RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-1

Updated Revenue Requirement Work Form (RRWF) and Models

Upon completing all interrogatories from Ontario Energy Board (OEB) staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the populated version of the RRWF filed in the initial applications. Entries for changes and adjustments should be included in the middle column on sheet 3 Data_Input_Sheet. Sheets 10 (Load Forecast), 11 (Cost Allocation), and 13 (Rate Design) should be updated, as necessary. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note. Such notes should be documented on Sheet 14 Tracking Sheet and may also be included on other sheets in the RRWF to assist understanding of changes.

In addition, please file an updated set of models that reflects the interrogatory responses. Please also ensure the models used are the latest available models on the OEB's 2027 Electricity Distributor Rate Applications webpage and incorporate the OEB's decision on the application for 2026 rates (EB-2025-0055).

RESPONSE:

Alectra Utilities has attached the updated 2027-2031 Revenue Requirement Work Forms ("RRWF") in Microsoft Excel format as Attachments 1 to 5, reflecting updates to the RRWFs in the pre-filed evidence. Alectra Utilities also files an updated set of the OEB's Chapter 2 Appendices, models, and workforms reflecting updates made in response to interrogatories. These materials, as listed in Tables 1 and 2, are filed as follows:

Table 1 – Updated Chapter 2 Appendices (live Excel)

Chapter 2 Appendix	IR Response	Attach. #
2-AA Capital Projects	1-SEC-24	1
2-AB Capital Expenditure	1-SEC-24	2
2-BA Fixed Asset Continuity Schedule	1-SEC-24	3
2-D Overhead	2-Staff-155	1
2-H Other Revenue	1-SEC-24	6
2-IB Load Forecast	3-SEC-69	1
2-JA Summary of Recoverable OM&A Expenses	1-SEC-24	4
2-JB Recoverable OM&A Cost Drivers	4-AMPCO-81	1
2-JC OM&A Programs	1-SEC-24	5
2-K Employee Costs	1-SEC-24	7
2-OA Capital Structure and Cost of Capital	5-Staff-199	1
2-ZA Commodity Expense (2027-2031)	2-Staff-149	1
2-ZB Cost of Power (2027-2031)	2-Staff-149	1

Table 2 – Updated OEB Models and Workforms

OEB Model	IR Response	Attach. #	Format
Revenue Requirement Workform (2027)	1-Staff-1	1	Excel
Revenue Requirement Workform (2028)	1-Staff-1	2	Excel
Revenue Requirement Workform (2029)	1-Staff-1	3	Excel
Revenue Requirement Workform (2030)	1-Staff-1	4	Excel
Revenue Requirement Workform (2031)	1-Staff-1	5	Excel
PILs Model	6-Staff-207	1	Excel
Cost Allocation Model	1-Staff-1	6	Excel
Cost Allocation Model Tabs I6.1, I6.2, I8, O1, and O2	1-Staff-1	7	PDF
Bill Impact and Tariff Model	1-Staff-1	8	Excel
2027-2031 Proposed Tariff of Rates	1-Staff-1	9	PDF
RTSR Workform	8.0-VECC-78	1	Excel
DVA Continuity Schedule HRZ	9-Staff-247	1	Excel
DVA Continuity Schedule BRZ	9-Staff-248	1	Excel
DVA Continuity Schedule PRZ	9-Staff-249	1	Excel
DVA Continuity Schedule ERZ	9-Staff-250	1	Excel
DVA Continuity Schedule GRZ	9-Staff-251	2	Excel

1. REVENUE REQUIREMENT

Alectra Utilities' base revenue requirement has been updated to $813.6MM for the 2027 Test Year.

Table 3 – Base Revenue Requirement ($000s)

	2027 (Application)	2027 (Updated)	Change ($)	Change (%)	Drivers
Return on Rate Base	$270,682	$276,497	$5,815	2.1%	Updated 2026 Opening RB to reflect 2025 actuals.
Distribution Expenses (excl. Amortization)	$352,423	$352,423	$0	0.0%	
Amortization	$195,649	$194,381	($1,268)	-0.6%	Due to the RB change
PILs	$22,401	$22,286	($115)	-0.5%	Due to the RB change
Service Revenue Requirement	**$841,155**	**$845,587**	**$4,432**	**0.5%**	
Revenue Offsets	($30,850)	($31,950)	($1,100)	3.6%	Added Interest Revenue to USoA 4405
Base Revenue Requirement	**$810,305**	**$813,637**	**$3,332**	**0.4%**	

Table 4 shows changes to the proposed revenue requirement from 2027 to 2031.

Table 4 – 2027-2031 Proposed Revenue Requirement ($000s)

	2027 CoS	2028	2029 Custom Price Cap Index	2030	2031
Revenue Requirement - Updated	$813.6	$868.9	$914.2	$973.5	$1,033.2
Revenue Requirement - Application	$810.3	$863.3	$907.2	$964.9	$1,025.0
Change ($)	$3.3	$5.6	$7.0	$8.7	$8.1
Change (%)	0.4%	0.6%	0.8%	0.9%	0.8%

Revenue Deficiency/Sufficiency for 2027-2031

Table 5 below shows the updated 2027-2031 revenue deficiency calculations.

Table 5 – Cumulative Revenue Deficiency ($MM)

Revenue Deficiency	2027	2028	2029	2030	2031
Service Revenue Requirement	$845.6	$904.8	$949.6	$1,009.6	$1,066.1
Other Revenue Offsets	$31.9	$32.4	$29.0	$29.8	$30.6
Base Revenue Requirement	$813.6	$872.4	$920.6	$979.9	$1,035.5
Distribution Revenue at Prior Year Rates	$703.9	$817.9	$874.6	$921.3	$980.5
Revenue Deficiency	($109.7)	($54.4)	($46.0)	($58.6)	($55.0)
Cumulative Deficiency - Updated	**($109.7)**	**($164.1)**	**($210.1)**	**($268.7)**	**($323.7)**
Cumulative Deficiency - Application	**($106.6)**	**($155.0)**	**($193.5)**	**($244.9)**	**($299.3)**

Other Revenue

Table 6 below presents an updated Other Revenue Summary by components for 2027-2031. The total Other Revenue increased by $1.1MM for each year from 2026 to 2031 due to the inclusion of interest income in UsoA 4405 (please see 6-Staff-212).

Table 6 – Other Revenue ($MM)

Other Revenue	2027	2028	2029	2030	2031
Miscellaneous Service Revenues	$8.8	$8.9	$8.9	$9.0	$9.0
Late Payment Charges	$8.5	$8.9	$9.3	$9.9	$10.5
Other Operating Revenues	$10.2	$10.3	$10.4	$10.6	$10.7
Other Income or Deductions	$4.4	$4.4	$0.4	$0.4	$0.4
Other Revenue - Updated	**$31.9**	**$32.4**	**$29.0**	**$29.8**	**$30.6**
Other Revenue - Application	$30.8	$31.3	$27.9	$28.7	$29.5
Change	**$1.1**	**$1.1**	**$1.1**	**$1.1**	**$1.1**

Load and Customer/Connections Forecasts

Alectra Utilities updated its load and customer/connection forecasts in response to 3-SEC-69 and proposes adopting these forecasts for rate-setting purposes. The updated forecast is based on historical data up to December 2025 and the most recent Conference Board of Canada economic forecast. Appendix 2-IB, as filed in response to 3-SEC-69, reflects these changes.

Table 7 – Load Forecast

Load Forecast		2027	2028	2029	2030	2031
Consumption (kWh)	Application	28,108,834,868	28,660,499,124	29,218,516,421	29,925,988,876	30,554,366,051
	Updated	27,922,545,572	28,437,675,671	28,950,515,152	29,622,531,677	30,218,170,865
	Change kWh	**(186,289,296)**	**(222,823,454)**	**(268,001,269)**	**(303,457,200)**	**(336,195,186)**
	Change %	**-0.66%**	**-0.78%**	**-0.92%**	**-1.01%**	**-1.10%**
Demand (kW)	Application	40,280,644	40,502,646	40,805,739	41,148,206	41,354,428
	Updated	40,307,128	40,493,177	40,847,014	41,335,024	41,708,673
	Change kW	**26,484**	**(9,469)**	**41,274**	**186,818**	**354,245**
	Change %	**0.07%**	**-0.02%**	**0.10%**	**0.45%**	**0.86%**
Customer Count/ Connections	Application	1,386,362	1,392,278	1,398,082	1,403,850	1,409,599
	Updated	1,386,174	1,392,038	1,397,834	1,403,632	1,409,427
	Change	**(188)**	**(240)**	**(248)**	**(218)**	**(172)**
	Change %	**-0.01%**	**-0.02%**	**-0.02%**	**-0.02%**	**-0.01%**

Cost of Power

Alectra Utilities updated its cost of power estimate to account for changes in energy sales volumes (re: updated load forecast) and pricing changes based on the most recent commodity and global adjustments estimates from the Regulated Price Plan report. In addition, the Wholesale Market Service, Class B CBR, and RRRP rates have been revised to incorporate the latest OEB-approved rates. Appendices 2-ZA and 2-ZB, as filed in response to 2-Staff-149, have been updated to reflect these changes.

Table 8 - Cost of Power

	2027	2028	2029	2030	2031
COP-Updated	**$4,011.9**	**$4,159.5**	**$4,309.0**	**$4,482.1**	**$4,653.3**
COP-Application	$3,474.3	$3,611.0	$3,750.8	$3,914.6	$4,074.8
Change ($)	$537.6	$548.5	$558.2	$567.5	$578.6
Change (%)	15.5%	15.2%	14.9%	14.5%	14.2%

Working Capital Allowance

Due to changes in the cost of power estimate, Alectra Utilities updated its working capital allowance. No changes were made to the underlying revenue lags and expense lead, which remain consistent with the Lead-Lag Study results as outlined in Exhibit 2B, Tab 4, Schedule 1 in the pre-filed evidence.

Table 9 – Working Capital Allowance

	2027	2028	2029	2030	2031
WCA-Updated	**$346.1**	**$361.4**	**$373.8**	**$389.7**	**$405.2**
WCA-Application	$305.0	$319.6	$331.4	$346.1	$361.2
Change ($)	$41.1	$41.8	$42.4	$43.6	$44.0
WCA-Updated	**7.93%**	**7.98%**	**7.96%**	**7.98%**	**8.00%**
WCA-Application	7.97%	8.03%	8.01%	8.02%	8.05%

Cost of Capital

Cost of Capital has been updated as a result of the changes to the rate base shown in Table 10. Appendix 2-OA, as filed in response to 5-Staff-199, reflects these changes.

Rate Base

Alectra Utilities updated the 2025-2031 rate base due to changes in actual closing balances for 2025, resulting in an overall increase of $48.4MM in capital expenditures as compared to the 2025 Budget. The overall increase in capex for 2025 has impacted the additions and Construction Work in Progress (CWIP) balances for 2025 to 2031, as presented in Table 9 below. No changes were made to the budgeted capital expenditures for 2026-2031. Appendix 2-BA, as filed in response to 1-SEC-24, reflects these changes.

Table 10 – 2025-2031 Capital Additions and CWIP ($MM)

	2025	2026	2027	2028	2029	2030	2031
Additions Change	$27.6	$28.1	($5.3)	($0.6)	$0.3	($1.4)	($0.3)
CWIP Change	$20.8	($28.1)	$5.3	$0.6	($0.3)	$1.4	$0.3
Total Change	**$48.4**	-	-	-	-	-	-

Table 11 provides details on the resulting changes to fixed assets and how these changes affect the rate base.

Table 11 – Continuity of Change to Fixed Assets Included in Rate Base

	2025	2026	2027	2028	2029	2030	2031
Opening Balance Change	-	19.7	47.8	42.5	41.9	42.2	40.9
Additions Change	**27.6**	**28.1**	**(5.3)**	**(0.6)**	**0.3**	**(1.3)**	**(0.3)**
Disposal Change	(7.9)	-	-	-	-	-	-
Net Change in Cost	**19.7**	**47.8**	**42.5**	**41.9**	**42.2**	**40.9**	**40.6**
Opening Balance Change	-	8.3	8.4	9.7	9.2	7.7	4.9
Depreciation Change	0.1	0.1	1.3	(0.5)	(1.5)	(2.8)	(2.4)
Change in Disposal	8.2	-	-	-	-	-	-
Net Change in Accumulated Depreciation	**8.3**	**8.4**	**9.7**	**9.2**	**7.7**	**4.9**	**2.5**
Net Change in Ending NBV	28.1	56.2	52.2	51.1	49.9	45.8	43.1
Net Change in Average NBV		**42.1**	**54.2**	**51.7**	**50.5**	**47.9**	**44.5**

Table 12 below provides an updated rate base for 2027-2031.

Table 12 - Rate Base

	2027	2028	2029	2030	2031
Opening Gross Assets	$5,592.3	$6,030.8	$6,498.2	$7,069.9	$7,692.0
Closing Gross Assets	$6,030.8	$6,498.2	$7,069.9	$7,692.0	$8,313.9
Average Gross Assets	**$5,811.6**	**$6,264.5**	**$6,784.1**	**$7,381.0**	**$8,003.0**
Opening Accumulated Depreciation	($1,531.2)	($1,722.9)	($1,923.8)	($2,140.3)	($2,374.1)
Closing Accumulated Depreciation	($1,722.9)	($1,923.8)	($2,140.3)	($2,374.1)	($2,621.6)
Average Accumulated Depreciation	**($1,627.0)**	**($1,823.3)**	**($2,032.0)**	**($2,257.2)**	**($2,497.9)**
Opening Net Book Value	$4,061.1	$4,307.9	$4,574.5	$4,929.7	$5,317.9
Closing Net Book Value	$4,307.9	$4,574.5	$4,929.7	$5,317.9	$5,692.3
Average Net Fixed Assets - Updated	**$4,184.5**	**$4,441.2**	**$4,752.1**	**$5,123.8**	**$5,505.1**
Average Net Fixed Assets - Application	**$4,130.3**	**$4,389.5**	**$4,701.5**	**$5,075.9**	**$5,460.6**
Change ($)	**$54.2**	**$51.7**	**$50.5**	**$47.9**	**$44.5**
ADD: Working Capital Allowance	$346.1	$361.4	$373.8	$389.7	$405.2
Rate Base - Updated	**$4,530.6**	**$4,802.6**	**$5,125.8**	**$5,513.4**	**$5,910.3**
Rate Base - Application	**$4,435.3**	**$4,709.2**	**$5,032.9**	**$5,422.0**	**$5,821.8**
Change ($)	**$95.3**	**$93.4**	**$92.9**	**$91.4**	**$88.5**

Operations, Maintenance and Administration Expense ("OM&A")

OM&A remain unchanged.

Payment in Lieu of Taxes ("PILs")

PILs have been updated as a result of the changes to the rate base shown in Table 11. PILs Model, as filed in response to 6-Staff-207, reflects these changes.

2. RATE CLASSES

Embedded Distributor Class Elimination

As part of Exhibit 8, Tab 1, Schedule 1, pp. 14 to 16 of the Application, Alectra Utilities proposed maintaining the Embedded Distributor rate class. Subsequent discussions with Hydro One Networks Inc. (HONI), Alectra Utilities' sole customer in this rate class, confirmed that this rate class will not be required upon the construction of the Pleasant M27 feeder by HONI. Therefore, Alectra Utilities proposes to eliminate the Embedded Distributor rate class effective January 1, 2027.

Cost Allocation Impact

To determine the cost allocation and rate design impacts of eliminating the Embedded Distributor class, Alectra Utilities ran two scenarios of its 2027 cost allocation model ("CAM").

The first scenario, "ED Eliminated", is based on the updated 2027 CAM run that incorporates all of the updates completed by Alectra Utilities as described in response to this interrogatory. This scenario reflects the elimination of the Embedded Distributor class in 2027. In this run, all CAM input tabs are updated to remove data input for the Embedded Distributor class. In the second scenario, "ED Remains", the Embedded Distributor class remains in 2027.

The CAM input worksheets I6.1 (Revenue), I6.2 (Customer Data) and output sheet O1(Revenue to Cost Summary) for both scenarios are provided in Attachment 7 to this interrogatory response. A summary of the 2027 CAM results for both scenarios is provided in Table 13.

Table 13 – 2027 CAM Results for ED Eliminated and ED Remains Scenarios

Rate Class	Res	GS<50 kW	GS>50 kW	Large Use	LUDA	S/L	Sentinel	USL	ED	Total
ED Eliminated										
Revenue at Current Rates	$412.00	$103.57	$190.88	$17.39	$1.19	$8.36	$0.06	$2.42	$0.00	$735.88
Escalated Revenue	$472.62	$119.11	$219.97	$20.04	$1.38	$9.61	$0.07	$2.78	$0.00	$845.59
Cost	$519.22	$95.20	$202.73	$18.66	$1.04	$6.09	$0.09	$2.56	$0.00	$845.59
R/C Ratio	0.91	1.25	1.08	1.07	1.33	1.58	0.84	1.09	1.48	1.00
ED Remains										
Revenue at Current Rates	$412.00	$103.57	$190.88	$17.39	$1.19	$8.36	$0.06	$2.42	$0.06	$735.94
Escalated Revenue	$472.58	$119.10	$219.95	$20.04	$1.38	$9.61	$0.07	$2.78	$0.07	$845.59
Cost	$519.19	$95.19	$202.72	$18.66	$1.04	$6.09	$0.09	$2.56	$0.05	$845.59
R/C Ratio	0.91	1.25	1.09	1.07	1.33	1.58	0.84	1.09	-	1.00

The elimination of the Embedded Distributor class results in a $63K[1] loss in total revenue at current rates, which in turn results in a marginally higher (re: 0.01%) uniform rate increase [2]across all rate classes. This increase does not materially impact the distribution rates for any of Alectra Utilities' customer classes.

Rate Design Impact

The outputs of the 2027 CAM provide the basis for rate design over the 2027-2031 period.

To evaluate the 2027 rate and bill impacts of eliminating the Embedded Distributor class in 2027, Alectra Utilities compared two scenarios of the 2027 rate design. The first scenario, "ED Eliminated", calculates 2027 rates based on the outputs of the ED Eliminated CAM, assuming the elimination of the Embedded Distributor class had taken place in 2027. This scenario is based on the output of the updated 2027 CAM filed in response to this interrogatory.

The second scenario, "ED Remains" calculates what the 2027 rates would be if the Embedded Distributor class remains in place for 2027-2031. Table 14 below includes the fixed and variable distribution rates that would apply in 2027 under both scenarios. The rate design includes any R/C ratio adjustments necessary to move within the OEB's approved

[1] $735,877,507 - $735,940,301 = -$62,794
[2] Escalated Revenue / Revenue at Current Rates

R/C ranges, except for the Sentinel class, which is proposed at 73% RCR under the ED Eliminated scenario vs. 71% at the ED Remains scenario.

Table 14 – 2027 Dx Rates under ED Eliminated and ED Remains Scenarios

Rate Class	ED Eliminated		ED Remains	
	2027 MFC	2027 Variable	2027 MFC	2027 Variable
Res	$38.26	-	$38.26	-
GS<50 kW	$47.08	$0.0207	$47.08	$0.0207
GS>50 kW	$294.98	$5.2004	$294.96	$5.1999
Large Use	$15,733.81	$3.9406	$15,732.41	$3.9403
LUDA	$7,090.86	$0.4194	$7,090.86	$0.4194
S/L	$1.37	$9.5631	$1.37	$9.5626
Sentinel	$6.51	$16.4505	$6.51	$16.4494
USL	$10.22	$0.0239	$10.22	$0.0239
Embedded Distributor	-	-	$4,888.98	-

Table 15 provides the 2027 total bill impacts under the ED Eliminated and ED Remains scenarios for all other rate classes at the typical consumption level.

Table 15 – 2027 Total Bill Impacts under ED Eliminated and ED Remains Scenarios

Rate Class	ED Eliminated		ED Remains	
	Change ($)	Change (%)	Change ($)	Change (%)
Res	$3.48	2.6%	$3.48	2.6%
GS<50 kW	$7.07	2.2%	$7.07	2.2%
GS>50 kW, Regular	-$313.51	-1.6%	-$313.67	-1.6%
GS>50 kW, Intermediate	-$1,494.45	-7.5%	-$1,494.61	-7.5%
Large Use	$1,106.48	0.2%	$1,101.51	0.2%
LUDA	-$86,839.37	-5.5%	-$86,839.37	-5.5%
S/L	-$1.38	-14.9%	-$1.38	-14.9%
Sentinel	$0.12	0.7%	$0.12	0.7%
USL	$0.36	0.9%	$0.36	0.9%
Embedded Distributor	-	-	-$14,517.31	-3.3%

Table 15 shows that the elimination of the Embedded Distributor class results in a small decrease in the notional harmonized 2026 to 2027 total bill impacts for GS>50 kW and Large Use rate classes, without any impact to other rate classes.

Large Use with Dedicated Assets (LUDA)

Please see Alectra Utilities' response to 8-Staff-236, for the proposed changes to the LUDA rate class. Alectra Utilities' intention is that only the six (6) existing customers remain in the LUDA rate class.

3. COST ALLOCATION AND RATE DESIGN

Cost Allocation

Alectra Utilities has updated its 2027 Cost Allocation Model to incorporate changes discussed this response (Revenue Requirement, Other Revenue, Load and Customer/Connections Forecast, Cost of Power, WCA, Rate Base, PILs, Embedded Distributor Class elimination). The updated model is included as an Excel Attachment 6 to 1-Staff-1.

Table 16 below provides comparison of the proposed revenue-to-cost ratios (RCR) at status quo and proposed adjusted RCR between the updated and the Application versions of the 2027 CAM.

Table 16 – Proposed RCR at CAM Status Quo and Adjusted

Rate Class	Application		Updated		Change	
	CAM Status Quo	Proposed	CAM Status Quo	Proposed	CAM Status Quo	Proposed
Residential	90.8%	93.2%	91.0%	92.5%	0.2%	-0.7%
GS<50 kW	124.2%	114.2%	125.1%	120.0%	0.9%	5.8%
GS>50 kW	109.3%	109.3%	108.5%	108.5%	-0.8%	-0.8%
Large Use	108.8%	108.8%	107.4%	107.4%	-1.4%	-1.4%
LUDA	133.8%	115.0%	132.6%	115.0%	-1.2%	0.0%
Street Lighting	159.5%	120.0%	157.8%	120.0%	-1.7%	0.0%
Sentinel Lighting	83.1%	71.0%	83.7%	73.0%	0.5%	2.0%
USL	110.5%	110.5%	108.7%	104.0%	-1.8%	-6.5%
Embedded Distributor	147.9%	120.0%	-	-	-	-

The results from the updated 2027 cost allocation show that there are three rate classes with RCR above the Upper Limit that require adjustments to bring them within the OEB-approved range: GS<50 kW, Large Use with Dedicated Assets, and Street Lighting. Alectra Utilities have applied the same approach as originally proposed in Exhibit 7, Tab 2, Schedule 3 of the Application to bring these ratios within the OEB-approved range in 2027. As part of the

updates, the GS>50 kW class total bill impact is now under 10%, resulting in no need for rate mitigation via an additional revenue allocation adjustment.

Table 17 provides comparison of the updated 2027 proposed revenue requirement by rate class to the Application.

Table 17 – 2027 Revenue Requirement by Rate Class ($MM)

Rate Class	Revenue ($)	Revenue (%)	Revenue ($)	Revenue (%)	Revenue ($)	Revenue/Total (%)
Residential	$460.3	56.8%	$457.1	56.2%	($3.2)	-0.6%
GS<50 kW	$105.7	13.0%	$110.4	13.6%	$4.7	0.5%
GS>50 kW	$213.8	26.4%	$215.7	26.5%	$1.9	0.1%
Large Use	$19.6	2.4%	$19.6	2.4%	$0.1	0.0%
LUDA	$1.2	0.1%	$1.2	0.1%	$0.0	0.0%
Street Lighting	$6.9	0.9%	$7.0	0.9%	$0.1	0.0%
Sentinel Lighting	$0.1	0.0%	$0.1	0.0%	$0.0	0.0%
USL	$2.7	0.3%	$2.6	0.3%	($0.1)	0.0%
Embedded Distributor	$0.1	0.0%	-	-	-	-
Total	**$810.3**	**100.0%**	**$813.6**	**100.0%**	**$3.4**	**0.0%**

Retail Transmission and Low Voltage Service Rates

Alectra Utilities has provided an updated RTSR Workform utilizing OEB's latest available RTSR Workform template.

The workform includes the update for the 2026 OEB-approved Uniform Transmission Rates (UTR) and Hydro One Sub-Transmission Rates (STR) in Table 4, UTRs and Sub-Transmission. For 2027–2031, the forecasted UTR and STR are based on the 2026 approved rates, escalated by 2% per year.

Alectra Utilities has also updated the Low Voltage Charges in Tab 9, LV Rates. The update of the LV Charges reflects the updated OEB-approved Hydro One's 2026 Sub-Transmission Facility Charge for Connection to Common ST Lines rate of $1.8196. For 2027-2031, the forecasted LV rates are based on the 2026 approved rate escalated by 2% per year. Alectra Utilities has also updated the billing determinants to derive the proposed rates, as based on the updated load forecast.

The updated RTSR and LV rates have been included in the Bill Impacts presented in the Bill Impact and Tariff Model and 2027-2031 Proposed Tariff of Rates attachments filed in response to this interrogatory.

Deferral and Variance Accounts

The DVA Continuity schedules have been updated for Group 2 Accounts, using the latest actuals. All interest rates have been updated per the most recent OEB- prescribed interest rate. Refer to attachments filed in response to 9-Staff-247 to 9-Staff-251.

Table 18 presents Group 2 account balances proposed for disposition.

Table 18 – Proposed Group 2 DVA Disposition

	Application			Updated		
USoA	Principal Balance	Carrying Charge Balance	Total Balance	Principal Balance	Carrying Charge Balance	Total Balance
	as of Dec31, 2026					
1508 - Energy East Consultation Costs	$0.1	$0.0	**$0.2**	$0.1	$0.0	**$0.2**
1508 - OEB Cost Assessment Variance	$20.5	$2.6	**$23.1**	$20.8	$2.6	**$23.4**
1508 - Other Post-Employment Benefit Deferral Account	($8.3)	$0.0	**($8.3)**	($11.2)	$0.0	**($11.2)**
1508 - OPEB Forecast Cash versus Forecast Accrual Differential Deferral Account	$1.6	$0.0	**$1.6**	$1.5	$0.0	**$1.5**
1508 - CGAAP-CWIP Differential Deferral Account	($0.2)	$0.1	**($0.1)**	($0.2)	$0.1	**($0.1)**
1508 - Hydro-One Charges	$0.1	$0.0	**$0.1**	($0.0)	$0.0	**$0.0**
1508 - Pole Attachment Revenue Variance	($19.8)	($2.7)	**($22.5)**	($19.8)	($2.6)	**($22.4)**
1508 - Capitalization Policy	($35.2)	$0.0	**($35.2)**	($37.4)	$0.0	**($37.4)**
1508 - Incremental Capital Module	$0.7	($4.1)	**($3.4)**	$0.6	($3.9)	**($3.3)**
1508 - Collection of Account Charge-Related Lost Revenue	$18.0	$2.2	**$20.3**	$18.0	$2.2	**$20.2**
1508 - GOCA Variance Account	$8.9	$0.7	**$9.5**	$9.4	$0.7	**$10.1**
1508 - LEAP Emergency Financial Assistance Funding Deferral Account	$3.1	$0.1	**$3.2**	$3.2	$0.1	**$3.4**
1511 Incremental Cloud Computing Implementation Costs	$1.8	$0.1	**$2.0**	$1.8	$0.1	**$1.9**
1518 Retail Cost Variance Account (RCVA) Retail	$0.5	$0.3	**$0.8**	$0.5	$0.3	**$0.8**
1548 RCVA STR	$0.3	$0.1	**$0.4**	$0.3	$0.1	**$0.4**
1522 - Pension and OPEB Forecast Accrual versus Actual Cash Payments Differential Tracking Account	$0.0	($2.0)	**($2.0)**	$0.0	($2.0)	**($2.0)**
1532 Renewable Connection OM&A Deferral Account	$0.1	$0.0	**$0.1**	$0.1	$0.0	**$0.1**
1533 Renewable Generation Connection Funding Adder Deferral Account	($0.3)	$0.0	**($0.3)**	($0.3)	$0.0	**($0.3)**
1535 Smart Grid OM&A Deferral Account	$2.7	$0.7	**$3.4**	$2.7	$0.7	**$3.4**
1536 Smart Grid Funding Adder Deferral Account	$0.0	($0.0)	**($0.0)**	$0.0	($0.0)	**($0.0)**
1555 Smart Meter Capital and Recovery Offset Variance Account, Sub-account Stranded Meter Costs	($0.2)	$0.4	**$0.1**	($0.2)	$0.4	**$0.1**
1557 Meter Cost Deferral Account	$11.4	$0.0	**$11.4**	$11.3	$0.0	**$11.3**
1508, Accounting Changes - Useful Lives	($40.2)	$0.0	**($40.2)**	$0.0	$0.0	**$0.0**
1508, Accounting Changes - Direct Labour Capitalization	($11.7)	$0.0	**($11.7)**	$0.0	$0.0	**$0.0**
1592 PILs and Tax Variance for 2006 and Subsequent Years, Sub-account - PILs and Tax Variances CCA Changes	($36.4)	($6.5)	**($42.9)**	($36.4)	($6.4)	**($42.8)**
TOTAL DVA BALANCE	**($82.6)**	**($7.9)**	**($90.4)**	**($35.1)**	**($7.5)**	**($42.6)**

Alectra Utilities is requesting a one-year rate rider for the proposed disposition period for the Group 1 and Group 2 accounts.

Bill Impacts

The updated bill impacts are provided in the Bill Impact and Tariff Model and 2027-2031 Proposed Tariff of Rates that are filed as a live Excel Attachment 8, and PDF Attachment 9, respectively, to 1-Staff-1.

Table 19 below summarizes key changes to the 2027 revenue requirement.

