. Maintaining stable staffing levels through short-term fluctuations is therefore necessary to ensure continuity of operations and long-term service reliability.

g) Table 2 below provides the breakdown of the system control OM&A labour costs for the 2017-2031 period between regular time and overtime pay.

Table 2: System Control OM&A Labour Costs

$MM	2017	2018	2019	2020	2021	2022	2023	2024
Regular	9.320	9.638	9.797	10.409	9.884	10.620	12.342	12.305
Overtime	1.452	1.755	2.878	2.628	2.806	2.890	3.688	3.317
Total	10.772	11.394	12.676	13.037	12.690	13.510	16.030	15.622

$MM	2025	2026	2027	2028	2029	2030	2031
Regular	8.582	12.112	13.711	14.613	15.061	15.522	16.021
Overtime	2.213	0.868	0.894	0.921	0.948	0.977	1.006
Total	10.795	12.980	14.605	15.533	16.010	16.499	17.028

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-51

Ref: Exhibit 4, Tab 2, Schedule 10, pp. 7-11

Question(s):

a) Please provide a more detailed version of Table 4-2-75 that shows the various cost components for the stations program. For example, to the extent that these cost components are relevant to the program, please show line items for labour / wages, third-party contractors, licensing fees, etc. Please add to the list any other cost components that are relevant to the program.

b) Please provide a table that shows the costs of the stations program between 2017-2031 by function (i.e., station design, station sustainment, and protection & control).

c) Please further explain the methodology applied to forecast costs for the stations program in the test period (including a discussion of the test year forecasting methodology and the 2028-2031 forecasting methodology if those methodologies are different).

RESPONSE:

a) **Table 1 - Detailed Stations Program Expenditures ($MM)**

Stations

	Historical							
Cost Driver	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
	7.40	**8.99**	**8.68**	**8.36**	**8.98**	**10.30**	**11.72**	**10.37**
Direct Labour Costs	4.23	5.83	5.54	5.60	5.65	6.57	7.16	6.16
Direct Vehicle Costs	0.35	0.50	0.35	0.19	0.33	0.67	0.84	0.79
Phone/mobile costs	0.77	1.11	1.22	0.99	1.15	0.97	1.04	1.11
Repairs and Maintenance	1.02	0.30	0.11	0.08	1.22	1.27	1.39	1.47
Other	1.03	1.25	1.46	1.50	0.63	0.82	1.29	0.84

		Bridge		Test		Forecast		
Cost Driver		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
		12.05	**13.37**	**13.96**	**14.45**	**15.04**	**15.35**	**15.77**
Direct Labour Costs		7.52	8.76	9.30	9.70	10.08	10.40	10.72
Direct Vehicle Costs		0.71	0.85	0.87	0.89	0.90	0.92	0.94
Phone/mobile costs		1.06	1.16	1.25	1.27	1.36	1.39	1.41
Repairs and Maintenance		1.53	1.59	1.62	1.65	1.74	1.78	1.82
Other		1.23	1.01	0.92	0.94	0.96	0.86	0.88

1 b) **Table 2: Stations Program Expenditures by Function ($MM)**

Protection & Control								
Cost Driver	**Historical**							
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
	2,689	**3,202**	**3,251**	**2,934**	**3,122**	**3,336**	**3,784**	**3,584**
Direct Labour Costs	1,129	1,745	1,787	1,830	1,801	2,055	2,304	2,041
Direct Vehicle Costs	38	97	64	21	54	159	220	170
Phone/mobile Costs	746	1,088	1,160	964	1,129	952	1,019	1,088
Repairs and Maintenance	464	53	52	36	21	9	19	34
Other	311	219	189	82	116	161	222	251

Cost Driver	**Bridge**		**Test**	**Forecast**			
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
	3,918	**4,490**	**4,612**	**4,821**	**5,092**	**5,122**	**5,241**
Direct Labour Costs	2,418	2,700	2,824	3,001	3,175	3,274	3,362
Direct Vehicle Costs	182	242	246	251	256	261	267
Phone/mobile Costs	1,017	1,127	1,216	1,238	1,326	1,348	1,370
Repairs and Maintenance	33	26	26	27	27	28	28
Other	268	396	299	304	308	212	215

Station Design								
Cost Driver	**Historical**							
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
	615	**437**	**361**	**453**	**432**	**582**	**679**	**253**
Direct Labour Costs	561	359	333	443	416	549	584	226
Direct Vehicle Costs	0	29	0	0	1	0	1	0
Phone/mobile Costs	0	9	14	0	3	1	10	7
Other	54	41	14	10	12	32	84	20

Cost Driver	**Bridge**		**Test**	**Forecast**			
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
	686	**998**	**1,212**	**1,251**	**1,291**	**1,334**	**1,379**
Direct Labour Costs	671	901	1,106	1,143	1,181	1,222	1,265
Direct Vehicle Costs	0	0	0	0	0	0	0
Phone/mobile Costs	5	13	15	15	16	16	16
Other	11	84	91	93	95	96	98

Station Sustainment								
Cost Driver	**Historical**							
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
	4,092	**5,356**	**5,069**	**4,972**	**5,430**	**6,380**	**7,258**	**6,534**
Direct Labour Costs	2,541	3,730	3,417	3,327	3,434	3,968	4,269	3,892
Direct Vehicle Costs	308	405	280	169	275	511	621	623
Phone/mobile Costs	18	20	58	26	14	13	21	14
Repairs and Maintenance	560	247	56	41	1,201	1,261	1,371	1,438
Other	664	954	1,257	1,409	506	627	976	566

Cost Driver	**Bridge**		**Test**	**Forecast**			
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
	7,448	**7,879**	**8,141**	**8,376**	**8,661**	**8,898**	**9,150**
Direct Labour Costs	4,427	5,161	5,371	5,554	5,726	5,901	6,090
Direct Vehicle Costs	526	611	623	635	648	661	674
Phone/mobile Costs	36	24	25	25	26	26	27
Repairs and Maintenance	1,499	1,563	1,594	1,626	1,717	1,754	1,789
Other	960	520	528	536	544	555	570

c) Costs for the Stations Program were forecasted using a bottom-up estimating approach where each line item is budgeted based on expected activity. Labour costs are estimated based on forecasted headcount each year (including headcount additions as described at Exhibit 4, Tab 2, Schedule 10, Page 15) and the expected split between Capital and Maintenance activities. Repairs and Maintenance costs are forecasted based on expected activity. Contractor costs associated with Repairs and Maintenance - such as landscaping, snow removal, and security services - are estimated based on service agreement pricing or expected volumes. Phone/mobile costs include telecommunication system maintenance costs such as network licencing and leasing costs for 3rd-party telecom networks. These costs are forecasted based on service agreement pricing and the expected telecom asset base. The same forecasting methodology was used for the Test and Forecast years.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-52

Ref: Exhibit 4, Tab 2, Schedule 11, pp. 1

Question(s):

a) Please provide a more detailed version of Table 4-2-78 that shows the various cost components for the records & mapping services program. For example, to the extent that these cost components are relevant to the program, please show line items for labour / wages, third-party contractors, licensing fees, etc. Please add to the list any other cost components that are relevant to the program.

b) Please further explain the methodology applied to forecast costs for the stations program in the test period (including a discussion of the test year forecasting methodology and the 2028-2031 forecasting methodology if those methodologies are different).

RESPONSE:

a) Please see Table 1 below.

Table 1 - Detailed Records and Mapping Services Program Expenditures

Program Costs ($millions) – Historic Period								
Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Direct Labour Costs	2.42	2.75	2.21	2.85	3.25	3.55	3.82	3.85
Outside Service Provider (Contract Labour)	0.00	0.00	0.01	0.00	0.10	0.34	0.49	0.53
Other	0.10	0.18	0.21	0.15	0.15	0.15	0.17	0,20
Total	**2.52**	**2.93**	**2.43**	**3.00**	**3.50**	**4.04**	**4.48**	**4.58**
Program Costs ($millions) – Bridge and Forecast Period								
Year	**2025A**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	
Direct Labour Costs	4.45	4.33	4.70	4.96	5.13	5.29	5.14	
Outside Service Provider (Contract Labour)	0.50	0.48	0.38	0.39	0.40	0.41	0.41	
Other	0.21	0.27	0.27	0.27	0.29	0.30	0.30	
Total	**5.16**	**5.08**	**5.35**	**5.62**	**5.82**	**6.00**	**5.85**	

b) The forecast for the Records & Mapping Services program for 2026-2031 is based on the historical actual costs for 2024, increased annually for inflation. In addition to inflationary increases, 3 additional FTEs are added in 2027 to support the increased data entry and data management volumes resulting from the increased capital investment proposed in Alectra Utilities' DSP.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-53

Ref: Exhibit 4, Tab 2, Schedule 12, pp. 1, 3-4, 7-8, 11
Exhibit 4, Tab 2, Schedule 11, p. 8

Question(s):

a) Please provide a table that provides the following information for each year of the 2017 to 2031 period (for the entire utility and by rate zone (if available)):

i. Number of locates
ii. Total Direct/External Contractor Locate Costs
iii. Average Direct/External Cost Per Locate
iv. Inspection / Supervision Costs
v. Ontario One Call costs
vi. Total Program Costs

Please provide any additional line items that are not reflected in the list above (as applicable).

b) Please explain the variability in the locate rate (particularly in 2023) across the various geographic regions as shown in Chart 4-2-9.

c) For each geographic region shown in Chart 4-2-9, please advise whether the relevant locate service provider(s) were contracted through the LAC or separate from the LAC.

d) Please confirm that the “Locate Program Costs (Net)” shown in Table 4-2-84 reflect the locate-related amounts built into rates.

e) Please explain how customer calls for underground locates, which are cleared by internal personnel without the need to send a vehicle to complete a cable locate are captured in the total number of locates set out in Table 4-2-86.

f) Please provide the number of project owners that have accessed the dedicated locater program between 2022-2025. Please also explain how the forecast use of this program is reflected in the volume of locates expected in the 2027-2031 period (i.e., provide the number of locates that have been excluded from the forecast).

RESPONSE:

a) Please see Tables 1 through 5 below.

Table 1 - Locates and Costs – AUC

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
i. Number of locates	200,686	191,447	180,767	174,313	198,805	198,381	199,452	189,460	185,372	191,428	191,428	191,428	191,428	191,428	191,428
ii. Total Direct/External Contractor Locate Costs	Data Not Available			$4.32M	$4.30M	$4.32M	$8.30M	$6.56M	$7.42M	$6.98M	$7.19M	$7.42M	$7.64M	$7.88M	$8.12M
iii. Average Direct/External Cost Per Locate	Data Not Available			$24.76	$21.64	$21.76	$41.62	$34.63	$40.04	$36.46	$ 37.58	$ 38.74	$ 39.93	$41.16	$42.43
iv. Inspection / Supervision Costs	Data Not Available			$1.69M	$1.23M	$0.62M	$0.60M	$0.46M	$0.47M	$0.84M	$0.78M	$0.80M	$0.82M	$0.84M	$0.86M
v. Ontario One Call costs*	Data Not Available			$0.26M	$0.26M	$0.26M	$0.35M	$0.43M	$0.52M	$0.67M	$0.69M	$0.72M	$0.75M	$0.78M	$0.82M
vi. Total Program Costs ($MM)	$6.36M	$6.27M	$5.97M	$6.26M	$5.79M	$5.19M	$9.25M	$7.46M	$8.42M	$8.48M	$8.67M	$8.94M	$9.22M	$9.50M	$9.80M

Table 2 - Locates and Costs – HRZ

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
i. Number of locates	45,892	47,002	45,710	45,045	50,691	51,501	46,915	37,833	38,038	40,929	40,929	40,929	40,929	40,929	40,929

ii. Total Direct/External Contractor Locate Costs	Data Not Available			$0.88M	$0.84M	$0.84M	$0.87M	$1.18M	$1.33M	$1.21M	$1.24M	$1.28M	$1.32M	$1.36M	$1.40M
iii. Average Direct/External Cost Per Locate	Data Not Available			$ 19.64	$16.57	$16.31	$18.62	$ 31.22	$ 35.08	$29.45	$30.34	$31.25	$32.18	$33.15	$34.14
iv. Inspection / Supervision Costs	Data Not Available (Refer to Table 1)														
v. Ontario One Call costs*	Data Not Available			$0.07M	$0.07M	$0.07M	$0.08M	$0.12M	$0.10M	$0.17M	$0.18M	$0.19M	$0.20M	$0.20M	$0.22M
vi. Total Program Costs ($MM)	Data Not Available (Refer to Table 1)														

*Not available at the regional level - refer to AUC for program level costs

Table 3 - Locates and Costs – GRZ

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
i. Number of locates	9,470	9,310	9,218	7,269	9,916	10,929	10,200	7,055	7,170	8,142	8,142	8,142	8,142	8,142	8,142
ii. Total Direct/External Contractor Locate Costs	Data Not Available			$0.22M	$0.22M	$0.22M	$0.65M	$0.32M	$0.39M	$0.34M	$0.35M	$0.36M	$0.38M	$0.39M	$0.40M

iii. Average Direct/External Cost Per Locate	Data Not Available			$30.35	$ 22.25	$ 20.19	$ 63.81	$ 44.90	$54.09	$41.99	$ 43.34	$44.72	$46.16	$47.64	$ 49.17
iv. Inspection / Supervision Costs	Data Not Available (Refer to Table 1)														
v. Ontario One Call costs*	Data Not Available			$0.02M	$0.02M	$0.02M	$0.04M	$0.04M	$0.04M	$0.04M	$0.04M	$0.04M	$0.04M	$0.04M	$0.04M
vi. Total Program Costs ($MM)	Data Not Available (Refer to Table 1)														

*Not available at the regional level - refer to AUC for program level costs

Table 4 - Locates and Costs – BRZ

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
i. Number of locates	30,717	27,566	30,331	28,127	32,136	30,533	31,236	27,664	26,720	28,540	28,540	28,540	28,540	28,540	28,540
ii. Total Direct/External Contractor Locate Costs	Data Not Available			$0.61M	$0.62M	$0.62M	$1.42M	$1.09M	$1.14M	$1.13M	$1.16M	$1.20M	$1.23M	$1.27M	$1.31M
iii. Average Direct/External Cost Per Locate	Data Not Available			$ 21.76	$ 19.21	$ 20.22	$ 45.33	$39.45	$42.75	$39.51	$40.69	$41.91	$43.17	$44.46	$45.80

iv. Inspection / Supervision Costs	Data Not Available (Refer to Table 1)														
v. Ontario One Call costs*	Data Not Available			$0.04M	$0.04M	$0.04M	$0.05M	$0.07M	$0.08M	$0.09M	$0.10M	$0.10M	$0.11M	$0.11M	$0.12M
vi. Total Program Costs ($MM)	Data Not Available (Refer to Table 1)														

*Not available at the regional level - refer to AUC for program level costs

Table 5 - Locates and Costs – ERZ

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
i. Number of locates	44,954	45,104	30,768	36,066	39,378	37,838	39,375	45,757	44,535	43,222	43,222	43,222	43,222	43,222	43,222
ii. Total Direct/External Contractor Locate Costs	Data Not Available			$0.81M	$0.82M	$0.82M	$1.35M	$1.47M	$1.72M	$1.48M	$1.53M	$1.57M	$1.62M	$1.67M	$1.72M
iii. Average Direct/External Cost Per Locate	Data Not Available			$22.54	$20.88	$21.73	$34.20	$32.09	$38.62	$34.31	$35.34	$36.40	$37.49	$38.61	$39.77
iv. Inspection / Supervision Costs	Data Not Available (Refer to Table 1)														

v. Ontario One Call costs*	Data Not Available			$0.06M	$0.06M	$0.06M	$0.06M	$0.08M	$0.14M	$0.11M	$0.12M	$0.12M	$0.13M	$0.13M	$0.14M
vi. Total Program Costs ($MM)	Data Not Available (Refer to Table 1)														

*Not available at the regional level - refer to AUC for program level costs

Table 6 - Locates and Costs – PRZ

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
i. Number of locates	69,653	62,465	64,740	57,806	66,684	67,580	71,726	71,151	68,909	70,595	70,595	70,595	70,595	70,595	70,595
ii. Total Direct/External Contractor Locate Costs	Data Not Available			$1.78M	$1.80M	$1.82M	$4.02M	$2.50M	$2.84M	$2.82M	$2.91M	$3.00M	$3.10M	$3.20M	$3.30M
iii. Average Direct/External Cost Per Locate	Data Not Available			$30.88	$27.03	$26.90	$55.98	$35.20	$41.19	$39.97	$41.23	$42.54	$43.89	$45.28	$46.72
iv. Inspection / Supervision Costs	Data Not Available (Refer to Table 1)														
v. Ontario One Call costs*	Data Not Available			$0.09M	$0.09M	$0.09M	$0.13M	$0.15M	$0.18M	$0.26M	$0.26M	$0.27M	$0.28M	$0.29M	$0.30M

vi. Total Program Costs ($MM)	Data Not Available (Refer to Table 1)

1 *Not available at the regional level - refer to AUC for program level costs

b) The variability in the locate rate per region shown in Chart 4-2-9 is due to several reasons. In 2022, the passing of the Getting Ontario Connected Act allowed Ontario One Call to apply Administrative Penalties for Underground Infrastructure Owners and excavators who fail to comply with the Ontario Underground Infrastructure Notification System Act. The increase in cost from 2022 to 2023 was driven primarily by this change in legislation, which coincided with labour shortages in the Locate Service Provider industry, putting upward pressure on labour costs and service fees.

In addition, the service fees indicated in Chart 4-2-9 were not normalized by segment length per billable unit. In 2022, Hamilton and St. Catharines utilized a 30m segment length for billing purposes, Mississauga and Brampton utilized a 200m segment length for billing purposes, while all other regions utilized a 300m segment length for billing purposes. In 2023, all regions were transitioned to a 300m segment length for billing purposes. When accounting for normalization, the differences, particularly in Brampton and Mississauga are reduced. However, for areas with large differences in billing segment length (Hamilton and St. Catharines), a direct comparison between 2022 and 2023 rates is less illustrative as it is unlikely that the supplier would submit a price ten times higher were a 300m segment used in place of a 30m billing segment, as not all locates reach the maximum segment length and individual service providers would take expected actual effort into consideration when determining a price.

Finally, it is important to note that during this period, Alectra made several productivity improvements to its Cable Locates program to mitigate these ongoing cost pressures. These productivity improvements are discussed in further detail in Schedule 4-2-12 pp. 11-12.

c) In 2022, a LAC agreement was utilized in York County and Simcoe County. In 2023 and 2024, a LAC agreement (or one similar to a LAC to achieve harmonization) was utilized in Guelph/Rockwood, Hamilton, St. Catherines, Mississauga, Brampton, York and Simcoe Counties.

d) Yes, the amounts in Table 4-2-84 are the locate-related amounts included in rates.

e) Table 4-2-86 captures total notifications to Alectra from Ontario One Call, which includes both remote and on-site resolutions.

f) See Table 7 below

Table 7 - Number of Programs with Locate Suppression 2022-2025[1]

	2022	2023	2024	2025
Number of Dedicated Locator Projects by notice date	4	37	10	16

The locate portfolio was forecasted on a top down approach. As a result, expected volumes were not adjusted for future potential uptake of the dedicated locator program based on historical experience. Locate notification volumes received by Alectra are influenced by a range of factors, including, but not limited to:

- Specific excavator project locations, and quantities
- Capital and maintenance programs of third parties operating within Alectra service territory (e.g., road maintenance programs, communication company capital programs, repair needs, etc.)
- Whether a member elects to use the dedicated locator program and whether that program represents regular baseload locate volume for that requestor or an additional volume for a particular program or project
- Economic factors that can influence the level of development and activity within Alectra service territory.

[1] Programs may be single or multi-year and may also have suppression applied in a different year than when notices are given. This table represents the year the suppression became active.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-54

Ref: Exhibit 4, Tab 2, Schedule 13, pp. 6, 8, 10-12

Question(s):

a) Please provide a more detailed version of Table 4-2-90 that shows the various cost components for the network metering program. For example, to the extent that these cost components are relevant to the program, please show line items for labour / wages, third-party contractors, licensing fees, etc. Please add to the list any other cost components that are relevant to the program.

b) Please advise whether Table 4-2-91 reflects FTEs or headcount.

c) Please explain further the timing of the ramp-up of resources for the AMI Renewal Project team. More specifically, please discuss why the majority of the team (10/11 FTEs) needs to be in place by 2027.

d) Please provide a table showing the breakout by cost category of the one-time OM&A AMI renewal project costs. As part of the response, please advise whether the cited $1.5M is an annual cost or a cumulative cost for the 2027-2031 period. Please also further explain how a letter of credit impacts operational costs.

e) Please explain how the transition from on-premise management of the AMI systems to a fully managed services model has been reflected in the forecast for the 2027-2031 test period.

RESPONSE:

:

a) See below

Table 1 - Detailed Network Metering Program Expenditures ($MM)

	Historical							
Cost Driver	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Direct Labour Costs	5.2	5.6	5.8	6.1	6.1	4.7	4.7	5.7
IST Licenses and Maintenance	0.2	0.0	0.0	0.0	0.0	0.0	0.0	1.7
Outside Service Provider (Contract Labour)	1.4	1.8	2.5	3.3	2.6	2.7	2.4	2.2
AMI Network Communications	1.2	1.0	1.0	0.8	1.3	1.2	1.2	1.2
Harvested AMI 1.0 meter labour	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	1.1	0.7	0.5	0.2	0.8	1.0	0.3	0.7
Total Expenditures	9.1	9.2	9.8	10.4	10.8	9.6	8.7	11.4

	Bridge		Test	Forecast			
Cost Driver	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Direct Labour Costs	5.5	5.8	6.0	6.2	6.4	6.6	6.8
IST Licenses and Maintenance	1.9	2.2	2.6	3.7	4.5	5.0	5.8
Outside Service Provider (Contract Labour)	2.2	2.6	3.8	3.5	3.6	3.3	3.0
AMI Network Communications	1.0	1.2	1.2	1.3	1.3	1.3	1.0
Harvested AMI 1.0 meter labour	1.1	0.0	0.8	0.7	0.5	0.2	0.0
Other	0.7	0.5	0.5	0.6	0.5	0.6	0.6
Total Expenditures	12.5	12.4	14.9	16.0	16.8	16.9	17.2

*2025 has been updated to reflect actuals.