Table 19 – Summary of Proposed Changes to Revenue Requirement

	Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement		
Item / Description	**Regulated Return on Capital**	**Regulated Rate of Return**	**Rate Base**	**Working Capital**	**Working Capital Allowance ($)**	**Amortization / Depreciation**	**Taxes/PILs**	**OM&A**	**Service Revenue Requirement**	**Other Revenues**	**Base Revenue Requirement**
APPLICATION	**$270,682,143**	**6.10%**	**$4,435,332,363**	**$3,826,749,254**	**$304,991,916**	**$195,649,453**	**$22,400,579**	**$352,422,897**	**$841,155,072**	**$30,849,746**	**$810,305,326**
Application Cost of Power				3,474,326,358							
Updated Cost of Power				4,011,903,568							
Net change	**-**		**-**	**537,577,211**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Application Average PP&E	252,068,912		4,130,340,447			195,649,453			447,718,365		447,718,365
Updated Average PP&E	255,375,857		4,184,527,250			194,381,136			449,756,993		449,756,993
Net change	**3,306,945**		**54,186,803**	**-**	**-**	**(1,268,317)**	**-**	**-**	**2,038,628**	**-**	**2,038,628**
Application WCA % 7.97%	18,613,231		304,991,916		304,991,916				18,613,231		18,613,231
Updated WCA % 7.93%	21,121,456		346,091,089		346,091,089				21,121,456		21,121,456
Net change	**2,508,225**		**41,099,173**	**-**	**41,099,173**	**-**	**-**	**-**	**2,508,225**	**-**	**2,508,225**
Application PILs							22,400,579		22,400,579		22,400,579
Updated PILs							22,285,853		22,285,853		22,285,853
Net change	**-**		**-**	**-**	**-**	**-**	**(114,726)**	**-**	**(114,726)**	**-**	**(114,726)**
Application Other Revenue										30,849,746	(30,849,746)
Updated Other Revenue										31,949,746	(31,949,746)
Net change	**-**		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**1,100,000**	**(1,100,000)**
Overall Changes	**$5,815,170**	**-**	**$95,285,976**	**$537,577,211**	**$41,099,173**	**($1,268,317)**	**($114,726)**	**-**	**$4,432,127**	**$1,100,000**	**$3,332,127**
Revised Amounts	**$276,497,313**	**6.10%**	**$4,530,618,338**	**$4,364,326,465**	**$346,091,089**	**$194,381,136**	**$22,285,853**	**$352,422,897**	**$845,587,199**	**$31,949,746**	**$813,637,453**
UPDATED	**$276,497,313**	**6.10%**	**$4,530,618,338**	**$4,364,326,465**	**$346,091,089**	**$194,381,136**	**$22,285,853**	**$352,422,897**	**$845,587,199**	**$31,949,746**	**$813,637,453**

1-Staff-1

Attachment 1
2027_Rev_Reqt_Workform_1.0_20260220

Please see live Excel

1-Staff-1

Attachment 2
2028_Rev_Reqt_Workform_1.0_20260220

Please see live Excel

1-Staff-1

Attachment 3
2029_Rev_Reqt_Workform_1.0_20260220

Please see live Excel

1-Staff-1

Attachment 4
2030_Rev_Reqt_Workform_1.0_20260220

Please see live Excel

1-Staff-1

Attachment 5
2031_Rev_Reqt_Workform_1.0_20260220

Please see live Excel

1-Staff-1

Attachment 6
Cost Allocation Model

Please see live Excel

1-Staff-1

Attachment 7
Cost Allocation Model Tabs I6.1, I6.2, O1

EMBEDDED DISTRIBUTOR – ELIMINATED

Ontario Energy Board

2026 Cost Allocation Model

EB-2025-0252

Sheet I6.1 Revenue Worksheet - Interrogatories

Total kWhs from Load Forecast	27,922,545,572
Total kWs from Load Forecast	40,307,128
Deficiency/sufficiency (RRWF 8. cell F51)	- 109,709,692
Miscellaneous Revenue (RRWF 5. cell F48)	31,949,746

			1	2	3	6	7	8	9	10	11
	ID	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Large Use >5MW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**	**Large Use >5MW with Dedicated Assets**
Billing Data											
Forecast kWh	**CEN**	27,922,545,572	8,726,286,424	2,875,761,314	13,182,366,199	2,142,187,817	94,572,090	585,590	47,436,520		853,349,619
Forecast kW	**CDEM**	40,307,128			34,388,480	4,047,427	264,100	1,609			1,605,512
Forecast kW, included in CDEM, of customers receiving line transformer allowance		14,872,947			10,895,945	3,977,002					
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		10,948,237		10,948,237							
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	27,144,990,506	8,726,286,424	2,875,761,314	13,036,478,847	2,142,187,817	94,572,090	585,590	47,436,520		221,681,904
Existing Monthly Charge			$ 32.56	$ 42.55	$ 264.43	$ 14,971.02	$ 1.57	$ 6.52	$ 9.26		$ 7,090.86
Existing Distribution kWh Rate				$0.0187					$0.0217		
Existing Distribution kW Rate					$4.4936	$3.1961	$10.9939	$16.4776			$0.4185
Existing TOA Rate				$0.0032	$0.6189	$0.4264					
Additional Charges											
Distribution Revenue from Rates		$712,402,090	$388,957,071	$99,762,904	$193,377,070	$18,684,854	$8,058,433	$58,276	$2,321,031	$0	$1,182,449
Transformer Ownership Allowance		$8,474,329	$0	$35,034	$6,743,500	$1,695,794	$0	$0	$0	$0	$0
Net Class Revenue	**CREV**	$703,927,761	$388,957,071	$99,727,870	$186,633,570	$16,989,061	$8,058,433	$58,276	$2,321,031	$0	$1,182,449

Ontario Energy Board

2026 Cost Allocation Model

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Sheet I6.2 Customer Data Worksheet - Interrogatories

			1	2	3	6	7	8	9	10	11
	ID	Total	Residential	GS <50	GS>50-Regular	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor	Large Use >5MW with Dedicated Assets
Billing Data											
Bad Debt 3 Year Historical Average	BDHA	$17,368,185	$11,068,983	$3,824,562	$2,473,824	$0	$198	$140	$478		$0
Late Payment 3 Year Historical Average	LPHA	$10,555,000	$7,404,859	$1,926,113	$1,134,045	$72,690	$6,115	$1,599	$3,820		$5,758
Number of Bills	CNB	13,241,112	11,945,856	1,080,756	146,916	384	384	2,340	64,404		72
Number of Devices	CDEV						273,617				
Number of Connections (Unmetered)	CCON	80,434					68,404	406	11,624		
Total Number of Customers	CCA	1,103,426	995,488	90,063	12,243	32	32	195	5,367		6
Bulk Customer Base	CCB	-									
Primary Customer Base	CCP	1,112,818	995,488	90,063	12,243	32	9,424	195	5,367		6
Line Transformer Customer Base	CCLT	1,111,506	995,488	89,973	11,058	1	9,424	195	5,367		-
Secondary Customer Base	CCS	1,015,993	959,153	45,950	5,296	-	32	195	5,367		-
Weighted - Services	CWCS	959,153	959,153	-	-	-	-	-	-		-
Weighted Meter -Capital	CWMC	407,655,094	234,149,180	111,436,216	61,401,712	549,472	-	-	-		118,514
Weighted Meter Reading	CWMR	15,649,857	11,945,856	1,610,326	2,072,768	17,197	-	-	-		3,709
Weighted Bills	CWNB	13,841,144	11,945,856	1,296,907	514,206	35,674	1,766	1,404	38,642		6,689

Bad Debt Data

Historic Year:	2022	16,109,352	9,088,338	3,576,779	3,444,222	-	12	1	-		-
Historic Year:	2023	18,746,929	12,380,818	4,766,918	1,597,878	-	34	417	864		-
Historic Year:	2024	17,248,274	11,737,793	3,129,990	2,379,372	-	549	1	570		-
Three-year average		**17,368,185**	**11,068,983**	**3,824,562**	**2,473,824**	**-**	**198**	**140**	**478**		**-**

Ontario Energy Board

2026 Cost Allocation Model

EB-2025-0252

Sheet O1 Revenue to Cost Summary Worksheet - Interrogatories

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS>50-Regular	6 Large Use >5MW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor	11 Large Use >5MW with Dedicated Assets
crev	Distribution Revenue at Existing Rates	$703,927,761	$388,957,071	$99,727,870	$186,633,570	$16,989,061	$8,058,433	$58,276	$2,321,031	$0	$1,182,449
mi	Miscellaneous Revenue (mi)	$31,949,746	$23,040,442	$3,843,837	$4,246,872	$405,124	$299,252	$4,668	$99,761	$0	$9,790
	Miscellaneous Revenue Input equals Output										
	Total Revenue at Existing Rates	**$735,877,507**	**$411,997,513**	**$103,571,707**	**$190,880,442**	**$17,394,184**	**$8,357,685**	**$62,944**	**$2,420,793**	**$0**	**$1,192,239**
	Factor required to recover deficiency (1 + D)	1.1559									
	Distribution Revenue at Status Quo Rates	$813,637,453	$449,577,440	$115,270,820	$215,721,088	$19,636,867	$9,314,369	$67,359	$2,682,773	$0	$1,366,738
	Miscellaneous Revenue (mi)	$31,949,746	$23,040,442	$3,843,837	$4,246,872	$405,124	$299,252	$4,668	$99,761	$0	$9,790
	Total Revenue at Status Quo Rates	**$845,587,199**	**$472,617,882**	**$119,114,657**	**$219,967,960**	**$20,041,991**	**$9,613,621**	**$72,027**	**$2,782,534**	**$0**	**$1,376,527**
	Expenses										
di	Distribution Costs (di)	$116,331,660	$66,694,511	$11,741,634	$32,965,528	$3,569,681	$947,477	$12,800	$380,070	$0	$19,959
cu	Customer Related Costs (cu)	$79,436,872	$63,502,246	$9,801,279	$5,142,421	$137,891	$590,648	$8,192	$227,798	$0	$26,397
ad	General and Administration (ad)	$156,654,364	$103,021,824	$17,202,448	$31,593,021	$3,051,436	$1,220,080	$16,737	$486,543	$0	$62,276
dep	Depreciation and Amortization (dep)	$194,294,129	$112,819,837	$24,126,704	$50,912,108	$4,367,962	$1,250,715	$18,228	$548,446	$0	$250,129
INPUT	PILs (INPUT)	$22,275,701	$12,917,594	$2,411,223	$6,124,781	$562,239	$155,284	$2,248	$68,310	$0	$34,022
INT	Interest	$113,343,398	$65,727,406	$12,268,805	$31,164,157	$2,860,787	$790,119	$11,438	$347,574	$0	$173,111
	Total Expenses	**$682,336,124**	**$424,683,419**	**$77,552,093**	**$157,902,016**	**$14,549,996**	**$4,954,322**	**$69,642**	**$2,058,741**	**$0**	**$565,895**
	Direct Allocation	**$223,113**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$223,113**
NI	Allocated Net Income (NI)	$163,027,961	$94,539,296	$17,646,888	$44,825,099	$4,114,826	$1,136,471	$16,452	$499,935	$0	$248,995
	Revenue Requirement (includes NI)	**$845,587,199**	$519,222,715	$95,198,980	$202,727,115	$18,664,822	$6,090,794	$86,094	$2,558,676	$0	$1,038,003
	Revenue Requirement Input equals Output										
	Rate Base Calculation										
	Net Assets										
dp	Distribution Plant - Gross	$6,360,819,346	$3,699,585,254	$704,576,615	$1,728,418,697	$155,792,573	$44,524,686	$647,839	$19,565,489	$0	$7,708,192
gp	General Plant - Gross	$713,161,277	$415,570,613	$76,034,892	$194,543,560	$17,713,005	$5,131,813	$74,697	$2,254,823	$0	$1,837,873
accum dep	Accumulated Depreciation	($1,622,175,399)	($932,469,656)	($198,822,017)	($434,949,476)	($38,448,012)	($10,283,514)	($148,605)	($4,509,581)	$0	($2,544,537)
co	Capital Contribution	($1,269,028,975)	($756,149,391)	($129,581,374)	($338,680,990)	($29,621,494)	($10,138,157)	($150,534)	($4,451,579)	$0	($255,457)
	Total Net Plant	**$4,182,776,249**	**$2,426,536,821**	**$452,208,116**	**$1,149,331,791**	**$105,436,072**	**$29,234,828**	**$423,397**	**$12,859,151**	**$0**	**$6,746,072**
	Directly Allocated Net Fixed Assets	**$1,751,001**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$1,751,001**
COP	Cost of Power (COP)	$4,011,903,568	$1,287,914,650	$423,234,574	$1,919,507,132	$314,934,143	$13,903,534	$86,091	$6,973,889	$0	$45,349,556
	OM&A Expenses	$352,422,897	$233,218,582	$38,745,361	$69,700,970	$6,759,008	$2,758,204	$37,729	$1,094,411	$0	$108,633
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	***$4,364,326,465***	***$1,521,133,232***	***$461,979,935***	***$1,989,208,102***	***$321,693,151***	***$16,661,737***	***$123,819***	***$8,068,300***	***$0***	***$45,458,189***
	Working Capital	**$346,091,089**	**$120,625,865**	**$36,635,009**	**$157,744,202**	**$25,510,267**	**$1,321,276**	**$9,819**	**$639,816**	**$0**	**$3,604,834**
	Total Rate Base	**$4,530,618,339**	**$2,547,162,686**	**$488,843,125**	**$1,307,075,994**	**$130,946,339**	**$30,556,104**	**$433,216**	**$13,498,967**	**$0**	**$12,101,908**
	Rate Base Input equals Output										
	Equity Component of Rate Base	**$1,812,247,335**	**$1,018,865,074**	**$195,537,250**	**$522,830,397**	**$52,378,536**	**$12,222,442**	**$173,286**	**$5,399,587**	**$0**	**$4,840,763**
	Net Income on Allocated Assets	**$163,027,961**	**$47,934,462**	**$41,562,564**	**$62,065,944**	**$5,491,995**	**$4,659,299**	**$2,385**	**$723,793**	**$0**	**$587,519**
	Net Income on Direct Allocation Assets	**$74,299**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$74,299**
	Net Income	**$163,102,260**	**$47,934,462**	**$41,562,564**	**$62,065,944**	**$5,491,995**	**$4,659,299**	**$2,385**	**$723,793**	**$0**	**$661,818**
	RATIOS ANALYSIS										
	REVENUE TO EXPENSES STATUS QUO%	**100.00%**	**91.02%**	**125.12%**	**108.50%**	**107.38%**	**157.84%**	**83.66%**	**108.75%**	0.00%	132.61%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($109,709,691)	($107,225,202)	$8,372,726	($11,846,673)	($1,270,637)	$2,266,892	($23,149)	($137,883)	$0	$154,235
	Deficiency Input equals Output										
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	$0	($46,604,833)	$23,915,676	$17,240,845	$1,377,169	$3,522,828	($14,067)	$223,858	$0	$338,524
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.00%	4.70%	21.26%	11.87%	10.49%	38.12%	1.38%	13.40%	0.00%	13.67%

EMBEDDED DISTRIBUTOR – REMAINS

Ontario Energy Board

2026 Cost Allocation Model

EB-2025-0252

Sheet I6.1 Revenue Worksheet -

Total kWhs from Load Forecast	27,939,557,986
Total kWs from Load Forecast	40,307,128
Deficiency/sufficiency (RRWF 8. cell F51)	- 109,646,898
Miscellaneous Revenue (RRWF 5. cell F48)	31,949,746

			1	2	3	6	7	8	9	10	11
	ID	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Large Use >5MW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**	**Large Use >5MW with Dedicated Assets**
Billing Data											
Forecast kWh	**CEN**	27,939,557,986	8,726,286,424	2,875,761,314	13,182,366,199	2,142,187,817	94,572,090	585,590	47,436,520	17,012,414	853,349,619
Forecast kW	**CDEM**	40,307,128			34,388,480	4,047,427	264,100	1,609			1,605,512
Forecast kW, included in CDEM, of customers receiving line transformer allowance		14,872,947			10,895,945	3,977,002					
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		10,948,237		10,948,237							
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	27,162,002,920	8,726,286,424	2,875,761,314	13,036,478,847	2,142,187,817	94,572,090	585,590	47,436,520	17,012,414	221,681,904
Existing Monthly Charge			$ 32.56	$ 42.55	$ 264.43	$ 14,971.02	$ 1.57	$ 6.52	$ 9.26	$ 5,232.85	$ 7,090.86
Existing Distribution kWh Rate				$0.0187					$0.0217		
Existing Distribution kW Rate					$4.4936	$3.1961	$10.9939	$16.4776			$0.4185
Existing TOA Rate				$0.0032	$0.6189	$0.4264					
Additional Charges											
Distribution Revenue from Rates		$712,464,884	$388,957,071	$99,762,904	$193,377,070	$18,684,854	$8,058,433	$58,276	$2,321,031	$62,794	$1,182,449
Transformer Ownership Allowance		$8,474,329	$0	$35,034	$6,743,500	$1,695,794	$0	$0	$0	$0	$0
Net Class Revenue	**CREV**	$703,990,555	$388,957,071	$99,727,870	$186,633,570	$16,989,061	$8,058,433	$58,276	$2,321,031	$62,794	$1,182,449

Ontario Energy Board

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Sheet I6.2 Customer Data Worksheet -

			1	2	3	6	7	8	9	10	11
	ID	Total	Residential	GS <50	GS>50-Regular	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor	Large Use >5MW with Dedicated Assets
Billing Data											
Bad Debt 3 Year Historical Average	BDHA	$17,368,185	$11,068,983	$3,824,562	$2,473,824	$0	$198	$140	$478	$0	$0
Late Payment 3 Year Historical Average	LPHA	$10,555,000	$7,404,859	$1,926,113	$1,134,045	$72,690	$6,115	$1,599	$3,820	$0	$5,758
Number of Bills	CNB	13,241,124	11,945,856	1,080,756	146,916	384	384	2,340	64,404	12	72
Number of Devices	CDEV						273,617				
Number of Connections (Unmetered)	CCON	80,434					68,404	406	11,624		
Total Number of Customers	CCA	1,103,427	995,488	90,063	12,243	32	32	195	5,367	1	6
Bulk Customer Base	CCB	-									
Primary Customer Base	CCP	1,112,819	995,488	90,063	12,243	32	9,424	195	5,367	1	6
Line Transformer Customer Base	CCLT	1,111,506	995,488	89,973	11,058	1	9,424	195	5,367	-	-
Secondary Customer Base	CCS	1,015,993	959,153	45,950	5,296	-	32	195	5,367	-	-
Weighted - Services	CWCS	959,153	959,153	-	-	-	-	-	-	-	-
Weighted Meter -Capital	CWMC	407,655,094	234,149,180	111,436,216	61,401,712	549,472	-	-	-	-	118,514
Weighted Meter Reading	CWMR	15,649,857	11,945,856	1,610,326	2,072,768	17,197	-	-	-	-	3,709
Weighted Bills	CWNB	13,842,259	11,945,856	1,296,907	514,206	35,674	1,766	1,404	38,642	1,115	6,689

Bad Debt Data

Historic Year:	2022	16,109,352	9,088,338	3,576,779	3,444,222	-	12	1	-	-	-
Historic Year:	2023	18,746,929	12,380,818	4,766,918	1,597,878	-	34	417	864	-	-
Historic Year:	2024	17,248,274	11,737,793	3,129,990	2,379,372	-	549	1	570	-	-
Three-year average		**17,368,185**	**11,068,983**	**3,824,562**	**2,473,824**	**-**	**198**	**140**	**478**	**-**	**-**

Ontario Energy Board

2026 Cost Allocation Model

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Sheet O1 Revenue to Cost Summary Worksheet -

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS>50-Regular	6 Large Use >5MW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor	11 Large Use >5MW with Dedicated Assets
crev	Distribution Revenue at Existing Rates	$703,990,555	$388,957,071	$99,727,870	$186,633,570	$16,989,061	$8,058,433	$58,276	$2,321,031	$62,794	$1,182,449
mi	Miscellaneous Revenue (mi)	$31,949,746	$23,039,590	$3,843,736	$4,246,785	$405,116	$299,249	$4,668	$99,758	$1,055	$9,789
	Miscellaneous Revenue Input equals Output										
	Total Revenue at Existing Rates	$735,940,301	$411,996,661	$103,571,606	$190,880,355	$17,394,176	$8,357,682	$62,944	$2,420,790	$63,849	$1,192,238
	Factor required to recover deficiency (1 + D)	1.1558									
	Distribution Revenue at Status Quo Rates	$813,637,453	$449,537,339	$115,260,538	$215,701,846	$19,635,116	$9,313,538	$67,353	$2,682,533	$72,574	$1,366,616
	Miscellaneous Revenue (mi)	$31,949,746	$23,039,590	$3,843,736	$4,246,785	$405,116	$299,249	$4,668	$99,758	$1,055	$9,789
	Total Revenue at Status Quo Rates	$845,587,198	$472,576,928	$119,104,274	$219,948,631	$20,040,232	$9,612,787	$72,021	$2,782,291	$73,629	$1,376,405
	Expenses										
di	Distribution Costs (di)	$116,323,965	$66,689,953	$11,740,869	$32,963,475	$3,569,458	$947,412	$12,799	$380,042	$0	$19,958
cu	Customer Related Costs (cu)	$79,431,149	$63,494,271	$9,800,354	$5,141,995	$137,870	$590,599	$8,191	$227,768	$3,707	$26,393
ad	General and Administration (ad)	$156,654,364	$103,012,496	$17,201,162	$31,591,149	$3,051,253	$1,219,995	$16,735	$486,500	$12,802	$62,273
dep	Depreciation and Amortization (dep)	$194,288,569	$112,815,210	$24,125,806	$50,909,985	$4,367,717	$1,250,661	$18,227	$548,418	$2,417	$250,127
INPUT	PILs (INPUT)	$22,274,816	$12,917,070	$2,411,092	$6,124,578	$562,221	$155,278	$2,248	$68,307	$0	$34,022
INT	Interest	$113,338,895	$65,724,740	$12,268,136	$31,163,125	$2,860,695	$790,089	$11,437	$347,562	$0	$173,111
	Total Expenses	$682,311,758	$424,653,739	$77,547,419	$157,894,306	$14,549,214	$4,954,033	$69,637	$2,058,598	$18,926	$565,884
	Direct Allocation	$253,956	$0	$0	$0	$0	$0	$0	$0	$30,843	$223,113
NI	Allocated Net Income (NI)	$163,021,485	$94,535,460	$17,645,926	$44,823,614	$4,114,693	$1,136,428	$16,451	$499,917	$0	$248,995
	Revenue Requirement (includes NI)	$845,587,198	$519,189,200	$95,193,346	$202,717,920	$18,663,907	$6,090,461	$86,088	$2,558,516	$49,769	$1,037,992
	Revenue Requirement Input equals Output										
	Rate Base Calculation										
	Net Assets										
dp	Distribution Plant - Gross	$6,360,597,876	$3,699,454,152	$704,547,106	$1,728,365,369	$155,787,368	$44,523,063	$647,816	$19,564,822	$0	$7,708,180
gp	General Plant - Gross	$713,161,277	$415,551,751	$76,030,556	$194,535,787	$17,712,308	$5,131,592	$74,694	$2,254,732	$32,011	$1,837,846
accum dep	Accumulated Depreciation	($1,622,106,562)	($932,419,230)	($198,812,935)	($434,927,146)	($38,445,565)	($10,282,812)	($148,595)	($4,509,276)	($16,480)	($2,544,522)
co	Capital Contribution	($1,269,028,975)	($756,149,250)	($129,581,341)	($338,680,932)	($29,621,489)	($10,138,155)	($150,534)	($4,451,579)	($238)	($255,457)
	Total Net Plant	$4,182,623,617	$2,426,437,422	$452,183,386	$1,149,293,078	$105,432,622	$29,233,688	$423,382	$12,858,699	$15,293	$6,746,047
	Directly Allocated Net Fixed Assets	$1,903,633	$0	$0	$0	$0	$0	$0	$0	$152,632	$1,751,001
COP	Cost of Power (COP)	$4,011,903,568	$1,287,114,204	$422,970,786	$1,918,309,526	$314,737,644	$13,894,859	$86,037	$6,969,538	$2,499,523	$45,321,453
	OM&A Expenses	$352,409,478	$233,196,720	$38,742,385	$69,696,618	$6,758,581	$2,758,005	$37,725	$1,094,311	$16,509	$108,624
	Directly Allocated Expenses	$13,419	$0	$0	$0	$0	$0	$0	$0	$13,419	$0
	Subtotal	***$4,364,326,465***	***$1,520,310,924***	***$461,713,171***	***$1,988,006,144***	***$321,496,225***	***$16,652,864***	***$123,762***	***$8,063,848***	***$2,529,450***	***$45,430,077***
	Working Capital	$346,091,089	$120,560,656	$36,613,854	$157,648,887	$25,494,651	$1,320,572	$9,814	$639,463	$200,585	$3,602,605
	Total Rate Base	$4,530,618,338	$2,546,998,079	$488,797,240	$1,306,941,965	$130,927,273	$30,554,260	$433,196	$13,498,162	$368,510	$12,099,652
	Rate Base Input equals Output										
	Equity Component of Rate Base	$1,812,247,335	$1,018,799,231	$195,518,896	$522,776,786	$52,370,909	$12,221,704	$173,279	$5,399,265	$147,404	$4,839,861
	Net Income on Allocated Assets	$163,021,485	$47,923,189	$41,556,855	$62,054,325	$5,491,017	$4,658,754	$2,383	$723,693	$23,860	$587,408
	Net Income on Direct Allocation Assets	$80,775	$0	$0	$0	$0	$0	$0	$0	$6,477	$74,299
	Net Income	$163,102,260	$47,923,189	$41,556,855	$62,054,325	$5,491,017	$4,658,754	$2,383	$723,693	$30,337	$661,707
	RATIOS ANALYSIS										
	REVENUE TO EXPENSES STATUS QUO%	100.00%	91.02%	125.12%	108.50%	107.37%	157.83%	83.66%	108.75%	147.94%	132.60%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($109,646,897)	($107,192,539)	$8,378,261	($11,837,565)	($1,269,731)	$2,267,221	($23,144)	($137,726)	$14,080	$154,246
	Deficiency Input equals Output										
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	($46,612,272)	$23,910,929	$17,230,711	$1,376,324	$3,522,326	($14,068)	$223,776	$23,860	$338,413
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.00%	4.70%	21.25%	11.87%	10.48%	38.12%	1.38%	13.40%	20.58%	13.67%

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Attachment 8
Bill Impact and Tariff Model

Please see live Excel

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Attachment 9
2027-2031 Proposed Tariff of Rates

Alectra Utilities Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 01, 2027
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2025-0252

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are single-phase. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	38.26
Smart Metering Entity Charge	$	0.42
Low Voltage Service Rate	$/kWh	0.0005
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers	$	1.43
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers	$	(0.11)
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Guelph Rate Zone Customers	$	0.96
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Horizon Rate Zone Customers	$	(0.85)
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former PowerStream Rate Zone Customers	$	0.93
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers	$	5.20
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers	$	(1.59)
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Guelph Rate Zone Customers	$	(1.46)
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Horizon Rate Zone Customers	$	(5.40)
Rate Rider for Incremental Capital Expenditures True-Up - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers	$	(0.39)
Rate Rider for Incremental Capital Expenditures True-Up - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers	$	(0.34)
Rate Rider for Incremental Capital Expenditures True-Up - effective until December 31, 2027 Applicable only for former PowerStream Rate Zone Customers	$	0.17
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers	$	(1.03)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers	$	(0.88)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Guelph Rate Zone Customers	$	(0.79)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Horizon Rate Zone Customers	$	(1.04)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former PowerStream Rate Zone Customers	$	(1.44)

Alectra Utilities Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 01, 2027
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EB-2025-0252

Retail Transmission Rate - Network Service Rate	$/kWh	0.0127
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0076

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Alectra Utilities Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 01, 2027
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EB-2025-0252

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non-residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	47.08
Smart Metering Entity Charge	$	0.42
Distribution Volumetric Rate	$/kWh	0.0207
Low Voltage Service Rate	$/kWh	0.0004
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers	$/kWh	0.0019
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers	$/kWh	0.0001
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Guelph Rate Zone Customers	$/kWh	0.0015
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Horizon Rate Zone Customers	$/kWh	(0.0003)
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former PowerStream Rate Zone Customers	$/kWh	0.0014
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers	$/kWh	0.0062
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers	$/kWh	(0.0022)
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Guelph Rate Zone Customers	$/kWh	(0.0022)
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Horizon Rate Zone Customers	$/kWh	(0.0083)
Rate Rider for Incremental Capital Expenditures True-Up - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers	$/kWh	(0.0005)
Rate Rider for Incremental Capital Expenditures True-Up - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers	$/kWh	(0.0005)
Rate Rider for Incremental Capital Expenditures True-Up - effective until December 31, 2027 Applicable only for former PowerStream Rate Zone Customers	$/kWh	0.0002
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers	$/kWh	(0.0012)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers	$/kWh	(0.0012)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Guelph Rate Zone Customers	$/kWh	(0.0012)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Horizon Rate Zone Customers	$/kWh	(0.0016)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former PowerStream Rate Zone Customers	$/kWh	(0.0019)

Alectra Utilities Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 01, 2027
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EB-2025-0252

Retail Transmission Rate - Network Service Rate	$/kWh	0.0117
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0069

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Alectra Utilities Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 01, 2027
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EB-2025-0252

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	294.98
Distribution Volumetric Rate	$/kW	5.2004
Low Voltage Service Rate	$/kW	0.1706
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers, General Service 50 to 699 KW Service Classification	$/kW	0.8072
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers, General Service 700 to 4,999 KW Service Classification	$/kW	1.0588
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers, General Service 50 to 499 KW Service Classification	$/kW	0.1151
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers, General Service 500 to 4,999 KW Service Classification	$/kW	0.2274
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Guelph Rate Zone Customers, General Service 50 to 999 KW Service Classification	$/kW	0.7151
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Guelph Rate Zone Customers, General Service 1,000 to 4,999 KW Service Classification	$/kW	1.0897
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Horizon Rate Zone Customers	$/kW	0.2898
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former PowerStream Rate Zone Customers	$/kW	0.6948
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers, General Service 50 to 699 KW Service Classification	$/kW	2.2113
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers, General Service 700 to 4,999 KW Service Classification	$/kW	2.7316
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers, General Service 50 to 499 KW Service Classification	$/kW	(0.7539)

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Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers, General Service 500 to 4,999 KW Service Classification	$/kW	(0.9951)
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Guelph Rate Zone Customers, General Service 50 to 999 KW Service Classification	$/kW	(0.7955)
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Guelph Rate Zone Customers, General Service 1,000 to 4,999 KW Service Classification	$/kW	(1.0428)
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Horizon Rate Zone Customers	$/kW	(2.9246)
Rate Rider for Incremental Capital Expenditures True-Up - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers, General Service 50 to 699 KW Service Classification	$/kW	(0.1663)
Rate Rider for Incremental Capital Expenditures True-Up - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers, General Service 700 to 4,999 KW Service Classification	$/kW	(0.2054)
Rate Rider for Incremental Capital Expenditures True-Up - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers, General Service 50 to 499 KW Service Classification	$/kW	(0.1632)
Rate Rider for Incremental Capital Expenditures True-Up - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers, General Service 500 to 4,999 KW Service Classification	$/kW	(0.2154)
Rate Rider for Incremental Capital Expenditures True-Up - effective until December 31, 2027 Applicable only for former PowerStream Rate Zone Customers	$/kW	0.0858
Rate Rider for Recovery of MIST Meter Assets - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers, General Service 50 to 699 KW Service Classification	$	69.05
Rate Rider for Recovery of MIST Meter Assets - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers	$	83.77
Rate Rider for Recovery of MIST Meter Assets - effective until December 31, 2027 Applicable only for former Guelph Rate Zone Customers, General Service 50 to 999 KW Service Classification	$	53.85
Rate Rider for Recovery of MIST Meter Assets - effective until December 31, 2027 Applicable only for former PowerStream Rate Zone Customers	$	112.11
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers, General Service 50 to 699 KW Service Classification	$/kW	(0.4392)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers, General Service 700 to 4,999 KW Service Classification	$/kW	(0.5425)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers, General Service 50 to 499 KW Service Classification	$/kW	(0.4170)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers, General Service 500 to 4,999 KW Service Classification	$/kW	(0.5505)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Guelph Rate Zone Customers, General Service 50 to 999 KW Service Classification	$/kW	(0.4319)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Guelph Rate Zone Customers, General Service 1,000 to 4,999 KW Service Classification	$/kW	(0.5661)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Horizon Rate Zone Customers	$/kW	(0.5644)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former PowerStream Rate Zone Customers	$/kW	(0.7441)
Retail Transmission Rate - Network Service Rate	$/kW	4.8104
Retail Transmission Rate - Network Service Rate - EV CHARGING	$/kW	0.8579
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.8600
Retail Transmission Rate - Line and Transformation Connection Service Rate - EV CHARGING	$/kW	0.4504

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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LARGE USE SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	15,733.81
Distribution Volumetric Rate	$/kW	3.9406
Low Voltage Service Rate	$/kW	0.1946
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers	$/kW	1.2834
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers	$/kW	0.3283
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Guelph Rate Zone Customers	$/kW	1.0284
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Horizon Rate Zone Customers	$/kW	0.4345
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former PowerStream Rate Zone Customers	$/kW	0.9944
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers	$/kW	3.2834
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers	$/kW	(1.2777)
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Guelph Rate Zone Customers	$/kW	(1.0024)
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Horizon Rate Zone Customers	$/kW	(3.5644)
Rate Rider for Incremental Capital Expenditures True-Up - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers	$/kW	(0.2469)
Rate Rider for Incremental Capital Expenditures True-Up - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers	$/kW	(0.2766)

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Rate Rider for Incremental Capital Expenditures True-Up - effective until December 31, 2027 Applicable only for former PowerStream Rate Zone Customers	$/kW	0.1145
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers	$/kW	(0.6521)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers	$/kW	(0.7068)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Guelph Rate Zone Customers	$/kW	(0.5442)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Horizon Rate Zone Customers	$/kW	(0.6879)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former PowerStream Rate Zone Customers	$/kW	(0.9929)
Retail Transmission Rate - Network Service Rate	$/kW	4.8030
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	3.2502

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Alectra Utilities Corporation
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LARGE USE WITH DEDICATED ASSETS SERVICE CLASSIFICATION

This classification only applies to former Horizon Rate Zone Customers who were in this classification as of December 31, 2026. This classification applies to an account where average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW and using dedicated assets. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	7,090.86
Distribution Volumetric Rate	$/kW	0.4194
Low Voltage Service Rate	$/kW	0.2382
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027	$/kW	0.9196
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027	$/kW	(4.4287)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027	$/kW	(0.8547)
Retail Transmission Rate - Network Service Rate	$/kW	5.3021
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	3.9782

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per luminaire)	$	1.37
Distribution Volumetric Rate	$/kW	9.5631
Low Voltage Service Rate	$/kW	0.1380
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers	$/kW	(0.1369)
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers	$/kW	0.8852
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Guelph Rate Zone Customers	$/kW	11.6234
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Horizon Rate Zone Customers	$/kW	(0.7619)
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former PowerStream Rate Zone Customers	$/kW	1.1441
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers	$/kW	2.1878
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers	$/kW	(0.8077)
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Guelph Rate Zone Customers	$/kW	(0.7860)
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Horizon Rate Zone Customers	$/kW	(3.0242)
Rate Rider for Incremental Capital Expenditures True-Up - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers	$/kW	(0.1645)
Rate Rider for Incremental Capital Expenditures True-Up - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers	$/kW	(0.1748)
Rate Rider for Incremental Capital Expenditures True-Up - effective until December 31, 2027 Applicable only for former PowerStream Rate Zone Customers	$/kW	0.0790
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers	$/kW	(0.4345)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers	$/kW	(0.4468)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Guelph Rate Zone Customers	$/kW	(0.4267)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Horizon Rate Zone Customers	$/kW	(0.5836)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former PowerStream Rate Zone Customers	$/kW	(0.6850)

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Retail Transmission Rate - Network Service Rate	$/kW	4.1309
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.3044

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification applies to safety/security lighting with a Residential, General Service or Large Use customer. This is typically exterior lighting, and often unmetered. Consumption is estimated based on the equipment rating and estimated hours of use. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	6.51
Distribution Volumetric Rate	$/kW	16.4505
Low Voltage Service Rate	$/kW	0.1711
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Guelph Rate Zone Customers	$/kW	3.8908
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Horizon Rate Zone Customers	$/kW	(1.2665)
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former PowerStream Rate Zone Customers	$/kW	0.3410
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Guelph Rate Zone Customers	$/kW	(0.7963)
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Horizon Rate Zone Customers	$/kW	(3.0220)
Rate Rider for Incremental Capital Expenditures True-Up - effective until December 31, 2027 Applicable only for former PowerStream Rate Zone Customers	$/kW	0.0816
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Guelph Rate Zone Customers	$/kW	(0.4323)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Horizon Rate Zone Customers	$/kW	(0.5832)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former PowerStream Rate Zone Customers	$/kW	(0.7072)
Retail Transmission Rate - Network Service Rate	$/kW	4.6962
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.8588

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	10.22
Distribution Volumetric Rate	$/kWh	0.0239
Low Voltage Service Rate	$/kWh	0.0004
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers	$/kWh	0.0013
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers	$/kWh	(0.0001)
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Guelph Rate Zone Customers	$/kWh	0.0028
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former Horizon Rate Zone Customers	$/kWh	(0.0010)
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2027 Applicable only for former PowerStream Rate Zone Customers	$/kWh	0.0014
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers	$/kWh	0.0062
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers	$/kWh	(0.0022)
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Guelph Rate Zone Customers	$/kWh	(0.0022)
Rate Rider for Disposition of Impact of Post-Merger Capitalization Policy - effective until December 31, 2027 Applicable only for former Horizon Rate Zone Customers	$/kWh	(0.0083)
Rate Rider for Incremental Capital Expenditures True-Up - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers	$/kWh	(0.0005)
Rate Rider for Incremental Capital Expenditures True-Up - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers	$/kWh	(0.0005)
Rate Rider for Incremental Capital Expenditures True-Up - effective until December 31, 2027 Applicable only for former PowerStream Rate Zone Customers	$/kWh	0.0002
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Brampton Rate Zone Customers	$/kWh	(0.0012)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Enersource Rate Zone Customers	$/kWh	(0.0012)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Guelph Rate Zone Customers	$/kWh	(0.0012)
Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former Horizon Rate Zone Customers	$/kWh	(0.0016)

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Rate Rider for Disposition of PILs and Tax Variance CCA Changes - effective until December 31, 2027 Applicable only for former PowerStream Rate Zone Customers	$/kWh	(0.0019)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0117
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0072

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that requires the distributor to provide back-up service for the following: a) an on-site generator, b) redundant supply (without load displacement generation). Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Standby Charge - the charge is calculated by multiplying the customer's reserved standby demand, less actual demand billed in a given month, by the applicable General Service 50 to 4,999 kW, Large Use, or Large Use with Dedicated Assets Volumetric Rate for a month where standby power is provided partially or is not provided. Where the customer’s reserved standby demand less actual demand billed in a given month results in a value of less than zero, the Standby Charge will be zero for that month.

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microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.00

ALLOWANCES

Transformer Allowance for Ownership - per kWh of billing consumption/month or per kW of billing demand/month		
General Service less than 50 kW Classification	$/kWh	(0.0032)
General Service 50 to 4,999 kW Classification	$/kW	(0.5920)
Large Use Classification	$/kW	(0.5920)
Primary Metering Allowance for transformer losses - applied to measured demand and energy	%	(1.00)

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SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Customer Administration

Arrears certificate	$	15.00
Statement of account	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Account history	$	15.00
Credit Check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Special billing service (aggregation)	$	125.00
Special billing service (sub-metering charge per meter)	$	25.00

Non-Payment of Account

Late payment – per month (effective annual rate 19.56% per annum or 0.0486% compounded daily rate)	%	1.5%
Reconnection at meter - during regular hours	$	65.00
Reconnection at meter - after regular hours	$	185.00
Reconnection at pole or transformer- during regular hours	$	185.00
Reconnection at pole or transformer - after regular hours	$	415.00

Other

Disconnect/reconnect at meter - during regular hours	$	295.00
Disconnect/reconnect at meter - after regular hours	$	470.00
Disconnect/reconnect at pole or transformer - during regular hours	$	525.00
Disconnect/reconnect at pole or transformer - after regular hours	$	1,090.00
Service Call - customer owned equipment	$	30.00
Service Call - after regular hours	$	165.00
Specific charge for access to the power poles - per pole/year (with the exception of wireless attachments)	$	40.59
Disconnect/reconnect - cancelled appointment	$	500.00

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RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	125.72
Monthly fixed charge, per retailer	$	50.29
Monthly variable charge, per customer, per retailer	$/cust.	1.24
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.74
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.74)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.63
Processing fee, per request, applied to the requesting party	$	1.24
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
more than twice a year, per request (plus incremental delivery costs)	$	5.03
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.51

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0356
Total Loss Factor - Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0254
Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0045

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RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are single-phase. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	40.62
Smart Metering Entity Charge	$	0.42
Low Voltage Service Rate	$/kWh	0.0005
Retail Transmission Rate - Network Service Rate	$/kWh	0.0125
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0075

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non-residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	49.98
Smart Metering Entity Charge	$	0.42
Distribution Volumetric Rate	$/kWh	0.0220
Low Voltage Service Rate	$/kWh	0.0004
Retail Transmission Rate - Network Service Rate	$/kWh	0.0116
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0069

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	313.15
Distribution Volumetric Rate	$/kW	5.5207
Low Voltage Service Rate	$/kW	0.1765
Retail Transmission Rate - Network Service Rate	$/kW	4.8820
Retail Transmission Rate - Network Service Rate - EV CHARGING	$/kW	0.8606
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.9026
Retail Transmission Rate - Line and Transformation Connection Service Rate - EV CHARGING	$/kW	0.4518

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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LARGE USE SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	16,702.90
Distribution Volumetric Rate	$/kW	4.1833
Low Voltage Service Rate	$/kW	0.2016
Retail Transmission Rate - Network Service Rate	$/kW	4.8809
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	3.3030

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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LARGE USE WITH DEDICATED ASSETS SERVICE CLASSIFICATION

This classification only applies to former Horizon Rate Zone Customers who were in this classification as of December 31, 2026. This classification applies to an account where average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW and using dedicated assets. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	7,527.61
Distribution Volumetric Rate	$/kW	0.4452
Low Voltage Service Rate	$/kW	0.2482
Retail Transmission Rate - Network Service Rate	$/kW	5.4203
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	4.0669

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per luminaire)	$	1.45
Distribution Volumetric Rate	$/kW	10.1521
Low Voltage Service Rate	$/kW	0.1435
Retail Transmission Rate - Network Service Rate	$/kW	4.2132
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.3503

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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Effective and Implementation Date January 01, 2028
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2025-0252

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification applies to safety/security lighting with a Residential, General Service or Large Use customer. This is typically exterior lighting, and often unmetered. Consumption is estimated based on the equipment rating and estimated hours of use. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	6.91
Distribution Volumetric Rate	$/kW	17.4637
Low Voltage Service Rate	$/kW	0.1837
Retail Transmission Rate - Network Service Rate	$/kW	4.9441
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	3.0097

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	10.85
Distribution Volumetric Rate	$/kWh	0.0254
Low Voltage Service Rate	$/kWh	0.0005
Retail Transmission Rate - Network Service Rate	$/kWh	0.0118
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0073

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that requires the distributor to provide back-up service for the following: a) an on-site generator, b) redundant supply (without load displacement generation). Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Standby Charge - the charge is calculated by multiplying the customer's reserved standby demand, less actual demand billed in a given month, by the applicable General Service 50 to 4,999 kW, Large Use, or Large Use with Dedicated Assets Volumetric Rate for a month where standby power is provided partially or is not provided. Where the customer’s reserved standby demand less actual demand billed in a given month results in a value of less than zero, the Standby Charge will be zero for that month.

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microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.00

ALLOWANCES

Transformer Allowance for Ownership - per kWh of billing consumption/month or per kW of billing demand/month		
General Service less than 50 kW Classification	$/kWh	(0.0032)
General Service 50 to 4,999 kW Classification	$/kW	(0.5920)
Large Use Classification	$/kW	(0.5920)
Primary Metering Allowance for transformer losses - applied to measured demand and energy	%	(1.00)

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SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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Customer Administration

Arrears certificate	$	15.00
Statement of account	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Account history	$	15.00
Credit Check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Special billing service (aggregation)	$	125.00
Special billing service (sub-metering charge per meter)	$	25.00

Non-Payment of Account

Late payment – per month (effective annual rate 19.56% per annum or 0.0486% compounded daily rate)	%	1.5%
Reconnection at meter - during regular hours	$	65.00
Reconnection at meter - after regular hours	$	185.00
Reconnection at pole or transformer- during regular hours	$	185.00
Reconnection at pole or transformer - after regular hours	$	415.00

Other

Disconnect/reconnect at meter - during regular hours	$	295.00
Disconnect/reconnect at meter - after regular hours	$	470.00
Disconnect/reconnect at pole or transformer - during regular hours	$	525.00
Disconnect/reconnect at pole or transformer - after regular hours	$	1,090.00
Service Call - customer owned equipment	$	30.00
Service Call - after regular hours	$	165.00
Specific charge for access to the power poles - per pole/year (with the exception of wireless attachments)	$	40.59
Disconnect/reconnect - cancelled appointment	$	500.00

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RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	125.72
Monthly fixed charge, per retailer	$	50.29
Monthly variable charge, per customer, per retailer	$/cust.	1.24
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.74
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.74)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.63
Processing fee, per request, applied to the requesting party	$	1.24
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
more than twice a year, per request (plus incremental delivery costs)	$	5.03
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.51

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0356
Total Loss Factor - Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0254
Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0045

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TARIFF OF RATES AND CHARGES

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RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are single-phase. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	42.44
Smart Metering Entity Charge	$	0.42
Low Voltage Service Rate	$/kWh	0.0005
Retail Transmission Rate - Network Service Rate	$/kWh	0.0123
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0074

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Alectra Utilities Corporation

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 01, 2029

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GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non-residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	52.22
Smart Metering Entity Charge	$	0.42
Distribution Volumetric Rate	$/kWh	0.0230
Low Voltage Service Rate	$/kWh	0.0004
Retail Transmission Rate - Network Service Rate	$/kWh	0.0115
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0068

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	327.20
Distribution Volumetric Rate	$/kW	5.7684
Low Voltage Service Rate	$/kW	0.1824
Retail Transmission Rate - Network Service Rate	$/kW	4.9546
Retail Transmission Rate - Network Service Rate - EV CHARGING	$/kW	0.8591
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.9457
Retail Transmission Rate - Line and Transformation Connection Service Rate - EV CHARGING	$/kW	0.4510

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Alectra Utilities Corporation
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LARGE USE SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	17,452.36
Distribution Volumetric Rate	$/kW	4.3710
Low Voltage Service Rate	$/kW	0.2010
Retail Transmission Rate - Network Service Rate	$/kW	4.7767
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	3.2324

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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LARGE USE WITH DEDICATED ASSETS SERVICE CLASSIFICATION

This classification only applies to former Horizon Rate Zone Customers who were in this classification as of December 31, 2026. This classification applies to an account where average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW and using dedicated assets. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

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If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	7,865.38
Distribution Volumetric Rate	$/kW	0.4652
Low Voltage Service Rate	$/kW	0.2573
Retail Transmission Rate - Network Service Rate	$/kW	5.5163
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	4.1390

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per luminaire)	$	1.52
Distribution Volumetric Rate	$/kW	10.6076
Low Voltage Service Rate	$/kW	0.1485
Retail Transmission Rate - Network Service Rate	$/kW	4.2807
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.3880

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Alectra Utilities Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 01, 2029
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2025-0252

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification applies to safety/security lighting with a Residential, General Service or Large Use customer. This is typically exterior lighting, and often unmetered. Consumption is estimated based on the equipment rating and estimated hours of use. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	7.22
Distribution Volumetric Rate	$/kW	18.2473
Low Voltage Service Rate	$/kW	0.1998
Retail Transmission Rate - Network Service Rate	$/kW	5.2797
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	3.2140

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Alectra Utilities Corporation
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Effective and Implementation Date January 01, 2029
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EB-2025-0252

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	11.34
Distribution Volumetric Rate	$/kWh	0.0265
Low Voltage Service Rate	$/kWh	0.0005
Retail Transmission Rate - Network Service Rate	$/kWh	0.0120
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0074

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Alectra Utilities Corporation
TARIFF OF RATES AND CHARGES
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EB-2025-0252

STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that requires the distributor to provide back-up service for the following: a) an on-site generator, b) redundant supply (without load displacement generation). Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Standby Charge - the charge is calculated by multiplying the customer's reserved standby demand, less actual demand billed in a given month, by the applicable General Service 50 to 4,999 kW, Large Use, or Large Use with Dedicated Assets Volumetric Rate for a month where standby power is provided partially or is not provided. Where the customer’s reserved standby demand less actual demand billed in a given month results in a value of less than zero, the Standby Charge will be zero for that month.

Alectra Utilities Corporation
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microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.00

ALLOWANCES

Transformer Allowance for Ownership - per kWh of billing consumption/month or per kW of billing demand/month		
General Service less than 50 kW Classification	$/kWh	(0.0032)
General Service 50 to 4,999 kW Classification	$/kW	(0.5920)
Large Use Classification	$/kW	(0.5920)
Primary Metering Allowance for transformer losses - applied to measured demand and energy	%	(1.00)

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TARIFF OF RATES AND CHARGES
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SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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Customer Administration

Arrears certificate	$	15.00
Statement of account	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Account history	$	15.00
Credit Check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Special billing service (aggregation)	$	125.00
Special billing service (sub-metering charge per meter)	$	25.00

Non-Payment of Account

Late payment – per month (effective annual rate 19.56% per annum or 0.0486% compounded daily rate)	%	1.5%
Reconnection at meter - during regular hours	$	65.00
Reconnection at meter - after regular hours	$	185.00
Reconnection at pole or transformer- during regular hours	$	185.00
Reconnection at pole or transformer - after regular hours	$	415.00

Other

Disconnect/reconnect at meter - during regular hours	$	295.00
Disconnect/reconnect at meter - after regular hours	$	470.00
Disconnect/reconnect at pole or transformer - during regular hours	$	525.00
Disconnect/reconnect at pole or transformer - after regular hours	$	1,090.00
Service Call - customer owned equipment	$	30.00
Service Call - after regular hours	$	165.00
Specific charge for access to the power poles - per pole/year (with the exception of wireless attachments)	$	40.59
Disconnect/reconnect - cancelled appointment	$	500.00

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TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 01, 2029
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

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RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

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Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	125.72
Monthly fixed charge, per retailer	$	50.29
Monthly variable charge, per customer, per retailer	$/cust.	1.24
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.74
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.74)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.63
Processing fee, per request, applied to the requesting party	$	1.24
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
more than twice a year, per request (plus incremental delivery costs)	$	5.03
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.51

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0356
Total Loss Factor - Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0254
Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0045

Alectra Utilities Corporation

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 01, 2030

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2025-0252

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are single-phase. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	44.83
Smart Metering Entity Charge	$	0.42
Low Voltage Service Rate	$/kWh	0.0005
Retail Transmission Rate - Network Service Rate	$/kWh	0.0120
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0072

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Alectra Utilities Corporation

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 01, 2030

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2025-0252

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non-residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	55.16
Smart Metering Entity Charge	$	0.42
Distribution Volumetric Rate	$/kWh	0.0243
Low Voltage Service Rate	$/kWh	0.0004
Retail Transmission Rate - Network Service Rate	$/kWh	0.0113
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0067

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	345.61
Distribution Volumetric Rate	$/kW	6.0930
Low Voltage Service Rate	$/kW	0.1898
Retail Transmission Rate - Network Service Rate	$/kW	5.0380
Retail Transmission Rate - Network Service Rate - EV CHARGING	$/kW	0.8604
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.9953
Retail Transmission Rate - Line and Transformation Connection Service Rate - EV CHARGING	$/kW	0.4517

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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LARGE USE SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	18,434.30
Distribution Volumetric Rate	$/kW	4.6169
Low Voltage Service Rate	$/kW	0.1926
Retail Transmission Rate - Network Service Rate	$/kW	4.4735
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	3.0273

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Alectra Utilities Corporation
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Effective and Implementation Date January 01, 2030
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LARGE USE WITH DEDICATED ASSETS SERVICE CLASSIFICATION

This classification only applies to former Horizon Rate Zone Customers who were in this classification as of December 31, 2026. This classification applies to an account where average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW and using dedicated assets. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

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If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	8,307.92
Distribution Volumetric Rate	$/kW	0.4914
Low Voltage Service Rate	$/kW	0.2685
Retail Transmission Rate - Network Service Rate	$/kW	5.6267
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	4.2217

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Alectra Utilities Corporation

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 01, 2030

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2025-0252

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per luminaire)	$	1.61
Distribution Volumetric Rate	$/kW	11.2044
Low Voltage Service Rate	$/kW	0.1549
Retail Transmission Rate - Network Service Rate	$/kW	4.3649
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.4349

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Alectra Utilities Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 01, 2030
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SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification applies to safety/security lighting with a Residential, General Service or Large Use customer. This is typically exterior lighting, and often unmetered. Consumption is estimated based on the equipment rating and estimated hours of use. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	7.63
Distribution Volumetric Rate	$/kW	19.2740
Low Voltage Service Rate	$/kW	0.2143
Retail Transmission Rate - Network Service Rate	$/kW	5.5340
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	3.3688

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Alectra Utilities Corporation

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 01, 2030

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UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	11.98
Distribution Volumetric Rate	$/kWh	0.0280
Low Voltage Service Rate	$/kWh	0.0005
Retail Transmission Rate - Network Service Rate	$/kWh	0.0121
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0075

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that requires the distributor to provide back-up service for the following: a) an on-site generator, b) redundant supply (without load displacement generation). Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Standby Charge - the charge is calculated by multiplying the customer's reserved standby demand, less actual demand billed in a given month, by the applicable General Service 50 to 4,999 kW, Large Use, or Large Use with Dedicated Assets Volumetric Rate for a month where standby power is provided partially or is not provided. Where the customer’s reserved standby demand less actual demand billed in a given month results in a value of less than zero, the Standby Charge will be zero for that month.

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microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.00

ALLOWANCES

Transformer Allowance for Ownership - per kWh of billing consumption/month or per kW of billing demand/month		
General Service less than 50 kW Classification	$/kWh	(0.0032)
General Service 50 to 4,999 kW Classification	$/kW	(0.5920)
Large Use Classification	$/kW	(0.5920)
Primary Metering Allowance for transformer losses - applied to measured demand and energy	%	(1.00)

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SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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Customer Administration

Arrears certificate	$	15.00
Statement of account	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Account history	$	15.00
Credit Check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Special billing service (aggregation)	$	125.00
Special billing service (sub-metering charge per meter)	$	25.00

Non-Payment of Account

Late payment – per month (effective annual rate 19.56% per annum or 0.0486% compounded daily rate)	%	1.5%
Reconnection at meter - during regular hours	$	65.00
Reconnection at meter - after regular hours	$	185.00
Reconnection at pole or transformer- during regular hours	$	185.00
Reconnection at pole or transformer - after regular hours	$	415.00

Other

Disconnect/reconnect at meter - during regular hours	$	295.00
Disconnect/reconnect at meter - after regular hours	$	470.00
Disconnect/reconnect at pole or transformer - during regular hours	$	525.00
Disconnect/reconnect at pole or transformer - after regular hours	$	1,090.00
Service Call - customer owned equipment	$	30.00
Service Call - after regular hours	$	165.00
Specific charge for access to the power poles - per pole/year (with the exception of wireless attachments)	$	40.59
Disconnect/reconnect - cancelled appointment	$	500.00

Alectra Utilities Corporation
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RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	125.72
Monthly fixed charge, per retailer	$	50.29
Monthly variable charge, per customer, per retailer	$/cust.	1.24
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.74
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.74)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.63
Processing fee, per request, applied to the requesting party	$	1.24
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
more than twice a year, per request (plus incremental delivery costs)	$	5.03
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.51

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0356
Total Loss Factor - Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0254
Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0045

Alectra Utilities Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 01, 2031
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EB-2025-0252

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are single-phase. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	47.22
Smart Metering Entity Charge	$	0.42
Low Voltage Service Rate	$/kWh	0.0005
Retail Transmission Rate - Network Service Rate	$/kWh	0.0118
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0070

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Alectra Utilities Corporation
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GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non-residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	58.11
Smart Metering Entity Charge	$	0.42
Distribution Volumetric Rate	$/kWh	0.0256
Low Voltage Service Rate	$/kWh	0.0004
Retail Transmission Rate - Network Service Rate	$/kWh	0.0112
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0066

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Alectra Utilities Corporation
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GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	364.07
Distribution Volumetric Rate	$/kW	6.4185
Low Voltage Service Rate	$/kW	0.1970
Retail Transmission Rate - Network Service Rate	$/kW	5.1201
Retail Transmission Rate - Network Service Rate - EV CHARGING	$/kW	0.8600
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	3.0441
Retail Transmission Rate - Line and Transformation Connection Service Rate - EV CHARGING	$/kW	0.4515

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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LARGE USE SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	19,419.03
Distribution Volumetric Rate	$/kW	4.8635
Low Voltage Service Rate	$/kW	0.1905
Retail Transmission Rate - Network Service Rate	$/kW	4.3338
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.9327

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Alectra Utilities Corporation
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Effective and Implementation Date January 01, 2031
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LARGE USE WITH DEDICATED ASSETS SERVICE CLASSIFICATION

This classification only applies to former Horizon Rate Zone Customers who were in this classification as of December 31, 2026. This classification applies to an account where average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW and using dedicated assets. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	8,751.72
Distribution Volumetric Rate	$/kW	0.5176
Low Voltage Service Rate	$/kW	0.2798
Retail Transmission Rate - Network Service Rate	$/kW	5.7392
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	4.3062

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Alectra Utilities Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 01, 2031
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2025-0252

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per luminaire)	$	1.70
Distribution Volumetric Rate	$/kW	11.8029
Low Voltage Service Rate	$/kW	0.1614
Retail Transmission Rate - Network Service Rate	$/kW	4.4518
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.4834

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Alectra Utilities Corporation
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EB-2025-0252

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification applies to safety/security lighting with a Residential, General Service or Large Use customer. This is typically exterior lighting, and often unmetered. Consumption is estimated based on the equipment rating and estimated hours of use. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	8.04
Distribution Volumetric Rate	$/kW	20.3036
Low Voltage Service Rate	$/kW	0.2280
Retail Transmission Rate - Network Service Rate	$/kW	5.7640
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	3.5088

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	12.62
Distribution Volumetric Rate	$/kWh	0.0295
Low Voltage Service Rate	$/kWh	0.0005
Retail Transmission Rate - Network Service Rate	$/kWh	0.0123
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0076

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that requires the distributor to provide back-up service for the following: a) an on-site generator, b) redundant supply (withou load displacement generation). Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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MONTHLY RATES AND CHARGES - Delivery Component

Standby Charge - the charge is calculated by multiplying the customer's reserved standby demand, less actual demand billed in a given month, by the applicable General Service 50 to 4,999 kW, Large Use, or Large Use with Dedicated Assets Volumetric Rate for a month where standby power is provided partially or is not provided. Where the customer's reserved standby demand less actual demand billed in a given month results in a value of less than zero, the Standby Charge will be zero for that month.