"Harvested AMI 1.0 Meter Labour" is a subset of the Outside Service Provider costs, broken out due to their relevance. This cost is due to the re-deployment of fully depreciated AMI 1.0 meters to meet the need for new connections and customer upgrades, meter reverification program requirements, and to address meter failures where the AMI 2.0 network has not been established. This expense was not incurred prior to 2025.

b) Table 4-2-91 reflects Network Metering's approved headcount, with a breakdown between the Network Metering work groups. This table has been updated with 2025 actuals and corrected in Alectra Utilities' response to interrogatory 4-VECC-55.

c) The timing of the resource ramp up reflects the phased structure of the AMI Renewal Program as set out in Exhibit 2A, Tab 1, Schedule 1, Appendix B06.

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From 2018 to 2023, early planning, procurement, standards development and initial deployments were largely supported by existing "business as usual" Network Metering resources. Dedicated project leadership and delivery roles were added in 2024 and 2025 as the program moved toward mass deployment readiness, system integration and process formalization.

In 2026, the project enters its final readiness phase, during which end-to-end testing, system commissioning, field integration, and customer communication processes are completed, supported by specialized data, customer, and field exception resources.

By 2027, the project transitions into sustained, high-volume mass deployment, with peak operational, technical, and customer service complexity and heightened risks related to billing accuracy, system performance and vendor oversight. Accordingly, the majority of the project team is required to be in place by 2027 to ensure sufficient internal capacity to manage these risks and support reliable, large-scale deployment.

d) The following table displays the one-time OM&A expenditures related to the AMI Renewal project.

Table 2 - AMI Renewal Program - One-time OM&A Expenditures ($MM)

AMI Renewal - One-time OM&A Expenditures ($MM)						
	2027	2028	2029	2030	2031	Total
Customer Education and Communications	0.6	0.7	0.7	0.7	0.2	2.9
Training	0.1	0.0	0.0	0.0	0.0	0.1
Vendor provided Letter of Credit	0.1	0.1	0.1	0.1	0.1	0.5
Re-deployment of fully depreciated harvested AMI 1.0 meters (labour)	0.8	0.7	0.5	0.2	0.0	2.2
AMI 2.0 Head End Security Audits	0.4	0.0	0.0	0.0	0.4	0.8
AMI 2.0 Incremental Licensing and Maintenance	0.6	0.7	0.6	0.9	0.3	3.1
Total One-time Project Costs	2.6	2.2	1.9	1.9	1.0	9.6

The reference to $1.5MM in one-time OM&A expenditures as a result of the AMI Renewal project on page in Exhibit 4, Tab 2, Schedule 13, Page 10 was intended to be an annual average spend and should have read $1.9MM as reflected in the above table. The 2027 to

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2031 one-time OM&A expenditures related to AMI Renewal are $9.6MM as provided in the chart above.

Throughout the mass deployment period, and upon demand by Alectra Utilities, a bank letter of credit is to be provided by the AMI 2.0 meter vendor with Alectra Utilities as the beneficiary. The fees related to the vendor's letter of credit are to be paid by Alectra Utilities.

The incremental AMI 2.0 licensing and maintenance expenditures reflect the expenses associated with the AMI 2.0 Head End, partially offset by declining AMI 1.0 licensing and maintenance costs within the Network Metering OM&A budget. AMI 1.0 Head End fees decrease as AMI 1.0 meters are removed from the network, or as the Head End is retired, depending on contractual obligations. As a result, the incremental costs decline over time.

e) Alectra Utilities has contracting in place for the licensing and maintenance of its AMI 1.0 and AMI 2.0 systems. These costs are included in the IST Licenses and Maintenance expenditures within the Network Metering program OM&A costs as shown in Table 1, above.

More specifically, the following chart provides the breakdown between the licensing and maintenance for Alectra Utilities' AMI 1.0 and AMI 2.0 systems. Expenditures related to the AMI 1.0 Head End systems will be eliminated as the system is retired or as the volume of meters attached to the Head End is reduced, depending on the contractual obligations.

Table 3: AMI 1.0 and AMI 2.0 Licensing and Maintenance Expenditures ($MM)

Licensing and Maintenance	2027	2028	2029	2030	2031	Total
AMI 1.0	2.1	2.2	1.8	0.8	0.2	7.2
AMI 2.0	0.6	1.1	1.8	2.6	3.4	9.4
Total	2.8	3.3	3.6	3.4	3.6	16.6

The discontinuation of on-premise AMI 1.0 management activities including testing and system administration builds necessary capacity within the Network Metering team

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throughout the AMI 2.0 Renewal project time frame. This includes the capacity to begin initiatives related to the enhanced functionality enabled through AMI 2.0 including power quality information, outage notifications, customer-specific alarms and functionality including remote disconnect and reconnect capabilities.

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RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-55

Ref: Exhibit 4, Tab 2, Schedule 14, pp. 1

Question(s):

a) Please provide a more detailed version of Table 4-2-92 that shows the various cost components for the program delivery program. For example, to the extent that these cost components are relevant to the program, please show line items for labour / wages, third-party contractors, licensing fees, etc. Please add to the list any other cost components that are relevant to the program.

b) Please further explain the methodology applied to forecast costs for the program delivery program in the test period (including a discussion of the test year forecasting methodology and the 2028-2031 forecasting methodology if those methodologies are different).

RESPONSE:

a) See below

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Table 1 - Detailed Program Delivery Group Program Expenditures ($MM)

Program Delivery Group								
Program Costs ($millions) – Historic Period								
Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Labour/Wages	1.02	0.69	0.64	0.61	0.62	0.66	0.61	0.71
Third-Party Contractors and Consultants	0.00	0.01	0.00	0.04	0.00	0.00	0.01	0.01
Licensing Fees	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Department Overhead (e.g., Training, Travel, etc.)	0.04	0.06	0.06	0.02	0.00	0.01	0.03	0.03
Total	1.08	0.77	0.71	0.67	0.63	0.67	0.65	0.76
Program Costs ($millions) – Bridge and Forecast Period								
Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	
Labour/Wages	1.06	1.44	1.50	1.56	1.62	1.67	1.73	
Third-Party Contractors and Consultants	0.02	0.00	0.08	0.08	0.08	0.09	0.09	
Licensing Fees	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Department Overhead (e.g., Training, Travel, etc.)	0.02	0.05	0.05	0.06	0.06	0.06	0.06	
Total	1.10	1.49	1.64	1.70	1.76	1.82	1.88	

b) The majority of costs in the Program Delivery segment are labour related. A tabulation of the planned FTE count for Program Delivery Group can be found in Table 4-3-2. The number of FTE required for this program was assessed based on the forecast volume of capital work coordinated by each program coordinator as shown in Table 4-2-96.

Other costs, such as Third-Party Contractors and Consultants are related to enhancements planned to Alectra's Program Delivery such as adding interfaces between various software platforms, improving access to project data and adding automation to reporting functions in order to expand Alectra' project management processes to include additional areas of the business and to allow for each program coordinator to manage a larger capital portfolio per FTE as shown in Table 4-2-96.

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RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-56

Ref: Exhibit 4, Tab 2, Schedule 15, pp. 1, 4, 8

Question(s):

a) Please provide a more detailed version of Table 4-2-100 that shows the various cost components for each segment (i.e., vegetation management cut cycle and reactive tree trimming) of the vegetation management program. For example, to the extent that these cost components are relevant to the program, please show line items for labour / wages, third-party contractors, licensing fees, etc. Please add to the list any other cost components that are relevant to the program.

b) With respect to the contracted services used as part of Alectra's vegetation management activities, please provide the term of its existing vegetation management contract(s) (e.g., 2024-2026, 2023-2027, etc.). Please also explain the process that Hydro Ottawa undertook to enter the tree trimming contract(s). As part of the response, please provide details about the RFP, the number of bidders, the selection process, etc.

c) Please provide additional details regarding the rotation of planned tree trimming for the defined geographical areas set out in Table 4-2-99. As part of the response, please provide a table showing the defined geographical areas (Table 4-2-99), which area(s) were completed in each year of the historical period, and which area(s) are planned for the test period. Please also advise whether different contractors are used for different areas.

RESPONSE:

a) A more detailed version of Table 4-2-100 that shows the various cost components for each segment is provided below in Table 1 and Table 2.

Table 1 - Detailed Vegetation Management Cut Cycle Segment Program Expenditures

Vegetation Management - Vegetation Management Cut Cycle								
Program Costs ($millions) – Historic Period								
Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Third-Party Contractors and Consultants	N/A	N/A	N/A	4.11	4.15	4.25	5.18	4.52
Other	N/A	N/A	N/A	1.15	0.89	0.98	1.59	1.33
Total	N/A	N/A	N/A	5.26	5.01	5.23	6.78	5.85
Program Costs ($millions) – Bridge and Forecast Period								
Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	
Third-Party Contractors and Consultants	5.63	5.89	6.69	6.83	6.97	7.11	7.25	
Other	0.79	0.13	0.13	0.13	0.13	0.14	0.14	
Total	6.42	6.02	6.81	6.96	7.10	7.24	7.39	

Table 2 - Detailed Reactive Tree Trimming Segment Program Expenditures

Vegetation Management - Reactive Tree Trimming								
Program Costs ($millions) – Historic Period								
Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Labour/Wages	N/A	N/A	N/A	0.21	0.18	0.18	0.20	0.21
Third-Party Contractors and Consultants	N/A	N/A	N/A	0.00	0.02	0.00	0.00	0.02
Other	N/A	N/A	N/A	0.06	0.06	0.06	0.05	0.08
Total	N/A	N/A	N/A	0.28	0.26	0.24	0.25	0.31
Program Costs ($millions) – Bridge and Forecast Period								
Year	**2025A**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	
Labour/Wages	0.20	0.22	0.24	0.25	0.27	0.28	0.29	
Third-Party Contractors and Consultants	0.02	0.02	0.02	0.03	0.03	0.03	0.03	
Other	0.07	0.00	0.00	0.00	0.00	0.00	0.00	
Total	0.27	0.22	0.24	0.25	0.27	0.28	0.29	

Labour/wages costs associated with Table 2 above are allocated to the Vegetation Management Reactive Tree Trimming for administration and program oversight as there are no FTEs for this program after 2021. Note that Third-Party Contractors and Consultant costs related to Reactive Tree Trimming are included in the Third-Party Contractors and Consultants line in Table 1 (Planned Cut Cycle).

b) It is assumed that the reference to Hydro Ottawa in this question was meant to refer to Alectra Utilities. The existing vegetation management contracts supporting Alectra's vegetation management activities are from 2023-2026.

A total of ten (10) bidders participated in the RFP for the current contract. Please see response 4-staff-191 b) for details on the process that Alectra Utilities undertook to enter the tree trimming contract(s).

c) Alectra Utilities achieved levels of completion of its planned cut cycles from 2021-2025 are indicated below in Table 3. Alectra does not have the accomplishment by defined geographical areas for the historical period due to differing tracking and reporting methods used in each region (reporting method had not been harmonized at that time). Alectra-wide percentages provided in Table 3 are the weighted average of the individual service region accomplishments, weighted by effort required to complete (the number of third-party contractor hours allocated to their individual completion). Different contractors are used for different areas across Alectra Utilities Corporation.

d) **Table 3 - Planned Cut Cycle Accomplishments 2021-2025**

Service Region	2021	2022	2023	2024	2025
West	91%	94%	89%	84%	50%
Southwest	100%	100%	100%	100%	100%
Central	50%	30%	61%	30%	36%
East	100%	100%	100%	83%	98%
Alectra	81%	73%	82%	62%	59%
Actual Program Costs	$5.01M	$5.23M	$6.78M	$5.58M	$6.42M

Alectra has faced several challenges with the planned cut cycle work including increasing contractor service rates, which have risen above inflation from 2021-2025 (with a CAGR of 9.49% over the period) and years with increase reactive demands.

Please the attached Figures 1 to 7 to find the overall maps for Alectra Utilities' vegetation management program. This program is conducted on a 3–4-year cycle varied by region. The years are indicated in the legend on the maps. Upon the completion of the program cycle in 2026/2027, the program cycle will restart from 2027/2028, varied as per the region's dedicated cycle. Additionally, different contractors are used for different areas across Alectra Utilities Corporation. Tables 4 and 5 below indicate the map areas planned for each year from 2027-2031.

1 **Table 4 - Planned Cut Cycle Map Areas 2027-2031 (West and Southwest)**

	2027	2028	2029	2030	2031
West	Hamilton: 16, 17, 18, 19, 20, 21, 22, 23, 24, 25, 26, 27, 44, 45, 46, 47, 48, 49, 50, 51, 69, 70, 71, 72, 73, 74, 213, 214, 215, 216, 217, 218, 219, 220, 221, 222, 223, 224, 225, 226, 227, 228, 229, 230, 231, 232, 233, 234, 235, 236, 237, 238, 239, 240, 241, 242, 243, 244, 245, 246, 247, 248, 249, 250, 251, 252, 253, 254 St. Catharines: 4, 5, 6, 7, 8, 9, 13, 14, 15, 16, 17, 18, 27, 28	Hamilton: 1, 2, 3, 4, 5, 6, 7, 8, 9, 34, 35, 36, 37, 58, 59, 60, 61, 62, 63, 64, 65, 66, 67, 82, 83, 84, 85, 86, 87, 100, 101, 102, 103, 116, 117, 118/Lynden, 119, 120, 121, 122, 129, 130, 131, 132, 149, 150, 160, 161, 162, 163, 164, 165, 167, 168, 169, 170, 171, 171, 172, 173, 176, 177 St. Catharines: 25, 26, 30, 31, 32, 33, 37, 38, 39, 40, 41, 43, 48, 49, 50	Hamilton: 10, 11, 12, 13, 14, 15, 28, 29, 30, 31, 32, 33, 38, 39, 40, 41, 42, 43, 52, 53, 54, 55, 56, 57, 68, 75, 76, 77, 78, 79, 80, 81, 88, 89, 90, 91, 92, 93, 94, 95, 96, 97, 98, 99, 104, 105, 106, 107, 108, 109, 110, 111, 112, 113, 114, 115 St. Catharines: 1, 2, 3, 10, 11, 12, 19, 21, 22, 23, 24, 34, 36, 45, 46, 47	Hamilton: 16, 17, 18, 19, 20, 21, 22, 23, 24, 25, 26, 27, 44, 45, 46, 47, 48, 49, 50, 51, 69, 70, 71, 72, 73, 74, 213, 214, 215, 216, 217, 218, 219, 220, 221, 222, 223, 224, 225, 226, 227, 228, 229, 230, 231, 232, 233, 234, 235, 236, 237, 238, 239, 240, 241, 242, 243, 244, 245, 246, 247, 248, 249, 250, 251, 252, 253, 254 St. Catharines: 4, 5, 6, 7, 8, 9, 13, 14, 15, 16, 17, 18, 27, 28	Hamilton: 1, 2, 3, 4, 5, 6, 7, 8, 9, 34, 35, 36, 37, 58, 59, 60, 61, 62, 63, 64, 65, 66, 67, 82, 83, 84, 85, 86, 87, 100, 101, 102, 103, 116, 117, 118/Lynden, 119, 120, 121, 122, 129, 130, 131, 132, 149, 150, 160, 161, 162, 163, 164, 165, 167, 168, 169, 170, 171, 171, 172, 173, 176, 177 St. Catharines: 25, 26, 30, 31, 32, 33, 37, 38, 39, 40, 41, 43, 48, 49, 50
Southwest	Area 2	Area 3	Area 1	Area 2	Area 3

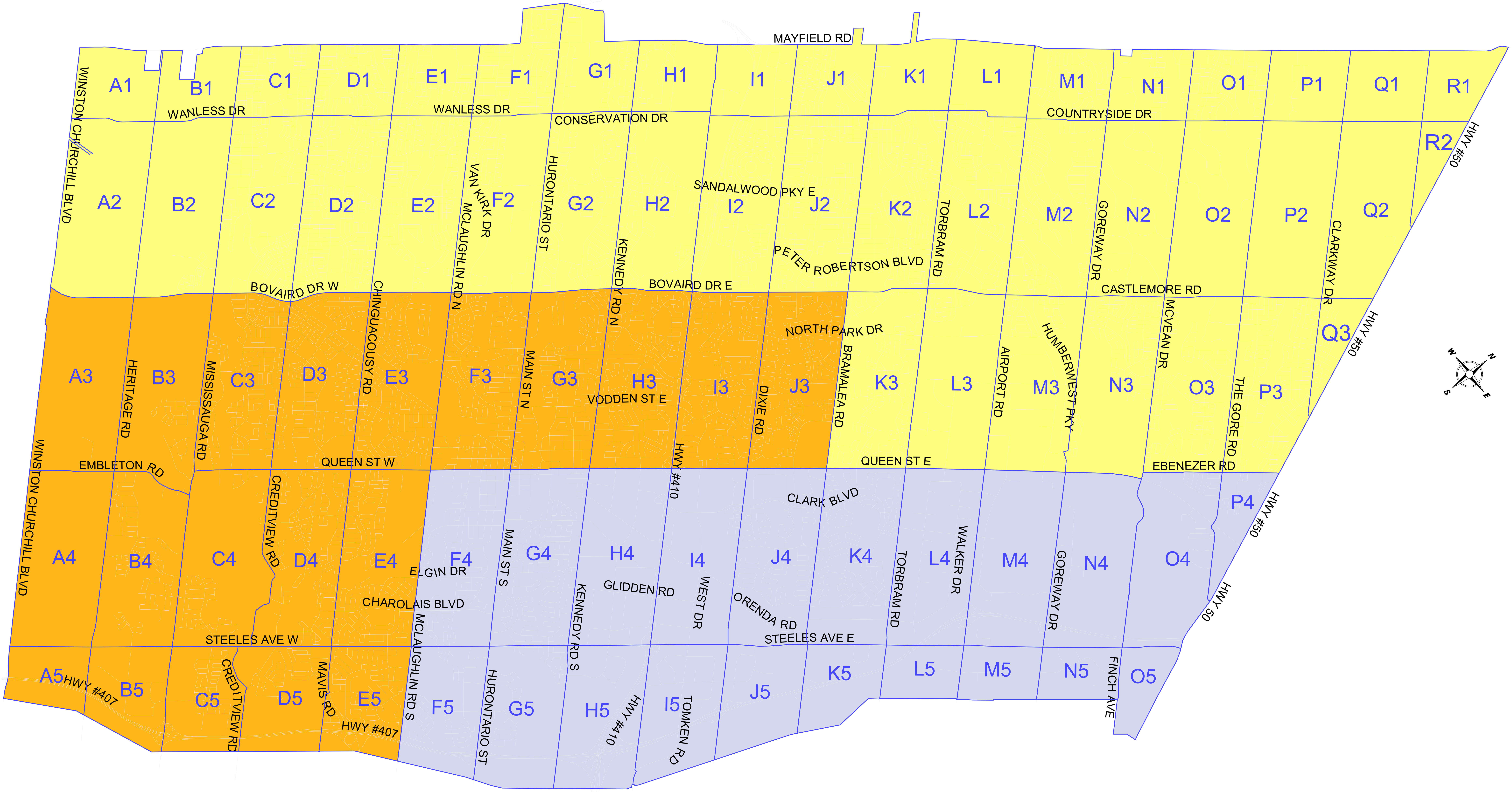
Table 5 - Planned Cut Cycle Map Areas 2027-2031 (Central and East)

	2027	2028	2029	2030	2031
Central	Mississauga: 33, 34, 35, 36, 37, 38, 40, 41, 42, 43, 44, 45, 46, 47, 48, 49, 50, 51, 52, 53, 54, 55 Brampton: A1, B1, C1, D1, E1, F1, G1, H1, I1, J1, K1, L1, M1, N1, O1, P1, Q1, R1, A2, B2, C2, D2, E2, F2, G2, H2, I2, J2, K2, L2, M2, N2, O2, P2, Q2, R2, K3, L3, M3, N3, O3, P3, Q3	Mississauga: 1, 5, 6, 13, 13, 19, 30, 31, 36, 37, 38 Brampton: A3, B3, C3, D3, E3, F3, G3, H3, I3, J3, A4, B4, C4, D4, E4, A5, B5, C5, D5, E5	Mississauga: 2, 7, 8, 9, 14, 15, 16, 33, 33 Brampton: F4, G4, H4, I4, J4, K4, L4, M4, N4, O4, P4, F5, G5, H5, I5, J5, K5, L5, M5, N5, O5	Mississauga: 3, 4, 10, 11, 17, 18, 34, 35, 39, 30, 31, 33, 39, 56, 57, 58, 59 Brampton: A1, B1, C1, D1, E1, F1, G1, H1, I1, J1, K1, L1, M1, N1, O1, P1, Q1, R1, A2, B2, C2, D2, E2, F2, G2, H2, I2, J2, K2, L2, M2, N2, O2, P2, Q2, R2, K3, L3, M3, N3, O3, P3, Q3	Mississauga: 33, 34, 35, 36, 37, 38, 40, 41, 42, 43, 44, 45, 46, 47, 48, 49, 50, 51, 52, 53, 54, 55 Brampton: A3, B3, C3, D3, E3, F3, G3, H3, I3, J3, A4, B4, C4, D4, E4, A5, B5, C5, D5, E5
East	York Region: Vaughan Simcoe County: Beeton, Alliston, Bradford West Gwillimbury, Penetanguishene	York Region: Richmond Hill / Aurora Simcoe County: Barrie (North)	York Region: Markham Simcoe County: Barrie (South), Tottenham, Thornton	York Region: Vaughan Simcoe County: Beeton, Alliston, Bradford West Gwillimbury, Penetanguishene	York Region: Richmond Hill / Aurora Simcoe County: Barrie (North)