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microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.00

ALLOWANCES

Transformer Allowance for Ownership - per kWh of billing consumption/month or per kW of billing demand/month		
General Service less than 50 kW Classification	$/kWh	(0.0032)
General Service 50 to 4,999 kW Classification	$/kW	(0.5920)
Large Use Classification	$/kW	(0.5920)
Primary Metering Allowance for transformer losses - applied to measured demand and energy	%	(1.00)

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SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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Customer Administration

Arrears certificate	$	15.00
Statement of account	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Account history	$	15.00
Credit Check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Special billing service (aggregation)	$	125.00
Special billing service (sub-metering charge per meter)	$	25.00

Non-Payment of Account

Late payment – per month (effective annual rate 19.56% per annum or 0.0486% compounded daily rate)	%	1.5%
Reconnection at meter - during regular hours	$	65.00
Reconnection at meter - after regular hours	$	185.00
Reconnection at pole or transformer- during regular hours	$	185.00
Reconnection at pole or transformer - after regular hours	$	415.00

Other

Disconnect/reconnect at meter - during regular hours	$	295.00
Disconnect/reconnect at meter - after regular hours	$	470.00
Disconnect/reconnect at pole or transformer - during regular hours	$	525.00
Disconnect/reconnect at pole or transformer - after regular hours	$	1,090.00
Service Call - customer owned equipment	$	30.00
Service Call - after regular hours	$	165.00
Specific charge for access to the power poles - per pole/year (with the exception of wireless attachments)	$	40.59
Disconnect/reconnect - cancelled appointment	$	500.00

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RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	125.72
Monthly fixed charge, per retailer	$	50.29
Monthly variable charge, per customer, per retailer	$/cust.	1.24
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.74
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.74)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.63
Processing fee, per request, applied to the requesting party	$	1.24
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
more than twice a year, per request (plus incremental delivery costs)	$	5.03
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.51

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0356
Total Loss Factor - Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0254
Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0045

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-2

Letters of Comment

Following publication of the Notice of Application, the OEB received more than 85 letters of comment. Section 2.1.6 of the Filing Requirements states that distributors will be expected to file with the OEB their response to the matters raised within any letters of comment sent to the OEB related to the distributor's application. If the applicant has not received a copy of the letters or comments, they may be accessed from the public record for this proceeding.

Please file a response to the matters raised in the letters of comment referenced above. Going forward, please ensure that responses to any matters raised in subsequent letters of comment are filed in this proceeding. All responses must be filed before the argument (submission) phase of this proceeding.

RESPONSE:

Chapter 2 of the Ontario Energy Board's Filing Requirements for Electricity Distribution Applications, Section 2.1.6 states that before the record of a proceeding is closed, the applicant must file a document addressing the issues raised in the letters of comment. The OEB specifies that the applicant need not respond to each letter individually, but must address all issues raised in the letters. Following this direction, Alectra proposes to file a document responding to the issues raised in the letters of comment received, prior to the closing of the record.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-3

Service Territory Population Growth Projection

Ref 1: Exhibit 1 / Tab 3 / Schedule 1 / Table 1-3-2 / p. 16 (pdf p. 186)

Question(s):

a) Please provide a source(s) of data from Table 1-3-2 and indicate when the projection data was prepared.

RESPONSE:

a) Please refer to Exhibit 2A, Tab 1, Schedule 1, Chapter 5.3.2, Table 5.3.2-2 for the data sources pertaining to the population and household growth projection and the respective date of publication for each source.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-4

Climate Projection

Ref 1: Exhibit 1 / Tab 3 / Schedule 1 / p. 19 (pdf p. 186)

Question(s):

a) Reference 1 states that climate projections show that the majority of Alectra Utilities' service territory will experience more damaging high wind events that will increase in severity and intensity. Please provide a source(s) of climate projections to support this statement.

RESPONSE:

Response Provided by Hatch

a) As noted on page 18 of Exhibit 1 Tab 3 Schedule 1, the referenced climate projections are from the climate risk and vulnerability assessment of Alectra Utilities' distribution system that was completed by Hatch, a copy of which is filed in Exhibit 2A Tab 1 Schedule 1, Appendix G. The following describes the sources used by Hatch in relation to this aspect of its assessment.

Historical wind speed information was sourced from Environment and Climate Change Canada (ECCC)'s relevant observation locations and then statistically analyzed. This information was combined with data for climate projections sourced from the Intergovernmental Panel on Climate Change (IPCC) Atlas, based at the Eastern North American regional scale. Filters were applied to extract land-based data only, excluding coastal and mountainous regions.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-5

Performance Measurement - Custom Scorecard
Ref 1: Exhibit 1 / Tab 3 / Schedule 1/ p. 30 (pdf p. 200)

Preamble:

In reference 1, Alectra Utilities presents its proposed Custom Scorecard for the 2027-2031 period. OEB staff notes that while the application includes a list of proposed custom metrics and associated targets, the evidence does not present:

- Any measures Alectra Utilities will undertake to ensure it meets custom scorecard targets; or
- Risks or consequences, including mitigation strategies, if Alectra Utilities is unable to meet these targets.

Question(s):

a) Please clarify how Alectra Utilities proposed custom scorecard is linked to its Distribution System Plan (DSP) and Operating, Maintenance and Administration (OM&A) projections.

b) Please explain how maintaining fleet availability at ≥90% contributes to cost control.

c) Please explain why Serious Electrical Incident Index (SEII) and Telephone Calls Answered On Time have not been proposed as custom scorecard measures since the utility has shown persistent underperformance.

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d) Please identify the main risks that could prevent Alectra Utilities from meeting the custom scorecard targets and describe how Alectra Utilities plans to mitigate or manage these risks.

e) Please explain how Alectra Utilities will monitor, track, and report performance against the custom scorecard, including any internal accountability mechanisms.

RESPONSE:

a) As outlined in Exhibit 2A, Tab 1, Schedule 1 at page 68, Alectra Utilities' proposed Custom Scorecard was developed to supplement the metrics that Alectra Utilities already tracks and reports through the OEB's Electricity Distributor Scorecard (EDS). The additional twelve performance measures of the Custom Scorecard, when aggregated with the EDS, provide a total of 41 performance measures to be tracked, monitored and reported by Alectra Utilities.

Table 1 has been provided to demonstrate the link of the proposed custom scorecard to the capital and operating initiatives. The associated Capital and OM&A components are provided to illustrate the contributing initiatives and resources required to deliver the proposed performance outcomes.

Table 1 – Performance Measures Alignment to Capital and Operating Investments

DSP Performance Measures	Contributing Capital and Operating Initiatives
Cost Control - Planned Capital (Actual vs Budget): Planned Capital (Actual Spend vs. Budgeted Spend (in dollars))	• Asset Strategy and Operations (AS&O), Supply Chain Management and Finance Resources • Information Technology Systems and Resources
Infrastructure Renewal: Alectra Utilities would have replaced the following assets, under the multi-year renewal investments by end of 2031: Poles: 5,256 Transformers: 4,771 Switches: 255 Switchgear: 344	• Overhead Asset Renewal • Underground Asset Renewal • AS&O Resources • Supply Chain Management Resources • Overhead and Underground Inspections & Maintenance

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DSP Performance Measures	Contributing Capital and Operating Initiatives
Cable Renewal (KM): 381	
Infrastructure: Total AMI 2.0 Meters installed	• AMI Renewal • Metering Resources • Information Technology Systems and Resources • Customer Service Resources
Enabling Resilience and Modernization: In service of automated devices on the distribution system	• SCADA, Automation and System Control Investments • Cyber Security Investments and Operations • AS&O Resources • Vegetation Management • Information Technology Systems and Resources • Facilities and Fleet • Supply Chain Management Resources
Meeting Growing Electricity Demand: Increased Station Capacity	• Station Capacity Investments • Non-Wires Solutions • DER Connections • SCADA, Automation and System Control Investments • Lines Capacity Investments • AS&O Resources • Information Technology Systems and Resources • Supply Chain Management Resources
Infrastructure: Vehicle Availability	• Fleet Renewal • Supply Chain Management Resources • Information Technology Systems and Resources
System Reliability: SAIDI – Excluding MED Customer Hours of Interruption (CHI) due to Failed Equipment	• Overhead Asset Renewal • Underground Asset Renewal • AS&O Resources • Supply Chain Management Resources • Information Technology Systems and Resources • Overhead and Underground Inspections & Maintenance • SCADA, Automation and System Control Investments • Vegetation Management • Grid Modernization and Resilience

b) The Fleet Availability metric supports cost control, operational efficiency, and customer satisfaction by enabling Alectra Utilities to carry out work as planned or needed, and avoid unnecessary expenses associated with vehicle downtime. When a vehicle is unavailable, work must be rescheduled, permits and plans revised, customer

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communication adjusted, and resources redirected, all of which add cost and complexity to work execution. By closely tracking Fleet Availability, Alectra Utilities can proactively schedule maintenance and manage assets to minimize vehicle downtime. This helps Alectra maintain effective resource optimization and adhere to planned project timelines. Fleet oversight also helps prevent unexpected vehicle breakdowns, which can impact customer service timelines, and result in incremental costs, such as repair bills, rental charges and lost productivity.

c) As noted above in the response to part a), the Custom Scorecard supplements the EDS and therefore, Alectra Utilities will continue to report on both the Serious Electrical Incident Index (SEII) and Telephone Calls Answered On Time performance measures. The company's performance with respect to these measures is being addressed through planned work programs in the DSP and OM&A investment plans.

Specifically, Alectra Utilities' proposed investments in Pole renewal, Overhead Rebuilds (#6 copper wire replacement, and Overhead conductor upgrades), Voltage Conversion and Rear Lot investments will all directly address wire to ground and pole down events (SEII events). Additionally, investments in transformer renewal will also reduce SEII events specifically related to vault transformers and fires that could start as a result of their failure.

Similarly, investments in Customer Service Technologies, including Web Chat, AI Chatbot, Knowledge Management Systems, Intelligent Virtual Assistant and Agent Assist will improve telephone service levels, deflecting a forecast 196,700 calls (18%) by 2031 and avoiding further increases in average handle time (AHT) as inquiries become more complex. The combined investment in these technologies and customer service agents will improve telephone service levels from 55% in 2025 to 80% in 2031. See Exhibit 4 Tab 2 Schedule 7, Table 4-2-55 for additional details (Page 45).[1]

[1] For details on these investments, please refer to *Appendix B14 – Enabling Resiliency and Modernization* in the Customer Service Technologies section.

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d) Alectra Utilities identifies attaining the necessary funding as the most significant risk to the achievement of its custom scorecard metrics. As mentioned in several metrics in Exhibit 1, Tab 1, Schedule 1, 5.2.3 Performance Measures and Continuous Improvement, the custom metrics are based on the investments proposed within the DSP, and therefore, any constraints in funding identified and proposed investments will impede the ability to deliver the outcomes proposed in the DSP and target performance measures developed in the Custom Scorecard.

e) Alectra Utilities has an established practice for tracking and reporting performance, this practice will be leveraged for reporting the custom Performance Metrics.

Accountability for the performance objectives will be assigned to business groups contributing to the outcomes. To ensure corporate alignment, senior leaders cascade objectives across divisions and departments including requirements for monitoring, tracking and reporting measures monthly and annually. Senior Alectra Utilities leaders will review and calibrate annual targets towards outcome achievement.

For example, Infrastructure Renewal objectives are reviewed at monthly Program Delivery meetings and include reviewing progress relating to renewal of poles, transformers, switches, switchgear and cable renewal projects. During these monthly meetings, alignment between groups is completed ensuring; designs are completed and released for construction, materials are available, resources are available and finally tracking the installation and closure of projects.

The monthly expenditures of planned capital are also reviewed at Program Delivery meetings, as well as the execution of distributed automation work. Monthly progress tracking measures are reported to senior leaders overseeing contributing business units.

Similarly, meter installs will be tracked monthly, ensuring the rate of execution aligns with the annual targets. Reliability metrics and vehicle availability will be reviewed and reported at monthly meetings. Monthly reports are presented to senior leaders overseeing contributing business units to ensure appropriate progress and adjustments are made.

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The tracking and reporting of increased capacity are aligned with the completion of capacity projects tracked under the Program Delivery meetings.

Table 2 provides the breakdown of specific internal monitoring, reporting and objective periods.

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Table 2 – DSP Performance Metrics Monitoring, Reporting and Objective Timelines

DSP Performance Measures	Monitoring	Reporting	Objective Target
Cost Control - Planned Capital (Actual vs Budget): Planned Capital (Actual Spend vs. Budgeted Spend (in dollars))	Monthly	Annual	Annual
Infrastructure Renewal: Alectra Utilities would have replaced the following assets, under the multi-year renewal investments by end of 2031: Poles: 5,256 Transformers: 4,771 Switches: 255 Switchgear: 344 Cable Renewal (KM): 381	Monthly	Annual	Cumulative (2027-2031)
Infrastructure: Total AMI 2.0 Meters installed	Monthly	Annual	Cumulative (2027-2031)
Enabling Resilience and Modernization: In service of automated devices on the distribution system	Monthly	Annual	Yearly
Meeting Growing Electricity Demand: Increased Station Capacity	Monthly	Annual	Cumulative (2027-2031)
Infrastructure: Vehicle Availability	Monthly	Annual	Annual
System Reliability: SAIDI – Excluding MED Customer Hours of Interruption (CHI) due to Failed Equipment	Monthly	Annual	Annual

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-6

Ref 1: Exhibit 1 / Tab 3 / Schedule 1 / p. 30 (pdf Exhibit 1 p. 200)
Ref 2: Exhibit 1 / Tab 6 / Schedule 2 / p. 14 (pdf Exhibit 1 p. 1402)

Preamble:
Alectra Utilities set a System Average Interruption Duration Index (SAIDI) target that is materially better compared to its historic SAIDI performance even though its SAIDI performance is materially better than Industry Average.

Question(s):

a) Please explain the basis for Alectra Utilities' Figure 1-3-4 SAIDI target (0.74) when Alectra Utilities' 5 Year Average SAIDI was 0.94 and the Industry Average was 1.79.

RESPONSE:

a) Alectra's target of 0.74 hours by the end of 2031 represents a 20% improvement over its historical five-year average (2020–2024), as outlined in Table 5.2.3 – 8 System Reliability (SAIDI – Excluding MEDs) Custom Performance Measure. This target reflects the outcomes and priorities that Alectra Utilities' customers have identified (Ex. 1-5-2), which the utility seeks to achieve through the 2027-2031 Distribution System Plan. The planned renewal investments are also intended to address critical operational requirements, and align with public policy and regulatory requirements.

The referenced "Industry Average" of 1.79 is an inappropriate benchmark for Alectra Utilities' performance, as it aggregates 54 Local Distribution Companies (LDCs) with vastly different system characteristics. This broad average includes large, rural-heavy distributors such as Hydro One Networks Inc., whose significantly higher SAIDI values skew the results upward.

Reflecting these issues, the Ontario Energy Board has established a specific peer group for performance benchmarking that includes Alectra Utilities, Toronto Hydro, and Hydro Ottawa Limited. As detailed in Table L-7, the average SAIDI for this specific peer group is 0.872 hours, which is less than half of the industry average.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-7

Ref 1: Exhibit 1 / Tab 3 / Schedule 1 / p. 30 (pdf Exhibit 1 p. 200)
Ref 2: Exhibit 2A / Tab 1 / Schedule 1 / 5.3.1 Asset Management Framework Overview / pp. 112-113 (pdf Exhibit 2A Part 1 pp. 118-119)

Preamble:

Alectra Utilities appears to be recommending a scorecard measure that targets its ability to track its capital spending in dollar amounts rather than its ability to complete planned work within the forecast cost.

Question(s):

a) Please confirm that Cost Control target in Figure 1-3-4 can be achieved if 95%-105% of the planned capital budget is spent, but only a fraction (e.g., 75-85%) of the planned scope of work is completed.
    i. With regards to Cost Control from Figure 1-3-4, please explain why Planned Capital - Actual vs. Planned measured on the basis of percentage of dollars spent (i.e. 100% +/-5%) is a better target for cost control and project execution effectiveness than measuring the scope of work planned vs. scope of work completed?

b) Based on the past 5 years, what scope of work percentage was not completed as planned.

c) Based on the past 5 years, what is the average cost overrun percentage for projects for which 100% of the originally planned scope was completed.

RESPONSE:

a) The 2027-2031 Custom Performance Scorecard is a balanced scorecard. The proposed measures and targets work together, and must be considered as such, to evaluate the delivery of Alectra's DSP in its entirety. Completion of the planned capital work has a direct impact on Alectra' performance across the scorecard including (i) asset replacement targets under Infrastructure Renewal and AMI Meters installed, (ii) adding Station Capacity to meet system needs, (iii) making progress with respect to Automation on the distribution system by tracking the number of devices installed, and (iv) and importantly, the achievement of Reliability performance outcomes related to SAIDI and Failed Equipment CHI. Therefore, although it is technically feasible to meet the 'Planned Capital – Actual vs. Planned' measure without completing all planned work, doing so would negatively impact other performance measures and outcomes and the overall results reflected on the Scorecard.

b) Over the 2020-2024 period, Alectra Utilities completed 82.1% of the planned capital work scope set out in Alectra Utilities' 2020-2024 Distribution System Plan. This historical result must be considered in the appropriate context of the M-Factor application (EB-2019-0018) where the capital funding requested was not approved, and therefore certain planned capital work could not be completed. When comparing completed planned capital work scope to post M-Factor adjusted budgets, Alectra completed 112.3% of the planned capital work.

c) Over the 2020-2024 period, Alectra Utilities incurred an average of 16% higher expenditure on completed planned capital work. As outlined in Exhibit 2, Tab 1, Schedule 1, 5.2.1 Overview, Page 5, Lines 4-7, Alectra Utilities' planned capital work expenditures were significantly impacted by the COVID-19 pandemic and the extraordinary inflation that ensued post-pandemic, due to supply chain disruption and other market changes and forces which were outside of Alectra's control. From 2020 to 2024 Alectra Utilities

observed a significant increase in material costs: poles had a 68.6% increase[1], cables had a 77.9% increase[2], switchgear had a 35.9% increase[3], and lastly transformers had a 103.2% increase[4]. These cost increases are directly linked to the overall increase of 16% on projects executed.

[1] Exhibit 2, Tab 1, Schedule 1, Appendix B01 - Overhead Asset Renewal, Page 11, Table B01 - 4
[2] Exhibit 2, Tab 1, Schedule 1, Appendix B02 - Underground Asset Renewal, Page 76, Table B02 - 5
[3] Exhibit 2, Tab 1, Schedule 1, Appendix B02 - Underground Asset Renewal, Page 98, Table B02 - 10
[4] Exhibit 2, Tab 1, Schedule 1, Appendix B03 - Transformer Asset Renewal, Page 124, Table B03 - 5

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-8

Performance Measurement - Scorecards

Ref 1: Exhibit 1 / Tab 6 / Schedule 2 / pp. 1-23 (pdf pp. 1389-1411)

Question(s):

a) Please provide an updated scorecard analysis for the years 2020 to 2024 and include an explanation for any metrics where Alectra Utilities consistently did not meet the target.

b) For each scorecard metric that consistently did not meet target, please further explain how Alectra Utilities' current plan to improve performance is grounded in a high probability of success. In your response, identify the actions being taken, the expected outcomes, and how success will be measured.

RESPONSE:

a) As requested, Alectra Utilities provides the updated tables and charts from Exhibit 1, Tab 6, Schedule 2 to reflect 2020-2024 scorecard metrics.

For the following updated scorecard metrics, please see Alectra Utilities' responses to the following interrogatories:

i. 2020-2024 SAIDI and SAIFI are provided in Alectra Utilities' response to 1-AMPCO-4.
ii. 2020-2024 DSP Implementation Measure is provided in Alectra Utilities' response to 1-AMPCO-5.
iii. 2020-2024 Total Cost per Customer is provided in Alectra Utilities' response to 1-AMPCO-6.

iv. 2020-2024 Total Cost per Kilometer of Line is provided in Alectra Utilities' response to 1-AMPCO-7.

The remaining scorecard metrics for 2020-2024 are presented below along with an explanation for any metrics where Alectra Utilities did not consistently meet the target.

Table 1 - Historical Scorecard Performance Results

Performance Outcomes	Performance Categories	Measures	2020	2021	2022	2023	2024
Customer Focus	Service Quality	New Residential/Small Business Services Connected on Time	↓	↑	↓	↓	↑
		Scheduled Appointments Met On Time	↓	↑	↓	↑	↑
		Telephone Calls Answered On Time	↓	↑	↓	↓	↓
	Customer Satisfaction	Billing Accuracy	↓	↑	↑	↑	↑
Operational Effectiveness	Safety	Level of Compliance with Ontario Regulation 22/04	↑	→	→	→	→
		Serious Electrical Incident Index - Number of General Public Incidents	↑	↓	↑	↑	↑
		Serious Electrical Incident Index - Rate per 1000 km of Line	→	↓	→	→	→
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted	↑	↑	↓	↓	↓
		Average Number of Times that Power to a Customer is Interrupted	↑	↓	↓	↓	↓
Public Policy Responsiveness	Connection of Renewable Generation	New Micro-embedded Generation Facilities Connected On Time	↓	↑	↑	↑	↓

CUSTOMER FOCUS

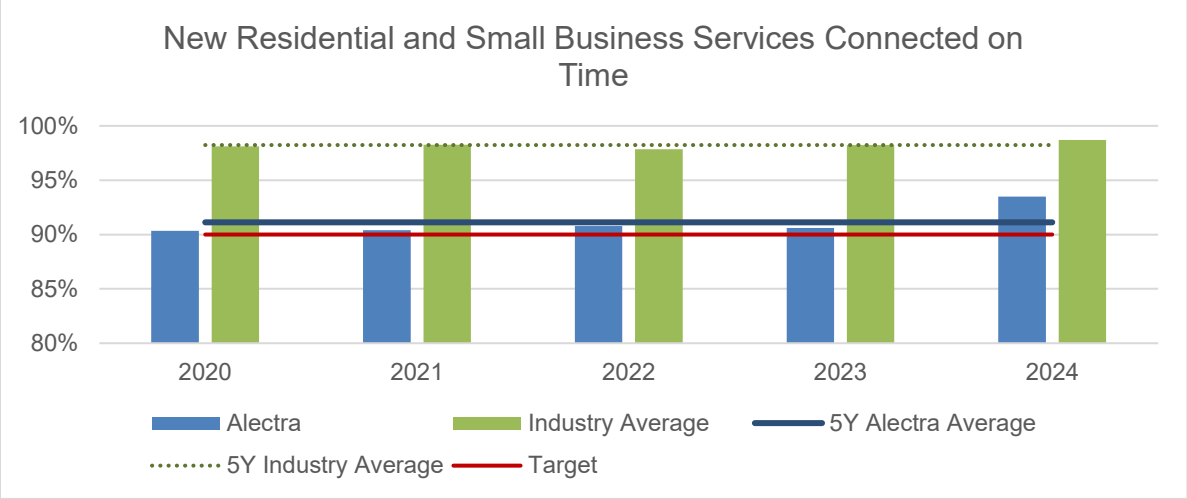
Service Quality

New Residential and Small Business Services Connected on Time

Table 2 - Scorecard Performance: New Residential and Small Business Services Connected on Time

	2020	2021	2022	2023	2024	5 Yr Avg
Alectra Utilities	90.3%	90.4%	90.8%	90.6%	93.5%	91.1%
Industry Average	98.1%	98.3%	97.8%	98.2%	98.7%	98.2%

Chart 1 - Industry Average vs. Alectra Utilities: New Residential and Small Business Services Connected on Time

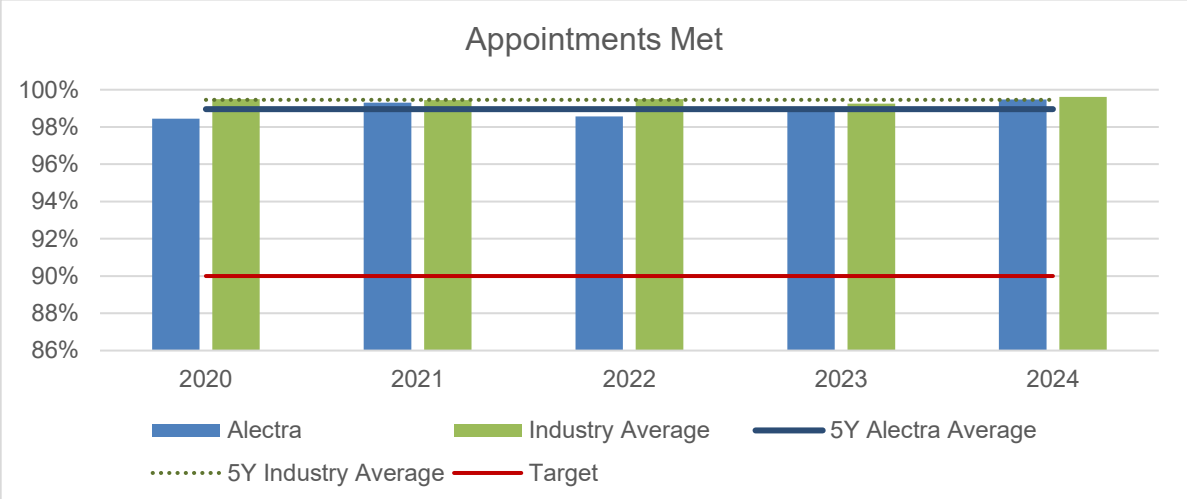


Scheduled Appointments Met on Time

Table 3 - Scorecard Performance: Scheduled Appointments Met on Time

	2020	2021	2022	2023	2024	5 Yr Avg
Alectra Utilities	98.4%	99.3%	98.6%	99.0%	99.5%	99.0%
Industry Average	99.5%	99.4%	99.5%	99.3%	99.6%	99.5%

Chart 2 - Industry Average vs. Alectra Utilities: Scheduled Appointments Met on Time

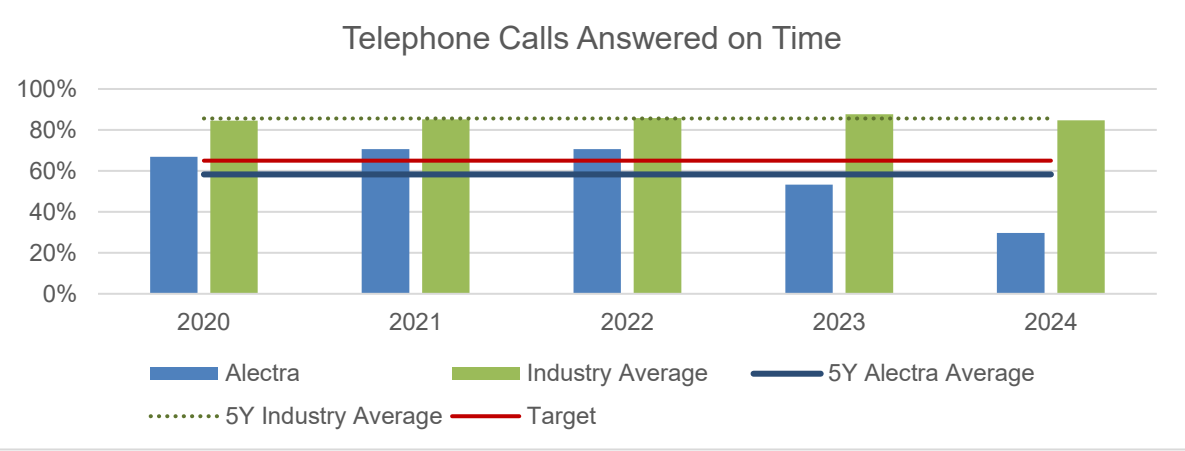


Telephone Calls Answered on Time

Table 4 - Scorecard Performance: Telephone Calls Answered on Time

	2020	2021	2022	2023	2024	5 Yr Avg
Alectra Utilities	66.9%	70.7%	70.7%	53.4%	29.8%	58.3%
Industry Average	84.6%	85.2%	85.8%	87.7%	84.7%	85.6%

Chart 3 - Industry Average vs. Alectra Utilities: Telephone Calls Answered on Time



As demonstrated in Table 4 above, the Telephone Accessibility Target was missed in both 2023 and 2024. In 2024, Alectra Utilities' Customer Service Representatives ("CSRs") received 636,233 customer calls, a 5% increase from the previous year. CSRs answered 29.78% of all calls within 30 seconds in 2024, falling short of the OEB target of 65%. This is primarily a result of receiving a higher than forecast volume of calls attributed to arrears management and collections activities. Calls of this nature are both sensitive and relatively complex, contributing to an increase in Average Handle Time ("AHT") from 10 minutes and 13 seconds to 11 minutes and 45 seconds. As a result, combined call hours – reflecting both call volume and AHT – increased by 20.9% in 2024. In addition to higher volumes of collections-related calls, the 2024 Canada Post strike generated 20,000 additional calls over a concentrated 2-month period, as customers contacted the call centre to inquire about bill and payment status, including account balances, further impacting service levels.

Alectra Utilities continuously monitors call statistics and workforce availability to best align staffing levels to call arrival rates. Furthermore, Alectra Utilities utilizes call deflection strategies to reduce call volumes through targeted messaging to reference self-service options on its website, such as forms for customer move requests (start/stop service), preauthorized payment registration, and rate plan changes. Additionally, Alectra Utilities has enhanced its Interactive Voice Response ("IVR") menu options and call queue management to further improve customer experience and operational efficiency. Performance improvements are forecast in the 2027-2031 period as a result of Alectra's digital-first strategy to introduce new online and self-serve options to customers, increased investment in internal and third-party agents, as well as enhanced staff training.

Customer Satisfaction

First Contact Resolution

Table 5 - Scorecard Performance: First Contact Resolution

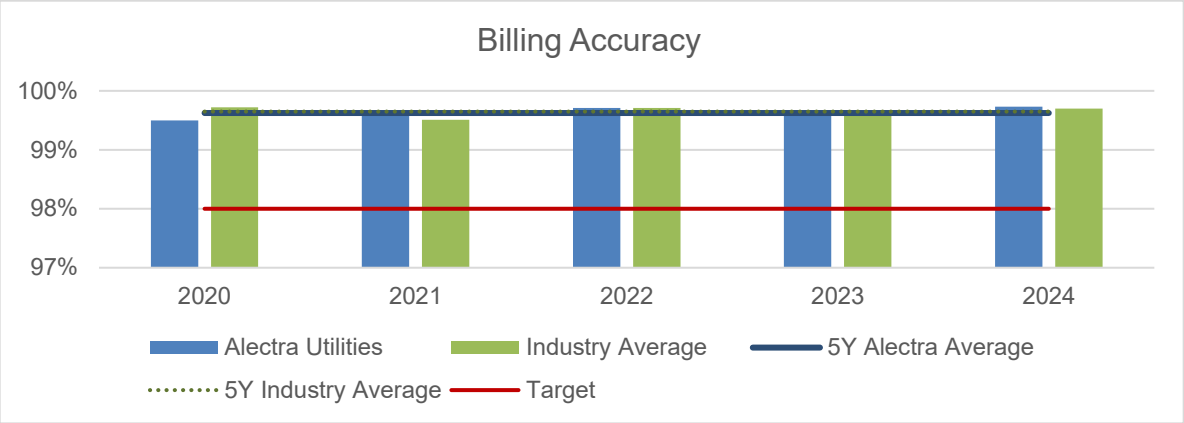
	2020	2021	2022	2023	2024	5 Yr Avg
Alectra Utilities	82.7%	83.5%	81.1%	79.9%	79.2%	81.3%

Billing Accuracy

Table 6 - Scorecard Performance: Billing Accuracy

	2020	2021	2022	2023	2024	5 Yr Avg
Alectra Utilities	99.5%	99.6%	99.7%	99.6%	99.7%	99.6%
Industry Average	99.7%	99.5%	99.7%	99.6%	99.7%	99.6%

Chart 4 - Industry Average vs. Alectra Utilities: Billing Accuracy



Customer Satisfaction Survey Results

Table 7 - Scorecard Performance: Customer Satisfaction Survey Results

	2020	2021	2022	2023	2024
Alectra Utilities	93.0%	92.0%	94.0%	94.0%	703[1]

OPERATIONAL EFFECTIVENESS

Safety

Level of Public Awareness

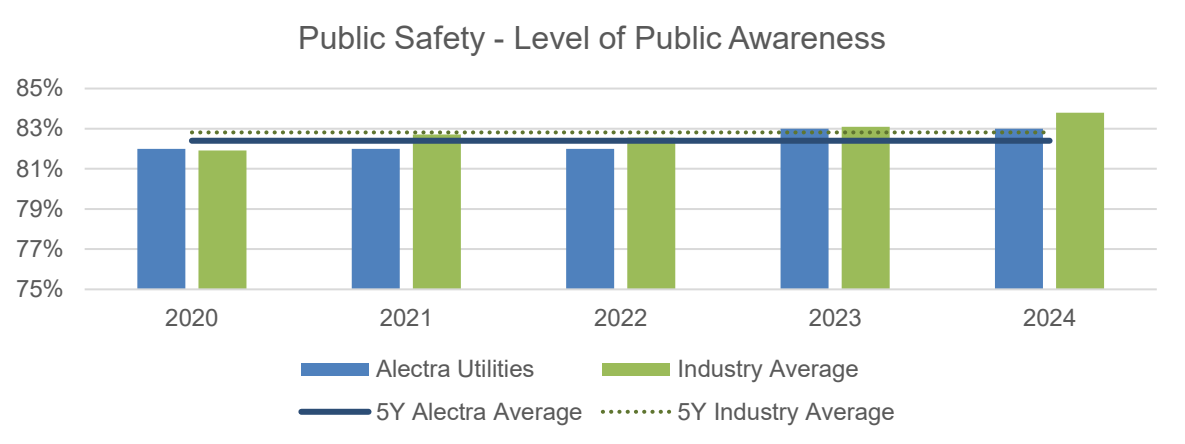
Table 8 - Scorecard Performance: Public Safety – Level of Public Awareness

	2020	2021	2022	2023	2024	5 Yr Avg
Alectra Utilities	82.0%	82.0%	82.0%	83.0%	83.0%	82.4%

[1] In 2024, Alectra Utilities engaged J.D. Power to conduct a comprehensive Customer Satisfaction survey with residential customers. Alectra Utilities achieved an index score of 703 points for overall customer satisfaction in 2024, which is equivalent to 7.03 out of 10 rating, where 10 represents an outstanding service. Prior to 2024, Alectra Utilities conducted the UtilityPulse customer satisfaction survey, commonly used throughout the industry. As a result, comparing the 2024 results to prior year results is not readily achievable, due to the different attributes measured, and the different scales used to assess performance.

	2020	2021	2022	2023	2024	5 Yr Avg
Industry Average	81.9%	82.7%	82.6%	83.1%	83.8%	82.8%

Chart 5 - Industry Average vs. Alectra Utilities: Public Safety - Level of Public Awareness



Level of Compliance with Ontario Regulation 22/04

Table 9 - Scorecard Performance: Public Safety - Level of Compliance with O. Reg 22/04.

	2020	2021	2022	2023	2024	5 Yr Avg
Alectra Utilities	C	C	C	C	C	C

Serious Electrical Incident Index

Table 10 - Scorecard Performance: Public Safety – Serious Electrical Incidents

	2020	2021	2022	2023	2024	5 Yr Avg
Serious Electrical Incident Index - Number of General Public Incidents						
Alectra Utilities	25	11	32	30	30	26
Industry Average	2	1	2	2	2	2
Serious Electrical Incident Index - Rate per 10, 100, 100 km of Line						
Alectra Utilities	0.504	0.222	0.617	0.591	0.587	0.504
Industry Average	0.330	0.071	0.099	0.322	0.141	0.193

Chart 6 - Industry Average vs. Alectra Utilities: Number of Serious Electrical Incidents

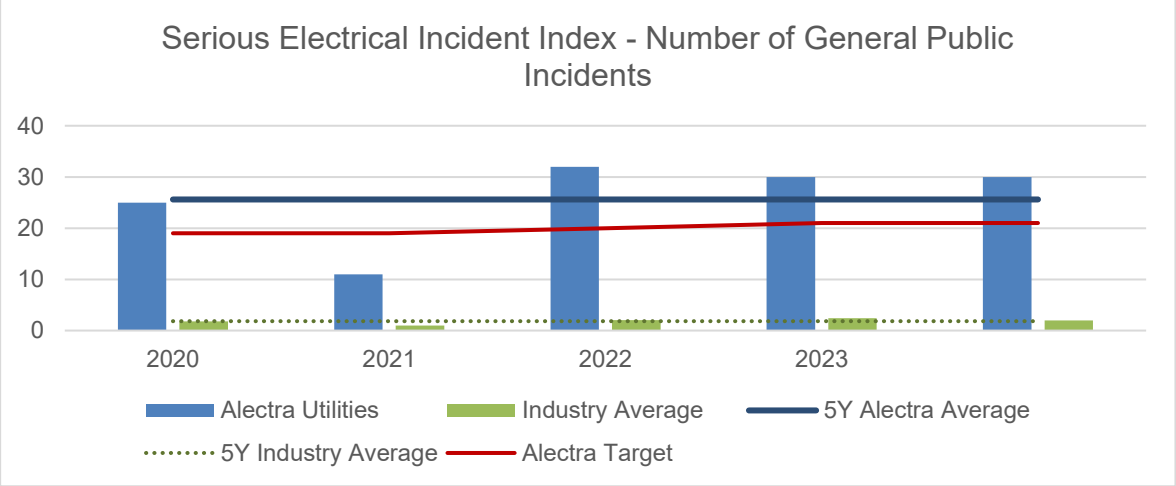
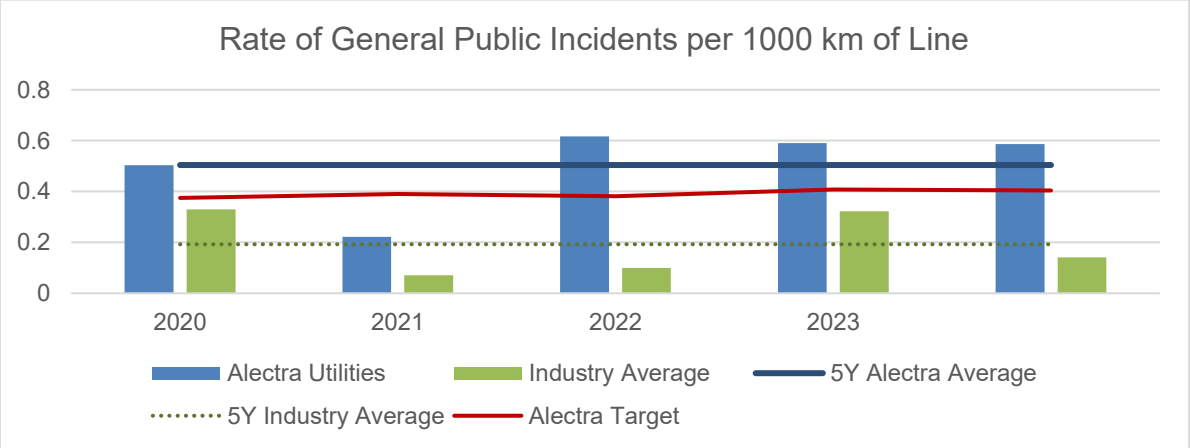


Chart 7 - Industry Average vs. Alectra Utilities: Rate of Serious Electrical Incidents per 1000 Km of Line



SEIs often relate to incidents that are outside the utility's control. Alectra Utilities experienced 30 incidents that met the SEI criteria (actual or potential electrical contact). This translates to 0.587 incidents per every 1,000 kilometers of line. Ten (10) incidents resulted from trees or tree branches falling on conductors, five (5) from motor vehicle accidents, five (5) from equipment failures, five (5) incidents resulted from adverse weather events that caused overhead conductors to come down to the ground, four (4) from animal contacts, and one (1)

from a pole fire. Alectra Utilities routinely reviews SEI's and makes appropriate adjustments to system renewal and maintenance activities to reduce, minimize, or prevent the risk of serious electrical events on the system to the extent possible and within Alectra Utilities' control.

Cost Control

Efficiency Assessment

Table 11 - Scorecard Performance: Efficiency Assessment

	2020	2021	2022	2023	2024
Alectra Utilities	3	3	3	3	3

PUBLIC POLICY RESPONSIVENESS

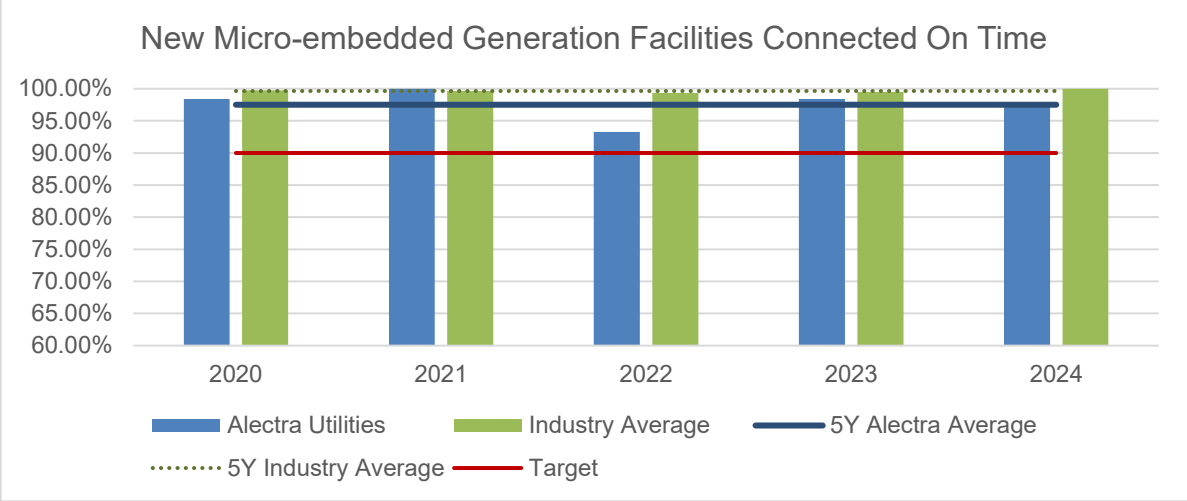
Connection of Renewable Generation

New Micro-embedded Generation Facilities Connected on Time

Table 12 - Scorecard Performance: New Micro-embedded Generation Facilities Connected on Time

	2020	2021	2022	2023	2024	5 Yr Avg
Alectra Utilities	98.4%	100.0%	93.3%	98.4%	97.5%	97.5%
Industry Average	99.8%	99.6%	99.3%	99.5%	100.0%	99.7%

Chart 8 - Industry Average vs. Alectra Utilities: New Micro-embedded Generation Facilities Connected on Time



FINANCIAL PERFORMANCE

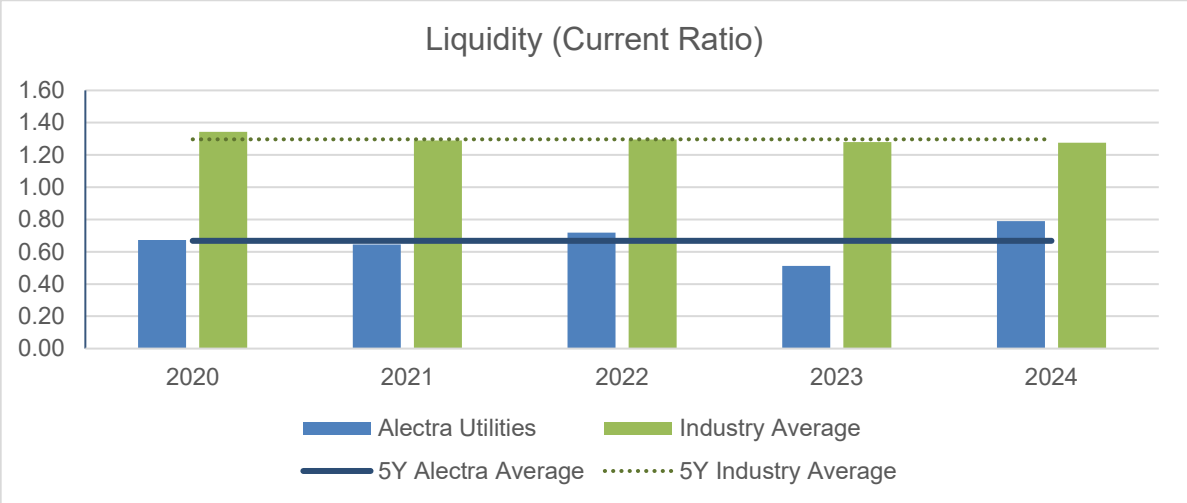
Financial Ratios

Liquidity (Current Ratio)

Table 13 - Scorecard Performance: Liquidity (Current Ratio)

	2020	2021	2022	2023	2024	5 Yr Avg
Alectra Utilities	0.67	0.65	0.72	0.51	0.79	0.67
Industry Average	1.34	1.29	1.30	1.28	1.28	1.30

Chart 9 - Industry Average vs. Alectra Utilities: Liquidity

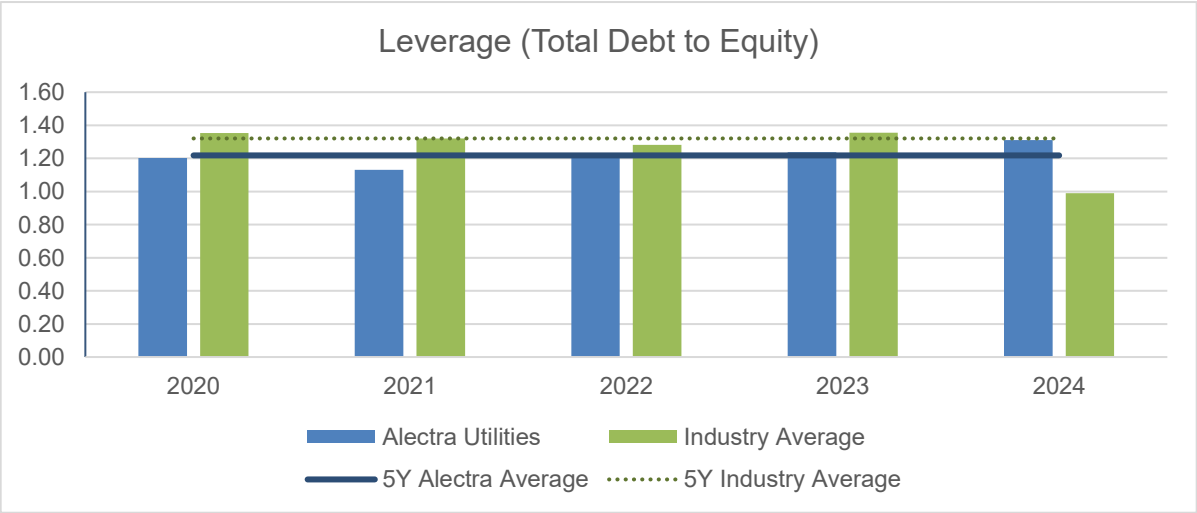


Leverage (Total Debt to Equity Ratio)

Table 14 - Scorecard Performance: Leverage

	2020	2021	2022	2023	2024	5 Yr Avg
Alectra Utilities	1.20	1.13	1.21	1.24	1.31	1.22
Industry Average	1.35	1.32	1.28	1.36	0.99	1.32

Chart 10 - Industry Average vs. Alectra Utilities: Leverage

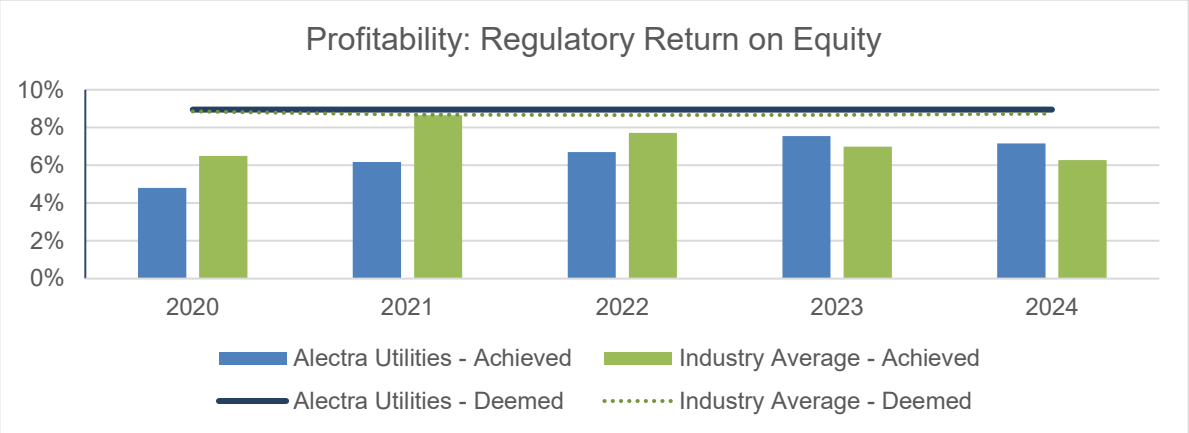


Profitability: Regulatory Return on Equity

Table 15 - Scorecard Performance: Return on Equity

	2020	2021	2022	2023	2024	5 Yr Avg
Profitability: Regulatory Return on Equity - Deemed						
Alectra Utilities - Deemed	8.95%	8.9%	8.9%	8.9%	8.9%	8.9%
Industry Average - Deemed	8.85 %	8.6%	8.6%	8.6%	8.7%	8.7%
Profitability: Regulatory Return on Equity - Achieved						
Alectra Utilities - Achieved	4.8%	6.1%	6.7%	7.5%	7.1%	6.4%
Industry Average - Achieved	6.5%	8.6%	7.7%	7.0%	6.2%	7.2%

Chart 11 - Industry vs. Alectra Utilities: Return on Equity



Overall, Alectra Utilities performed well in meeting its 2024 targets across all scorecard measures. In 2024, Alectra Utilities did not achieve its performance target for Telephone Accessibility, and Serious Electrical Incidents ("SEIs") affecting the general public.

As above, Alectra Utilities has not consistently missed achievement of any scorecard metric over the past five (5) years, with the exception of the rate of SEIs affecting the general public, which was missed in 2020, 2022, 2023 and 2024, and Telephone Accessibility which was missed in 2023 and 2024.

b) As described in the response to part a) above, there were only two metrics that were missed with some consistency during the 2020-2024 period.

Serious Electrical Incidents ("SEIs")

As explained above, SEIs often relate to incidents that are outside the utility's control. Frequent causes include trees or tree branches falling on conductors, motor vehicle accidents, equipment failures, adverse weather events that caused overhead conductors to come down to the ground, animal contacts, and pole fires. For Alectra Utilities' plans to address factors within the utility's control that may improve the number of SEIs, please refer to the following evidence:

- For a discussion on Alectra Utilities Vegetation Management program, please refer to Exhibit 4, Tab 2, Schedule 15.
- For a discussion on Alectra Utilities' climate adaptation strategies, please refer to Exhibit 2A, Tab 1, Schedule 1, Table 5.3.2 - 7 on pages 151-152.
- For a discussion on asset renewal please refer to Exhibit 2A, Tab 1, Schedule 1, Section 5.3.3 and Appendix B01 - Overhead Asset Renewal.

Telephone Accessibility

Alectra Utilities did not meet the Telephone Accessibility Target in both 2023 and 2024. Performance improvements are forecast in the 2027-2031 period as a result of increased third-party support, enhanced staff training, and added technological support.

For a discussion on these planned improvements, please refer to Exhibit 4, Tab 2, Schedule 7, pages. 17-20.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-9

Clearspring's Research and Report
Ref 1: Exhibit 1 / Tab 6 / Schedule 2 / Attachment 1-3
Ref 2: Clearspring Energy Advisors (Clearspring) working papers

Preamble:
Clearspring undertook a total cost econometric benchmarking study of Alectra Utilities' distributor costs. This study provides a comparison of the total cost of Alectra Utilities' distribution services to the benchmark costs after adjusting for differences in the specific output levels, input prices, and miscellaneous other business conditions of sampled utilities.

Question(s):

a) Are there any corrections, adjustments, clarifications, or other changes to the research or the report that Clearspring wishes to make since the evidence was filed?

b) If so, please provide an updated report and/or working papers and briefly describe the updates.

RESPONSE:

Response provided by Clearspring

a) No changes to our research or report. The only data correction is reflected in 1-Staff-11 and is inconsequential. Additionally, we were requested to show the total cost benchmark impacts of moving to the Handy-Whitman index in 1-Staff-20. Neither modification changes the stretch factor recommendation of 0.15%.

b) No updated report or working papers are required, including in respect of the above minor modifications.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-10

Alectra Utilities Business Conditions
Ref 1: Exhibit 1 / Tab 6 / Schedule 2 / Attachment 1-3

Question(s):

a) Please discuss any special external business conditions that tend to materially increase or reduce the cost of Alectra Utilities' services.

b) How pervasive is bulk metering of multi-family residential establishments in Alectra Utilities' service territory?

c) Does the non-contiguous service territory of Alectra Utilities pose challenges (e.g., higher costs)?

RESPONSE:

a) A discussion of external business conditions that impact costs for distributors is presented in Section 3 of Attachment 1-3, *Clearspring Energy Advisors Econometric Benchmarking and Incentive Regulation Parameter Study*.

For a discussion of discrete OM&A conditions that impact the cost of Alectra Utilities' services, please refer to Exhibit 4 – Operating Expenses. For a discussion of discrete Capital items impacting Alectra Utilities' services, please refer to Exhibit 2A, parts 1-6. For a discussion of costs related to financing that impact Alectra Utilities' services, please refer to Exhibit 5 – Cost of Capital and Capital Structure.

b) Alectra Utilities estimates that approximately 92.77% of known multi-unit residential establishments in its service territory are bulk metered. Please note that a multi-unit residential building is only identified where a customer has self-declared as multi-unit for the purposes of RPP and OER rate applicability. Multi-unit customers who have not self-declared are not included in these figures.

c) As described in Exhibit 1, Tab 5, Schedule 4, page 3, and further discussed in Exhibit 2A, pages 10-12, Alectra Utilities' non-contiguous service territory poses logistical and planning challenges, including the management of diverse geographies, degrees of urbanization, and varying ages of distribution system assets. A large service area also poses challenges to Alectra Utilities' operations, particularly in terms of managing and responding to adverse weather impacts.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-11

Clearspring's Data
Ref 1: Exhibit 1 / Tab 6 / Schedule 2 / Attachment 1-3
Ref 2: Clearspring working papers
Ref 3: PacifiCorp Fact Sheet as downloaded from:
https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/about/PacifiCorp_Fact_Sheet.pdf

Preamble:
OEB staff has questions related to some data series used by Clearspring in its calculations.

Question(s):

a) When the Clearspring computer code was modified to export a larger amount of data, approximately 25 cases were noted where the A&G allocator (alloc) was either negative or over 100%. These values for an allocator do not appear plausible. Please confirm if Clearspring observes a similar result and comment.

b) Clearspring has assigned a service territory area value of 90,819 km^2 to PacifiCorp. In Pacific Economics Group (PEG)'s recent datasets, an area of 372,695 km^2 was assigned to PacifiCorp, which is similar to the area noted on PacifiCorp's website. Clearspring uses area as a scale variable and gives it full translog treatment in its total cost model.
   i. Does Clearspring believe its PacifiCorp value is correct?
   ii. If the much larger estimate is correct, please test the model using that value and comment on any effect of changing the value on the model parameters and Alectra Utilities' performance.

:

c) Clearspring uses a variable that estimates the percentage of the utility service territory that is forested.

   i. Please provide additional details on how Clearspring calculates its forestation variable.

RESPONSE:

Response provided by Clearspring

a) Confirmed. Clearspring did not make manual adjustments to these observations. The impact of doing so would be inconsequential given there are a total of 1,903 total observations in the dataset.

b) In investigating this, the larger value appears to be the correct one. When inserting the 372,695 value for PacifiCorp, the model continues to be robust with all variables statistically significant. This change has a minor impact on Alectra's benchmark score. During the 2027 to 2031 period the score moves from -21.5% to -20.2%. This continues to imply a 0.15% stretch factor.

c) Clearspring's description of the forestation variable calculation can be found on page 14 of the Clearspring Report. The types of land cover that are designated as "forested" within each utility's service territory are divided by the total land area. This variable retains the same values and methodology that Clearspring has used for several Custom IR applications. No additional research or modifications to the variable has been undertaken in the Alectra study. PEG has also used this same variable in its responding research in several Custom IR applications.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-12

Scope of Clearspring's Benchmarking Work
Ref 1: Exhibit 1 / Tab 6 / Schedule 2 / Attachment 1-3
Ref 2: Clearspring working papers
Ref 3: EB-2023-0195 / Exhibit 1B / Tab 3 / Schedule 3 / Appendix A / pp. 25-31 (pdf pp. 359-365)
Ref 4: EB-2019-0261 / Exhibit 1 / Tab 1/ Schedule 12 / Attachment A, pp. 26-31 (pdf pp. 382-387)

Preamble:
Clearspring only provides total cost benchmarking. Clearspring provided reliability benchmarking results in its recent custom incentive rate-setting (CIR) evidence for Toronto Hydro-Electric System Limited (Toronto Hydro)'s 2025-2029 CIR application (reference 3) and its evidence in Hydro Ottawa's 2021-2025 CIR application (reference 4).

Question(s):

a) Would the incremental cost of OM&A and capital cost benchmarking be fairly modest once total cost benchmarking is underway?

b) Did Clearspring develop OM&A and capital cost benchmarking models for Alectra Utilities? If so, please provide the most credible models developed and the benchmarking results for Alectra Utilities.

c) Did Clearspring undertake any reliability benchmarking for Alectra Utilities? If yes, please present best-model results. If not, why not?

d) Is reliability benchmarking a sensible complement to cost benchmarking? Please explain.

RESPONSE:

Response provided by Clearspring

a) The incremental cost of conducting OM&A and capital cost benchmarking would be considerably lower if total cost benchmarking is undertaken as well.

b) No.

c) No. Reliability benchmarking was not in our scope of work.

d) Reliability benchmarking is not currently necessary for an application and does not factor into the escalation parameters. Reliability benchmarking has received limited attention in other custom IR proceedings where Clearspring has produced reliability benchmarking research. Clearspring cannot say whether it is sensible for distributors to fund the research given the current regulatory situation.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-13

Clearspring's Total Cost Model

Ref 1: Exhibit 1 / Tab 6 / Schedule 2 / Attachment 1-3 / pp. 14-15 (pdf pp. 1429-1430)

Ref 2: Clearspring Working Papers

Ref 3: EB-2021-0110, Custom IR Application (2023-2027) for Hydro One Networks Inc. Transmission and Distribution - Clearspring Energy Advisors and Pacific Economics Group Research Joint Report, June 13, 2022

Preamble:

The variables in the total cost model that Clearspring features are very similar to those in Clearspring's model for the Joint Report in the Hydro One Networks Inc. (HONI) proceeding.

Question(s):

a) Why was a rolling average of peak demand used in this model rather than ratcheted peak demand? Which variable received stronger statistical support?

b) Did Clearspring exclude any variables from its featured cost model in this proceeding that its research found to have statistically significant and plausible parameter estimates? If so, please explain why they were excluded from the featured model and provide benchmarking results from a model that includes them.

RESPONSE:

Response provided by Clearspring

a) In Clearspring's report in the last Hydro One proceeding (EB-2021-0110), we explained the rationale for using an average peak demand variable rather than a ratcheted one. One reason includes Clearspring considering the merits of and then responding to intervenors who in the past questioned how it makes sense that a ratcheted peak demand variable can never decrease even after years of falling peak demands. The total cost research is focused on the long-run total costs of utilities. This is why capital costs are included into the analysis and Clearspring goes back to the 1940's to gather cost data to best determine total costs. To say that utilities will never adjust costs downward in response to declining peak demands is not an accurate assumption. This assumption is inherent in the ratcheted peak demand construct. While there will be a lag and a residual cost impact to prior high peak demand values, this will not last indefinitely. For this reason, we have settled on using the 10-year rolling average approach in our research and have done so for the last several custom IR applications.