4-CCC-56

Attachment 1
Alectra – Central North Cycle Map

ALECTRA - CENTRAL NORTH (BRAMPTON) - 3 YEAR CYCLE - TREE TRIMMING



LEGEND

TREE TRIMMING ZONES BY YEAR

- 2024
- 2025
- 2026

0 1 2 3 4 5
Kilometers

alectra utilities

ALECTRA CENTRAL NORTH
(City of Brampton)

TREE TRIMMING
3 YEAR CYCLE
OVERALL

SCALE:
1:24,271

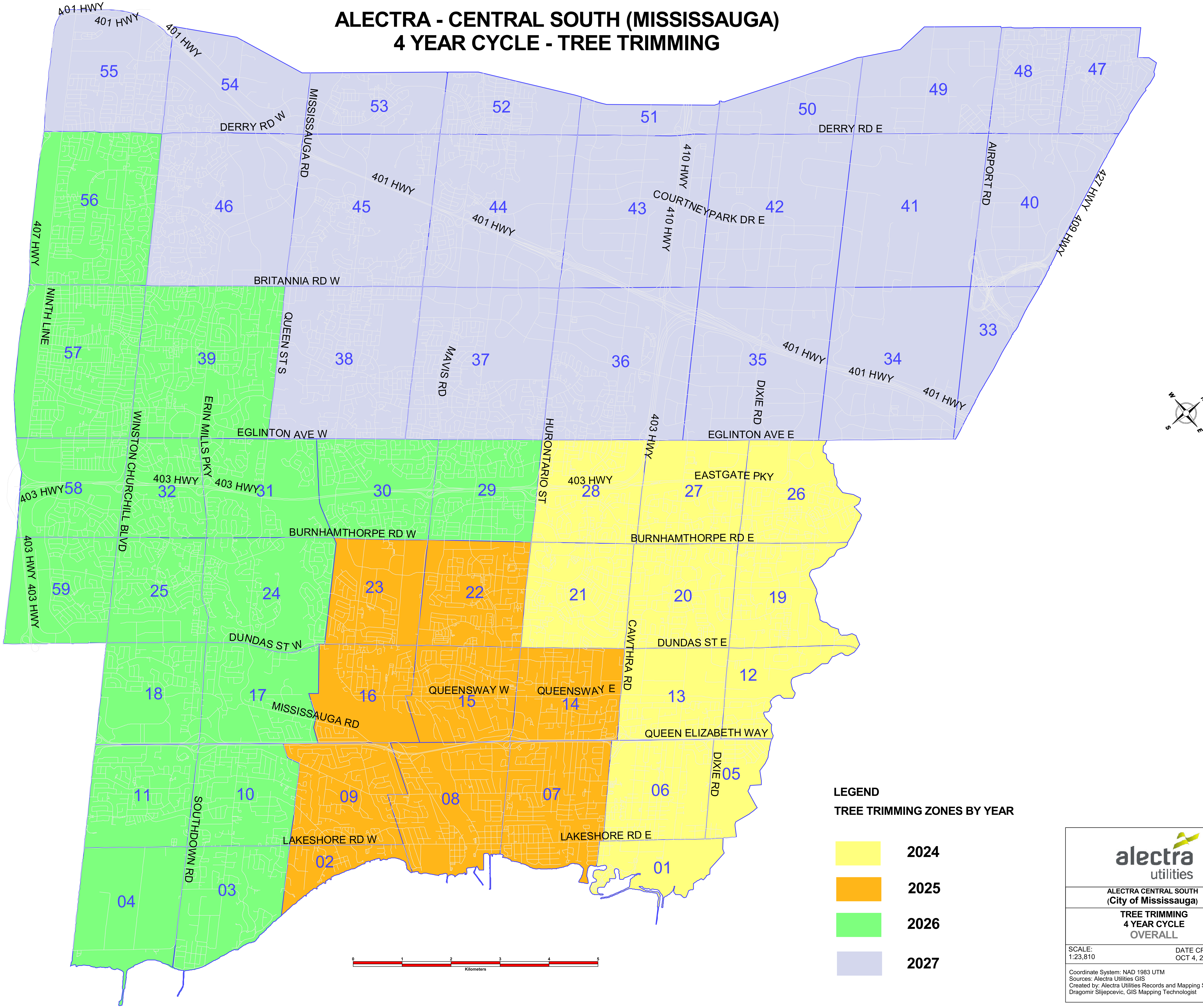
DATE CREATED:
JAN.22, 2025

Coordinate System: NAD 1983 UTM
Sources: Alectra Utilities GIS
Created by: Alectra Utilities Records and Mapping Services
Dragomir Slijepcevic, GIS Mapping Technologist

4-CCC-56

Attachment 2
Alectra – Central South Cycle Map

ALECTRA - CENTRAL SOUTH (MISSISSAUGA)
4 YEAR CYCLE - TREE TRIMMING



LEGEND

TREE TRIMMING ZONES BY YEAR

- 2024
- 2025
- 2026
- 2027

alectra utilities

ALECTRA CENTRAL SOUTH
(City of Mississauga)

TREE TRIMMING
4 YEAR CYCLE
OVERALL

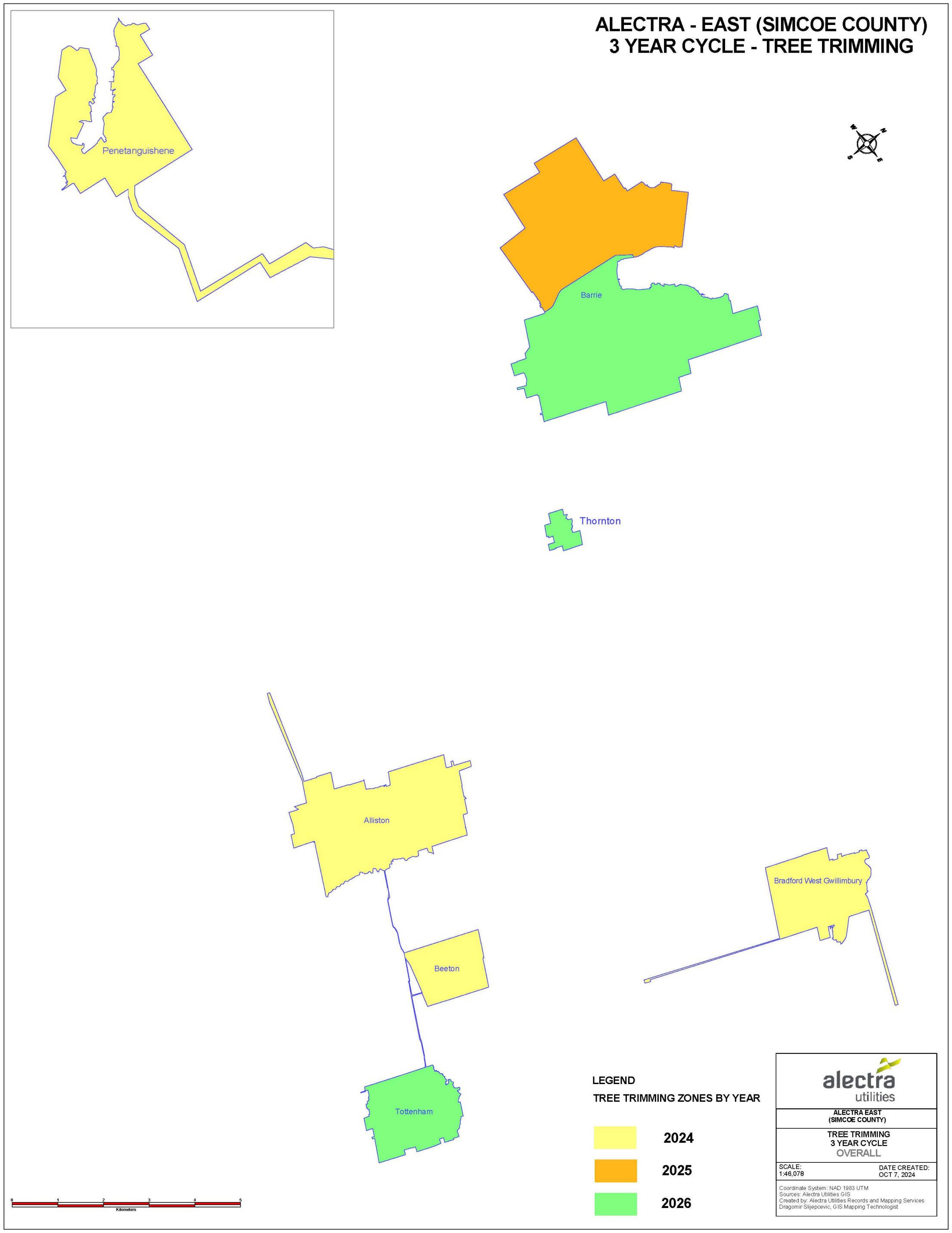
SCALE:
1:23,810

DATE CREATED:
OCT 4, 2024

Coordinate System: NAD 1983 UTM
Sources: Alectra Utilities GIS
Created by: Alectra Utilities Records and Mapping Services
Dragomir Slijepcevic, GIS Mapping Technologist

4-CCC-56

Attachment 3
Alectra – East North Cycle Map



ALECTRA - EAST (SIMCOE COUNTY)
3 YEAR CYCLE - TREE TRIMMING
Penetanguishene
Barrie
Thornton
Alliston
Beeton
Tottenham
Bradford West Gwillimbury
LEGEND
TREE TRIMMING ZONES BY YEAR
2024
2025
2026
alectra utilities
ALECTRA EAST
(SIMCOE COUNTY)
TREE TRIMMING
3 YEAR CYCLE
OVERALL
SCALE:
1:46,078
DATE CREATED:
OCT 7, 2024
Coordinate System: NAD 1983 UTM
Sources: Alectra Utilities GIS
Created by: Alectra Utilities Records and Mapping Services
Dragomir Slijepcevic, GIS Mapping Technologist

4-CCC-56

Attachment 4
Alectra – East South Cycle Map

ALECTRA - EAST (YORK REGION)
3 YEAR CYCLE - TREE TRIMMING

LEGEND

TREE TRIMMING ZONES BY YEAR

Yellow	2024
Orange	2025
Green	2026

alectra utilities

ALECTRA EAST
(YORK REGION)

TREE TRIMMING
3 YEAR CYCLE
OVERALL

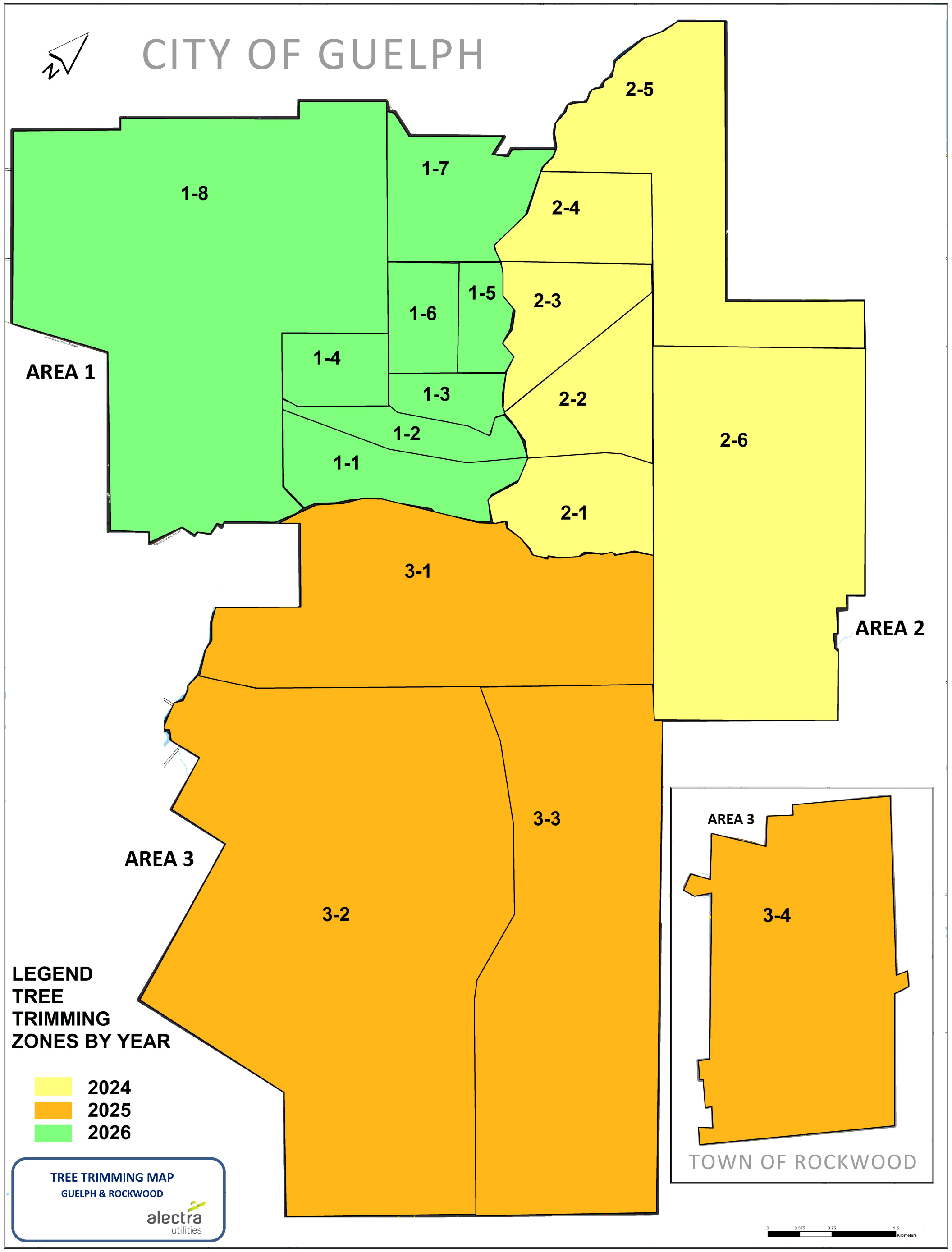
SCALE:
1:43,305

DATE CREATED:
OCT 7, 2024

Coordinate System: NAD 1983 UTM
Sources: Alectra Utilities GIS
Created by: Alectra Utilities Records and Mapping Services
Dragomir Slijepcevic, GIS Mapping Technologist

4-CCC-56

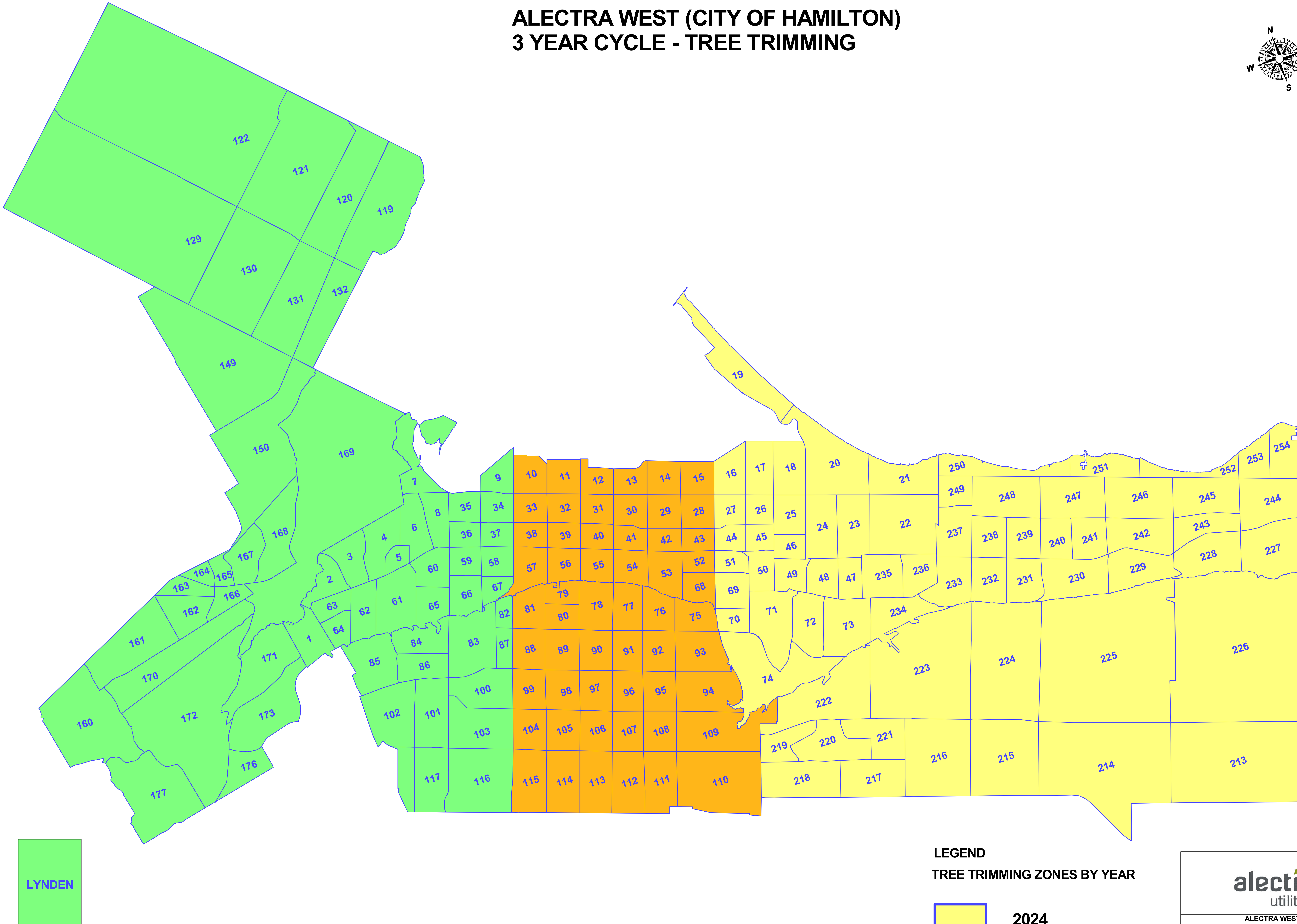
Attachment 5
Alectra – Southwest Cycle Map


CITY OF GUELPH
N
AREA 1
1-1
1-2
1-3
1-4
1-5
1-6
1-7
1-8
AREA 2
2-1
2-2
2-3
2-4
2-5
2-6
AREA 3
3-1
3-2
3-3
AREA 3
3-4
TOWN OF ROCKWOOD
LEGEND
TREE
TRIMMING
ZONES BY YEAR
2024
2025
2026
TREE TRIMMING MAP
GUELPH & ROCKWOOD
alectra
utilities

4-CCC-56

Attachment 6
Alectra – West - Hamilton Cycle Map

ALECTRA WEST (CITY OF HAMILTON)
3 YEAR CYCLE - TREE TRIMMING



LEGEND

TREE TRIMMING ZONES BY YEAR

Yellow	**2024**
Green	**2025**
Orange	**2026**

alectra utilities

ALECTRA WEST
(City of Hamilton)

TREE TRIMMING
3 YEAR CYCLE
OVERALL

SCALE:
1:33,730

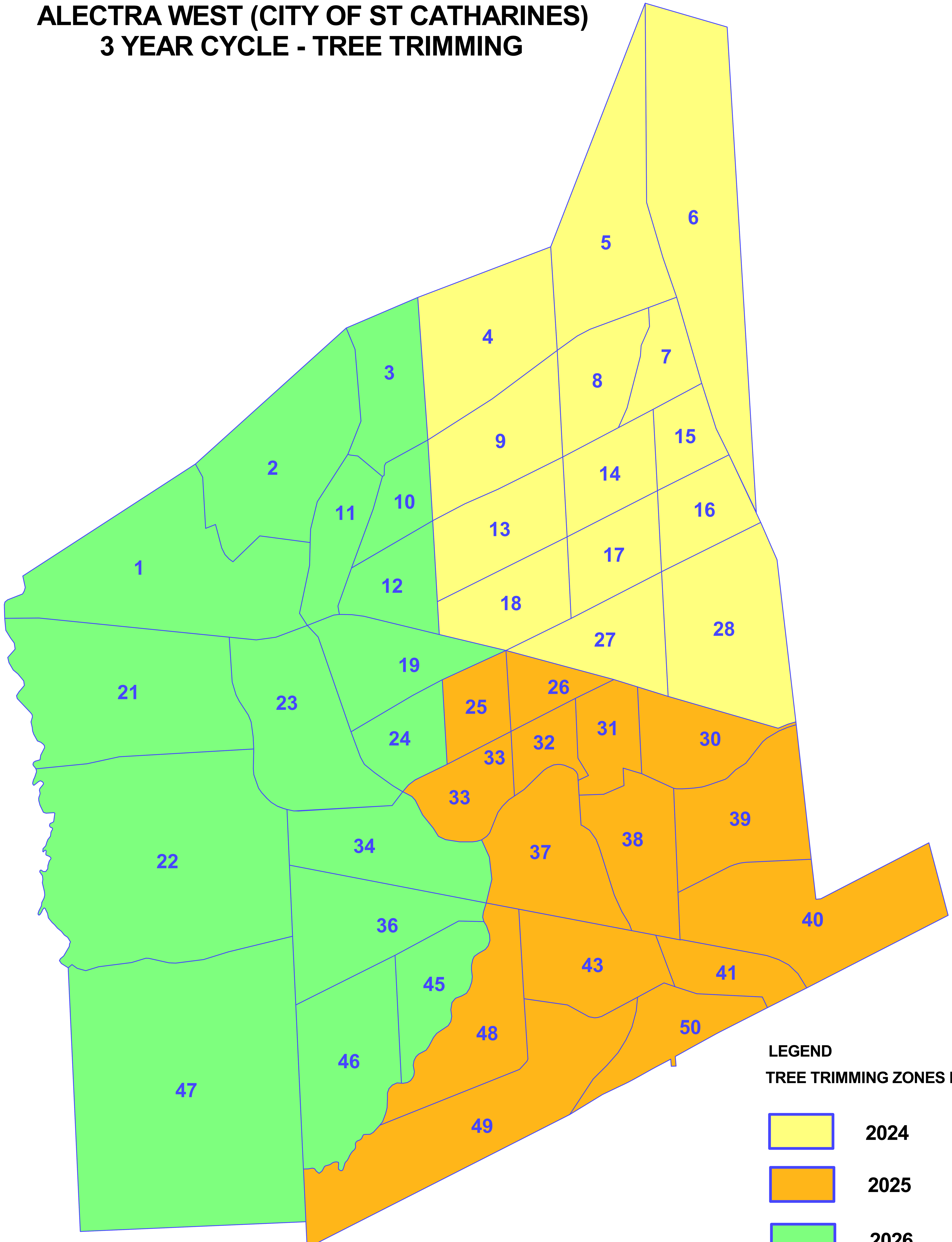
DATE CREATED:
FEB 02, 2026

Coordinate System: NAD 1983 UTM
Sources: Alectra Utilities GIS
Created by: Alectra Utilities Records and Mapping Services
Dragomir Slijepcevic, GIS Mapping Technologist

4-CCC-56

Attachment 6
Alectra – West – St Catharines Cycle Map

ALECTRA WEST (CITY OF ST CATHARINES)
3 YEAR CYCLE - TREE TRIMMING



LEGEND

TREE TRIMMING ZONES BY YEAR

Yellow	**2024**
Orange	**2025**
Green	**2026**

alectra utilities

ALECTRA WEST
(City of St Catharines)

TREE TRIMMING
3 YEAR CYCLE
OVERALL

SCALE: 1:20,075

DATE CREATED: FEB 02, 2026

Coordinate System: NAD 1983 UTM
Sources: Alectra Utilities GIS
Created by: Alectra Utilities Records and Mapping Services
Dragomir Slijepcevic, GIS Mapping Technologist

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-57

Ref: Exhibit 4, Tab 2, Schedule 16, pp. 6, 8, 10, 13, 30-34

Question(s):

a) Please provide a more detailed version of Table 4-2-105 that shows the various cost components for each segment (i.e., asset inspection, disconnect/reconnect, etc.) of the overhead inspections and maintenance program. For example, to the extent that these cost components are relevant to the program, please show line items for labour / wages, third-party contractors, licensing fees, etc. Please add to the list any other cost components that are relevant to the program.

b) Please further explain the methodology applied to forecast costs for the overhead inspections and maintenance program in the test period (including a discussion of the test year forecasting methodology and the 2028-2031 forecasting methodology if those methodologies are different).

c) With respect to the overhead asset inspection segment, please advise whether Alectra has moved entirely to a contractor model for overhead inspection services in 2024. Please provide the implications on internal resources (FTEs) of this change (as between before and after the increased reliance on contractors).

d) Please provide the annual volume of actual and forecast disconnects / reconnects for the 2020-2031 period. Please also provide the annual cost of this activity in the same table.

e) Please provide the annual volume of actual and forecast trouble calls for the 2020-2031 period. Please also provide the annual cost of this activity in the same table.

:

f) Please provide the annual volume of actual and forecast porcelain insulators maintained for the 2020-2031 period. Please also provide the annual cost of this activity in the same table.

g) Please provide the annual volume of actual and forecast overhead switches maintained for the 2020-2031 period. Please also provide the annual cost of this activity in the same table.

h) Please explain why Alectra did not complete the planned switch maintenance program during the 2020-2024 period.

RESPONSE:

a) A detailed version of Table 4-2-105 is provided for each segment of the Overhead Inspections and Maintenance program in Tables 1-4 below. As noted in Exhibit 4-2-16 Page 6, segment level data for this program is not available from 2017 to 2019 due to varying legacy financial systems and segmentation approaches.

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Table 1 - Overhead Inspections and Maintenance Expenditures – Overhead Asset Inspections ($MM)

Asset Inspections								
Program Costs ($millions) – Historic Period								
Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Labour/Wages	N/A	N/A	N/A	0.69	0.57	0.61	0.47	0.29
Third-Party Contractors and Consultants	N/A	N/A	N/A	0.44	0.38	2.09	1.42	1.51
Other	N/A	N/A	N/A	0.12	0.13	0.22	0.09	0.08
Total	N/A	N/A	N/A	**1.25**	**1.08**	**2.92**	**1.98**	**1.88**
Program Costs ($millions) – Bridge and Forecast Period								
Year	**2025A**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	
Labour/Wages	0.39	0.56	0.62	0.67	0.71	0.73	0.76	
Third-Party Contractors and Consultants	2.07	1.35	1.88	1.68	1.81	1.86	1.91	
Other	0.54	0.42	0.10	0.11	0.11	0.12	0.13	
Total	**3.00**	**2.54**	**2.41**	**2.59**	**2.69**	**2.77**	**2.85**	

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Table 2 - Overhead Inspections and Maintenance Expenditures – Overhead Disconnects/Reconnects ($MM)

Overhead Disconnects/Reconnects Program Costs ($millions) – Historic Period								
Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Labour/Wages	N/A	N/A	N/A	5.83	5.26	5.53	6.21	5.31
Direct Vehicle	N/A	N/A	N/A	0.63	0.94	0.88	0.75	0.90
Third-Party Contractors and Consultants	N/A	N/A	N/A	0.95	1.49	2.22	1.30	1.99
Other	N/A	N/A	N/A	0.39	0.57	0.51	0.70	0.74
Total	**N/A**	**N/A**	**N/A**	**7.80**	**8.26**	**9.14**	**8.96**	**8.94**
Program Costs ($millions) – Bridge and Forecast Period								
Year	**2025A**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	
Labour/Wages	5.55	5.57	6.15	6.62	7.03	7.29	7.54	
Direct Vehicle	0.70	0.75	0.77	0.78	0.80	0.81	0.83	
Third-Party Contractors and Consultants	1.92	1.94	1.96	1.98	2.02	2.06	2.10	
Other	0.61	0.34	0.35	0.36	0.37	0.39	0.40	
Total	**8.78**	**8.60**	**9.23**	**9.74**	**10.22**	**10.55**	**10.87**	

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Table 3 - Overhead Inspections and Maintenance Expenditures – Overhead Preventative Maintenance ($MM)

Overhead Preventative Maintenance Program Costs ($millions) – Historic Period								
Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Labour/Wages	N/A	N/A	N/A	0.44	0.51	0.67	0.57	0.33
Direct Vehicle	N/A	N/A	N/A	0.05	0.10	0.16	0.12	0.09
Third-Party Contractors and Consultants	N/A	N/A	N/A	0.26	0.71	0.53	0.67	0.52
Other	N/A	N/A	N/A	0.07	0.11	0.11	0.14	0.13
Total	**N/A**	**N/A**	**N/A**	**0.82**	**1.43**	**1.47**	**1.50**	**1.07**
Program Costs ($millions) – Bridge and Forecast Period								
Year	**2025A**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	
Labour/Wages	0.64	1.06	1.17	1.26	1.34	1.39	1.44	
Direct Vehicle	0.07	0.14	0.15	0.15	0.15	0.16	0.16	
Third-Party Contractors and Consultants	0.95	1.15	1.16	1.18	1.19	1.21	1.22	
Other	0.92	0.07	0.07	0.07	0.08	0.07	0.08	
Total	**2.58**	**2.42**	**2.55**	**2.66**	**2.76**	**2.83**	**2.90**	

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Table 4 - Overhead Inspections and Maintenance Expenditures – Overhead System Reactive Repairs and Maintenance ($MM)

Overhead Preventative Maintenance Program Costs ($millions) – Historic Period								
Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Labour/Wages	N/A	N/A	N/A	13.29	8.99	11.96	9.86	9.14
Direct Vehicle	N/A	N/A	N/A	1.17	1.62	1.61	1.36	1.46
Third-Party Contractors and Consultants	N/A	N/A	N/A	1.17	1.43	1.86	1.28	1.52
Other	N/A	N/A	N/A	1.00	1.14	1.77	1.20	2.21
Total	**N/A**	**N/A**	**N/A**	**16.63**	**13.18**	**17.20**	**13.70**	**14.33**
Program Costs ($millions) – Bridge and Forecast Period								
Year	**2025A**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	
Labour/Wages	10.41	12.53	13.48	14.28	15.01	15.53	16.05	
Direct Vehicle	1.19	1.17	1.19	1.21	1.24	1.26	1.29	
Third-Party Contractors and Consultants	1.70	1.03	1.05	1.08	1.10	1.12	1.14	
Other	0.96	0.77	0.81	0.83	0.85	0.89	0.90	
Total	**14.26**	**15.50**	**16.53**	**17.40**	**18.20**	**18.80**	**19.38**	

b) The Overhead Inspections and Maintenance program expenditures were forecast for the 2027-2031 period based on historical cost trends and inflationary adjustments to account for changes in labour rates, contractor service fees, and other costs.

c) Alectra transitioned to a fully contracted model for asset inspection activities, including overhead inspection services, beginning in 2022. Prior to 2022, overhead asset inspection services were performed by a combination of internal staff and contractors, with the transition to contractors occurring gradually in the years leading up to 2022.

:

Before 2022, inspection volumes were lower (see IR response 4-AMPCO-67, table 1). The shift to fully contracted Asset Inspections aligned with higher program achievements and enabled Alectra Utilities to complete the full inspection program without increasing internal FTE Requirements. Because the transition away from internally completed asset inspections occurred incrementally and these activities represented a relatively small portion of overall Powerline Technician duties, the move a fully contracted model did not result in any reduction of internal FTE requirements. Internal staff were redeployed to other activities within the program.

d) Please see the response to 4-AMPCO-67 d). Please see the response to this IR, 4-CCC-57 a)ii above for costs related to this segment.

e) Table 5 below provides the number of trouble calls from 2020-2025 with a forecast range provided for the 2026–2031 period. Trouble calls in this table include both overhead and underground related trouble calls as Alectra Utilities does not separately track overhead and underground trouble calls.

Table 5 - Trouble Call Volumes and Segment Costs 2020-2031

Year	Trouble Calls	Overhead Inspections and Maintenance Segment Cost ($MM)	Underground Inspections and Maintenance Segment Cost ($MM)
2020	6,941	$16.63M	$17.94M
2021	6,646	$13.18M	$19.30M
2022	6,648	$17.20M	$23.96M
2023	6,267	$13.70M	$21.70M
2024	6,354	$14.33M	$23.45M
2025	6,529	$14.26M	$28.29M
2026	6,267 to 6,941	$15.50M	$23.31M
2027	6,267 to 6,941	$16.53M	$25.18M

:

2028	6,267 to 6,941	$17.40M	$26.48M
2029	6,267 to 6,941	$18.20M	$27.64M
2030	6,267 to 6,941	$18.80M	$28.48M
2031	6,267 to 6,941	$19.38M	$29.29M

f) Alectra Utilities does not track or forecast the number of porcelain insulators in its system that require washing. Alectra Utilities conducts an insulator inspection and washing program and the costs are dependent on year over year weather, road maintenance and insulator contamination condition. Alectra forecast the preventative maintenance program on a total, top-down basis, using 2024 actual costs as a starting point and considering expected inflationary increases to third-party contractor rates and internal labour rates.

g) Alectra forecast the overhead switch preventative maintenance program on a total, top-down basis, using 2024 actual costs as a starting point and considering expected inflationary increases to third-party contractor rates and internal labour rates. Individual inputs can vary depending on weather and other factors (see response f above), and not all inputs are available to prepare a bottom-up approach itemizing each program within the segment. Historical and forecast switch maintenance volumes can be found in the table below:

Table 6 – Number of Switches Maintained

	2020	2021	2022	2023	2024	2025
Number of switches maintained	134	384	163	326	364	452

Table 7 – Forecast Number of Switches Maintained

	2026	2027	2028	2029	2030	2031
Forecast Number of switches maintained	521	549	549	549	549	549

:

h) Alectra's ability to complete its planned switch maintenance program during the 2020–2024 period was constrained by system capacity limitations that restricted outage windows, challenges coordinating planned outages with customers, and asset condition issues that prevented safe isolation of certain switches. These operational constraints were compounded by pandemic-related impacts that redirected resources toward critical response activities. As a result, Alectra prioritized higher-risk assets in some years and was unable to complete the full maintenance program annually.

:

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-58

Ref: Exhibit 4, Tab 2, Schedule 17, pp. 6, 9-10

Question(s):

a) Please provide a more detailed version of Table 4-2-116 that shows the various cost components for each segment (i.e., asset inspection, preventative maintenance, system reactive) of the underground inspections and maintenance program. For example, to the extent that these cost components are relevant to the program, please show line items for labour / wages, third-party contractors, licensing fees, etc. Please add to the list any other cost components that are relevant to the program.

b) Please further explain the methodology applied to forecast costs for the underground inspections and maintenance program in the test period (including a discussion of the test year forecasting methodology and the 2028-2031 forecasting methodology if those methodologies are different).

c) Please provide the annual volume of actual and forecast underground inspections for the 2020-2031 period. Please also provide the annual cost of this activity.

d) With respect to the underground asset inspection segment, please advise whether Alectra has moved entirely to a contractor model for underground inspection services in 2024. Please provide the implications on internal resources (FTEs) of this change (as between before and after the increased reliance on contractors).

e) Please provide the annual volume of actual and forecast trouble calls for the 2020-2031 period. Please also provide the annual cost of this activity in the same table.

:

RESPONSE:

a) Please find the requested cost components by segment within the Underground Inspections & Maintenance program. As noted in Exhibit 4, Tab 2, Schedule 17, Line 6 segment level data is not available from 2017 to 2019 due to varying legacy financial systems and segmentation approaches.

Table 1 - Underground Asset Inspection Segment Detailed Costs ($MM)

Actuals	2020	2021	2022	2023	2024	2025
Segment Total	2.28	2.88	3.66	2.70	2.47	2.26
Labour/Wages	1.46	1.78	1.68	1.36	0.75	0.70
Third-Party Contractors and Consultants	0.56	0.71	1.61	1.04	1.33	1.36
Other	0.26	0.39	0.37	0.30	0.39	0.20
Bridge/Forecast	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Segment Total	2.65	2.75	2.96	3.07	3.17	3.26
Labour/Wages	0.71	0.78	0.84	0.89	0.93	0.96
Third-Party Contractors and Consultants	1.80	1.82	1.97	2.03	2.09	2.15
Other	0.14	0.15	0.15	0.15	0.15	0.15

:

Table 2 - Underground Preventative Maintenance Segment Detailed Costs ($MM)

Actuals	2020	2021	2022	2023	2024	2025
Segment Total	0.69	1.34	1.35	0.51	0.31	0.34
Labour/Wages	0.10	0.18	0.08	0.02	0.01	0.04
Third-Party Contractors and Consultants	0.29	0.28	0.33	0.23	0.28	0.28
Other	0.30	0.88	0.94	0.26	0.02	0.02
Bridge/Forecast	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Segment Total	0.41	0.43	0.46	0.47	0.48	0.49
Labour/Wages	0.07	0.08	0.09	0.09	0.10	0.10
Third-Party Contractors and Consultants	0.32	0.34	0.35	0.36	0.37	0.38
Other	0.02	0.01	0.02	0.02	0.01	0.01

:

Table 3 - Underground System Reactive Repairs and Trouble Calls Segment Detailed Costs ($MM)

Actuals	2020	2021	2022	2023	2024	2025
Segment Total	17.94	19.30	23.96	21.70	23.45	28.29
Labour/Wages	9.83	8.67	10.99	10.57	9.62	12.09
Direct Material	0.98	1.48	1.25	1.13	1.53	1.74
Direct Vehicles	0.89	1.16	1.49	1.19	1.42	1.42
Third-Party Contractors and Consultants	5.53	6.58	7.52	7.95	9.89	11.11
Other	0.71	1.41	2.71	0.86	0.99	1.93
Bridge/Forecast	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Segment Total	23.31	25.18	26.48	27.64	28.48	29.29
Labour/Wages	12.52	13.83	14.88	15.80	16.40	16.96
Direct Material	1.54	1.57	1.60	1.64	1.67	1.70
Direct Vehicles	1.69	1.73	1.76	1.80	1.83	1.87
Third-Party Contractors and Consultants	6.47	6.93	7.07	7.21	7.35	7.50
Other	1.09	1.12	1.17	1.19	1.23	1.26

b) The 2026-2031 forecast for the Underground System Reactive Repairs and Trouble call segment was established based on the resourcing requirements required to respond to the Trouble call volumes as presented in IR response 4-CCC-57 (e). The 2026-2031 forecast for the other segments in this program was based on 2024 actuals, adjusted annually for inflation.

c) Table 4 and 5 below provides the historical underground asset inspections completed, along with a forecast from 2026-2031:

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Table 4 - Actual Underground Asset Inspections 2020-2025

	2020	2021	2022	2023	2024	2025
# Underground Asset Inspections Completed	16,361	14,428	48,657	25,578	34,640	32,972
Cost $	$2.28M	$2.88M	$3.66M	$2.70M	$2.47M	$2.63M

Table 5 - Forecast Underground Asset Inspections 2026-2031

	2026	2027	2028	2029	2030	2031
# Underground Asset Inspections Forecast	28,617	33,175	29,347	28,617	33,175	29,347
Cost $	$2.65M	$2.75M	$2.96M	$3.07M	$3.17M	$3.26M

d) Alectra has transitioned fully to utilizing contractors to perform its full asset inspection activities, including underground inspection services, beginning in 2022. Prior to 2022, underground asset inspection services were completed by both internal staff and contractors in each region, however the transition to contractors occurred gradually leading up to the fully contracted model that began in 2022. Previous to 2022, Alectra completed lower inspection volumes (see IR response 4-AMPCO-68, table 1). The transition to fully utilizing contractors for Asset Inspections corresponded with higher achievements in the program and contracting out Asset Inspections avoided a need to increase FTE's to achieve full program completion. Since the transition away from internally completed asset inspections was completed gradually leading up to 2022 and this work only accounted for a small portion of the overall duties taken on by Alectra Powerline Technician staff, the transition to utilizing contractors did not result in any reduction of internal FTE requirements and internal staff were engaged on other work in this program, the Overhead Inspections and Maintenance program and in capital work.

e) Table 6 below provides the number of trouble calls from 2020-2025 with a forecast range provided for the 2026–2031 period. Trouble calls in this table include both overhead and underground related trouble calls as Alectra Utilities does not separately track overhead and underground trouble calls.

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1 **Table 6 - Trouble Call Volumes and Segment Costs 2020-2031**

Year	Trouble Calls	Schedule 16 Segment Cost ($MM)	Schedule 17 Segment Cost ($MM)
2020	6,941	$16.53M	$17.94M
2021	6,646	$13.18M	$19.30M
2022	6,648	$17.20M	$23.96M
2023	6,267	$13.70M	$21.70M
2024	6,354	$14.33M	$23.45M
2025	6,529	$14.26M	$28.29M
2026	6,267 to 6,941	$15.50M	$23.30M
2027	6,267 to 6,941	$16.53M	$25.18M
2028	6,267 to 6,941	$17.40M	$26.48M
2029	6,267 to 6,941	$18.20M	$27.64M
2030	6,267 to 6,941	$18.80M	$28.48M
2031	6,267 to 6,941	$19.38M	$29.29M

:

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-59

Ref: Exhibit 4, Tab 2, Schedule 18, p. 6

Question(s):

a) Please provide a more detailed version of Table 4-2-125 that first breaks out the facilities management program between facilities management services and utilities & communications. Please also show the various cost components for each of these segments of the facilities program. For example, to the extent that these cost components are relevant to the program, please show line items for labour / wages, third-party contractors, licensing fees, rent, etc. Please add to the list any other cost components that are relevant to the program.

b) Please further explain the methodology applied to forecast costs for the facilities program in the test period (including a discussion of the test year forecasting methodology and the 2028-2031 forecasting methodology if those methodologies are different).

RESPONSE:

a) See below

Table 1 - Detailed Facilities Management Program Expenditures ($MM)

Cost Driver	Historical							
	2017	2018	2019	2020	2021	2022	2023	2024
Total	**12.52**	**15.58**	**14.68**	**17.00**	**17.01**	**16.72**	**18.53**	**15.39**
Direct Labour Costs	2.23	2.45	2.42	2.75	2.12	2.33	2.63	2.70

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Utilities	2.97	3.21	3.59	3.56	3.27	3.10	3.51	2.59
Repairs and Maintenance	5.01	6.25	5.57	6.08	6.56	7.22	7.46	6.96
Rent Expense	1.63	1.82	1.32	1.40	1.72	1.55	1.33	1.33
Outside Service Provider (Contract Labour)	0.12	0.24	0.23	0.89	0.32	0.19	1.77	0.26
Postage, Printing and Communications	0.13	0.62	0.79	1.56	2.47	1.57	0.93	0.84
Other	0.41	0.95	0.73	0.73	0.51	0.73	0.88	1.07
Cost Driver		**Bridge**		**Test**	**Forecast**			
		2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Total		**16.07**	**13.35**	**13.58**	**13.87**	**14.23**	**14.45**	**14.75**
Direct Labour Costs		2.82	2.73	2.84	2.93	3.02	3.11	3.21
Utilities		2.96	2.79	2.84	2.90	2.96	3.02	3.08
Repairs and Maintenance		7.12	5.35	5.45	5.56	5.67	5.79	5.90
Rent Expense		0.94	0.94	0.94	0.94	0.94	0.94	0.94
Outside Service Provider (Contract Labour)		0.57	0.00	0.00	0.00	0.00	0.00	0.00
Postage, Printing and Communications		0.84	0.52	0.46	0.47	0.48	0.49	0.50
Other		0.79	1.00	1.03	1.05	1.14	1.08	1.10

b) The methodology of the forecast for the 2028 – 2031 period is based on inflationary increase provided by finance.

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RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-60

Ref: Exhibit 4, Tab 2, Schedule 19, p. 4

Question(s):

a) Please provide a more detailed version of Table 4-2-129 that shows the various cost components of the fleet asset management program. For example, to the extent that these cost components are relevant to the program, please show line items for labour / wages, third-party contractors, licensing fees, rent, etc. Please add to the list any other cost components that are relevant to the program.

b) Please further explain the methodology applied to forecast costs for the fleet asset management program in the test period (including a discussion of the test year forecasting methodology and the 2028-2031 forecasting methodology if those methodologies are different).

RESPONSE:

a) Please see the Table 1 below.