The second rationale for the rolling average peak demand variable versus the ratcheted approach is that a lot of the focus on the benchmarking research results in this context are on the projected Custom IR years. Those peak demands are weather normalized expectations, or averages, around the probabilities of extreme or mild weather outcomes. Since the peak demand forecasts themselves are 50/50 average probability outcomes, using a variable that is itself an average is the more consistent approach in Clearspring's view.

Regarding statistical support, we have not constructed the ratcheted peak variable for the Alectra research since we had already settled on the rolling average being the better approach. We did, however, test this in response to an interrogatory in the most recent Toronto Hydro application (EB-2023-0195).

In our response to 1B-Staff-60 (part d), we state, *"Yes, Clearspring did calculate the variable. The first order ratcheted peak demand variable while still highly statistically significant is less so than the 10-year rolling average used by Clearspring. The t-stat on the ratcheted peak demand is 13.82 versus a t-stat of 22.16 for the rolling average*

variable. This indicates that it is the rolling average variable that has the stronger t-statistic."

b) No. Clearspring believes our current model, which has the same methodology and model as the recent Toronto Hydro application, is a robust and extremely strong total cost benchmarking model. Clearspring is of the view that it adds credibility to the benchmarking model exercise when models and methodology are consistent from application to application. We do not have a Hydro One model, a Toronto Hydro model, an Alectra model, or any other client model. Clearspring, instead, has one model that we believe performs the best in predicting total costs for large distributors regardless if they serve a large congested urban core, have extensive rural territory, or are somewhere in the middle. Naturally, we will make improvements over time but this is done consistently.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-14

Clearspring's Total Cost Model
Ref 1: Exhibit 1 / Tab 6 / Schedule 2 / Attachment 1-3 / p. 17 (pdf p. 1432)
Ref 2: Clearspring working papers

Preamble:
Cost models with translogged scale variables yield utility-specific estimates of the elasticities of cost with respect to these variables. This can provide checks on whether the output elasticity estimates are reasonable.

Question(s):

a) What are the estimated elasticities of total cost with respect to the three scale variables for Alectra Utilities in Clearspring's model?

b) How common was it for these elasticities to be negative for other companies in Clearspring's sample?

RESPONSE:

Response provided by Clearspring

a) We calculated the first derivative with respect to each output to calculate the custom elasticities. The equation for the custom customer elasticity that we calculated is, thus, the first order customer coefficient plus the coefficient on the quadratic customer variable times the natural log of the mean-scaled customer value plus the coefficient on interaction with customers and peak demand multiplied by the natural log of the mean-scaled peak demand variable plus the coefficient on the interaction with the customers and service

area variable multiplied by the natural log of the mean-scaled service area variable. For the custom peak demand elasticity and the area elasticity we conducted the same calculation procedure but using the peak demand and area first order, quadratic, and interaction terms.

The 2024 values for Alectra are calculated to be 0.484 for customers, 0.636 for peak demand, and -0.032 for service area.

b) Given the flexibility of the translog cost function, it leaves open the possibility of specific output variable elasticities being negative as the model adjusts for economies of scale and interactions with other output variables. In the case of Alectra, it is the service area custom elasticity that is negative. This means that the cost benchmark for Alectra would decline in the model IF Alectra added service territory. In the real world, it is difficult to imagine how this would occur without Alectra at the same time adding customers and peak demands being raised. Even under the scenario of Alectra adding service territory, its benchmark costs would increase because of the corresponding increases in customers and demand. When looked at from a holistic and real-world perspective, a negative elasticity on the area variable is not a concern. There are other instances of custom output elasticities being negative within the sample. The majority of them are regarding the service area variable as well.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-15

Clearspring's Urban Congestion Variable

Ref 1: Exhibit 1 / Tab 6 / Schedule 2 / Attachment 1-3 / pp. 14-15 pp. 17-18 (pdf pp. 1432-1433)

Ref 2: Clearspring working papers

Preamble:

Clearspring's cost model includes a congested urban (CU) variable that has been made time-variant using data on the number of skyscrapers in cities served by sampled utilities.

Question(s):

a) Please confirm that, in Clearspring's sample, the parameter estimate for CU is highly sensitive to the inclusion of just one company (Consolidated Edison of New York). Does that create a disadvantage?

b) Was a CU value calculated for all utilities in the sample? For example, was CU calculated for the following utilities that are included in Clearspring's sample and known to serve cities with skyscrapers topping 100 metres?
   - Atlantic City Electric
   - Puget Sound Energy
   - Consumers Energy
   - Connecticut Power and Light

c) Data for buildings that are at least 100 metres tall are used to adjust a congested urban variable that was calculated with respect to what minimum building height?

d) Did Clearspring consider using lower minimum heights for skyscrapers? If not, why not?

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e) For metro areas that include one or more sizable business districts in smaller satellite cities (e.g., the St. Louis area, which includes Clayton, MO), did Clearspring include the satellite business district(s) in its CU calculations?

f) Would the parameter estimate for CU be improved by including data for utilities serving Canadian cities with urban congestion (e.g., Toronto and Calgary)?

g) Do the number of skyscrapers data that Clearspring uses pertain to the same areas as the congested urban data?

h) Why not just use the number of skyscrapers as the CU variable?

i) Does the inclusion of the CU variable in the model improve or worsen the benchmarking score of Alectra Utilities?

RESPONSE:

Response provided by Clearspring

a) It is true that it would be helpful, if it were possible, to add more utilities similar to Consolidated Edison to the sample. However, that is not currently feasible. Both Clearspring and PEG have agreed on the need and importance of including the percent congested urban variable in the last several Custom IR applications. During the experts' Hydro One joint conferral process (EB-2021-0110), the inclusion of the percent congested urban variable was not controversial or a concern raised by PEG.

b) All utilities in the sample were considered. However, constructing the congested urban variable involved a large effort which required meticulous mapping of city blocks and streets. For this reason, only cities with populations above 200,000 at the time of the investigation were examined. The cities cited above did not pass that threshold.

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c) The congested urban variable was constructed based on examining areas of cities that had building clusters of seven stories or higher.

d) No, consistent with our prior research we only used skyscrapers at 100m or greater to escalate the percent congested urban variable. We are unsure how trustworthy the data is below this threshold since 100m is the lowest defined category in the dataset. There is a "Under 100m" category but no definition on what the lower bound cut-off would be or if that would be consistently applied across all the included cities. We do acknowledge that using a seven-story cut-off would be preferable to use to escalate the variable but, to Clearspring's knowledge, trustworthy data is not available. Examining the growth rate in buildings at 100m or above is a good proxy of the growth in a congested urban area.

e) No, we only examined cities with populations above 200,000 at the time of the examination. Clayton, MO has a population of around 17,000 and would not have been included in the analysis.

f) Adding these new types of utilities presents an issue with making consistent cost and variable definitions with the entire sample, including excluded costs such as pensions and benefits. If the cost and variable definitions are not the same or compromises are necessary on excluded cost categories then inclusion with those compromises would not necessarily improve the congested urban parameter estimate.

g) The skyscraper data is used as a proxy for the growth rate in the congested urban variable. We examined the growth rate in cities within each service territory. However, we did not map each skyscraper in the U.S. individually but even if there are a handful of examples of skyscrapers not actually in the service territory we would be unconcerned regarding the validity of the variable given this is being used as a proxy for the growth rate.

h) The construction of the congested urban variable was a meticulous effort, conducted by engineers, who were of the view that seven story building clusters within city centers will

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pose substantially higher costs on distribution utilities. This contrasts with the skyscraper data that is simply a growth rate analysis to move the congested urban variable slightly up or down over time. While the congested urban variable was a "street-by-street" analysis for all cities above 200,000, the skyscraper data has not been mapped. The drawbacks of using the skyscraper data would be that the trustworthy data is at 100 m which is substantially higher than the seven stories used for the congested urban, clusters would need to be identified in the skyscraper data, and a locational analysis of each skyscraper to assure it's within the service territory would also need to be conducted.

i) The inclusion of the Clearspring percent congested urban variable worsens the benchmark score for Alectra. Clearspring, however, does not have separate models for separate clients. This model is, in our view, the best depiction of electric distribution total costs for large Ontario distributors. We are of the view that a model that includes a percent congested urban variable is a better model that best captures the total cost drivers and, thus, provides the most accurate benchmarks for intervenors to assess the cost performance of the utility and to produce stretch factors.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-16

Clearspring's Distribution Work Variable

Ref 1: Exhibit 1 / Tab 6 / Schedule 2 / Attachment 1-3 / pp. 15, 17 (pdf pp. 1430, 1432)

Preamble:

Clearspring's model includes a Distribution Work variable defined as the share of transmission line length with a rating that exceeds 50 kV.

Question(s):

a) Please confirm that this variable does not just reflect whether a utility's subtransmission lines are classified as transmission assets. Relevant counterexamples include the following.
    i. The value is large because the Dx and Tx systems have relatively few lines of subtransmission voltage.
    ii. The value is small because a lot of the power is delivered to the utility on the transmission systems of other utilities.
    iii. The value is large because the utility has sizable transmission capacity to access power supplies in remote areas.

RESPONSE:

Response provided by Clearspring

a) Confirmed. There could be other explanations. However, we do note that the variable comes in strongly statistically significant.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-17

Clearspring's Inflation Forecasts

Ref 1: Clearspring Working papers

Preamble:

The Clearspring working papers indicate that the forecasts used to escalate Alectra Utilities' salaries and wages and the gross domestic product implicit price index (GDPIPI) are from February 26, 2025.

Question(s):

a) Please confirm that the notes on this matter in the file "alectra.prg" (reference 1) with regard to the referenced price forecasts are accurate.

b) Are more recent forecasts available? If so, how do these compare to what was assumed in the study?

RESPONSE:

Response provided by Clearspring

a) Confirmed.

b) Yes, more recent forecasts are available. The growth rates are similar between the forecasts used in this study compared to forecasts from January 2026. The average weekly earnings growth rate from 2027 to 2031 moves from 2.43% to 2.37%. The average GDP-IPI growth rate moves from 1.68% to 1.87%. This will have an inconsequential impact on the total cost benchmark results of Alectra.

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The IPD and benchmark scores are calculated as of a given point in time. The IPD figure would be sensitive to and potentially impacted by on-going forecast updates and could go up or down as a result of them (based on different specific points in time).

The updated forecasts, as of the above point in time, would reduce the calculated IPD from 0.36% to 0.24%.

Table 1 – Jan 2026 CBoC Forecasts

Jan 2026 CBoC Forecasts							
	AWE Ontario		GDP-IPI		30/70 OEB IPI	OM&A Input Price	
2027	1432.111		1.345057				
2028	1463.058	2.16%	1.371176	1.94%	2.01%	2.11%	0.10%
2029	1498.902	2.45%	1.399154	2.04%	2.16%	2.35%	0.19%
2030	1536.258	2.49%	1.424213	1.79%	2.00%	2.33%	0.33%
2031	1574.544	2.49%	1.449721	1.79%	2.00%	2.33%	0.33%
2027-2031	2.37%	**2.40%**	1.87%	**1.89%**	2.04%	2.28%	**0.24%**

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-18

Clearspring's OM&A Input Prices
Ref 1: Exhibit 1 / Tab 6 / Schedule 2 / Attachment 1-3 / pp. 31, 35 (pdf pp. 1446, 1450)
Ref 2: Clearspring Working papers

Preamble:
Clearspring states, "To ascertain Alectra's wage level, we gathered job occupation wage estimates from the 2011 Canadian Census, using wage data reported for Ontario, translated job occupations to match their U.S. counterparts, and then weighted the job occupation wages by the BLS estimates."

Question(s):

a) Please show where the support for the values used to construct the wage level for Alectra Utilities in the file "alectra.prg" can be found in the working papers (reference 2). If they have not yet been provided, please provide.

b) Please comment on the methodological consistency of the source used to establish the wage level for Alectra Utilities and US companies.

c) The input price index (IPI) for Alectra Utilities uses the average weekly earnings for the Ontario industrial aggregate from Statistics Canada. Would the analogous fixed weighted index of average hourly earnings for all employees for the Ontario industrial aggregate, excluding unclassified businesses, be more accurate? If no, please explain why not.

d) Does the listing of outside services provided in Clearspring's working papers include all outside services purchased by Alectra Utilities or just those classified as administrative and general expenses in account 5630? If it does not include all outside services, please

provide an estimate of the proportion of total OM&A that is used to purchase outside services.

e) Clearspring levelized its OM&A input prices in 2010 and its construction cost index in 2015. Why did Clearspring not use more recent years?

f) Clearspring used the gross domestic product price index to measure the trend in the material and service prices of U.S. utilities. Please confirm that, due to the brisk multifactor productivity growth of the U.S. economy, this index tends to materially understate the growth in U.S. input prices.

RESPONSE:

Response provided by Clearspring:

a) In the alectra.prg file, Clearspring provides the description that the wage level was set at the average 2011 Census wages of Toronto and Ontario. Clearspring processed the 2011 Census job category data which includes wages levels of 154 different occupations for several cities. These different occupations are then weighted based on the analogous weights used for the U.S. distributor dataset. However, some of the major cities in Alectra's service territory are not included in that dataset. The two cities that are served and included are Hamilton and St. Catherines. The average wage level for those two cities is $77,450. However, since this seemed to exclude a large portion of Alectra's service territory (namely the area surrounding Toronto and north of Toronto). So instead, we decided to take the average of Toronto and Ontario. This produced a value of $77,204. We used the lower number for the wage level for Alectra. Alectra's benchmark score would slightly improve if we used the higher value. Please see the file "1-Staff-18_Attach 1_Wage Levels.xls" for each Ontario cities' calculated wage levels.

b) Please see part (a) of this response.

c) Clearspring did not examine the component indexes in the Board's IPI in our study.

d) It is Clearspring's understanding that the referenced listing includes all outside service provider expenses.

e) Clearspring maintained those same years to remain consistent with the most recent Toronto Hydro benchmarking research (EB-2023-0195) and the Hydro One joint conferral research (EB-2021-0110) and decided it was not worth the effort to update those items.

f) The index understates U.S. input prices of all goods and services in the U.S. economy because of the brisk MFP growth. This is not necessarily the same as the input prices within the U.S. electric distribution sector. Inflation may be higher or lower than the economy, at large. The GDP-IPI is used as a proxy for the non-labour portion of expenses in Ontario with no reference to the MFP for Canada (or Ontario). Specifically, the inflation factor assumes that the non-labour portion of expenses is captured by the GDP-IPI growth rate, full stop. We make no claim regarding if that is a true depiction of non-labour inflation for the electric distribution industry. However, to be consistent between the U.S. and utilities in Ontario and what the Board has decided is the proper non-labour inflation rate, we continue to use the GDPPI for U.S. utility non-labour expense inflation and the GDP-IPI for Ontario utility non-labour expense inflation. Further, it does seem wrong to us that there would be dramatically different inflation rates between U.S. and Ontario distributors for non-labour inflation given the interconnectedness of the two country's economies.

1-Staff-18

Attachment 1
Wage Levels

Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-19

Clearspring's Sample

Ref 1: Exhibit 1 / Tab 6 / Schedule 2 / Attachment 1-3 / pp. 15-17 (pdf pp. 1430-1432)

Ref 2: Clearspring working papers

Preamble:

The sample period for Clearspring's econometric work was the 24 years from 2000 to 2023. Data for 82 companies operating in 2023 were included in Clearspring's sample.

Question(s):

a) Why did Clearspring use such a long sample period in its featured research for Alectra Utilities?

b) Were shorter sample periods considered? If so, how did the benchmarking results differ?

c) The sample that PEG is currently using in power distributor cost research contains 91 US utilities. Please explain why each of the following 18 utilities that are included in PEG's power distributor cost research sample are excluded from Clearspring's sample.

1. Dayton Power and Light Company
2. Fitchburg Gas and Electric Light Company
3. Georgia Power Company
4. Green Mountain Power Corporation
5. Kansas City Power & Light Company
6. Kingsport Power Company
7. Massachusetts Electric Company
8. MidAmerican Energy Company
9. Narragansett Electric Company

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10. Northwestern Energy
11. NSTAR Electric Company
12. Ohio Power Company
13. Rochester Gas and Electric Corp
14. Southwestern Electric Power Company
15. Superior Water, Light and Power Company
16. Upper Peninsula Power Company
17. Westar Energy (KPL)
18. Wheeling Power Co

d) It initially appears that many, if not most, U.S. utilities that underwent mergers within the sample period have been excluded from Clearspring's sample. Does the exclusion of merged companies from the econometric model improve or benefit the model's performance in the context of benchmarking Alectra Utilities? Please explain.

RESPONSE:

Response provided by Clearspring

a) Clearspring did not see a reason to deviate from our research methodology in recent applications where we used 2000 as the start year. This is the same start year that we had in the recent Toronto Hydro application (EB-2023-0195) and the Hydro One joint report (EB-2021-0110).

b) No. We did not examine other time periods.

c) Clearspring's sample includes 82 U.S. utilities implying that we are including some utilities that PEG is not including as well. Most of the exclusions cited are due to mergers, and the remaining from missing or implausible data. Recent mergers are excluded due to the extensive effort necessary to "reconstruct" the new utility for all the model variables. For example, Clearspring's methodology builds up a capital stock

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starting in the 1940s to accurately calculate capital costs. The 82 utilities and 1,903 observations are more than sufficient to produce robust and statistically sound cost models.

d) No. We would be of the view that either dataset assuming the mergers are aggregated properly and with sound methodology and model specification, could produce a robust cost model and, therefore, a reliable benchmark analysis.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-20

Clearspring's Asset Price Index

Ref 1: Exhibit 1 / Tab 6 / Schedule 2 / Attachment 1-3 / pp. 8, 34-35 (pdf p. 1423, 1449-1450)

Ref 2: Clearspring working papers

Preamble:

Clearspring uses a 50/50 average of the growth in a) the Handy-Whitman summary power distribution construction cost index for the North Atlantic region (HWI) and b) a Canadian implicit capital stock deflator in its total cost research, while stating that it "remain[s] partial to using the Handy-Whitman electric distribution indexes."

Question(s):

a) Please provide a new total cost model and benchmarking results using only the HWI.

RESPONSE:

Response provided by Clearspring

a) Clearspring's position has been for several past Custom IR applications that HWI is the most appropriate index to use for Ontario utility asset price inflation. Conversely, PEG promoted the use of the Canadian implicit capital stock deflator instead of the HWI. To reduce differences, Clearspring and PEG used an average of the two indexes in the last few Custom IR applications including the most recent Hydro One (EB-2021-0110) and Toronto Hydro (EB-2023-0195) applications. We have continued our advocacy for the HWI as illustrated in our statement found in the Preamble.

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The econometric total cost model is estimated without Alectra included in the dataset to provide an external benchmark for the Company. As such, the total cost model will be unchanged when moving to the HWI as the measure of capital asset price inflation for Alectra. The benchmark results when making this change are provided below. Clearspring notes they are more stable year-over-year due to this change. The 2027-2031 average comes in at -19.4% (compared to -21.5% before the change) which continues to indicate strong cost performance and a 0.15% stretch factor.

Table 1 - % Difference from Total Cost Benchmark

Year	% Difference from Total Cost Benchmark
2019	-15.9%
2020	-20.1%
2021	-19.6%
2022	-18.3%
2023	-17.1%
2024	-18.8%
2022-2024 average score	-18.1%
2025	-18.8%
2026	-20.3%
2027	-19.5%
2028	-19.8%
2029	-19.7%
2030	-18.8%
2031	-19.4%
2027-2031 average score	-19.4%

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-21

Clearspring's G Factor Rationale

Ref 1: Exhibit 1 / Tab 6 / Schedule 2 / Attachment 1-3, pp. 20-21 (pdf pp. 1435-1436)
Ref 2: Denny, Michael, Melvyn A. Fuss, and Leonard Waverman, 1981. "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., Productivity Measurement in Regulated Industries, (Academic Press, New York) pages 172-218.

Preamble:

Clearspring explains the theory behind its G factor design on pages 20-21 of its report (reference 1).

Question(s):

a) This derivation does not explain why an *elasticity-weighted* output index should be used in G factor development. Why not instead use the theory discussed in the classic Denny, Fuss, and Waverman paper, which was authored by University of Toronto economists? The authors show the TFP growth is a function of the growth of a cost-elasticity weighted output index.

RESPONSE:

Response provided by Clearspring

a) The theory explains that the growth factor should mimic the construction of the output quantity index in the TFP trend research. The TFP trend research used a cost-elasticity

weighted output quantity index, which is the proper approach. The growth factor calculated by Clearspring mirrors this approach.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-22

Clearspring's G Factor Research
Ref 1: Exhibit 1 / Tab 6 / Schedule 2 / Attachment 1-3 / pp. 22, 25-26 (pp. 1437, 1440-1441)
Ref 2: Clearspring working papers

Preamble:
Clearspring's report contains formulas to adjust the OM&A revenue requirement using information from its total cost model.

Question(s):

a) Please explain why a G factor based on cost-elasticity estimates from a *total* cost model makes more sense than one that is based on analogous estimates from an *OM&A* cost model.

b) Please explain the rationale for only using two of the three scale variables in Clearspring's model to calculate the G factor.

c) If the area variable were time-variant, wouldn't its growth likely be as slow or slower than customer growth?

RESPONSE:

Response provided by Clearspring

a) Clearspring is skeptical in regard to using OM&A cost models in setting parameters within a price or revenue cap index. Accounting differences in capitalization policies and

substitution decisions between OM&A and capital will distort these disaggregated models. These issues are mitigated when using a total cost model approach.

b) The two variables used in the construction of the growth factor are customers and peak demand. These are the two outputs that are time variant and were also used in the TFP trend research that set the productivity factor. Mathematically, the growth factor should be constructed in a similar manner as the output quantity index in the TFP trend research. If service area had been used in the TFP trend research, the corresponding TFP trend would have likely been lower. If a lower productivity factor had been implemented due to using an area variable as an output component, only then would it be appropriate to include area in the growth factor.

c) Likely slower for utilities with positive customer growth.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-23

Clearspring Input Price Differential

Ref 1: Exhibit 1 / Tab 6 / Schedule 2 / Attachment 1-3 / pp. 14-15 (pdf pp. 1429-1430)
Ref 2: EB-2023-0195, Partial Decision and Order, November 12, 2024, Schedule A, p. 17 (pdf p. 41)
Ref 3: EB-2021-0110, Decision on Settlement Proposal and Order on Rates, Revenue Requirement and Charge Determinants, November 29, 2022 Schedule A, pp. 5-8 (pdf pp. 18-21)

Preamble:

Alectra Utilities proposes to include a fixed input price differential (IPD) in its OM&A revenue requirement escalator.

Question(s):

a) Please confirm that the results from combining the OEB's approved IPI and the IPD that are presented in the report would be similar to those resulting from using an OM&A price index that was constructed using company-specific or industry cost share weights and the same price subindexes as those used in the IPI. Please explain why the IPD approach is being used.

b) Would an IPD have been warranted if Alectra Utilities had proposed to make the capital as well as the OM&A revenue requirement conditional on inflation and later trued up to actual inflation? Approaches of this nature have recently been approved by the OEB for HONI and Toronto Hydro.

c) Please explain why Alectra Utilities did not propose such an approach?

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RESPONSE:

a) **Response provided by Clearspring**

Confirmed. The IPD approach provides the necessary adjustment to the existing inflation factor to enable the tracking of the expected inflation that the Company will encounter. Using weights that are company-specific or close to company-specific would produce a similar outcome of enabling the inflation adjustment to match the inflation experience of Alectra.

b) The CPCI values presented in Exhibit 1, Tab 11, Schedule 2, p. 15 (Table 1-11-5) are based on a forecast of the OEB's annual inflation rate for the years 2028-2031. For the purposes of the application, this rate is forecast to be 2.0% on an annual basis. The forecast inflation rate of 2.0% is proposed to be replaced each year going forward in Alectra's annual rate applications, with the then OEB-approved inflation rate (or "I" factor), normally established in October each year.

The IPD is warranted as it isolates the gap between the OEB's regulatory inflation factor and the actual OM&A cost inflation Alectra Utilities expects to face. It accomplishes this by adjusting for the incremental difference between what the inflation index would be using Alectra's true proportion of labour in its OM&A expenses relative to the 30/70 calculation that defines the OEB-approved inflation rate. As the rate plan will continue to rely on the OEB-approved inflation rate going forward, this difference will continue to exist and the IPD is needed to close the gap.

c) Please see response to part b)

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-24

Ratemaking Treatment of Capital
Ref 1: Exhibit 1 / Tab 11 / Schedule 2
Ref 2: Exhibit 2A / Tab 1 / Schedule 1
Ref 3: Alberta Utilities Commission, Decision 27388-D01-2023 (October 4, 2023) Appendix 7 (K-bar calculation) pp. 126-128.
Ref 4: Lowry, Mark Newton, David Hovde, Rebecca Kavan and Matthew Makos, "Impact of Multiyear Rate Plans on Power Distributor Productivity: Evidence from Alberta,"), *The Electricity Journal*, Volume 36, Issue 5, June 2023.

Preamble:
OEB staff would like to explore alternative approaches to CIR for Alectra Utilities, which would help the panel evaluate Alectra Utilities' proposed capital spending in this proceeding. For example, OEB staff is interested in a K-bar approach, which is a revenue requirement cap wherein the capital portion depends in part on the utility's recent historical gross plant additions (as escalated for construction cost inflation and customer growth) instead of forecasted additions. The revenue requirement for some assets, including many that are especially sensitive to the energy transition, would still be forecasted and/or subject to variance account treatment

Question(s):

a) Please provide revenue requirement and rate growth projections for each year of the proposed plan (2027-2031) period that are comparable to the Company's proposal and are consistent with the following assumptions.

    i. Revenue requirement for 2027 as Alectra Utilities proposed.

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ii. Revenue requirement for OM&A expenses net of other operating revenue in years 2028-2031 as proposed.

iii. Capital-related revenue requirement from 2028 to 2031 calculated as proposed except for an alternative basis for some gross plant additions.

Gross plant additions for the following asset categories would be based on Company forecasts as Alectra Utilities proposed. Most of these plant additions are especially sensitive to the energy transition. Some of these costs may be eligible for variance account treatment.

- the AMI Renewal Portion of Network Metering
- the Renewable Generation, Customer Initiated Relocations, and Transit Connections portions of Customer Connections
- Capacity (Lines)
- Capacity (Stations)
- Distributed Energy Resources Integration
- the DER Wholesale Market Preparedness, Advanced Distribution Management System, and Planning Tools and Automation portions of Information Technology
- Connection and Cost Recovery Agreements

Gross plant additions for the other asset categories would be set in the K-bar style based on the Company's 2020-2024 actual gross plant additions, escalated for annual inflation and customer growth to the applicable year of the 2028-31 period. The inflation measure for these calculations would be that used for gross plant additions in the Clearspring study. Please apply a reasonable approach regarding the value of disposals or other implementation complications and provide the assumptions you relied upon in your response.

iv. The resultant growth in the Capital-Related Revenue Requirement would be subject to a 0.15% X factor markdown, as Alectra Utilities has proposed.

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v. The portions of the capital revenue requirement that are accorded K-bar treatment would not be subject to Alectra Utilities' proposed underspend clawback.
The excel file "Attachment_1-staff-24" illustrates the procedure using capital expenditure data because the analogous gross plant additions data were not readily available.

b) OEB staff invites comments on this K-bar approach to ratemaking and on alternative applications of the basic K-bar approach (e.g., different asset categories subject to K-bar treatment).

RESPONSE:

a) and b)
Alectra Utilities does not agree that this request and exercise is relevant and appropriate, or reasonably doable in the time period for responding to interrogatories. Alectra Utilities understands that PEG has on its own been able to complete the calculations requested in part a) in other proceedings in any event. In response to 2-CCC-11, Alectra has provided Appendix 2-AA on an in-service additions basis. Alectra is unable to undertake the detailed analysis required to answer part a) of this question within the discovery timelines in the proceeding. Further, for a number of reasons Alectra Utilities does not agree with, and is not supportive of, the application of a K-bar construct to its ratemaking. Exhibit 2, inclusive of Alectra Utilities' extensive and detailed Distribution System Plan, lays out comprehensive details regarding the needs and pressures of Alectra Utilities' system and customers, the investments required to address those needs, and the pacing of such investments. Alectra Utilities proposed ratemaking framework has been designed to fund these detailed requirements, inclusive of explicit adjustments to incent productivity and manage costs for ratepayers, in a manner that recognizes that the capital needs of any given program vary and are not uniform over the 2027 to 2031 period. This approach

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is consistent with the OEB's guidance that CIR be informed by a distributor's forecasts,[1] consistent with the OEB-stated purpose of CIR, as a means to address "capital programs that are expected to be significant and may include 'lumpy" investments…", [2] and consistent with numerous CIR applications heard and approved by the OEB[3]. Alectra Utilities believes it is more appropriate to build on the OEB's prior success in CIR, as opposed to fundamentally changing it. To the degree such a change was to take place, it should take place on a generic basis and would be more appropriately addressed through OEB's Next Generation Rate Framework Consultation.[4]

[1] Ontario Energy Board, Report of the Board: Renewed Regulatory Framework for Electricity Distributors, October 18, 2012, page 13
[2] Ibid., pages 9-10
[3] E.g. EB-2012-0459, EB-2014-0116, EB-2017-0049, EB-2018-0165, EB-2019-0261, EB-2021-0110, EB-2023-0195
[4] EB-2026-0002

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-25

Ratemaking Treatment of Capital

Ref 1: Exhibit 1 / Tab 11 / Schedule 1

Ref 2: Handbook for Utility Rate Applications, October 13, 2016, pp. 25-28

Ref 3: EB-2023-0195, Partial Decision and Order, November 12, 2024, p. 10 (pdf p. 12)

Ref 4: EB-2021-0110, Decision on Settlement Proposal and Order on Rates, Revenue Requirement and Charge Determinants, November 29, 2022 Schedule A, pp. 5-8 (pdf pp. 18-21)

Preamble:

CIR treatments of capital are sometimes accompanied by a supplemental capital stretch factor like that featured in references 3 and 4.