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Table 1 - Fleet Asset Management Program Budget by Cost Drivers

	Historical							
Cost Driver	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Total	**9.38**	**10.14**	**10.28**	**11.63**	**13.09**	**12.68**	**12.04**	**12.92**
Repairs & Maintenance	3.56	4.20	3.73	6.17	6.57	5.35	5.08	5.89
Fuel & Transportation	2.52	2.95	2.65	2.22	2.67	3.44	3.42	2.47
Direct Labour Costs	2.47	2.52	2.66	2.80	2.86	2.85	2.80	2.79
Other	0.83	0.47	1.24	0.44	0.99	1.04	0.74	0.83
			Bridge		**Test**		**Forecast**	
Cost Driver		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Total		**13.31**	**12.18**	**12.48**	**12.75**	**13.05**	**13.23**	**13.46**
Repairs & Maintenance		5.86	4.91	5.00	5.09	5.11	5.09	5.22
Fuel & Transportation		3.47	3.38	3.43	3.51	3.57	3.64	2.96
Direct Labour Costs		3.09	3.04	3.15	3.25	3.35	3.45	3.56
Other		0.89	0.85	0.90	0.90	1.02	0.95	0.96

b) The methodology of the forecast for the 2027 – 2031 period is based primarily on annual inflationary adjustments. Repairs and Maintenance costs increase at a rate lower than inflation, as a result of decreased maintenance due to the capital replacement plan.

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RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-61

Ref: Exhibit 4, Tab 2, Schedule 20, pp. 1-2

Question(s):

a) Please confirm that the entirety of the property tax program cost is comprised of municipal property taxes. If not, please advise what other cost categories are reflected in the property tax budget.

b) Please advise whether there has been any update to the expected timing of the next MPAC reassessment of Alectra's facilities.

c) Please provide the basis for the forecast that there "will be a 50% increase in the 2026 CVA in comparison to the 2016 CVA." As part of the response, please provide any internal analysis / reports that were generated in support of this forecast.

d) Please explain why MPAC provided a "2016 CVA" for the Kennedy Road Operations Centre in the context that the building was not completed until 2023.

RESPONSE:

a) Approximately 99% of the property tax program relates to municipal property taxes. The remaining 1% relates to Payments-in-Lieu of Property Taxes, which is paid to the Ontario Electricity Financial Corporation.

b) Alectra has not received an update to the expected timing of the next MPAC reassessment of Alectra's facilities.

c) The 2026 CVA is forecast to increase by approximately 50% relative to the 2016 CVA, based on historical assessment trends for Alectra's higher-value properties. As shown in Table 1 below, assessed values increased by 18% in the most recent assessment cycle. Assuming the next CVA occurs in 2026, approximately 2.5 assessment cycles will have been missed since that last assessment. Applying the historical cycle increase and accounting for compounding effects results in an estimated 50% increase in the 2026 CVA.

Table 1 - Derivation of Estimated 2026 CVA Increase

	2012 CVA	2016 CVA	
395 Southgate Dr	9.4	11.9	
80 Addiscott Crt	19.3	23.3	
161 Cityview Blvd	18.8	19.9	
2185 Derry Rd W	12.0	15.1	
450 Nebo Rd	6.3	6.8	
55 John St N	4.6	6.5	
55 Patterson Rd	6.0	7.4	
340 Vansickle Rd	5.3	5.8	
	81.7	96.5	[A]
Change from 2012 to 2016 Assessment Cycle $		14.84	
Change from 2012 to 2016 Assessment Cycle %		18.18%	
Actual 2016 CVA		96.5	
Estimated % increase		18.18%	
Estimated 2020 CVA of above properties assuming 18.18% increase $		114.03	
Estimated % increase		18.18%	
Estimated 2024 CVA of above properties assuming 18.18% increase $		134.75	
Estimated % increase (reduced by half for short cycle)		9.09%	
Estimated 2026 CVA of above properties assuming 9.09% increase $		147.00	[B]
Estimated % increase from 2016 CVA to 2026 CVA		52.34%	([B] - [A]) / [A]
Estimated % increase from 2016 CVA to 2026 CVA - rounded		50%	

d) MPAC retroactively assigned a "2016 CVA" for the Kennedy Road Operations Centre. MPAC must assess and classify all properties in Ontario in compliance with the Assessment Act and regulations set by the Government of Ontario, which currently states that all property assessments in Ontario are based on the fully phased-in January 1, 2016 assessed values.

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RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-62

Ref: Exhibit 4, Tab 2, Schedule 21, pp. 2-5
Appendix 2-K
Appendix 2-JC

a) Please advise whether the "other recoveries" shown in Table 4-2-134 is entirely comprised of a vacancy provision over the 2017-2031 period. If not, please provide a breakout of the other recoveries line.

b) For the test period, please provide the other recoveries amount associated with the vacancy provision of 4%. Please also show the derivation of other recoveries amount associated with the vacancy provision.

c) Please confirm that Appendix 2-K does not reflect the application of the vacancy provision and that the impact of the vacancy provision is captured in corporate allocations in Appendix 2-JC.

RESPONSE:

a) The Other Recoveries presented over the 2027-2031 period are almost entirely made up of the vacancy provision. The exception is pool balancing adjustments that average $7k per year over the 2027-2031 period. The Other Recoveries balances presented over the historical period reflect the total (over)/under recoveries of burden pool costs to OM&A and Capital programs at the end of each year. While Alectra does perform a true-up for the burden pools at year end, there will always be an immaterial balance remaining - which is assigned to Other Recoveries.

b) The other recoveries amount associated with the OM&A vacancy provision is provided in the table below. The other recoveries amount associated with the vacancy provision is calculated at the position level and applied to the Salary and Benefit cost of staff. The calculation is made up of (Total OM&A Salaries * Provision Rate) + (Total OM&A Benefits * Provision Rate). Alectra has identified that the derivation of the other recoveries amount associated with the vacancy provision included the calculation of a provision on non-productive time (vacation, sick, stat holiday) as benefits, which double counted amounts that were already included in total salaries. As a result, the effective vacancy provision embedded in this application is 4.7% on-average over the 2027-2031 period. Below is a calculation of the provision and effective rate in this application. There is no impact to the figures or analysis presented in this application aside from clarifying the effective rate.

"Table 1" – Vacancy Provision Calculation

Vacancy Provision Calculation (OM&A)	2027	2028	2029	2030	2031
Total Compensation - per Schedule 2-K (OM&A)	183,402,837	196,158,291	210,752,435	220,553,095	229,751,047
Add Back: Vacancy Provision - Other Recoveries	8,504,522	9,205,696	9,877,743	10,338,768	10,769,100
Less: Adjust for Overtime/Premiums	(9,005,797)	(9,005,797)	(9,005,797)	(9,005,797)	(9,005,797)
Compensation applicable for Provision (OM&A)	182,901,562	196,358,190	211,624,381	221,886,066	231,514,350
Vacancy Rate	**4.0%**	**4.0%**	**4.0%**	**4.0%**	**4.0%**
Vacancy Provision @ 4%	7,316,062	7,854,328	8,464,975	8,875,443	9,260,574
Vacancy Provision included in Other Recoveries	8,504,522	9,205,696	9,877,743	10,338,768	10,769,100
Difference	**1,188,459**	**1,351,369**	**1,412,767**	**1,463,326**	**1,508,526**
Effective Provision Rate embedded in Application	**4.6%**	**4.7%**	**4.7%**	**4.7%**	**4.7%**

c) Confirming that the vacancy provision is not reflected in the number of FTEs reported in Appendix 2-K and the impact of the vacancy provision is captured in corporate allocations in Appendix 2-JC.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-63

Ref: Exhibit 4, Tab 3, Schedule 2, p. 1

Question(s):

Please provide a revised version of Table 4-3-1 that includes 2025-2030.

RESPONSE:

The following tables have been updated to include 2024-2031.

Table 1 – Workforce Skills by Segment

Segment	2024		2025		2026		2027	
	FTE	%	FTE	%	FTE	%	FTE	%
Certified and Skilled Trade	453.9	31.0%	477.8	31.8%	542.6	33.4%	575.1	34.3%
Corporate and Shared Services	377.6	25.8%	374.1	24.9%	407.3	25.1%	399.3	23.8%
Front Line Leadership	250.5	17.1%	265.5	17.7%	267.2	16.5%	273.0	16.3%
Designated and Technical Professionals	321.1	21.9%	321.4	21.4%	341.8	21.1%	363.7	21.7%
Senior Management	59.9	4.1%	65.1	4.3%	64.0	3.9%	68.0	4.0%

Segment	2028		2029		2030		2031	
	FTE	%	FTE	%	FTE	%	FTE	%
Certified and Skilled Trade	593.6	33.9%	602.6	33.2%	602.6	32.8%	603.6	32.5%
Corporate and Shared Services	416.0	23.8%	449.0	24.7%	461.0	25.1%	469.0	25.3%
Front Line Leadership	285.5	16.3%	295.0	16.2%	297.0	16.2%	299.0	16.1%
Designated and Technical Professionals	385.3	22.0%	400.3	22.0%	409.3	22.3%	414.3	22.3%
Senior Management	69.0	3.9%	69.0	3.8%	69.0	3.8%	69.0	3.7%

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RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-64

Ref:

Exhibit 4, Tab 3, Schedule 3, p. 2

Question(s):

a) Please provide a revised version of Table 4-3-2 that provides the FTEs at the program level allocated to each of capital and OM&A.

b) Please provide a revised version of Table 4-3-2 that shows the FTEs at the program segment level. Using the customer service program as an example, please include a breakout of the FTEs between the specific segments of that program (i.e., billing, collections & payments, customer care - call centre, etc.).

c) Please provide an alternative version of Table 4-3-2 that shows all the actual/forecast FTEs by positions/job titles in each program.

RESPONSE:

a) The table provides a revised version of Table 4-3-2 for 2026-2031 at the program level allocated to each of capital and OM&A. Alectra is unable to provide the breakdown of FTE by OM&A and Capital for historical years.

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	2026			2027			2028		
OM&A and Capital FTE by Program	**OM&A**	**Capital**	**Total**	**OM&A**	**Capital**	**Total**	**OM&A**	**Capital**	**Total**
Asset Management	46	20	66	39	35	74	43	38	81
Cable Locates	7	12	19	8	14	21	8	14	21
Corporate Services	51	-	51	53	-	53	55	-	55
Customer Service	214	8	222	197	8	204	203	8	210
Digital and Innovation	103	21	124	105	22	127	109	23	132
Distribution Design	39	119	159	43	135	178	46	150	196
Facilities	19	-	19	19	-	19	19	-	19
Finance	79	1	79	81	1	82	85	1	86
Fleet	19	-	19	19	-	19	19	-	19
Human Resources	79	0	79	80	0	80	83	0	83
Network Metering	40	67	107	40	66	106	40	67	107
Overhead Inspections and Maintenance	171	221	392	181	234	415	188	242	430
Program Delivery	9	7	16	9	7	16	9	7	16
Records and Mapping Services	28	14	42	29	15	44	30	15	45
Stations	51	34	85	52	35	87	53	35	88
Supply Chain Services	52	-	52	53	-	53	56	-	56
System Control	62	30	92	68	34	102	71	36	106
1 Total	1,068	555	1,623	1,074	605	1,679	1,114	636	1,749

	2029			2030			2031		
OM&A and Capital FTE by Program	**OM&A**	**Capital**	**Total**	**OM&A**	**Capital**	**Total**	**OM&A**	**Capital**	**Total**
Asset Management	43	38	81	43	38	81	43	38	81
Cable Locates	8	14	21	8	14	21	8	14	21
Corporate Services	56	-	56	56	-	56	56	-	56
Customer Service	223	8	231	231	9	240	240	10	249
Digital and Innovation	116	24	140	119	26	145	124	26	150
Distribution Design	49	157	206	50	161	211	50	162	212
Facilities	19	-	19	19	-	19	19	-	19
Finance	92	1	92	94	1	94	94	1	94
Fleet	19	-	19	19	-	19	19	-	19
Human Resources	87	0	88	87	0	88	87	0	88
Network Metering	40	67	106	40	67	106	40	67	106
Overhead Inspections and Maintenance	193	249	442	195	249	444	195	250	445
Program Delivery	9	7	16	9	7	16	9	7	16
Records and Mapping Services	30	15	45	30	15	45	30	15	45
Stations	53	36	89	53	36	89	53	36	89
Supply Chain Services	58	-	58	58	-	58	58	-	58
System Control	71	36	106	71	36	106	71	36	106
2 Total	1,164	652	1,816	1,180	659	1,839	1,194	661	1,855

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b)

The tables below provide a revised version of Table 4-3-2 provides a further breakdown of the FTE by program from 2020 to 2025. This table has been updated with 2025 actuals.

	2020	2021	2022	2023	2024	2025
Overhead Inspections and Maintenance	**220.6**	**380.4**	**371.1**	**355.7**	**348.7**	**352.2**
Customer Service	**189.0**	**202.2**	**201.8**	**213.2**	**210.9**	**210.0**
Billing	55.9	65.2	62.0	66.1	61.5	67.0
Collections & Payments	40.1	34.7	34.1	39.0	39.6	36.2
Customer Care	64.1	66.7	67.1	71.7	65.6	62.3
Customer Connections and Key Accounts	17.2	23.4	25.0	22.8	20.8	19.1
Customer Excellence	11.8	12.2	13.6	13.6	23.4	25.4
Distribution Design	**114.8**	**122.1**	**124.7**	**129.9**	**133.5**	**136.3**
Digital and Innovation	**108.2**	**111.6**	**112.3**	**113.5**	**120.7**	**124.5**
Cyber	4.0	4.0	4.6	4.9	5.9	5.9
D&I Business	16.0	16.8	15.5	17.6	11.9	12.1
GRE&T Centre	16.8	19.6	18.4	20.5	21.1	23.0
IT Operations	23.8	24.0	26.4	27.5	38.0	37.8
Product Management	47.7	47.2	47.4	43.0	43.8	45.9
Network Metering	**85.3**	**89.5**	**93.1**	**87.7**	**96.7**	**102.5**
System Control	**65.5**	**63.3**	**69.2**	**74.2**	**74.8**	**80.3**
Finance and Treasury	**85.6**	**83.3**	**78.9**	**76.0**	**76.1**	**81.6**
Finance	77.6	76.3	72.6	68.7	68.5	72.9
Treasury	7.9	7.0	6.3	7.3	7.6	8.6
Stations	**64.5**	**68.3**	**64.3**	**65.9**	**64.7**	**69.4**
Human Resources	**70.7**	**75.5**	**80.8**	**77.3**	**80.3**	**81.9**
Business Transformation	12.3	15.5	14.2	15.1	18.4	20.4
Health Safety Wellness & Environmental	12.8	13.6	15.3	11.3	12.2	12.0
People Services, L&OD, Employee Communications, Payroll	45.7	46.4	51.4	50.9	49.7	49.5
Asset Management	**38.8**	**44.2**	**41.2**	**40.9**	**53.2**	**60.0**
Asset Management	38.8	44.2	41.2	40.9	53.2	55.6
Grid Modernization						4.3
Supply Chain Services	**51.1**	**55.5**	**50.2**	**52.0**	**52.0**	**52.4**
Corporate Services	**48.4**	**48.3**	**45.9**	**42.5**	**45.1**	**45.6**
Government and Corporate Relations	11.8	11.4	12.0	12.0	11.1	12.0

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Internal Audit	3.9	2.8	2.0	2.0	2.8	2.6
Legal	8.0	8.0	8.0	6.0	6.0	6.2
Regulatory	21.0	21.0	21.1	19.6	22.1	21.8
Strategy & Special Projects	3.7	5.1	2.9	3.0	3.0	3.0
Records and Mapping Services	**41.1**	**45.2**	**40.8**	**44.1**	**43.0**	**41.9**
Cable Locates	**27.0**	**19.6**	**19.1**	**18.2**	**16.7**	**18.3**
Fleet	**22.0**	**23.9**	**20.7**	**18.9**	**17.2**	**17.8**
Facilities	**19.1**	**17.4**	**20.0**	**18.8**	**19.0**	**18.6**
Program Delivery	**9.7**	**9.9**	**9.7**	**9.7**	**10.1**	**10.5**
Vegetation Management	**1.0**	**0.8**				
Underground Inspections and Maintenance	**159.6**	**3.8**	**2.0**	**0.3**	**0.3**	
Total	**1422.0**	**1464.7**	**1445.7**	**1438.7**	**1462.9**	**1503.9**

The tables below provide a revised version of Table 4-3-2 provides a further breakdown of the FTE by program from 2026 to 2031.

	2026	2027	2028	2029	2030	2031
Overhead Inspections and Maintenance	**392.0**	**415.0**	**430.0**	**442.0**	**444.0**	**445.0**
Customer Service	**222.1**	**204.3**	**210.3**	**231.3**	**240.3**	**249.3**
Billing	67.8	56.7	56.7	57.7	58.7	59.7
Collections & Payments	36.4	32.0	33.0	37.0	37.0	38.0
Customer Care	69.5	68.0	69.5	81.0	86.0	92.0
Customer Connections and Key Accounts	22.7	22.0	22.5	24.0	26.0	27.0
Customer Excellence	25.7	25.7	28.7	31.7	32.7	32.7
Distribution Design	**158.5**	**178.0**	**196.0**	**206.0**	**211.0**	**212.0**
Digital and Innovation	**124.0**	**127.0**	**131.5**	**140.0**	**145.0**	**150.0**
Cyber	6.0	6.5	8.0	9.0	9.0	9.0
D&I Business	12.0	13.0	13.0	16.0	16.0	16.0
GRE&T Centre	22.0	22.0	22.5	23.0	23.0	23.0
IT Operations	37.0	38.5	40.5	41.0	41.0	41.0
Product Management	47.0	47.0	47.5	51.0	56.0	61.0
Network Metering	**106.8**	**106.1**	**107.3**	**106.3**	**106.3**	**106.3**
System Control	**92.3**	**102.3**	**106.3**	**106.3**	**106.3**	**106.3**
Finance and Treasury	**79.5**	**81.5**	**85.5**	**92.0**	**94.0**	**94.0**
Finance	71.5	73.0	76.5	83.0	85.0	85.0
Treasury	8.0	8.5	9.0	9.0	9.0	9.0

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Stations	**85.0**	**87.0**	**88.0**	**89.0**	**89.0**	**89.0**
Human Resources	**79.0**	**80.2**	**83.2**	**87.7**	**87.7**	**87.7**
Business Transformation	19.3	19.5	20.5	22.0	22.0	22.0
Health Safety Wellness & Environmental	11.3	11.8	12.8	14.3	14.3	14.3
People Services, L&OD, Employee Communications, Payroll	48.3	48.8	49.8	51.3	51.3	51.3
Asset Management	**65.8**	**73.7**	**81.3**	**81.3**	**81.3**	**81.3**
Asset Management	61.5	64.0	67.0	66.0	66.0	66.0
Grid Modernization	4.3	9.7	14.3	15.3	15.3	15.3
Supply Chain Services	**52.0**	**52.5**	**55.5**	**58.0**	**58.0**	**58.0**
Corporate Services	**51.0**	**52.5**	**54.5**	**56.0**	**56.0**	**56.0**
Government and Corporate Relations	14.0	14.0	14.0	14.0	14.0	14.0
Internal Audit	3.0	3.5	4.5	6.0	6.0	6.0
Legal	8.0	8.0	8.0	8.0	8.0	8.0
Regulatory	23.0	24.0	25.0	25.0	25.0	25.0
Strategy & Special Projects	3.0	3.0	3.0	3.0	3.0	3.0
Records and Mapping Services	**42.0**	**44.0**	**45.0**	**45.0**	**45.0**	**45.0**
Cable Locates	**19.0**	**21.0**	**21.0**	**21.0**	**21.0**	**21.0**
Fleet	**19.0**	**19.0**	**19.0**	**19.0**	**19.0**	**19.0**
Facilities	**19.0**	**19.0**	**19.0**	**19.0**	**19.0**	**19.0**
Program Delivery	**16.0**	**16.0**	**16.0**	**16.0**	**16.0**	**16.0**
Vegetation Management						
Underground Inspections and Maintenance						
Total	**1623.0**	**1679.2**	**1749.5**	**1816.0**	**1839.0**	**1855.0**

c) Alectra Utilities has provided a detailed discussion of its workforce plan, including an explanation of all the labour resources it intends to add in the bridge and forecast years (see Exhibit 4, Tab 3, Schedule 3).In addition to this pre-filed evidence, Alectra Utilities has provided the following detailed breakdown of Alectra Utilities' actual/forecast FTEs in its interrogatory responses and submissions:

- In 4-Staff-171, part a) ii), please find a table containing the job titles and the number of new positions associated with each title for OM&A program between 2025-2031

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- In 4-CCC-63, please find a table containing workforce skill by workforce segment (i.e., skilled trades, designated and technical professionals, corporate and shared services, front line leadership, and management) from 2024-2031
- In 4-AMPCO-73, please find a table showing the number of temporary, student, and apprentice FTEs from 2017-2031
- In 4-AMPCO-58, please find tables providing the breakdown of internal/external labour in each program segment from 2017-2031.
- In part b) of this interrogatory, please find the breakdown of actual/forecast FTEs in each of Alectra's 35 program segments
- In part a) of this interrogatory, please find the allocation of actual/forecast FTEs in each program to capital/OM&A
- In Appendix 2-K, Alectra Utilities provides the breakdown of unionized and non-unionized FTEs, as well as the expenditures on compensation for each workforce category.

In light of the extensive information already provided by Alectra Utilities regarding its workforce as summarized above, Alectra respectfully notes the requested information is overly broad, cumbersome to produce and not necessary to evaluate Alectra's workforce needs.

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RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-65

Ref: Exhibit 4, Tab 3, Schedule 4, p. 3

Question(s):

Please provide the total utility-wide historical and forecast training and development budgets for the 2017-2031 period. Please breakout the total training budget into categories of training if that information is available. Please also advise which operational programs include the training budget(s).

RESPONSE:

The historical and forecast training expenditures for all operational programs is provided below. A further category breakdown is not available. The 2025 figures have been updated to reflect actual results for the period.

Table 1 – Training Expenditures by Program (2017-2024)

JC Program	2017	2018	2019	2020	2021	2022	2023	2024
Asset Management	45,982	62,165	52,029	13,040	36,613	171,742	145,693	135,928
Cable Locates	767	4,985	4,245	12	1	1,125	1,320	0
Corporate Allocations	25,792	6,963	269	0	0	0	0	0
Corporate Services	48,512	73,525	75,389	37,885	27,878	90,064	82,661	110,911
Customer Service	28,254	22,184	20,187	2,734	20,712	43,170	366,677	34,475
Digital and Innovation	94,605	105,405	162,795	130,904	149,743	222,744	159,625	247,982
Distribution Design	14,925	67,778	80,027	18,119	76,828	52,167	115,623	126,187
Facilities	4,884	4,724	(10,208)	0	0	0	0	10,245
Finance and Treasury	25,973	41,250	166,659	51,889	41,436	30,229	44,455	54,369
Fleet	1,477	4,592	1,964	2,237	0	100	0	2,750
Human Resources	849,321	581,647	613,552	278,142	185,292	583,099	786,518	563,709
Network Metering	53,828	27,457	53,684	31,988	10,672	29,341	36,441	59,913
Overhead Inspections and Maintenance	86,564	109,387	288,660	93,544	149,718	187,092	265,009	175,781
Program Delivery	13,751	5,126	10,044	1,024	102	0	14,707	10,924
Records and Mapping Services	5,040	1,802	1,750	1,470	23,924	13,938	17,449	28,402
Stations	46,066	39,216	79,103	57,902	56,546	99,314	232,193	95,308
Supply Chain Services	19,107	84,208	84,856	18,376	11,253	8,896	9,628	30,736
System Control	40,003	74,313	45,568	41,192	18,459	48,370	64,417	49,459
Underground Inspections and Maintenance	64,161	95,152	139,802	52,372	106,965	127,380	185,330	116,314
Vegetation Management	0	366	0	1,225	1,879	1,620	3,100	2,460
	1,469,011	**1,412,244**	**1,870,373**	**834,056**	**918,020**	**1,710,392**	**2,530,846**	**1,855,851**

Table 2 – Training Expenditures by Program (2025-2031)

JC Program	2025	2026	2027	2028	2029	2030	2031
Asset Management	101,472	163,922	188,028	209,316	214,586	218,878	223,255
Cable Locates	0	0	0	0	0	0	0
Corporate Allocations	0	0	0	0	0	0	0
Corporate Services	85,841	162,648	158,307	165,722	171,745	175,180	178,684
Customer Service	53,689	79,742	79,514	81,410	83,349	85,143	86,846
Digital and Innovation	290,209	313,162	331,002	360,332	390,444	405,882	421,794
Distribution Design	172,946	171,764	190,151	205,012	215,456	222,862	318,383
Facilities	2,274	25,722	26,236	26,761	27,296	27,842	28,399
Finance and Treasury	45,588	102,866	106,095	110,009	114,579	119,081	121,463
Fleet	3,233	15,826	16,142	16,465	16,794	17,130	17,473
Human Resources	874,625	871,384	890,714	917,657	947,225	964,167	981,446
Network Metering	33,667	69,986	71,386	72,813	74,270	75,755	77,270
Overhead Inspections and Maintenance	163,400	220,213	232,003	244,424	257,511	271,299	285,825
Program Delivery	106	23,918	25,199	26,548	27,970	29,468	31,045
Records and Mapping Services	7,278	33,080	34,992	36,329	37,055	37,797	38,553
Stations	129,269	138,907	143,039	145,900	148,818	151,794	154,830
Supply Chain Services	28,177	84,743	87,219	94,407	98,056	100,017	102,018
System Control	73,868	86,188	87,671	89,185	90,729	92,291	93,885
Underground Inspections and Maintenance	146,496	197,459	208,030	219,168	230,903	243,266	256,291
Vegetation Management	1,996	0	0	0	0	0	0
	2,214,134	**2,761,529**	**2,875,729**	**3,021,458**	**3,146,787**	**3,237,852**	**3,417,460**

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-66

Ref: Exhibit 4, Tab 3, Schedule 5, pp. 2-3, 6-7
Exhibit 4, Tab 2, Schedule 21, p. 5

Question(s):

a) Please explain the methodology applied with respect to forecasting merit increases for the test period. Please also provide the average merit increase (as a percentage of salary) provided in the historical period and the average merit increase assumed for the test period.

b) Please explain the basis of the allocation of pension costs between capital and expenses (Table 4-3-13). Is it simply the same allocation as all compensation costs (as shown in Appendix 2-K)?

c) Please advise whether employee benefit costs (Table 4-3-12) are also allocated to capital. If so, please confirm that it is the same allocation as is applied across all compensation costs (as shown in Appendix 2-K).

d) Please explain how the employer pension contribution amount (Table 4-3-13) is forecast for the test period. As part of the response, please discuss whether Alectra applies an average contribution rate to the total base salary amount. If so, please provide the average contribution rate applied.

RESPONSE:

a) See response to interrogatory 4-Staff-195.

b) The basis of the allocation of pension costs between capital and operating expenses follows the same basis of allocation of all compensation costs. Pension costs are allocated to capital as part of Alectra's Benefit Burden, further described in Exhibit 2B, Tab 6, Schedule 2, Ref 1.1.3 (page 2).

c) The basis of the allocation of benefit costs between capital and operating expenses follows the same basis of allocation of all compensation costs. Benefit costs are allocated to capital as part of Alectra's Benefit Burden, further described in Exhibit 2B, Tab 6, Schedule 2, Ref 1.1.3 (page 2).

d) Please See Alectra's response to IR 4-Staff-196 for the assumptions used to forecast employer pension contributions. OMERS is a jointly sponsored pension plan, and as such Alectra matches employee plan contributions 1:1. Alectra calculates the employer portion at the position level based on the contribution rates set by OMERS - 9% on contributory earnings up to the YMPE and 14.6% on contributory earnings over the YMPE.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-67

Ref: Exhibit 4, Tab 3, Schedule 5, Attachment 4-7, pp. 2, 5

Preamble:

Mercer states that it used two separate peer groups (i.e., energy and general industry) in its benchmarking analysis. In the detailed findings, there appears to be only one comparator used in the analysis.

Question(s):

Please advise how the market median was determined for each position. As part of the response, please discuss whether the market median reflects an average of the two peer groups or, alternatively, specific peer groups were used for different positions. If specific peer groups were used, please provide a table showing which peer group was used for each position.

RESPONSE:

Response provided by Mercer:

The market median for each benchmark job was based on the industry within which required skillsets exist for Alectra. As noted in the Mercer report, the Energy Peer Group was primarily used for sector specific jobs that require skillsets predominately seen within the utilities/energy industry. In contrast, the General Industry Peer Group was primarily used for non-sector specific jobs that require skillsets that are seen across different industries in Canada.

As such, in consultation with Alectra, each benchmark job was compared to market data from one of the defined peer groups based on data availability, as set out in the table below.

Table 1 - Benchmark Non-Union Jobs with Peer Group

Non-Union Jobs	Peer Group	Non-Union Jobs	Peer Group
Coordinator, Human Resources	General	Supervisor, Warehouse	General
Executive Assistant	General	Architect	General
Specialist, Programmer	General	BI Solutions Developer	General
Advisor, Audit	General	Engineer	Energy
Specialist, Communications	General	Supervisor, Design	Energy
Analyst, Payroll	General	Supervisor, Lines	Energy
Coordinator, Program Planning & Analysis	General	Supervisor, Records	Energy
Engineering Associate	Energy	Supervisor, Station Sustainment	Energy
Specialist, Applications	General	Supervisor, System Control	Energy
Specialist, CC&B and Emerging Technologies	General	Manager, Accounting	General
Specialist, Commodity Management	General	Manager, Customer Experience	Energy
Specialist, Customer Technology	General	Project Manager	General
Specialist, Financial	General	Manager, Distribution Design	Energy
Specialist, Meter Data Management	Energy	Manager, Grid	Energy
Specialist, Regulatory	Energy	Manager, Health and Safety	Energy
Administrator, Network/Infrastructure	General	Manager, HR	General
HR Business Partner	General	Manager, Lines	Energy
Specialist, Government & Stakeholder Relations	Energy	Manager, System Control	Energy
Specialist, Health & Safety	Energy	Director, Supply Chain	General
Supervisor, Accounting	General	Director, Regulatory	Energy
Supervisor, Customer Service	Energy	Director, Operations	Energy

Non-Union Jobs	Peer Group	Non-Union Jobs	Peer Group
Supervisor, Facilities	General	VP, Network Metering	Energy
Supervisor, Financial	General	VP, Finance	General
Supervisor, Fleet	General	VP, Asset Management	Energy
Supervisor, IT Support Services	General	VP, People & Safety	General
Specialist, Learning & Org. Development	General	VP, Distribution Design	Energy

Table 2 - Benchmark Union Jobs with Peer Group

Union Jobs	Peer Group	Union Jobs	Peer Group
Powerline Technician	Energy	Meter Technician	Energy
Design Technologist	Energy	Storeperson	General
Lead Hand Lines	Energy	Accounting Analyst	General
CSR	Energy	Mapping Technician	Energy
Billing Clerk	Energy	Facilities Maintainer	General
Apprentice, Lines	Energy	GIS Specialist	Energy
System Controller	Energy		

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 4-CCC-68

Ref: Exhibit 4, Tab 4, Schedule 1, p. 7

Preamble:

The $4.8M increase in net services provided by Alectra Inc. between 2017 to 2027 is primarily due to executives moving from Alectra Utilities to Alectra Inc. during the 2022 corporate restructuring.

Question(s):

a) Please provide the number of executives that are employed by each of Alectra Inc. and Alectra Utilities during the 2021-2031 period.

b) For each member of the executive management team employed by Alectra Inc., please provide the percentage of their time allocated to Alectra Utilities for each year of the 2022-2031 period. Please explain why it is more cost-effective for Alectra Utilities to contract for the executive management team, rather than having them as full-time employees and contracting their services to other related/affiliated companies.

RESPONSE:

a) Table 1 provides the number of executives that are employed by Alectra Utilities during the 2021-2031 period.

Table 1 - AUC Executives 2021-2031

2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1.00	2.00	2.00	2.00	2,00	2.00	2.00	2.00	2.00	2.00	2.00

Table 2 provides the number of executives that are employed by Alectra Inc. during the 2021-2031 period.

Table 2 - Alectra Inc. Executives

2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
3.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0

b) Alectra Utilities' allocation of shared corporate services is not performed at the individual level. Instead, the allocation process is conducted at the Line of Business level, which provides shared corporate services. This approach involves identifying specific service activities delivered by each Line of Business, assessing the most appropriate allocation methodologies for each activity and developing allocation factors or time-based surveys to ensure costs are accurately and fairly distributed between Alectra Utilities and its affiliates.

Attachment 4-9 (OEB Appendix 2-N – Shared Services and Corporate Cost Allocations) sets out the percentage of corporate costs allocated from each Line of Business in Alectra Inc. to Alectra Utilities. For ease of reference, Table 3 below presents the percentages of services offered by the line of businesses that include Alectra Utilities' executives. Corporate and Financial Stewardship includes the portion of the Chief Financial Officer's time and Chief Executive Officer.

Table 3 - % of Corporate Costs Allocated from AI to AUC (Line of businesses that include executives)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Digital & Innovation	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%
Legal, Strategy & Corporate Secretary	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
People & Transformation	98%	97%	97%	97%	97%	97%	97%	97%	97%	97%
Corporate and Financial Stewardship	90%	88%	89%	78%	78%	78%	78%	78%	79%	79%

From a pricing methodology perspective, there is no cost difference between employing executives as full-time employees of Alectra Utilities or as employees of Alectra Inc.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 7-CCC-69

Ref: Exhibit 7, Tab 2, Schedule 3, pp. 2-6

Question(s):

a) Please provide revised versions of Tables 7-2-18, 7-2-19 and 7-2-21 based on setting the RCR for the GS<50 kW class at 120% (instead of 114.2%).

b) Please provide a table similar to Table 7-2-19 for the residential class showing the current proposed RCR (93.2%) and the RCR that would result from setting the RCR for the GS <50 KW at 120% (instead of 114.2%).

RESPONSE:

a) Please see Tables 1 to 3 below, which were produced using the Application version of the models (pre-filed evidence) to illustrate the impact of changing the GS<50 kW RCR to 120%.

Table 1 - Revised Table 7-2-18 – Alectra Utilities Revenue-to-Cost Ratios with GS<50 kW RCR set to 120%

Rate Class	Legacy Ratios (as Currently Approved)					Status Quo (2027)	Proposed Ratios (2027)	OEB-Approved Range
	BRZ (2015)	ERZ (2013)	GRZ (2016)	HRZ (2019)	PRZ (2017)			
Residential	95.6%	90.0%	93.3%	101.1%	98.6%	90.8%	**92.1%**	85 - 115
GS<50 kW	120.0%	109.0%	116.0%	98.7%	106.5%	124.2%	**120.0%**	80 - 120
GS>50 kW, Regular	95.7%	109.0%	108.5%	97.6%	99.1%	109.3%	**109.3%**	80 - 120
GS>50 kW, Intermediate	120.0%	108.0%	120.0%					80 - 120
Large User	95.7%	109.0%	93.3%	111.4%	85.2%	108.8%	**108.8%**	85 - 115
LUDA				96.3%		133.8%	**115.0%**	85 - 115
Street Lighting	95.7%	96.1%	99.2%	100.0%	120.0%	159.5%	**120.0%**	80 - 120
Sentinel Lighting			109.3%	91.8%	83.6%	83.1%	**71.0%**	80 - 120
USL	95.6%	109.0%	120.0%	114.6%	101.6%	110.5%	**110.5%**	80 - 120
Embedded Distributor	100.0%					147.9%	**120.0%**	80 - 120

Table 2 - Revised Table 7-2-19 – 2027 Total Bill Impact with GS<50 kW RCR set to 120%

	BRZ	ERZ	GRZ	HRZ	PRZ
2027 Cost Allocation (R/C 124%)	8.9%	-3.3%	12.5%	-2.7%	3.7%
Rebalanced Revenue (R/C 120%)	7.9%	-4.3%	11.5%	-3.7%	2.7%

Table 3 - Revised Table 7-2-21 – Calculated Class Revenue ($MM) with GS<50 kW RCR set to 120%

Rate Class	2027 Base Revenue at Existing Rates	2027 Proposed Base Revenue Allocated at Existing Rates Proportion	2027 Proposed Base Revenue	Miscellaneous Revenue
Residential	$389.2	$448.1	$454.7	$22.3
GS<50 kW	$100.1	$115.3	$111.3	$3.7
GS>50 kW	$185.7	$213.8	$213.8	$4.0
Large User	$17.0	$19.6	$19.6	$0.4
LUDA	$1.2	$1.4	$1.2	$0.0
Street Lighting	$8.1	$9.3	$6.9	$0.3
Sentinel Lighting	$0.1	$0.1	$0.1	$0.0
USL	$2.3	$2.7	$2.7	$0.1
Embedded Distributor	$0.1	$0.1	$0.1	$0.0
Total	**$703.7**	**$810.3**	**$810.3**	**$30.8**

b) Please see Table 4 below.

Table 4 - Total Bill Impact for Residential Rate Class with GS<50 kW RCR set to 120%

	BRZ	ERZ	GRZ	HRZ	PRZ
Rebalanced Revenue as Filed (R/C 93%)	9.9%	1.3%	2.5%	-2.1%	3.7%
Rebalanced Revenue with GS<50 kW RCR set to 120% (R/C 92%)	9.6%	0.9%	2.1%	-2.5%	3.3%

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 8-CCC-70

Ref: Exhibit 8, Tab 1, Schedule 1. p. 19
Attachment 8-5, Tariff and Bill Impact Schedule
OPG Payment Amounts Application, EB-2025-0297, Exhibit I1

Question(s):

a) Please confirm, or correct, the following table that shows the 5-year bill impacts (Sub-Total A and excluding rate riders) for a typical residential customer in the various rate zones and on average. The average was derived using the "notional 2026" monthly charge of $32.56/month.

Sub-Total A	BRZ	ERZ	GRZ	HRZ	PRZ	Average
Residential Total 5-Year Impact (Excl. Riders)	58.5%	58.8%	31.8%	44.2%	37.8%	45.7%

b) Please add an additional line to the above table (as corrected, if necessary) to show the total bill impacts (excluding rate riders) inclusive of Ontario Power Generation's proposed changes to payment amounts for the 2027-2031 period (EB-2025-0297, Exhibit I1).

RESPONSE:

a) Alectra Utilities confirms that the table included in the question is correct.

In response to 1-Staff-1, Alectra Utilities has updated its models to reflect its interrogatory responses. The updated 5-Year cumulative distribution bill impact is provided in Table 1, below.

Table 1: 5-Year Cumulative Distribution Bill Impact

5-Yr Dx Bill Impact	2026 Dx Chg.	2027 Impact	2028 Impact	2029 Impact	2030 Impact	2031 Impact	Total 5-Yr Increase	% Incr/ 2026 Dx Chg.
BRZ	$29.93	$8.33	$2.36	$1.82	$2.39	$2.39	$17.29	57.8%
ERZ	$29.86	$8.40	$2.36	$1.82	$2.39	$2.39	$17.36	58.1%
GRZ	$35.99	$2.27	$2.36	$1.82	$2.39	$2.39	$11.23	31.2%
HRZ	$32.90	$5.36	$2.36	$1.82	$2.39	$2.39	$14.32	43.5%
PRZ	$34.43	$3.83	$2.36	$1.82	$2.39	$2.39	$12.79	37.1%
Notional	**$32.56**	**$5.70**	**$2.36**	**$1.82**	**$2.39**	**$2.39**	**$14.66**	45.0%

b) The OEB's bill impact calculation methodology relies on the Regulated Price Plan ("RPP") Time-of-Use prices and the average IESO wholesale market price, as embedded in the OEB-provided bill impact models. These inputs are externally determined and are not developed by, nor within the control of, Alectra Utilities.

Alectra Utilities does not have visibility into how OPG's proposed payment amounts, if approved, would be reflected in future RPP prices or wholesale market price forecasts. Any impact of OPG's proposed payment amounts on customer bills would occur indirectly through province-wide price forecasting processes and would be incorporated into the OEB's standardized models once updated values are published. Alectra Utilities cannot speculate on the magnitude or timing of such impacts.

Accordingly, Alectra Utilities is unable to provide updated bill impact calculations reflecting OPG's proposed payment amounts.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 8-CCC-71

Ref: Exhibit 8, Tab 3, Schedule 2, pp. 2-3
Appendix 2-H

Question(s):

a) Please confirm that Table 8-3-2 includes all of the specific charges that were charged by the predecessor utilities in the historical period and all the specific charges that Alectra intends to charge in the forecast period.

b) For each year during the 2017-2031 period (or a shorter historical time period if the information is not available back to 2017), please provide a table showing the actual/forecast revenues for each specific service charge set out in Table 8-3-2.

c) For each specific service charge that Alectra proposes to apply during the test period, please describe the methodology applied to determine the associated forecast revenue amounts. As part of the response, please provide the detailed calculations and describe the assumptions.

RESPONSE:

a) Alectra confirms that Table 8-3-2 includes all of the specific charges that were charged by the predecessor utilities in the historical period and all of the specific charges that Alectra intends to charge in the 2027-2031 forecast period.

b) At Table 8-CCC-71-b below, Alectra provides a table showing actual and forecast revenues for each specific service charge for the 2019 to 2031 period.

c) A common methodology was used to determine forecast revenue amounts associated with the majority of the specific service charges. Five historical years of billed data (2019 to 2023) was used to establish the average annual volume of charges and revenue earned for each charge in each rate zone.

A forecast volume of charges was established for each rate zone based on historical data for rate zones where a given specific service charge is currently approved. The forecast volume of charges for rate zones without current approval was determined through extrapolation based on total customer count. The combined forecast volume of charges for Alectra as a whole was escalated by a customer count growth factor to establish a 2027 harmonized volume of charges.

Under many specific service charges, a consistent approved level of charge historically applied across all or most of Alectra's rates zones. Levels of charge that are common to all or the majority of Alectra's rate zones matched to the OEB standard rate established in the Electricity Distribution Rate Handbook Chapter 11 - Other Regulated Charges, where applicable. Alectra made a determination to propose continued use of OEB standard rates, where applicable, in the interest of harmonization and limiting the impact to the majority of customers.

Assumptions made in the process of forecasting specific service charge revenue include:

1. The volume of charges within each rate zone is proportional to customer count for forecasting purposes.

2. Forecast reconnection for non-payment of account volumes were normalized due to atypical disconnection activity through the historical period of study (2019-2023) due to measures associated with the COVID-19 pandemic.

3. Where a single rate zone has approval for customer class- or service size-specific variation of the same charge type, the volume of charges attributed to all variations has been accounted for within a generic charge.

The methodology associated with the following specific service charges deviates from the description above:

- Special Billing Service (aggregation and sub-metering charge per meter) charges are currently billed to specific customers who have requested a specific service; the forecast assumes no additional customers will access this service offering in the 2027 to 2031 period.
- Disconnect/Reconnect charges under the Other heading would, if approved, be applied to customer-driven and distributor-required disconnection and reconnections. Forecast volumes are based on historical service requests and proposed rates which were established through a cost-recovery methodology designed to reflect the current direct and allocated costs required to perform the service.
- Specific Charge for Access to the Power Poles revenues have been forecasted based on the actual 2024 rate of $39.14 inflated by 2.0% each year, and volumes were estimated based on historical activity.

At Table 8-CCC-71-c, Alectra Utilities provides the detailed calculations associated with each specific service charge proposed to apply to the 2027 to 2031 test period.