Question(s):

a) Please comment whether the proposed ratemaking treatment of capital offers much weaker cost containment incentives than the proposed ratemaking treatment of OM&A expenses (reference 1).

b) Please explain how, and to what extent Alectra Utilities' proposed ratemaking treatment of capital results in the capital component of the revenue requirement that aligns with the annual rate adjustment requirements in reference 2.

RESPONSE:

a) For Capital, Alectra has an incentive to manage its costs and deliver its plan within the OEB's standard inflationary factor.

As outlined in detail in Exhibit 2A of this application, Alectra Utilities is facing substantial

capital needs over the 2027 to 2031 period, reflecting the need to address the substantial inventory of deteriorated assets, while ensuring the system has sufficient capacity to meet the growth in electricity demand through a resilient and modern system. To deliver its capital plan—and achieve the customer and grid outcomes associated with its plan—Alectra must manage a broad range of complex execution risks and factors, which create additional incentives to control project schedules and costs while driving towards accomplishment of plan outcomes. Alectra's capital work execution plan is detailed in Exhibit 2A, Tab 1, Schedule 1, Section 5.3.1.3. Moreover, as noted in the Clearspring report, the adoption of the 0% productivity factor, despite empirical evidence which shows a negative productivity trend, creates an implicit stretch factor on capital.[1]

b) Alectra Utilities' proposed ratemaking of capital is aligned with the referenced sections of the OEB's Handbook for Utility Rate Applications ("Handbook"):

- **Term:** Alectra Utilities has proposed a five-year term for its capital plan, and a custom rate index supported by empirical evidence in accordance with OEB expectations;
- **Index for Annual Rate Adjustment:** Custom index supported by empirical third-party benchmarking evidence to establish an appropriate utility-specific stretch factor, which provides explicit financial incentives for continuous improvement and cost control;
- **Benchmarking:** Provision of a third-party expert benchmarking report to substantiate Alecta Utilities' total cost performance[2], syndicated benchmarking from J.D. Power and Electricity Canada to compare performance and service delivery[3], Activity and Program-Based Benchmarking to assess capital and OM&A execution cost performance,[4], and dedicated productivity evidence

[1] See section 4.4 of the Clearspring Report at Exhibit 1, Tab 6, Schedule 2, Attachment 1-3.
[2] Exhibit 1, Tab 6, Schedule 2, Attachment 1-3
[3] Exhibit 1, Tab 5, Schedule 1, Pages 14-15
[4] Exhibit 1, Tab 6, Schedule 3

demonstrating Alectra Utilities' achievement and pursuit of continuous improvement[5];

- **Performance Metrics:** A custom scorecard as outlined in Exhibit 1, Tab 3, Schedule 1, pp. 29-30 and Exhibit 2A, Tab 1, Schedule 1, Section 5.2.3 Performance Measurement for Continuous Improvement;
- **Updates:** A rate-setting framework that only provides for mechanistic inflationary annual updates under delegated authority and clearance of Group 1 accounts; and
- **Protecting Customers:** Proposal of an Earnings Sharing Mechanism to protect customers and allow for the sharing of revenues in excess of 150 basis points of OEB-approved ROE, calculated on a cumulative basis over the 5 year rate-setting term.

[5] Exhibit 1, Tab 6, Schedule 4

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-26

Performance Measurement - Activity and Program-based Benchmarking (APB)
Ref 1: Exhibit 1 / Tab 6 / Schedule 3 / p. 1 (pdf p. 1460)

Question(s):

a) Please provide all instances identified in the mapping review that demonstrate differences in GL-to-USoA mappings between consolidated legacy entities. Please include examples of:

   i. Legacy-specific GL accounts mapped to different USoAs across entities;
   ii. Any inter-entity inconsistencies in categorization within the same USoA subcategory;
   iii. Cases where mapping adjustments were made as part of the 2024 review.

RESPONSE:

a)

i. Alectra brought the Enersource, Brampton, Powerstream and Horizon financial systems together into a common platform in 2019. At that time the costs contained in each legacy General Ledger (GL) account were reviewed and mapped by USoA on the Alectra platform. Distinct differences in the organization of costs among legacies were evident at that time. However, Alectra can no longer trace back the specific nature of each cost historically recorded in individual GLs under legacy Enersource, Brampton, Horizon and Powerstream's systems prior to 2019. Guelph Rate Zone was integrated with Alectra's core financial system separately in 2022. Inconsistencies in categorization that were noted when Guelph Rate Zone was integrated include those listed below:

- Lines OM: Costs pertaining to Lines operations and maintenance were recorded under USoA 5120 – Maintenance of Poles, Towers and Fixtures, which should have been mapped to USoA 5040 - Underground Distribution Lines and Feeders - Operation Labour.
- Vegetation Management: Third party service provider costs associated with vegetation management activities were allocated to USoA 5045 - Underground Distribution Lines and Feeders - Operation Supplies and Expenses, which should have been mapped to USoA 5135 - Overhead Distribution Lines and Feeders - Right of Way.

ii. Please refer to 1-Staff-26 a).

iii. Alectra responds below on a program-by-program basis. The mapping revisions referred to within this response pertain to differences in cost activity in the 2024 year relative to the 2023 year and are not necessarily indicative of future activity.

Table 1 - Billing O&M

	Cost ('000s)	2020	2021	2022	2023	2024
Billing O&M	Original	$28,891	$29,565	$32,263	$33,651	$16,169
	Restated	$15,212	$14,601	$16,201	$16,065	no change

Notable changes to USoA 5315 Customer Billing resulting from the remapping exercise include:

- Approximately $9M in annual direct labour costs for functions related to the call centre, revenue assurance, key accounts, new connections and billing supervision were remapped to USoA 5340 Miscellaneous Customer Accounts Expenses and USoA 5305 Billing and Collecting Supervision.

- Approximately $5M in annual costs for functions performed by outside service providers such as call centre and outage management were remapped to USoA 5340 Miscellaneous Customer Accounts Expenses.

- Approximately $3M in annual costs related to meter reading were remapped to USoA 5310 Meter Reading Expense.

- $0.5M in total costs pertaining to a customer care call centre software provider and completion of customer satisfaction surveys were remapped to USoA 5340 Miscellaneous Customer Accounts Expenses and USoA 5630 Outside Services Employed, respectively.

Table 2 - Meters O&M

	Cost ('000s)	2020	2021	2022	2023	2024
Metering O&M	Original	$3,580	$4,540	$3,821	$3,240	$11,946
	Restated	$9,884	$10,724	$9,985	$9,164	no change

Approximately $6M in direct labour burdens associated with non-union benefits were remapped out of the relevant USoAs for the Meters O&M APB program area (i.e., 5065 Meter Expense, 5175 Maintenance of Meters and 5310 Meter Reading Expense). These credits relate to the apportioning of costs between operations and capital. The largest shares pertain to USoAs 5120 Maintenance of Poles, Towers and Fixtures and 5005 Operation Supervision and Engineering, with smaller shares pertaining to 5070 Customer Premises Operation Labour, 5085 Miscellaneous Distribution Expense, 5105 Maintenance Supervision and Engineering, and 5315 Customer Billing.

Table 3 - Vegetation Management O&M

	Cost ('000s)	2020	2021	2022	2023	2024
Vegetation Management O&M	Original	$5,099	$4,937	$4,834	$6,227	$5,562
	Restated	$5,190	$4,896	$5,059	$6,526	no change

The remapping exercise completed in 2024 did not result in significant changes to USoA 5135 Overhead Distribution Lines and Feeders - Right of Way.

A small number of GLs were mapped out of USoA 5135 and into USoA 5105 Maintenance Supervision and Engineering or USoA 5615 General Admin Salaries and Expenses. The annual value associated with these GLs is nominal.

GLs that were remapped into USoA 5135 as a result of the remapping exercise include those stemming from the cost areas referenced below. Alectra notes that direct labour costs related to vegetation management activities were not materially impacted by the remapping effort.

- Operation supplies and expenses, specifically those pertaining to 3rd party contracts in the Guelph Rate Zone, which had been mapped to USoA 5045 Underground Distribution Lines and Feeders - Operation Supplies and Expenses since Guelph Rate Zone was integrated with Alectra's financial system in 2022.
- Some vehicle costs were previously recorded under USoA 5665 Miscellaneous General Expense (USoA 5665).

Table 4 - Lines O&M

	Cost ('000s)	2020	2021	2022	2023	2024
Lines O&M	Original	$48,091	$48,865	$61,689	$55,042	$49,772
	Restated	$44,308	$43,525	$55,890	$48,536	no change

Direct labour costs tracked within the Lines O&M program area decreased by approximately $6M per year as result of the 2024 remapping. Remapped costs are primarily associated with design and inspection and were moved from USoA 5020 Overhead Distribution Lines and Feeders - Operation Labour and 5040 Underground Distribution Lines and Feeders - Operation Labour to USoA 5005 Operation Supervision and Engineering and 5105 Maintenance Supervision and Engineering.

Table 5 - Distribution Station Equipment O&M

	Cost ('000s)	2020	2021	2022	2023	2024
Stations O&M	Original	$7,155	$8,413	$9,661	$11,015	$9,199
	Restated	$7,041	$7,580	$8,836	$9,960	no change

The remapping exercise did not result in any significant costs being moved into the relevant USoAs for the Distribution Station Equipment O&M program area (i.e., 5016 Distribution Station Equipment - Operation Labour, 5017 Distribution Station Equipment - Operation Supplies and Expenses and 5114 Maintenance of Distribution Station Equipment) from alternate accounts.

Some station sustainment-related costs associated with labour and vehicles were moved out of USoA 5114 Maintenance of Distribution Station Equipment and into USoA 5005 Operation Supervision and Engineering or 5110 Maintenance of Building and Fixtures.

Table 6 - Poles, Towers and Fixtures O&M

	Cost ('000s)	2020	2021	2022	2023	2024
Poles O&M	Original	$436	$623	$ (2)	$112	$1,192
	Restated	$1,097	$1,365	$1,146	$1,110	no change

The remapping exercise completed in 2024 did not result in the removal of any significant costs originally recorded in 5120 Maintenance of Poles, Towers and Fixtures. Alectra

Utilities' underreported costs related to poles-related operations and maintenance until the USoA mapping review was conducted in 2024.

Guelph Rate Zone recorded costs of a Lines nature, including labour, materials and maintenance related expenses, in USoA 5120 until 2022. These costs were appropriately mapped into USoA 5040 Underground Distribution Lines and Feeders - Operation Labour upon integration with Alectra's financial system in 2022. Guelph's lines-related costs comprised approximately 85% of all costs originally recorded in USoA 5120 for 2020 and 2021.

A small number of poles-related labour costs were correctly mapped into USoA 5120 in 2023. The majority of poles operations and maintenance costs remained recorded in the following USoAs prior to being moved into 5120 in 2024:

- USoA 5020 Overhead Distribution Lines and Feeders - Operation Labour
- USoA 5025 Overhead Distribution Lines and Feeders - Operation Supplies and Expenses
- USoA 5040 Underground Distribution Lines and Feeders - Operation Labour
- USoA 5125 Maintenance of Overhead Conductors and Devices

Costs tracked in USoA 5120 remain below industry average and Alectra acknowledges that a component of labour costs remains missing from this USoA. This stems primarily from projects containing both operations and maintenance costs related to both poles and lines, which results in all costs being recorded as entirely underground or overhead within either poles or lines. About 65% of the costs recorded in USoA 5120 in 2024 pertain to vehicle-related expenses.

Table 7 - Distribution Station Equipment CAPEX

	Cost ('000s)	2020	2021	2022	2023	2024
Stations CAPEX	Original	$1,262	$7,968	$1,873	$2,012	$21,000
	Restated	$5,037	no change	no change	no change	$4,159

Alectra determined that the APB Limited Data Request submission completed in March 2022 included only partial balances and the full population was not captured for 2020.

In 2024, Alectra Utilities reclassified $16.8M in costs related to wholesale meters from the USoA 1860 (Meters) to USoA 1820 (Station Equipment). The in-service year for the wholesale meters in question ranged from 2004 to 2019. Therefore, the reclassification impacts 2024 only for benchmarking purposes.

There are no known GL mapping issues within USoA 1820. There are no known inconsistencies in categorization within the same USoA subcategory among legacies.

Table 8 - Poles, Towers and Fixtures CAPEX

	Cost ('000s)	2020	2021	2022	2023	2024
Poles CAPEX	Original	$47,007	$47,453	$49,475	$58,318	$59,951
	Restated	$48,663	no change	$49,513	no change	no change

Alectra determined that the APB Limited Data Request submission completed in March 2022 included only partial balances and the full population was not captured for 2020.

The minor variance in additions for 2022 is due to some transaction adjustments that were not reflected correctly in the balances submitted in the RRR.

There are no known GL mapping issues within USoA 1830. There are no known inconsistencies in categorization within the same USoA subcategory among legacies.

Table 9 - Line Transformers CAPEX

	Cost ('000s)	2020	2021	2022	2023	2024
Line Transformer CAPEX	Original	$46,927	$63,626	$53,734	$96,557	$101,083
	Restated	$48,743	no change	$53,888	no change	no change

Alectra determined that the APB Limited Data Request submission completed in March 2022 included only partial balances and the full population was not captured for 2020.

The minor variance in additions for 2022 is due to some transaction adjustments that were not reflected correctly in the balances submitted in the RRR.

There are no known GL mapping issues within USoA 1850. There are no known inconsistencies in categorization within the same USoA subcategory among legacies.

Table 10 - Meters CAPEX

	Cost ('000s)	2020	2021	2022	2023	2024
Meters CAPEX	Original	$16,061	$12,793	$15,375	$23,049	$17,166
	Restated	$14,536	no change	no change	no change	$24,458

Alectra determined that the APB Limited Data Request submission completed in March 2022 included only partial balances and the full population was not captured for 2020.

In 2024, as noted under the Distribution Station Equipment CAPEX section above, a balance of $16.8M was reclassified from USoA 1860 to USoA 1820 related to wholesale meters.

There are no known GL mapping issues within USoA 1860. There are no known inconsistencies in categorization within the same USoA subcategory among legacies.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-27

Performance Measurement - Benchmarking

Ref 1: Exhibit 1 / Alectra_Attach 1-4_PEG Benchmarking Forecast Analysis_20251121.xlsx

Ref 2: Exhibit 4 / Alectra_Attach 4-1_OEB Appendix 2-JA - Summary of Recoverable OM&A Expenses_20251014

Preamble:

Reference 1 requires entering detailed OM&A data by USoA accounts under the subcategories of Operations, Maintenance, Billing and Collections, Community Relations, Administrative & General (A&G) Expenses, Insurance, and Advertising.

OEB staff notes that not all USoA accounts are required to be included in reference 1. However, for those subcategories where the values should match between reference 1 and reference 2, OEB staff was unable to reconcile the OM&A values in reference 2 with the ones in reference 1 (Model Inputs tab) across all years.

Question(s):

a) Please provide the detailed OM&A values by USoA account, by subcategory (Operations, Maintenance, Billing and Collections, Community Relations, A&G Expenses, Insurance, and Advertising), that were used to populate reference 1.

b) Please reconcile the values provided in response to part (a) with the values shown in reference 2 and explain the differences other than the exclusion of certain USoA accounts.

RESPONSE:

a) The detailed OM&A values by USoA that were used to populate the PEG Benchmarking Forecast Analysis in Attachment 1-4 are provided in Attachment 1-STAFF-27, Table 1. Alectra notes that discrepancies between the values presented in Attachment 1-4 and Attachment 4-1 exist in two subcategories:

- Billing & Collecting
- Administration & General

There are no discrepancies in the values presented in Attachment 1-4 and Attachment 4-1 in the following subcategories:

- Operations
- Maintenance
- Community Relations

Additionally, two subcategories are presented in Attachment 1-4 that are not presented as a distinct subcategory in Attachment 4-1:

- Insurance
- Advertising

b) A reconciliation of discrepancies between Attachment 1-4 and Attachment 4-1 is presented in Attachment 1-STAFF-27, Table 2 and described below.

- Billing and Collecting subcategory:
  USoA 5335 Bad Debt Expense fully explains the variance between the Billing and Collecting subcategories in Attachment 1-4 and Attachment 4-1. USoA 5335 is included in Attachment 4-1 under the Billing and Collecting subcategory, and it is not present in Attachment 1-4 because it is not part of the PEG Benchmarking Model.

- Administration and General subcategory:

The USoAs listed below are included under the Administration and General subcategory of Attachment 4-1 but are not part of the Administration and General category of the PEG Benchmarking Forecast Analysis model at Attachment 1-4. USoA 5635 Property Insurance falls under the separate insurance category of Attachment 1-4. All other USoAs listed below are not presented in Attachment 1-4.

- 5505 Supervision
- 5510 Demonstrating and Selling Expense
- 5515 Advertising Expense
- 5520 Miscellaneous Sales Expense
- 5635 Property Insurance
- 5660 General Advertising Expenses
- 5681 Special Purpose Charge Expense
- 5685 Independent Market Operator Fees and Penalties
- 5695 OM&A Contra
- 6105 Property Taxes
- 6205 LEAP Donations
- Adjustments:
    - Other adjustments
    - GRE&T Centre: Exhibit 1, Tab 11, Schedule 1, pp. 2, describes the adjustment made to OM&A forecast for GRE&T Centre costs. Over the 2027-2031 rate term, Alectra Utilities proposes to limit ratepayer funding for the GRE&T Centre, thus Alectra Utilities reduced the OM&A forecast captured in Exhibit 4 to calculate revenue requirement. This adjustment to OM&A is reflected in the PEG Benchmarking Forecast Analysis model.

1-Staff-27

Attachment 1
Tables

Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-28

Performance Measurement – APB

Ref 1: Exhibit 1 / Tab 6 / Schedule 3 / pp. 3-22 (pdf pp. 1462 - 1481)

Ref 2: APB_Unit Cost Calculations_OEB-2024_20240929

Preamble:

OEB staff have observed that several APB values filed in evidence differ from the values published in the 2024 APB Report.

Question(s):

a) Please provide an updated APB analysis for the years 2020 to 2024, and include an explanation for any significant variances in 2024 unit costs when compared to:
   i. 2023 (explanations for variances that exceed 20%)
   ii. Alectra Utilities' five-year average (explanations for variances that exceed 20%)
   iii. the industry average, where applicable (explanations for variances that exceed 25%)

b) Please clarify whether the discrepancies between the APB values in reference 1 and the values published in the 2024 APB dataset in reference 2 are a result of Alectra Utilities' 2024 USoA mapping review, or any other internal reclassification or data revision.

c) For all 10 APB programs, please identify each instance where APB values were updated, adjusted, or restated. For each program, provide:
   i. The original value filed,
   ii. The updated or corrected value,
   iii. The reason for the change (e.g., USoA mapping revision, data correction, re-allocation), and

iv. Supporting calculations and/or documentation.

RESPONSE:

a) An updated APB analysis for the years 2020 to 2024 is presented below. Discussion of the variances requested for parts i) through iii) follows the APB presentation.

Table 1 - Billing O&M - Historical Performance

	2020	2021	2022	2023	2024	5Y Avg
Cost ('000s)	15,212	14,601	16,201	16,065	16,169	15,650
Total Customers ('000s)	1,062	1,070	1,077	1,083	1,086	1,075
($/Customer)	14.32	13.65	15.05	14.84	14.89	14.55
YoY Change (%)	-19%	-5%	10%	-1%	0%	

Chart 1 - Billing O&M - Historical Annual Results

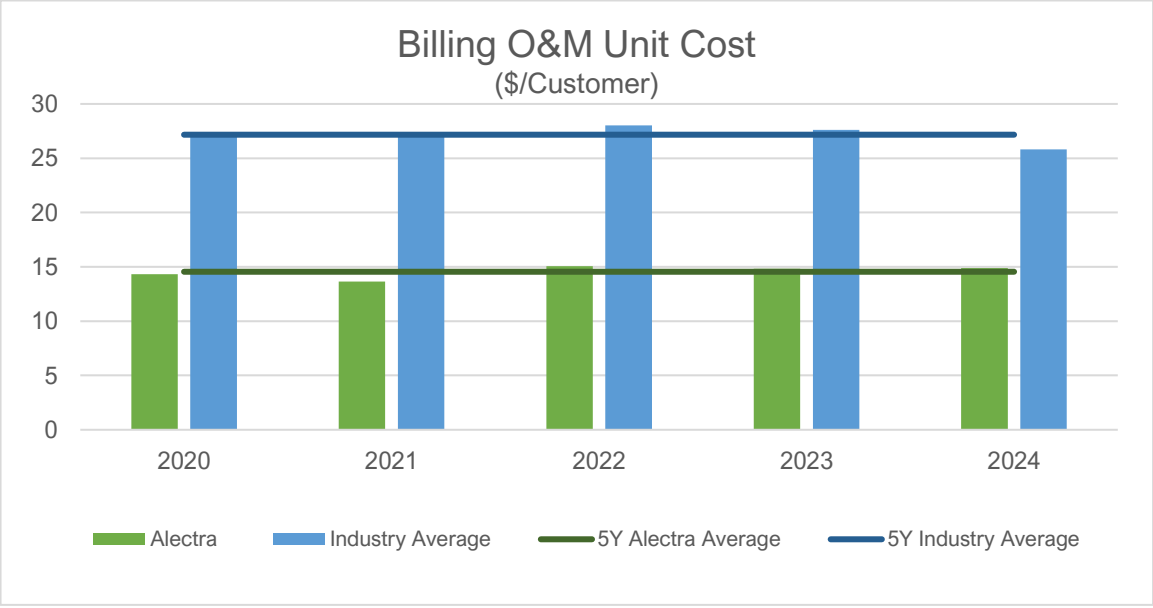


Table 2 - Meters O&M - Historical Performance

	2020	2021	2022	2023	2024	5Y Avg
Cost ('000s)	9,884	10,724	9,985	9,164	11,946	10,341
Total Customers ('000s)	1,062	1,070	1,077	1,083	1,086	1,075
$/Customer	9.31	10.03	9.28	8.46	11.00	9.61
YoY Change (%)	7%	8%	-7%	-9%	30%	

Chart 2 - Meters O&M - Historical Annual Results

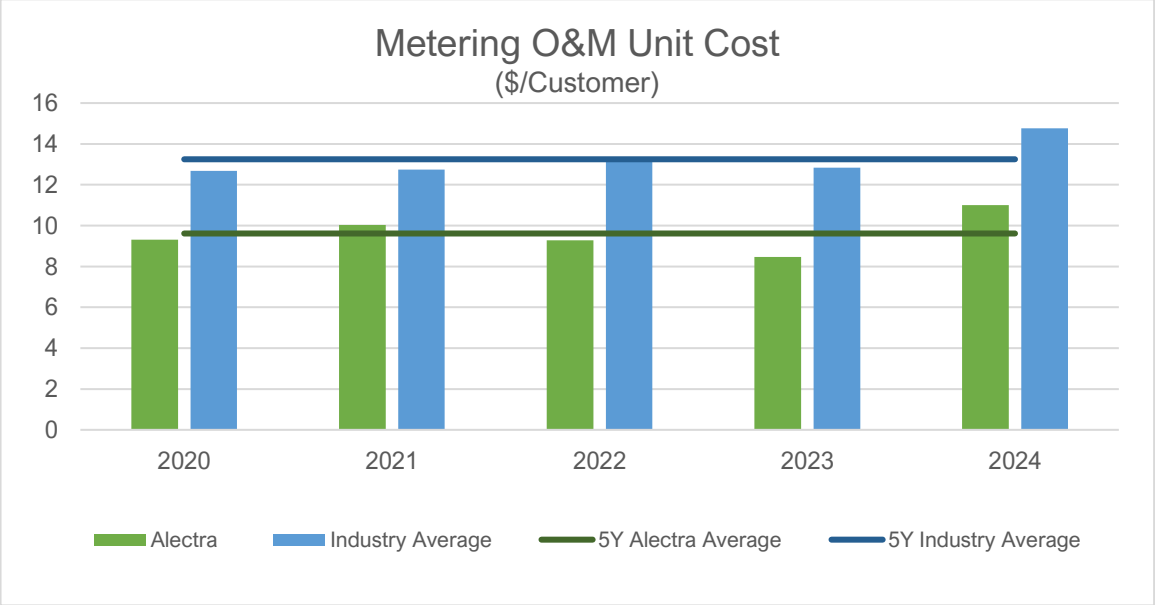


Table 3 - Vegetation Management O&M - Historical Performance

	2020	2021	2022	2023	2024	5Y Avg
Cost (‘000s)	5,190	4,896	5,059	6,526	5,562	5,447
Poles ('000s)	134	136	136	138	137	136
$/Pole	38.71	36.12	37.08	47.44	40.60	39.99
YoY Change (%)	-7%	-7%	3%	28%	-14%	

Chart 3 - Vegetation Management O&M - Historical Annual Results

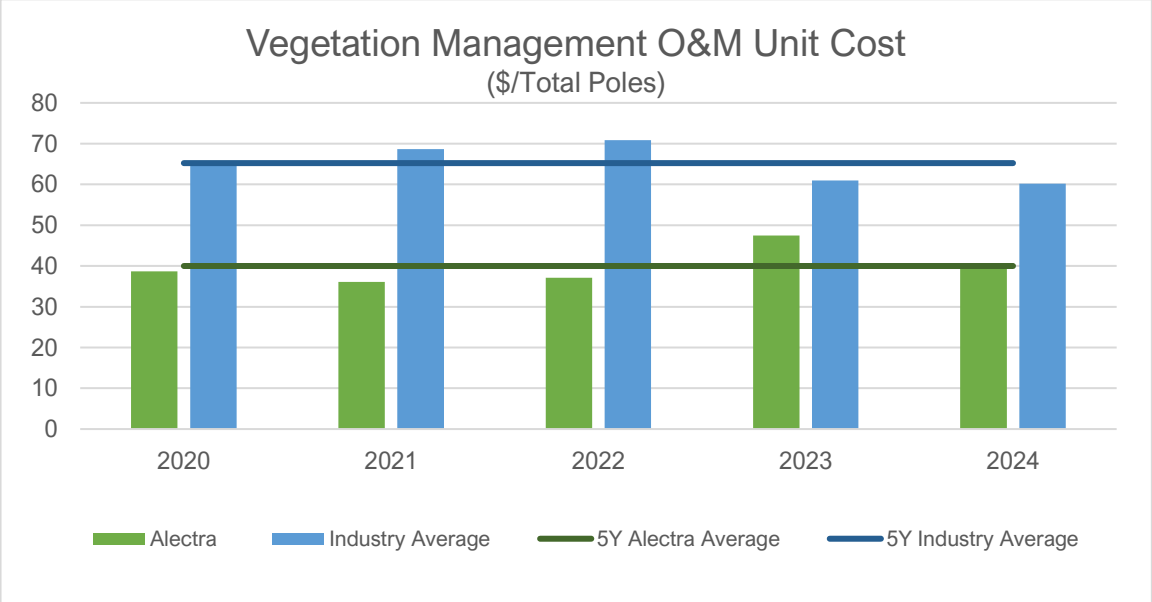


Table 4 - Lines O&M - Historical Performance

	2020	2021	2022	2023	2024	5Y Avg
Cost ('000s)	44,308	43,525	55,890	48,536	49,772	48,406
Circuit km of Primary Line	21,171	21,581	21,684	21,963	22,158	21,711
$/km of Primary Line	2,093	2,017	2,577	2,210	2,246	2,229
YoY Change (%)	-2%	-4%	28%	-14%	2%	

Chart 4 - Lines O&M - Historical Annual Results

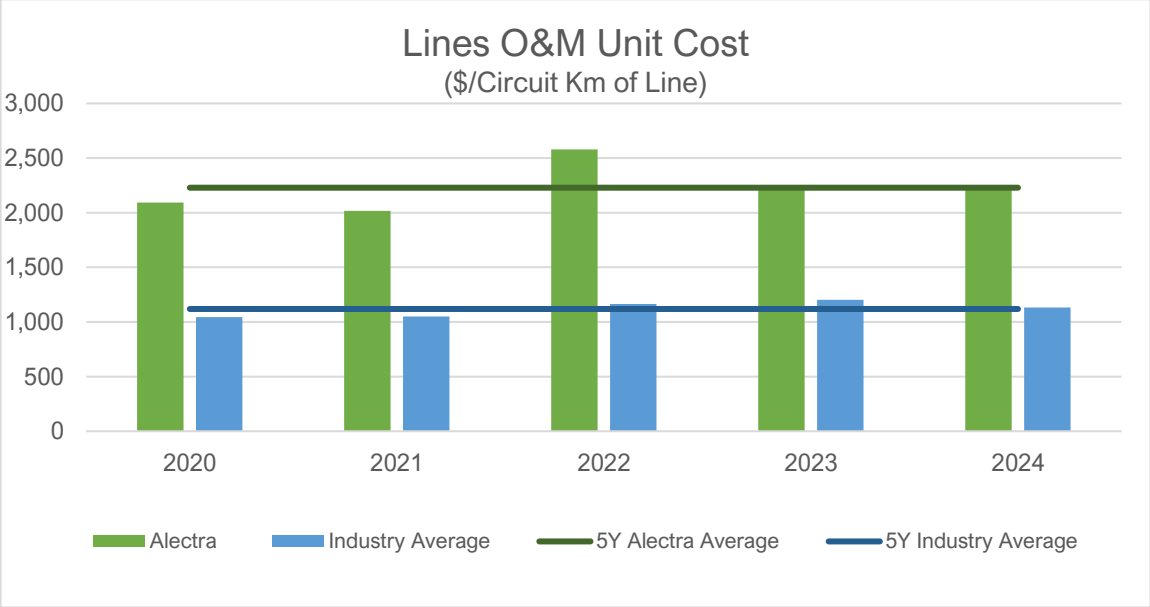


Table 5 - Distribution Station Equipment O&M - Historical Performance

	2020	2021	2022	2023	2024	5Y Avg
Cost ('000s)	7,041	7,580	8,836	9,960	9,199	8,523
Total MVA	7,044	7,044	7,044	7,038	6,986	7,031
$/MVA	1,000	1,076	1,254	1,415	1,317	1,212
YoY Change (%)	-14%	8%	17%	13%	-7%	