Table 8-CCC-71-b: Historical and Forecast Specific Service Charge revenues for 2019 to 2031

	Actual	
Specific Service Charges	**2019**	**2020**
Customer Administration		
Arrears certificate	$ 27,586	$ 22,427
Statement of account	$ 570	$ 15
Pulling of post-dated cheques	$ -	$ -
Duplicate invoices for previous billing	$ 735	$ 390
Request for other billing information	$ 210	$ 90
Easement letter	$ 360	$ 2,668
Income tax letter	$ 60	$ 75
Notification Charge	$ -	$ -
Account history	$ 15	$ 45
Credit Check (plus credit agency costs)	$ 705	$ 1,575
Credit Check (plus credit agency costs) - General Service	$ 75	$ 150
Returned cheque (plus bank charges)	$ 42,273	$ 50,733
Charge to certify cheque	$ -	$ -
Legal letter charge	$ -	$ -
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$ 1,477,496	$ 2,641,548
Account set up charge/change of occupancy charge (plus credit agency costs if applicable) -	$ 202,140	$ 309,020
Special meter reads	$ -	$ 30
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$ -	$ 30
Credit Card Convenience Charge	$ -	$ -
Interval Meter request change	$ -	$ -
Special billing service (aggregation)	$ 750	$ 1,500
Special billing service (sub-metering charge per meter)	$ 600	$ 1,225
Credit service charge for paperless bill	-$ 39,120	-$ 40,050
Non-Payment of Account		
Reconnection at meter - during regular hours	$ 249,913	$ 41,179
Reconnection at meter - after regular hours	$ 7,215	$ 2,775
Reconnection at pole - during regular hours	$ 3,885	$ 185
Reconnection at pole - after regular hours	$ 415	$ -
Reconnection for >300 volts - during regular hours	$ 7,500	$ 4,560
Reconnection for >300 volts - after regular hours	$ 310	$ -
Other		
Disconnect/reconnect at meter - during regular hours	$ -	$ -
Disconnect/reconnect at meter - after regular hours	$ -	$ -
Disconnect/reconnect at pole - during regular hours	$ -	$ -
Disconnect/reconnect at pole - after regular hours	$ -	$ -
Disconnect/reconnect - cancelled appointment	$ -	$ -
Service Call - customer owned equipment	$ -	$ -
Service Call - after regular hours	$ -	$ -
Specific charge for access to the power poles - per pole/year (with the exception of wireless	$ 5,843,279	$ 5,986,974
Temporary Service - Install and Remove - Overhead - No Transformer	$ 2,400	$ 800
Temporary Service - Install and Remove - Underground - No Transformer	$ -	$ -
Temporary Service - Install and Remove - Overhead - with Transformer	$ -	$ -
Administrative billing charge	$ -	$ -
Overhead bond connection - per connection	$ 3,255	$ 2,205
Underground bond connection - per connection	$ -	$ -
Total Specific Service Charges	$ 7,832,627	$ 9,030,149

	Actual	
Specific Service Charges	**2021**	**2022**
Customer Administration		
Arrears certificate	$ 26,552	$ 19,410
Statement of account	$ 45	$ 45
Pulling of post-dated cheques	$ -	$ -
Duplicate invoices for previous billing	$ 855	$ 1,425
Request for other billing information	$ 300	$ 375
Easement letter	$ 5,790	$ 10,035
Income tax letter	$ 225	$ 165
Notification Charge	$ -	$ -
Account history	$ 420	$ 60
Credit Check (plus credit agency costs)	$ 3,570	$ 5,025
Credit Check (plus credit agency costs) - General Service	$ 225	$ 175
Returned cheque (plus bank charges)	$ 42,579	$ 55,260
Charge to certify cheque	$ -	$ -
Legal letter charge	$ 45	$ -
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$ 3,013,640	$ 2,557,343
Account set up charge/change of occupancy charge (plus credit agency costs if applicable) -	$ 420,620	$ 304,900
Special meter reads	$ -	$ -
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$ -	$ -
Credit Card Convenience Charge	$ -	$ -
Interval Meter request change	$ -	$ -
Special billing service (aggregation)	$ 1,500	$ 1,375
Special billing service (sub-metering charge per meter)	$ 300	$ 300
Credit service charge for paperless bill	-$ 46,030	-$ 33,840
Non-Payment of Account		
Reconnection at meter - during regular hours	$ 7,759	$ 44,020
Reconnection at meter - after regular hours	$ 185	$ 1,850
Reconnection at pole - during regular hours	$ 185	$ 2,775
Reconnection at pole - after regular hours	$ -	$ -
Reconnection for >300 volts - during regular hours	$ 120	$ 480
Reconnection for >300 volts - after regular hours	$ -	$ -
Other		
Disconnect/reconnect at meter - during regular hours	$ -	$ -
Disconnect/reconnect at meter - after regular hours	$ -	$ -
Disconnect/reconnect at pole - during regular hours	$ -	$ -
Disconnect/reconnect at pole - after regular hours	$ -	$ 415
Disconnect/reconnect - cancelled appointment	$ -	$ -
Service Call - customer owned equipment	$ -	$ -
Service Call - after regular hours	$ -	$ -
Specific charge for access to the power poles - per pole/year (with the exception of wireless	$ 6,050,361	$ 4,941,563
Temporary Service - Install and Remove - Overhead - No Transformer	$ -	$ -
Temporary Service - Install and Remove - Underground - No Transformer	$ -	$ -
Temporary Service - Install and Remove - Overhead - with Transformer	$ -	$ -
Administrative billing charge	$ -	$ -
Overhead bond connection - per connection	$ 1,995	$ 210
Underground bond connection - per connection	$ -	$ -
Total Specific Service Charges	$ 9,531,241	$ 7,913,366

	Actual	
Specific Service Charges	**2023**	**2024**
Customer Administration		
Arrears certificate	$ 14,000	$ 23,655
Statement of account	$ 60	$ 45
Pulling of post-dated cheques	$ -	$ -
Duplicate invoices for previous billing	$ 3,030	$ 4,680
Request for other billing information	$ 450	$ 450
Easement letter	$ 2,041	$ 2,670
Income tax letter	$ 135	$ 315
Notification Charge	$ 15	$ -
Account history	$ 225	$ 60
Credit Check (plus credit agency costs)	$ 2,970	$ 2,235
Credit Check (plus credit agency costs) - General Service	$ 300	$ 325
Returned cheque (plus bank charges)	$ 76,942	$ 106,905
Charge to certify cheque	$ -	$ -
Legal letter charge	$ 45	$ 15
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$ 2,332,830	$ 2,236,024
Account set up charge/change of occupancy charge (plus credit agency costs if applicable) -	$ 270,048	$ 276,440
Special meter reads	$ -	$ -
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$ -	$ -
Credit Card Convenience Charge	$ -	$ -
Interval Meter request change	$ -	$ -
Special billing service (aggregation)	$ 1,625	$ 1,500
Special billing service (sub-metering charge per meter)	$ 300	$ 300
Credit service charge for paperless bill	-$ 34,750	-$ 31,630
Non-Payment of Account		
Reconnection at meter - during regular hours	$ 381,280	$ 686,265
Reconnection at meter - after regular hours	$ 45,880	$ 12,580
Reconnection at pole - during regular hours	$ 6,290	$ 15,540
Reconnection at pole - after regular hours	$ -	$ 415
Reconnection for >300 volts - during regular hours	$ 20,460	$ 36,060
Reconnection for >300 volts - after regular hours	$ 930	$ 1,085
Other		
Disconnect/reconnect at meter - during regular hours	$ -	$ -
Disconnect/reconnect at meter - after regular hours	$ -	$ -
Disconnect/reconnect at pole - during regular hours	$ -	$ -
Disconnect/reconnect at pole - after regular hours	$ -	$ 830
Disconnect/reconnect - cancelled appointment	$ -	$ -
Service Call - customer owned equipment	$ -	$ -
Service Call - after regular hours	$ -	$ -
Specific charge for access to the power poles - per pole/year (with the exception of wireless	$ 5,018,376	$ 5,361,246
Temporary Service - Install and Remove - Overhead - No Transformer	$ -	$ -
Temporary Service - Install and Remove - Underground - No Transformer	$ -	$ -
Temporary Service - Install and Remove - Overhead - with Transformer	$ -	$ -
Administrative billing charge	$ -	$ -
Overhead bond connection - per connection	$ 4,305	$ 2,415
Underground bond connection - per connection	$ -	$ -
Total Specific Service Charges	$ 8,147,788	$ 8,740,425

	Actual	Forecast
Specific Service Charges	**2025**	**2026**
Customer Administration		
Arrears certificate	$ 21,190	$ 13,529
Statement of account	$ 45	$ 54
Pulling of post-dated cheques	$ -	$ -
Duplicate invoices for previous billing	$ 1,845	$ 2,317
Request for other billing information	$ 225	$ 411
Easement letter	$ 1,260	$ 4,734
Income tax letter	$ 165	$ 158
Notification Charge	$ -	$ 9
Account history	$ 135	$ 214
Credit Check (plus credit agency costs)	$ 2,025	$ 3,618
Credit Check (plus credit agency costs) - General Service	$ 275	$ 258
Returned cheque (plus bank charges)	$ 131,450	$ 56,246
Charge to certify cheque	$ -	$ -
Legal letter charge	$ -	$ 1,928
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$ 2,227,949	$ 2,520,530
Account set up charge/change of occupancy charge (plus credit agency costs if applicable) -	$ 283,660	$ 303,315
Special meter reads	$ -	$ -
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$ -	$ -
Credit Card Convenience Charge	$ -	$ -
Interval Meter request change	$ -	$ -
Special billing service (aggregation)	$ 1,500	$ 1,500
Special billing service (sub-metering charge per meter)	$ 300	$ 300
Credit service charge for paperless bill	-$ 55,540	-$ 36,320
Non-Payment of Account		
Reconnection at meter - during regular hours	$ 395,520	$ 274,837
Reconnection at meter - after regular hours	$ 725,940	$ 27,966
Reconnection at pole - during regular hours	$ 12,395	$ 4,510
Reconnection at pole - after regular hours	$ -	$ -
Reconnection for >300 volts - during regular hours	$ 21,240	$ 12,416
Reconnection for >300 volts - after regular hours	$ 17,980	$ 558
Other		
Disconnect/reconnect at meter - during regular hours	$ -	$ -
Disconnect/reconnect at meter - after regular hours	$ -	$ -
Disconnect/reconnect at pole - during regular hours	$ -	$ -
Disconnect/reconnect at pole - after regular hours	$ 415	$ 109
Disconnect/reconnect - cancelled appointment	$ -	$ -
Service Call - customer owned equipment	$ -	$ -
Service Call - after regular hours	$ -	$ -
Specific charge for access to the power poles - per pole/year (with the exception of wireless	$ 5,448,523	$ 5,472,188
Temporary Service - Install and Remove - Overhead - No Transformer	$ -	$ -
Temporary Service - Install and Remove - Underground - No Transformer	$ -	$ -
Temporary Service - Install and Remove - Overhead - with Transformer	$ -	$ -
Administrative billing charge	$ -	$ -
Overhead bond connection - per connection	$ 9,240	$ 351
Underground bond connection - per connection	$ -	$ -
Total Specific Service Charges	$ 9,247,737	$ 8,665,738

	Forecast	
Specific Service Charges	**2027**	**2028**
Customer Administration		
Arrears certificate	$ 22,360	$ 22,484
Statement of account	$ 253	$ 254
Pulling of post-dated cheques		
Duplicate invoices for previous billing	$ 1,746	$ 1,756
Request for other billing information	$ 308	$ 310
Easement letter	$ 4,514	$ 4,539
Income tax letter	$ 143	$ 143
Notification Charge		
Account history	$ 208	$ 209
Credit Check (plus credit agency costs)	$ 5,004	$ 5,032
Credit Check (plus credit agency costs) - General Service		
Returned cheque (plus bank charges)	$ 48,050	$ 48,316
Charge to certify cheque		
Legal letter charge		
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$ 2,923,214	$ 2,939,376
Account set up charge/change of occupancy charge (plus credit agency costs if applicable) - Residential		
Special meter reads	$ 30	$ 30
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$ 30	$ 30
Credit Card Convenience Charge		
Interval Meter request change		
Special billing service (aggregation)	$ 1,500	$ 1,500
Special billing service (sub-metering charge per meter)	$ 300	$ 300
Credit service charge for paperless bill		
Non-Payment of Account		
Reconnection at meter - during regular hours	$ 418,841	$ 421,157
Reconnection at meter - after regular hours	$ 35,705	$ 35,902
Reconnection at pole - during regular hours	$ 90,507	$ 91,018
Reconnection at pole - after regular hours	$ 2,934	$ 2,950
Reconnection for >300 volts - during regular hours		
Reconnection for >300 volts - after regular hours		
Other		
Disconnect/reconnect at meter - during regular hours	$ 456,955	$ 459,481
Disconnect/reconnect at meter - after regular hours	$ 7,520	$ 7,562
Disconnect/reconnect at pole - during regular hours	$ 2,842,350	$ 2,858,064
Disconnect/reconnect at pole - after regular hours	$ 61,040	$ 61,377
Disconnect/reconnect - cancelled appointment	$ 178,500	$ 179,487
Service Call - customer owned equipment	$ -	$ -
Service Call - after regular hours	$ -	$ -
Specific charge for access to the power poles - per pole/year (with the exception of wireless	$ 5,582,161	$ 5,693,525
Temporary Service - Install and Remove - Overhead - No Transformer		
Temporary Service - Install and Remove - Underground - No Transformer		
Temporary Service - Install and Remove - Overhead - with Transformer		
Administrative billing charge		
Overhead bond connection - per connection		
Underground bond connection - per connection		
1 **Total Specific Service Charges**	$ 12,684,172	$ 12,834,801

	Forecast		
Specific Service Charges	**2029**	**2030**	**2031**
Customer Administration			
Arrears certificate	$ 22,610	$ 22,734	$ 22,856
Statement of account	$ 256	$ 257	$ 259
Pulling of post-dated cheques			
Duplicate invoices for previous billing	$ 1,766	$ 1,775	$ 1,785
Request for other billing information	$ 311	$ 313	$ 315
Easement letter	$ 4,564	$ 4,589	$ 4,614
Income tax letter	$ 144	$ 145	$ 146
Notification Charge			
Account history	$ 210	$ 211	$ 212
Credit Check (plus credit agency costs)	$ 5,060	$ 5,088	$ 5,115
Credit Check (plus credit agency costs) - General Service			
Returned cheque (plus bank charges)	$ 48,588	$ 48,852	$ 49,115
Charge to certify cheque			
Legal letter charge			
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$ 2,955,923	$ 2,972,034	$ 2,988,007
Account set up charge/change of occupancy charge (plus credit agency costs if applicable) - Residential			
Special meter reads	$ 30	$ 30	$ 30
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$ 30	$ 31	$ 31
Credit Card Convenience Charge			
Interval Meter request change			
Special billing service (aggregation)	$ 1,500	$ 1,500	$ 1,500
Special billing service (sub-metering charge per meter)	$ 300	$ 300	$ 300
Credit service charge for paperless bill			
Non-Payment of Account			
Reconnection at meter - during regular hours	$ 423,528	$ 425,836	$ 428,125
Reconnection at meter - after regular hours	$ 36,104	$ 36,301	$ 36,496
Reconnection at pole - during regular hours	$ 91,540	$ 92,049	$ 92,553
Reconnection at pole - after regular hours	$ 2,967	$ 2,983	$ 2,999
Reconnection for >300 volts - during regular hours			
Reconnection for >300 volts - after regular hours			
Other			
Disconnect/reconnect at meter - during regular hours	$ 462,068	$ 464,586	$ 467,083
Disconnect/reconnect at meter - after regular hours	$ 7,604	$ 7,646	$ 7,687
Disconnect/reconnect at pole - during regular hours	$ 2,874,154	$ 2,889,819	$ 2,905,350
Disconnect/reconnect at pole - after regular hours	$ 61,723	$ 62,059	$ 62,393
Disconnect/reconnect - cancelled appointment	$ 180,497	$ 181,481	$ 182,456
Service Call - customer owned equipment	$ -	$ -	$ -
Service Call - after regular hours	$ -	$ -	$ -
Specific charge for access to the power poles - per pole/year (with the exception of wireless	$ 5,807,674	$ 5,927,641	$ 6,046,054
Temporary Service - Install and Remove - Overhead - No Transformer			
Temporary Service - Install and Remove - Underground - No Transformer			
Temporary Service - Install and Remove - Overhead - with Transformer			
Administrative billing charge			
Overhead bond connection - per connection			
Underground bond connection - per connection			
Total Specific Service Charges	$ 12,989,152	$ 13,148,259	$ 13,305,481

Table 8-CCC-71-c: Detailed Calculation of Specific Service Charge revenues for 2024 to 2031

Specific Service Charges	2024		
	AUC		
	Volume	Charge	Revenue
Customer Administration			
Arrears certificate	1,577	15	23,655
Statement of account	3	15	45
Pulling of post-dated cheques	-	15	-
Duplicate invoices for previous billing	312	15	4,680
Request for other billing information	30	15	450
Easement letter	178	15	2,670
Income tax letter	21	15	315
Notification Charge	-	15	-
Account history	4	15	60
Credit Check (plus credit agency costs)	149	15	2,235
Credit Check (plus credit agency costs) - General Service	13	25	325
Returned cheque (plus bank charges)	6,191	varies	106,905
Charge to certify cheque	-	15	-
Legal letter charge	1	15	15
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	74,566	varies	2,236,024
Account set up charge/change of occupancy charge (plus credit agency costs if applicable) - Residential	13,822	20	276,440
Special meter reads	-	30	-
Meter dispute charge plus Measurement Canada fees (if meter found correct)	-	varies	-
Credit Card Convenience Charge	-	15	-
Interval Meter request change	-	40	-
Special billing service (aggregation)	12	125	1,500
Special billing service (sub-metering charge per meter)	12	25	300
Credit service charge for paperless bill	3,163	-10	(31,630)
Non-Payment of Account			
Reconnection at meter - during regular hours	12,324	varies	686,265
Reconnection at meter - after regular hours	68	varies	12,580
Reconnection at pole - during regular hours	84	varies	15,540
Reconnection at pole - after regular hours	1	varies	415
Reconnection for >300 volts - during regular hours	601	60	36,060
Reconnection for >300 volts - after regular hours	7	155	1,085
Other			
Disconnect/reconnect at meter - during regular hours	-	varies	-
Disconnect/reconnect at meter - after regular hours	-	varies	-
Disconnect/reconnect at pole - during regular hours	-	185	-
Disconnect/reconnect at pole - after regular hours	2	415	830
Disconnect/reconnect - cancelled appointment			
Service Call - customer owned equipment	-	varies	-
Service Call - after regular hours	-	varies	-
Temporary Service - Install and Remove - Overhead - No Transformer	-	varies	
Temporary Service - Install and Remove - Underground - No Transformer	-	varies	-
Temporary Service - Install and Remove - Overhead - with Transformer	-	varies	-
Specific charge for access to the power poles - per pole/year (with the exception of wireless attachments)	142,114	39.14	5,361,246
Administrative billing charge	-	150	-
Overhead bond connection - per connection	23	105	2,415
Underground bond connection - per connection	-	100	-
Total			8,740,425

Specific Service Charges	2025		
	AUC		
	Volume	Charge	Revenue
Customer Administration			
Arrears certificate	1,413	15	21,190
Statement of account	3	15	45
Pulling of post-dated cheques	-	15	-
Duplicate invoices for previous billing	123	15	1,845
Request for other billing information	15	15	225
Easement letter	84	15	1,260
Income tax letter	11	15	165
Notification Charge	-	15	-
Account history	9	15	135
Credit Check (plus credit agency costs)	135	15	2,025
Credit Check (plus credit agency costs) - General Service	11	25	275
Returned cheque (plus bank charges)	7,608	varies	131,450
Charge to certify cheque	-	15	-
Legal letter charge	-	15	-
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	74,311	varies	2,227,949
Account set up charge/change of occupancy charge (plus credit agency costs if applicable) - Residential	14,183	20	283,660
Special meter reads	-	30	-
Meter dispute charge plus Measurement Canada fees (if meter found correct)	-	varies	-
Credit Card Convenience Charge	-	15	-
Interval Meter request change	-	40	-
Special billing service (aggregation)	12	125	1,500
Special billing service (sub-metering charge per meter)	12	25	300
Credit service charge for paperless bill	5,554	-10	(55,540)
Non-Payment of Account			
Reconnection at meter - during regular hours	7,518	varies	395,520
Reconnection at meter - after regular hours	3,924	varies	725,940
Reconnection at pole - during regular hours	67	varies	12,395
Reconnection at pole - after regular hours	-	varies	-
Reconnection for >300 volts - during regular hours	354	60	21,240
Reconnection for >300 volts - after regular hours	116	155	17,980
		0	
Other			
Disconnect/reconnect at meter - during regular hours	-	varies	-
Disconnect/reconnect at meter - after regular hours	-	varies	-
Disconnect/reconnect at pole - during regular hours	-	185	-
Disconnect/reconnect at pole - after regular hours	1	415	415
Disconnect/reconnect - cancelled appointment			
Service Call - customer owned equipment	-	varies	-
Service Call - after regular hours	-	varies	-
Temporary Service - Install and Remove - Overhead - No Transformer	-	varies	
Temporary Service - Install and Remove - Underground - No Transformer	-	varies	-
Temporary Service - Install and Remove - Overhead - with Transformer	-	varies	-
Specific charge for access to the power poles - per pole/year (with the exception of wireless attachments)	139,206	39.14	5,448,523
Administrative billing charge	-	150	-
Overhead bond connection - per connection	88	105	9,240
Underground bond connection - per connection	-	100	-
Total			9,247,737

Specific Service Charges	2026		
	AUC		
	Volume	Charge	Revenue
Customer Administration			
Arrears certificate	902	15	13,529
Statement of account	4	15	54
Pulling of post-dated cheques	-	15	-
Duplicate invoices for previous billing	154	15	2,317
Request for other billing information	27	15	411
Easement letter	444	15	4,734
Income tax letter	11	15	158
Notification Charge	1	15	9
Account history	14	15	214
Credit Check (plus credit agency costs)	241	15	3,618
Credit Check (plus credit agency costs) - General Service	10	25	258
Returned cheque (plus bank charges)	3,879	varies	56,246
Charge to certify cheque	-	15	-
Legal letter charge	129	15	1,928
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	84,050	varies	2,520,530
Account set up charge/change of occupancy charge (plus credit agency costs if applicable) - Residential	15,166	20	303,315
Special meter reads	-	30	-
Meter dispute charge plus Measurement Canada fees (if meter found correct)	-	varies	-
Credit Card Convenience Charge	-	15	-
Interval Meter request change	-	40	-
Special billing service (aggregation)	12	125	1,500
Special billing service (sub-metering charge per meter)	12	25	300
Credit service charge for paperless bill	3,632	-10	(36,320)
Non-Payment of Account			
Reconnection at meter - during regular hours	4,843	varies	274,837
Reconnection at meter - after regular hours	151	varies	27,966
Reconnection at pole - during regular hours	24	varies	4,510
Reconnection at pole - after regular hours	-	varies	-
Reconnection for >300 volts - during regular hours	207	60	12,416
Reconnection for >300 volts - after regular hours	4	155	558
		0	
Other			
Disconnect/reconnect at meter - during regular hours	-	varies	-
Disconnect/reconnect at meter - after regular hours	-	varies	-
Disconnect/reconnect at pole - during regular hours	-	185	-
Disconnect/reconnect at pole - after regular hours	0	415	109
Disconnect/reconnect - cancelled appointment			
Service Call - customer owned equipment	-	varies	-
Service Call - after regular hours	-	varies	-
Temporary Service - Install and Remove - Overhead - No Transformer	-	varies	
Temporary Service - Install and Remove - Underground - No Transformer	-	varies	-
Temporary Service - Install and Remove - Overhead - with Transformer	-	varies	-
Specific charge for access to the power poles - per pole/year (with the exception of wireless attachments)	139,206	39.31	5,472,188
Administrative billing charge	-	150	-
Overhead bond connection - per connection	3	105	351
Underground bond connection - per connection	-	100	-
Total			8,665,738

Specific Service Charges	2027			2028		
	AUC			AUC		
	Volume	Charge	Revenue	Volume	Charge	Revenue
Customer Administration						
Arrears certificate	1,491	$ 15	$ 22,360	1,499	$ 15	$ 22,484
Statement of account	17	$ 15	$ 253	17	$ 15	$ 254
Duplicate invoices for previous billing	116	$ 15	$ 1,746	117	$ 15	$ 1,756
Request for other billing information	21	$ 15	$ 308	21	$ 15	$ 310
Easement letter	301	$ 15	$ 4,514	303	$ 15	$ 4,539
Income tax letter	10	$ 15	$ 143	10	$ 15	$ 143
Account history	14	$ 15	$ 208	14	$ 15	$ 209
Credit Check (plus credit agency costs)	334	$ 15	$ 5,004	335	$ 15	$ 5,032
Returned cheque (plus bank charges)	3,203	$ 15	$ 48,050	3,221	$ 15	$ 48,316
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	97,440	$ 30	$ 2,923,214	97,979	$ 30	$ 2,939,376
Special meter reads	1	$ 30	$ 30	1	$ 30	$ 30
Meter dispute charge plus Measurement Canada fees (if meter found correct)	1	$ 30	$ 30	1	$ 30	$ 30
Special billing service (aggregation)	12	$ 125	$ 1,500	12	$ 125	$ 1,500
Special billing service (sub-metering charge per meter)	12	$ 25	$ 300	12	$ 25	$ 300
Non-Payment of Account						
Reconnection at meter - during regular hours	6,444	$ 65	$ 418,841	6,479	$ 65	$ 421,157
Reconnection at meter - after regular hours	193	$ 185	$ 35,705	194	$ 185	$ 35,902
Reconnection at pole - during regular hours	489	$ 185	$ 90,507	492	$ 185	$ 91,018
Reconnection at pole - after regular hours	7	$ 415	$ 2,934	7	$ 415	$ 2,950
Other						
Disconnect/reconnect at meter - during regular hours	1,549	$ 295	$ 456,955	1,558	$ 295	$ 459,481
Disconnect/reconnect at meter - after regular hours	16	$ 470	$ 7,520	16	$ 470	$ 7,562
Disconnect/reconnect at pole - during regular hours	5,414	$ 525	$ 2,842,350	5,444	$ 525	$ 2,858,064
Disconnect/reconnect at pole - after regular hours	56	$ 1,090	$ 61,040	56	$ 1,090	$ 61,377
Disconnect/reconnect - cancelled appointment	357	$ 500	$ 178,500	359	$ 500	$ 179,487
Service Call - customer owned equipment	-	$ 30	$ -	-	$ 30	$ -
Service Call - after regular hours	-	$ 165	$ -	-	$ 165	$ -
Specific charge for access to the power poles - per pole/year (with the exception of wireless attachments)	139,206	$ 40.10	$ 5,582,161	139,206	$ 40.90	$ 5,693,525
Total			$ 12,684,172			$ 12,834,801

Specific Service Charges	2029			2030		
	AUC			AUC		
	Volume	Charge	Revenue	Volume	Charge	Revenue
Customer Administration						
Arrears certificate	1,507	$ 15	$ 22,610	1,516	$ 15	$ 22,734
Statement of account	17	$ 15	$ 256	17	$ 15	$ 257
Duplicate invoices for previous billing	118	$ 15	$ 1,766	118	$ 15	$ 1,775
Request for other billing information	21	$ 15	$ 311	21	$ 15	$ 313
Easement letter	304	$ 15	$ 4,564	306	$ 15	$ 4,589
Income tax letter	10	$ 15	$ 144	10	$ 15	$ 145
Account history	14	$ 15	$ 210	14	$ 15	$ 211
Credit Check (plus credit agency costs)	337	$ 15	$ 5,060	339	$ 15	$ 5,088
Returned cheque (plus bank charges)	3,239	$ 15	$ 48,588	3,257	$ 15	$ 48,852
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	98,531	$ 30	$ 2,955,923	99,068	$ 30	$ 2,972,034
Special meter reads	1	$ 30	$ 30	1	$ 30	$ 30
Meter dispute charge plus Measurement Canada fees (if meter found correct)	1	$ 30	$ 30	1	$ 30	$ 31
Special billing service (aggregation)	12	$ 125	$ 1,500	12	$ 125	$ 1,500
Special billing service (sub-metering charge per meter)	12	$ 25	$ 300	12	$ 25	$ 300
Non-Payment of Account						
Reconnection at meter - during regular hours	6,516	$ 65	$ 423,528	6,551	$ 65	$ 425,836
Reconnection at meter - after regular hours	195	$ 185	$ 36,104	196	$ 185	$ 36,301
Reconnection at pole - during regular hours	495	$ 185	$ 91,540	497	$ 185	$ 92,049
Reconnection at pole - after regular hours	7	$ 415	$ 2,967	7	$ 415	$ 2,983
Other						
Disconnect/reconnect at meter - during regular hours	1,566	$ 295	$ 462,068	1,575	$ 295	$ 464,586
Disconnect/reconnect at meter - after regular hours	16	$ 470	$ 7,604	16	$ 470	$ 7,646
Disconnect/reconnect at pole - during regular hours	5,475	$ 525	$ 2,874,154	5,504	$ 525	$ 2,889,819
Disconnect/reconnect at pole - after regular hours	57	$ 1,090	$ 61,723	57	$ 1,090	$ 62,059
Disconnect/reconnect - cancelled appointment	361	$ 500	$ 180,497	363	$ 500	$ 181,481
Service Call - customer owned equipment	-	$ 30	$ -	-	$ 30	$ -
Service Call - after regular hours	-	$ 165	$ -	-	$ 165	$ -
Specific charge for access to the power poles - per pole/year (with the exception of wireless attachments)	139,206	$ 41.72	$ 5,807,674	139,310	$ 42.55	$ 5,927,641
Total			$ 12,989,152			$ 13,148,259

Specific Service Charges	2031		
	AUC		
	Volume	Charge	Revenue
Customer Administration			
Arrears certificate	1,524	$ 15	$ 22,856
Statement of account	17	$ 15	$ 259
Duplicate invoices for previous billing	119	$ 15	$ 1,785
Request for other billing information	21	$ 15	$ 315
Easement letter	308	$ 15	$ 4,614
Income tax letter	10	$ 15	$ 146
Account history	14	$ 15	$ 212
Credit Check (plus credit agency costs)	341	$ 15	$ 5,115
Returned cheque (plus bank charges)	3,274	$ 15	$ 49,115
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	99,600	$ 30	$ 2,988,007
Special meter reads	1	$ 30	$ 30
Meter dispute charge plus Measurement Canada fees (if meter found correct)	1	$ 30	$ 31
Special billing service (aggregation)	12	$ 125	$ 1,500
Special billing service (sub-metering charge per meter)	12	$ 25	$ 300
Non-Payment of Account			
Reconnection at meter - during regular hours	6,587	$ 65	$ 428,125
Reconnection at meter - after regular hours	197	$ 185	$ 36,496
Reconnection at pole - during regular hours	500	$ 185	$ 92,553
Reconnection at pole - after regular hours	7	$ 415	$ 2,999
Other			
Disconnect/reconnect at meter - during regular hours	1,583	$ 295	$ 467,083
Disconnect/reconnect at meter - after regular hours	16	$ 470	$ 7,687
Disconnect/reconnect at pole - during regular hours	5,534	$ 525	$ 2,905,350
Disconnect/reconnect at pole - after regular hours	57	$ 1,090	$ 62,393
Disconnect/reconnect - cancelled appointment	365	$ 500	$ 182,456
Service Call - customer owned equipment	-	$ 30	$ -
Service Call - after regular hours	-	$ 165	$ -
Specific charge for access to the power poles - per pole/year (with the exception of wireless attachments)	139,310	$ 43.40	$ 6,046,054
Total			$ 13,305,481

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 9-CCC-72

Ref: Exhibit 9, Tab 3, Schedule 3, p. 3

Question(s):

a) Please advise whether the amounts built into rates related to OEB cost assessment have been escalated by the PCI. If not, please explain why.

b) For each rate zone, please provide a table showing the escalation of the OEB cost assessment-related amount initially established in base rates to 2026. As part of the table, please show the relevant PCI adjustments (%).

RESPONSE:

a) The amounts built into rates related to OEB cost assessment have not been escalated by the PCI. Alectra Utilities has followed the OEB's guidance for recording balances in this account, as set out in the OEB's February 9, 2016 letter to regulated entities subject to OEB cost assessments. That letter does not explicitly require electricity distributors to apply PCI escalation to the amounts embedded in distribution rates.

b) Tables 1-5 below provide the escalation of the OEB cost assessment-related amount initially established in base rates to 2026 for each rate zone. For 2016, the amounts are prorated for 9 months based on the effective date of April 1, 2016 for this deferral account.

Table 1 – HRZ OEB Cost Assessments $MM

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2026	2026
Amount in Rates	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
PCI%	0.0%	0%	0%	0%	1.7%	1.9%	3.0%	3.4%	4.5%	3.3%	3.4%
Escalated Amount	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7

Table 2 – BRZ OEB Cost Assessments ($MM)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2026	2026
Amount in Rates	0.4	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
PCI%	0.0%	1.8%	1.6%	0.9%	1.2%	1.7%	1.9%	3.0%	3.4%	4.5%	3.3%	3.4%
Escalated Amount	0.4	0.3	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5

Table 3 – PRZ OEB Cost Assessments ($MM)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2026	2026
Amount in Rates	0.8	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
PCI%	0.0%	0.0%	0.9%	1.2%	1.7%	1.9%	3.0%	3.4%	4.5%	3.3%	3.4%
Escalated Amount	0.8	1.0	1.0	1.1	1.1	1.1	1.1	1.2	1.2	1.3	1.3

Table 4 – ERZ OEB Cost Assessments ($MM)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Amount in Rates	0.9	0.9	0.9	0.6	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
PCI%	0.0%	1.6%	1.5%	2.0%	1.8%	0.9%	1.2%	1.7%	1.9%	3.0%	3.4%	4.5%	3.3%	3.4%
Escalated Amount	0.9	0.9	0.9	0.7	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.1	1.1	1.1

Table 5 – GRZ OEB Cost Assessments ($MM)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Amount in Rates	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
PCI%	0.0%	1.6%	0.9%	1.2%	1.7%	1.9%	3.0%	3.4%	4.5%	3.3%	3.4%
Escalated Amount	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 9-CCC-73

Ref: Exhibit 9, Tab 3, Schedule 14, pp. 1-6

Question(s):

a) Please confirm that the entirety of actual locate program costs that are in excess of the locate-related amounts built into rates have been recorded in the GOCA variance account.

b) Please advise whether the entirety of the locate costs recorded in the GOCA variance account are associated with external service providers costs.

c) Please explain why Ontario One Call-related costs and Top Shelf Screening-related costs are properly recorded in the GOCA variance account.

d) For 2023, please confirm that only the actual costs incurred between April 1, 2023, to year-end (net of the amount built into rates for 2023) are reflected in the account.

e) For each rate zone, please provide a table showing the escalation of the locate-related amount initially established in base rates to 2026. As part of the table, please show the relevant PCI adjustments (%).

RESPONSE:

a) The locate costs recorded in the GOCA variance account are only associated with external service providers costs in excess of the locate-related amounts built into rates.

b) The entirety of the locate costs recorded in the GOCA variance account are associated with external service providers costs in excess of the locate-related amounts built into rates.

c) The GOCA account is intended to track incremental costs of locates arising from the implementation of Bill 93. Alectra Utilities has recorded Ontario One Call-related costs in the variance account as the increase in costs is directly related to the implementation of Bill 93. These costs are mandatory for underground infrastructure owners per the Ontario Underground Infrastructure Notification System Act (OUINS Act). The increase in costs is incremental to the level of costs incurred to provide locate services prior to the introduction of Bill 93.

In addition, Alectra Utilities has responded to the increased costs, complexities and stricter timelines of delivering locate services introduced as a result of Bill 93, by making operational improvements and changes to its infrastructure and approach to delivering locates. This included introducing Top Shelf Screening as a third party. Top Shelf Screening provides locate screening, routing, and reporting data for Alectra Utilities and functions as an adjunct to traditional locate service provider resources by increasing the complement of third-party staff Alectra has access to. These operational improvements ensure that high compliance rates can be met, while higher cost field locates are avoided, where possible.

d) Alectra Utilities confirms that only the actual costs incurred between April 1, 2023, to year-end (net of the amount built into rates for 2023) are reflected in the account.

e) Tables 1-5 below provide the escalation of the locate-related amount in base rates to 2026 for each rate zone. For 2023, the amounts are prorated for 9 months based on the effective date of April 1, 2023 for this deferral account.

Table 1 - HRZ Locate Amount in Rates $MM

	2019	2020	2021	2022	2023	2024	2026	2026
Amount in Rates	0.7	0.7	0.7	0.7	0.5	0.7	0.7	0.7
PCI%	0.0%	1.7%	1.9%	3.0%	3.4%	4.5%	3.3%	3.4%
Escalated Amount	0.7	0.7	0.8	0.8	0.6	0.8	0.9	0.9

Table 2 - BRZ Locate Amount in Rates $MM

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2026	2026
Amount in Rates	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.6	0.6	0.6
PCI%	0.0%	1.8%	1.6%	0.9%	1.2%	1.7%	1.9%	3.0%	3.4%	4.5%	3.3%	3.4%
Escalated Amount	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.6	0.8	0.8	0.8

Table 3 - PRZ Locate Amount in Rates $MM

	2017	2018	2019	2020	2021	2022	2023	2024	2026	2026
Amount in Rates	2.2	2.2	2.2	2.2	2.2	2.2	1.6	2.2	2.2	2.2
PCI%	0.0%	0.9%	1.2%	1.7%	1.9%	3.0%	3.4%	4.5%	3.3%	3.4%
Escalated Amount	2.2	2.2	2.2	2.2	2.3	2.4	1.8	2.5	2.6	2.7

Table 4 - ERZ Locate Amount in Rates $MM

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Amount in Rates	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.6	0.6	0.6
PCI%	0.0%	1.6%	1.5%	2.0%	1.8%	0.9%	1.2%	1.7%	1.9%	3.0%	3.4%	4.5%	3.3%	3.4%
Escalated Amount	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.6	0.8	0.8	0.8

Table 5 - GRZ Locate Amount in Rates $MM

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Amount in Rates	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.3	0.3	0.3
PCI%	0.0%	1.6%	0.9%	1.2%	1.7%	1.9%	3.0%	3.4%	4.5%	3.3%	3.4%
Escalated Amount	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.3	0.3	0.3

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 9-CCC-74

Ref: Exhibit 9, Tab 3, Schedule 20, p. 1

Question(s):

Please provide additional details with respect to the incremental expenses incurred with respect to renewable enabling improvements in the ERZ between 2010 and 2019.

RESPONSE:

Table 1 provides a breakdown of the incremental expenses incurred for renewable enabling improvements in the ERZ between 2010 and 2019.

Table 1 - ERZ Renewable Enabling Improvements Costs in $MM

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Capital Costs	-	-	0.4	0.1	0.1	0.2	0.1	0.2	0.0	0.3
Depreciation	-	-	0.0	0.0	0.0	0.0	0.1	0.1	0.1	(0.0)
OM&A	-	-	-	-	0.0	0.0	0.1	0.1	0.1	-

The capital costs reflect the expenditures incurred to connect ERZ's FIT and microFIT customers to its distribution system as set out in its approved 2012 GEA Basic Plan (refer to EB-2012-0033, Enersource 2013 EDR, April 27, 2012, Exhibit 2, Tab 2, Schedule 3 Appendix 1). The OEB approved Enersource's GEA Plan and directed Enersource to adjust its test year rate base by removing the impact of the GEA plan related capital expenditure and OM&A. Please refer to EB-2012-0033, Decision and Order, December 13, 2012, page 24.

The depreciation amounts reflect the annual amortization of the associated capital assets. The OM&A expenses are attributable to the labor costs from the Engineering team to support Enersource’s renewable enabling improvements projects.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 9-CCC-75

Ref: Exhibit 9, Tab 6, Schedule 1, p. 2

Question(s):

Please provide rationale supporting the allocation methodologies applied to each Group 2 account shown in Table 9-6-1. If the rationale is that the allocation is in accordance with the EDDVAR Report or that the allocation methodology has been previously approved, please state that.

RESPONSE:

For Account 1508 Hydro One Charges, Account 1508 Incremental Capital Module, 1535 Smart Grid OM&A Deferral Account, 1536 Smart Grid Funding Adder Deferral Account, and 1555 Smart Meter Capital and Recovery Offset Variance Account, Sub-account Stranded Meter Costs, Alectra Utilities applied the previously approved methodology (kWh as the allocator) from proceeding EB-2015-0003, PowerStream Inc., 2016–2020 Custom IR Application, PowerStream Schedule K – EDVAR Continuity Schedule and Rate Riders_20160912.

For Account 1508 – Pole Attachment Revenue Variance, Alectra Utilities follows the OEB's Accounting Guidance on Wireline Pole Attachment Charges dated July 20, 2018. The balance in this account is allocated to each class using the proposed 2027 distribution revenue.

Alectra Utilities allocates the balances for Accounts 1518 and 1548 based on the number of customers in accordance with the methodologies set out in the OEB's EDDVAR Report.

For Account 1557 – Meter Cost Deferral Account, Alectra Utilities applies the principle of cost causality. The balance is allocated exclusively to the GS > 50 kW rate class, as the costs recorded in this account relate to the installation of Metering Inside Settlement Time (MIST) meters on existing customer facilities where the customer's monthly average peak demand during a calendar year exceeds 50 kW.

For the remaining Group 2 accounts, which were not in existence at the time the EDDVAR Report was issued or for which the EDDVAR Report prescribes a case-by-case allocation methodology, Alectra Utilities has used kWh as the default allocator. Alectra Utilities submits that this approach is reasonable and appropriate. The use of kWh ensures consistency in the allocation methodology, reflects the non-rate-class-specific nature of these accounts, and provides a transparent basis for allocation in the absence of a prescribed allocator.

For ease of reference, Table 1 below provides the allocation applied to Alectra Utilities' each Group 2 account in Table 9-6-1.

Table 1 - Allocation for Group 2 accounts

Account	Allocator
1508 - Energy East Consultation Costs	kWh
1508 - OEB Cost Assessment Variance	kWh
1508 - Other Post-Employment Benefit Deferral Account	kWh
1508 - CGAAP IFRS Differential	kWh
1508 - Hydro-One Charges	kWh
1508 - Pole Attachment Revenue Variance	Distribution Rev.
1508 - Capitalization Policy	kWh.
1508 - Incremental Capital Module	kWh
1508 - Long-term Load Mitigation	kWh
1508 - Collection of Account Charge-Related Lost Revenue	kWh
1508 - GOCA Variance Account	kWh
1508 - LEAP Emergency Financial Assistance Funding Deferral Account	kWh
1511 - Incremental Cloud Computing Implementation Costs	kWh
1518 Retail Cost Variance Account (RCVA) Retail	# of Customers

Account	Allocator
1548 RCVA STR	# of Customers
1522 - Pension and OPEB Forecast Accrual versus Actual Cash Payments Differential Tracking Account	kWh
1525 - Miscellaneous Deferred Debits	kWh
1531 Renewable Connection Capital Deferral Account	kWh
1532 Renewable Connection OM&A Deferral Account	kWh
1533 Renewable Generation Connection Funding Adder Deferral Account	kWh
1535 Smart Grid OM&A Deferral Account	kWh
1536 Smart Grid Funding Adder Deferral Account	kWh
1555 Smart Meter Capital and Recovery Offset Variance Account, Sub-account Stranded Meter Costs	kWh
1508 Sub-account - Useful Life Changes	kWh
1508 Direct Labour Capitalization Changes	kWh
1557 Meter Cost Deferral Account	GS>50
1592 PILs and Tax Variance for 2006 and Subsequent Years, Sub-account - PILs and Tax Variances CCA Changes	kWh

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 9-CCC-76

Ref: Exhibit 9, Tab 8, Schedule 3, p. 1

Question(s):

To the extent that an actual NWS implemented during the test period defers/replaces/offsets a capital investment that is included as part of the DSP (and for which funding is sought in the application), please explain whether the associated capital-related revenue requirement will be applied as an offset to the balance in the NWSDA. If not, please explain why not.

RESPONSE:

Please see 1-ED-1.