Chart 5 - Distribution Station Equipment O&M - Historical Annual Results

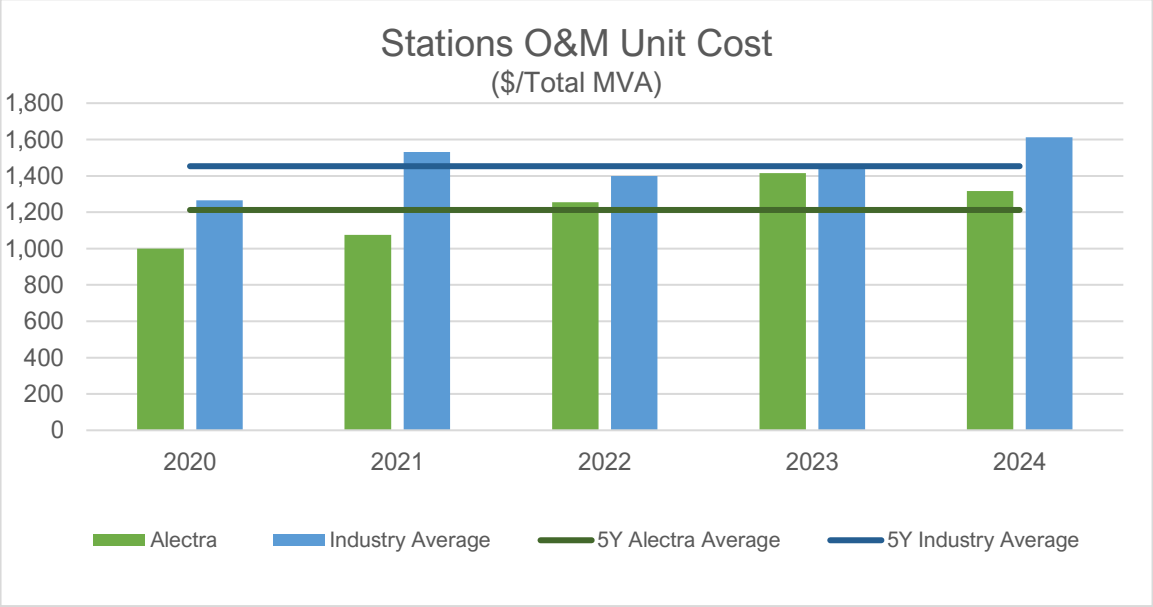


Table 6 - Poles, Towers and Fixtures O&M - Historical Performance

	2020	2021	2022	2023	2024	5Y Avg
Cost ('000s)	1,097	1,365	1,146	1,110	1,192	1,182
Total Poles ('000s)	134	136	136	138	137	136
$/Pole	8.18	10.07	8.40	8.07	8.70	8.68
YoY Change (%)	4%	23%	-17%	-4%	8%	

Chart 6 - Poles, Towers and Fixtures O&M - Historical Annual Results

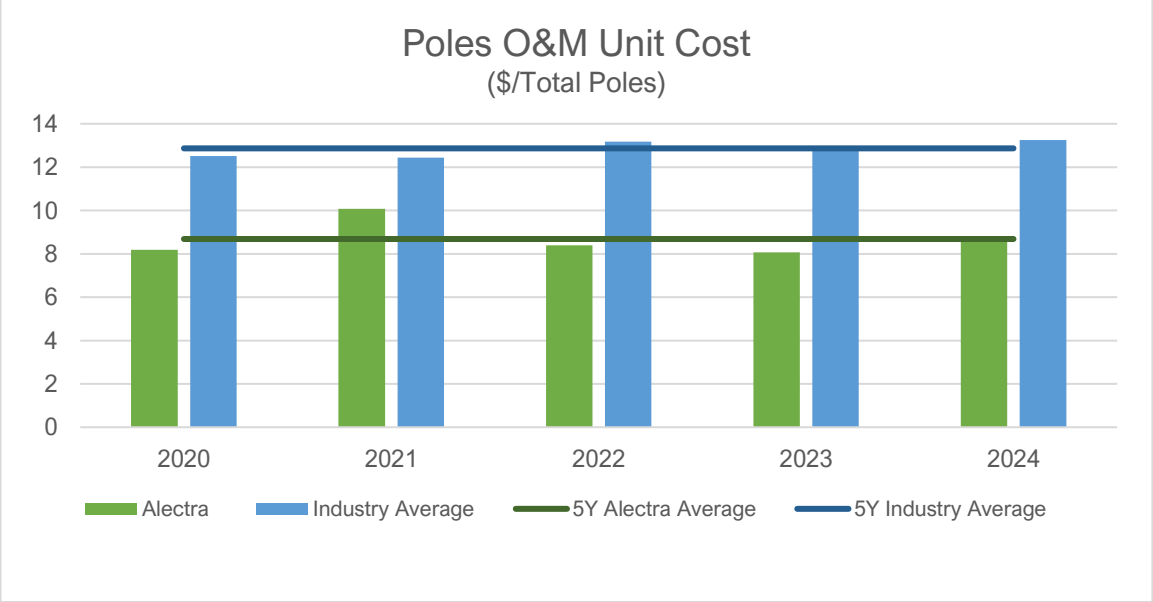


Table 7 - Distribution Station Equipment CAPEX - Historical Performance

	2020	2021	2022	2023	2024	5Y Avg
Cost ('000s)	5,037	7,968	1,873	2,012	4,159	4,210
Total MVA	7,044	7,044	7,044	7,038	6,986	7,031
$/MVA	715	1,131	266	286	595	599
YoY Change (%)	3%	58%	-76%	7%	108%	

Chart 7 - Distribution Station Equipment CAPEX - Historical Annual Results

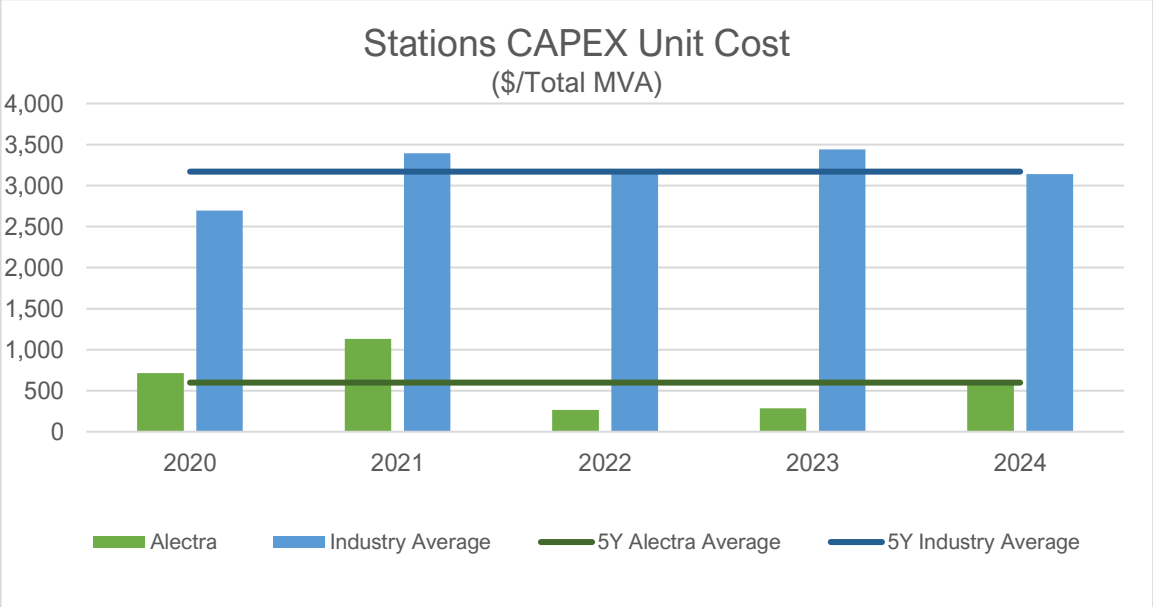


Table 8 - Poles, Towers and Fixtures CAPEX - Historical Performance

	2020	2021	2022	2023	2024	5Y Avg
Cost ('000s)	48,663	47,453	49,513	58,318	59,951	52,779
Quantity of Pole Additions	2,621	2,389	1,493	1,908	1,701	2,022
$/Pole Added	18,566	19,863	33,163	30,565	35,245	27,480
YoY Change (%)	-45%	7%	67%	-8%	15%	

Chart 8 - Poles, Towers and Fixtures CAPEX - Historical Annual Results

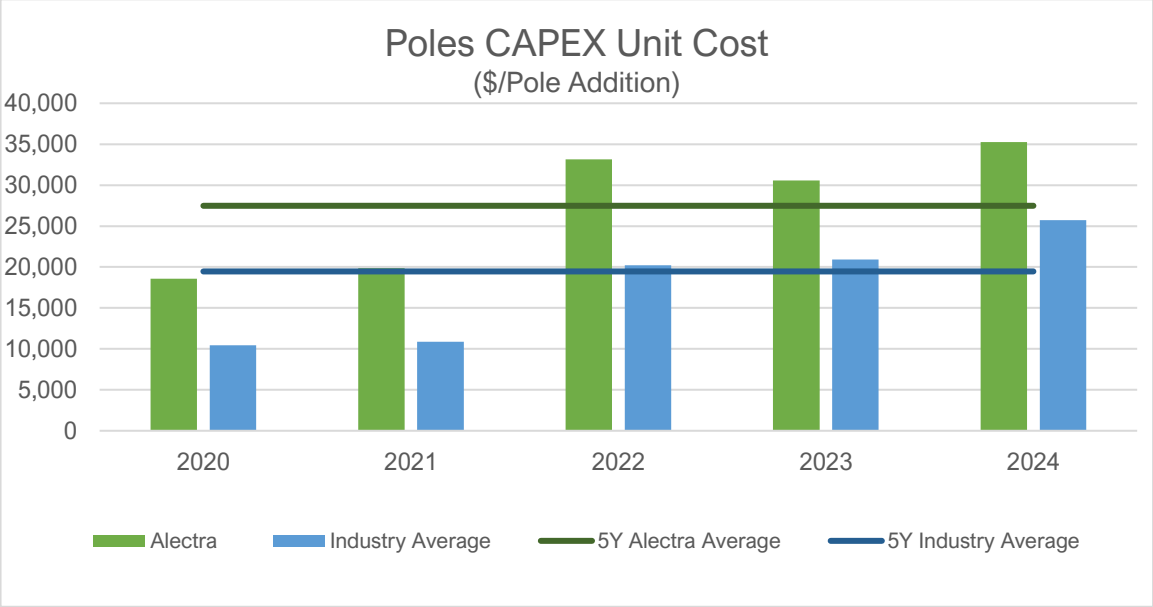


Table 9 - Line Transformers CAPEX - Historical Performance

	2020	2021	2022	2023	2024	5Y Avg
Cost ('000s)	48,743	63,626	53,888	96,557	101,083	72,779
Quantity of Line Tx Additions	2,288	2,278	1,264	2,078	2,431	2,068
$/Line Tx Added	21,304	27,931	42,633	46,466	41,581	35,983
YoY Change (%)	0%	31%	53%	9%	-11%	

Chart 9 - Line Transformers CAPEX - Historical Annual Results

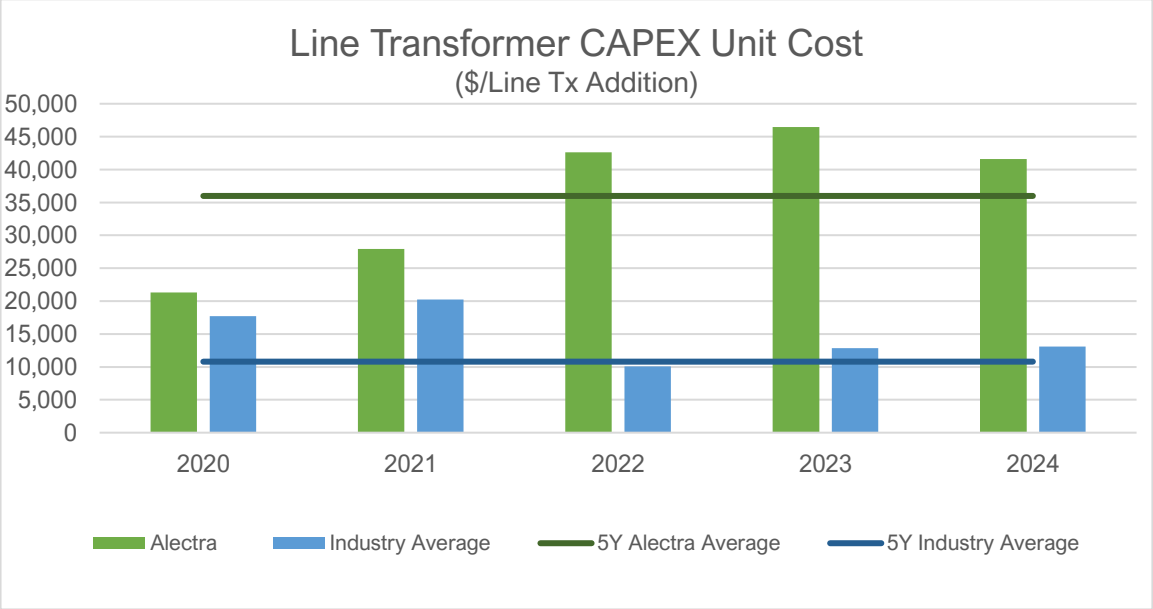
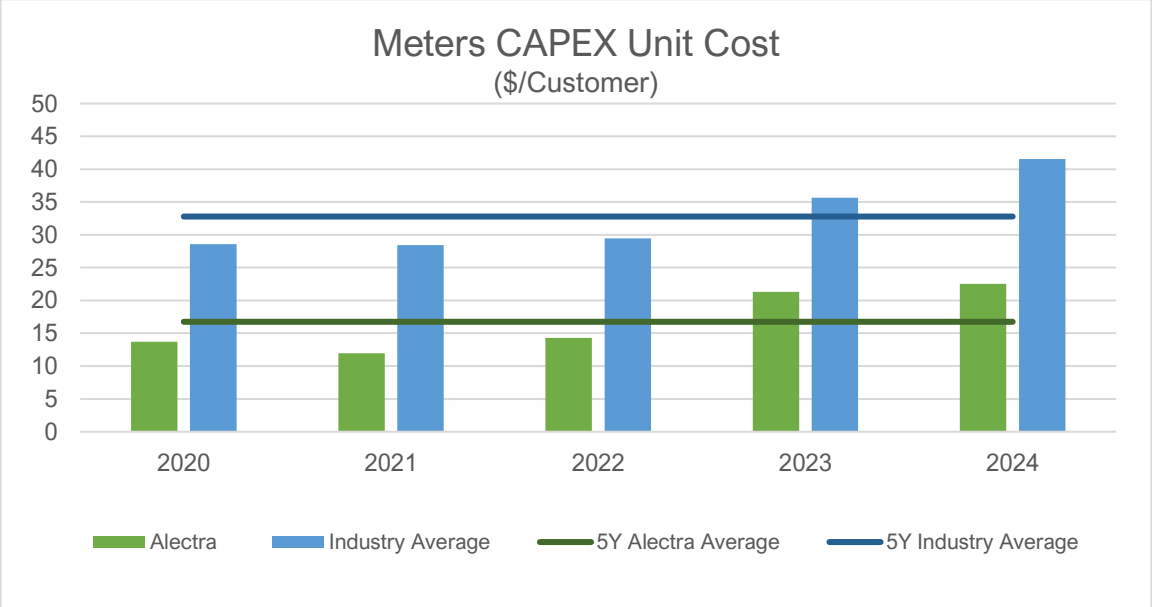


Table 10 - Meters CAPEX - Historical Performance

	2020	2021	2022	2023	2024	5Y Avg
Cost ('000s)	14,536	12,793	15,375	23,049	24,458	18,042
Total Customers ('000s)	1,062	1,070	1,077	1,083	1,086	1,075
$/Customer	13.69	11.96	14.28	21.29	22.52	16.75
YoY Change (%)	-19%	-13%	19%	49%	6%	

Chart 10 - Meters CAPEX - Historical Annual Results



i. An explanation of variances between Alectra's 2023- and 2024-unit cost results in excess of 20% is provided below.

a. Metering O&M: This trend relates primarily to a reallocation of $1.1MM in licensing and maintenance fees to Network Metering which was previously budgeted within the Digital and Innovation department. Additionally, labour costs increased due to returning to a full complement of required employees as workloads returned to pre-pandemic levels, and increases in outside service provider costs related to one AMI 1.0 services provider.

b. Stations CAPEX: Unit costs increased from $286 in 2023 to $595 in 2024 (increase of 108%). Cost increases are related to design activities for a new station project. Additionally in 2024, to ensure continued operational

efficiency, transformer reconditioning and remediation projects occurred at various stations, as well as station protection upgrade projects and communications infrastructure deployment projects.

ii. An explanation of variances between Alectra's 2024 and 5-year average unit cost results in excess of 20% is provided below.

a. Poles, Towers and Fixtures CAPEX – Alectra's 5-year average unit cost of $27,480 is 28% lower than its 2024-unit cost of $35,245. The relatively high 2024-unit cost can be attributed to a number of projects with non-standard requirements. A portion of the 2024 work effort is described below.

Poleline works intersecting with major public infrastructure, rail corridors or roadways often involve atypical installation at a higher overall unit cost. A sample of 2024 projects include poleline relocations completed along the Queen Elizabeth Way at Dixie Road, at Bayview Avenue East of Woodbine Avenue in the Markham area, and along Highway 400 in the Powerstream Rate Zone. Projects of this nature are complicated by atypical spans associated with highway crossings and frequent demobilization/mobilization efforts required to work within rail corridors. Some projects of this nature involve a small quantity of poles at a significant cost.

Project location is also a key factor in cost levels. Work in the downtown core comes with additional requirements and challenges which can exacerbate costs, and also involves paid officers to ensure safety, as was the case for a voltage conversion project at Central MS in Hamilton.

Specific project requirements can come with atypical costs, such as the examples noted below:

- The work effort involved with Barrie TS upgrades included atypically large poles to accommodate station risers and primary metering units.

- A pole renewal project in Alectra's Central North region involved H-framed main pole lines with cross arms, reduced spacing to accommodate Grade 1 construction near a CN Rail line, and challenging access conditions. Workflow was impacted by the requirement to halt work for each train passing the work site. Crews worked through evenings and weekends to limit impact on existing businesses and customers.
- Hurontario Light Rail Transit projects in Mississauga, Brampton and Hamilton included a variety of pole sizes.

b. Meters CAPEX – Alectra's 5-year average unit cost of $16.75 is 34% lower than its 2024-unit cost of $22.52. Increases in total program expenditures relate primarily to the initial phases of the AMI Renewal project with the installation of AMI 2.0 network equipment and single-phase meters beginning in 2023.

iii. An explanation of variances between Alectra's 5-year average unit cost results and 5-year industry average unit costs exceeding 25% is provided below.

a. Lines O&M – Alectra's 5-year average unit cost of $2,229 is 99% higher than the 5-year industry average of $1,119. At $2,229, Alectra's unit cost is in the middle of the industry average range of $519 to $4,885 per circuit kilometer of primary line. Fourteen utilities report a 5-year average unit cost higher than Alectra's. Program costs fluctuate annually depending on seasonal storm severity and weather-related outages and contracted labour rates, among other factors. Alectra Utilities is a strong cost performer on an overall basis and demonstrates a stable cost trend in this APB program area. Differences in the categorization of costs amongst utilities could be a contributing factor to variances between Alectra Utilities' reported costs and the sector at large. Please refer to Exhibit 4, Tab 2, Schedule 16 Overhead Inspections and Maintenance, and Schedule 17 Underground Inspections and Maintenance for further information.

b. Poles, Towers and Fixtures CAPEX – Alectra's 5-year average unit cost of $27,480 is 41% higher than the 5-year industry average of $19,462. Alectra has not historically tracked or reported fixtures, and it is unclear what, how, or for how long other utilities have captured this data, if at all. Alectra's reported Poles CAPEX costs may also allocate the entirety of some work efforts which include both an overhead and underground component based on the primary intent of the work due to allocation and tracking methodologies. A limitation of Alectra's enterprise resource planning software tool is that non-materials related costs are automatically allocated to a project based on the distribution activity, which is either marked as overhead or underground. This means that the costs allocated to this program activity may incidentally include some underground costs. The issue here is one of allocation, and not total cost accounting. Alectra's Poles, Towers and Fixtures CAPEX unit cost is additionally impacted by its urban nature and load density.

c. Line Transformer CAPEX – Alectra's 5-year average unit cost of $35,983 is 233% higher than the 5-year industry average of $10,795. Variances in cost performance are attributed to increasing supply chain costs and cost tracking practices as described above under the Poles, Towers and Fixtures CAPEX. Alectra Utilities notes that both contracted labour and material costs went up significantly since 2020 (during and post-COVID-19 pandemic) due to related supply chain challenges and labour shortages. Significant increases in labour costs, metals, transportation, and nearly all materials have been experienced, particularly as it relates to line transformers through this period.

Alectra notes that under an additional six APB program areas, including Billing O&M, Metering O&M, Vegetation Management O&M, Poles and Fixtures O&M, Stations CAPEX, and Meters CAPEX, Alectra's five-year average cost is better than the five-year industry average by more than 20%.

Consistent with the pre-filed evidence, Alectra Utilities presents below an assessment of Alectra's unit cost performance across the six APB O&M programs and four CAPEX programs outlined above, respectively, measured on an aggregate basis and compared with the same outcome for the industry. The data shows Alectra to be a strong cost performer with respect to both aggregate O&M and aggregate capital costs.

Table 11 - Total APB O&M - Historical Performance relative to Industry

	2020	2021	2022	2023	2024	5Y Avg
Total Cost ('000s)						
Alectra	82,731	82,690	97,117	91,362	93,840	89,548
Industry	655,584	672,199	714,994	698,090	692,985	686,770
Scale - Total Customers ('000s)						
Alectra	1,062	1,070	1,077	1,083	1,086	1,075
Industry	5,300	5,351	5,402	5,454	5,503	5,402
OM Unit Cost ($/Customer)						
Alectra	78	77	90	84	86	83
Industry	124	126	132	128	126	127
Variance						
Alectra vs. Industry ($/Customer)	-46	-48	-42	-44	-40	-44
Alectra vs. Industry (%)	-37%	-38%	-32%	-34%	-31%	-35%

Chart 11 - Total APB O&M – Unit Cost relative to Industry

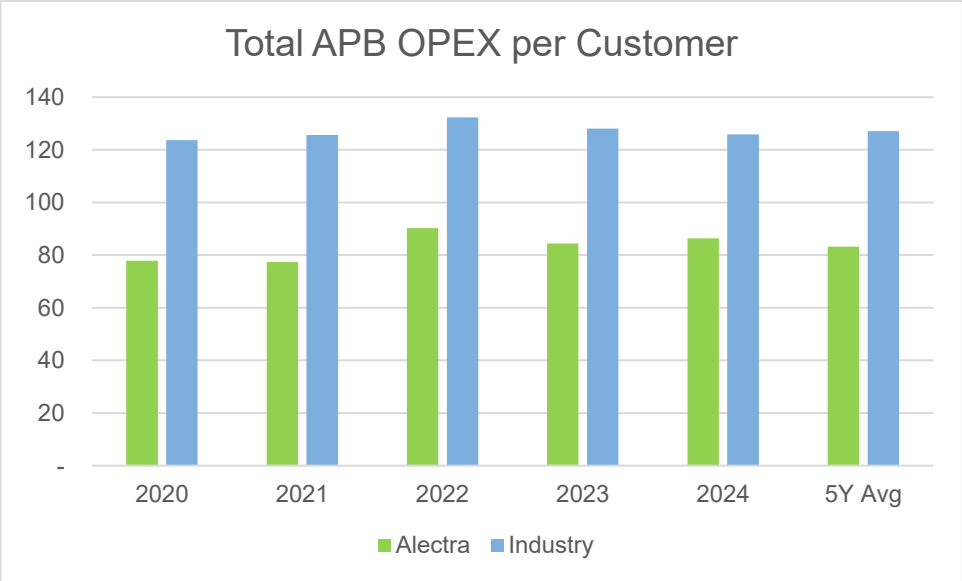
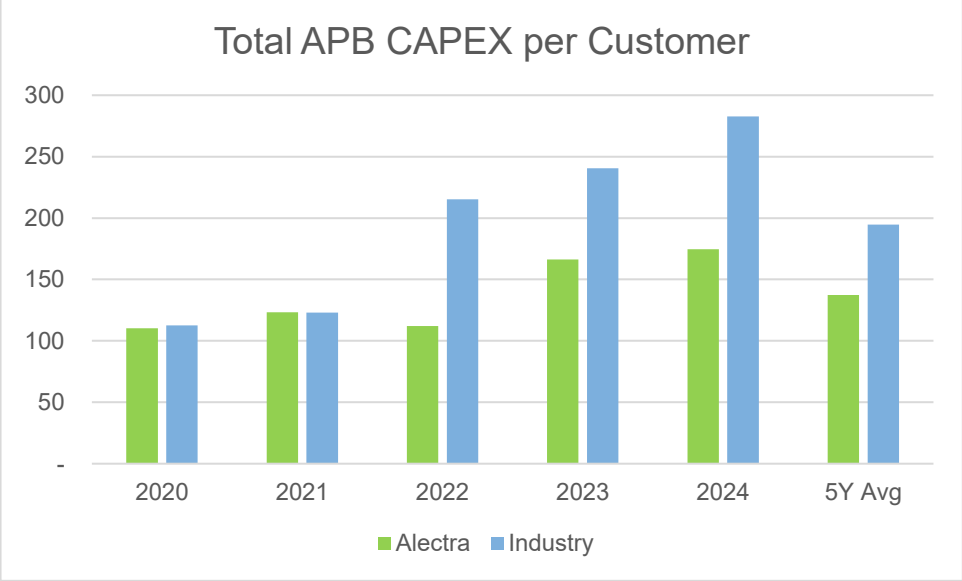


Table 12 - Total APB CAPEX - Historical Performance relative to Industry

	2020	2021	2022	2023	2024	5Y Avg
Total Cost ('000s)						
Alectra	116,979	131,840	120,649	179,935	189,650	147,811
Industry	596,397	657,729	1,162,513	1,311,691	1,555,742	1,056,814
Scale - Total Customers ('000s)						
Alectra	1,062	1,070	1,077	1,083	1,086	1,075
Industry	5,300	5,351	5,402	5,454	5,503	5,402
CAPEX Unit Cost ($/Customer)						
Alectra	110	123	112	166	175	137
Industry	113	123	215	241	283	195
Variance						
Alectra vs. Industry ($/Customer)	-2	0	-103	-74	-108	-58
Alectra vs. Industry (%)	-2%	0%	-48%	-31%	-38%	-30%

Chart 12 - Total APB CAPEX – Unit Cost relative to Industry



b) The discrepancies between APB values in reference 1 and reference 2 relate strictly to the 2024 USoA mapping review for OM&A programs. Mapping adjustments were made on a go-forward basis effective January 2024.

CAPEX programs were affected by one internal reclassification of $16.8M which refers to balances moved from USoA 1860 to USoA 1820 in 2024. At an aggregate level, total balances remain unchanged as result of this reclassification. The reclassification relates to wholesale meters capitalized in the 2004 to 2019 timeframe.

c) In Table 13 below Alectra Utilities provides:
- original values, consistent with historical RRR reporting (i.e., Trial Balance and Fixed Asset Continuity Schedules), and
- updated values reflecting restatements and reclassifications.

For further information pertaining to the reason for each restatement or update and related supporting documentation, please refer to 1-Staff-26.

Alectra confirms that restatements and updates are limited to cost data. Scale variables did not require an update for any APB program area.

Table 13 - Original and Updated APB Values

	Cost ('000s)	2020	2021	2022	2023	2024
1. Billing O&M	Original	$28,891	$29,565	$32,263	$33,651	$16,169
	Restated	$15,212	$14,601	$16,201	$16,065	no change
2. Metering O&M	Original	$3,580	$4,540	$3,821	$3,240	$11,946
	Restated	$9,884	$10,724	$9,985	$9,164	no change
3. Vegetation Management O&M	Original	$5,099	$4,937	$4,834	$6,227	$5,562
	Restated	$5,190	$4,896	$5,059	$6,526	no change
4. Lines O&M	Original	$48,091	$48,865	$61,689	$55,042	$49,772
	Restated	$44,308	$43,525	$55,890	$48,536	no change
5. Stations O&M	Original	$7,155	$8,413	$9,661	$11,015	$9,199
	Restated	$7,041	$7,580	$8,836	$9,960	no change
6. Poles O&M	Original	$436	$623	$ (2)	$112	$1,192
	Restated	$1,097	$1,365	$1,146	$1,110	no change
7. Stations CAPEX	Original	$1,262	$7,968	$1,873	$2,012	$21,000
	Restated	$5,037	no change	no change	no change	$4,159
	Original	$47,007	$47,453	$49,475	$58,318	$59,951

	Cost ('000s)	2020	2021	2022	2023	2024
8. Poles CAPEX	Restated	$48,663	no change	$49,513	no change	no change
9. Line Transformer CAPEX	Original	$46,927	$63,626	$53,734	$96,557	$101,083
	Restated	$48,743	no change	$53,888	no change	no change
10. Meters CAPEX	Original	$16,061	$12,793	$15,375	$23,049	$17,166
	Restated	$14,536	no change	no change	no change	$24,458

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-29

Framework Initiative Savings

Ref 1: Exhibit 1 / Tab 6 / Schedule 4 / pp. 10-23 (pdf pp. 1491-1504)

Preamble:

In Table 1-6-34 from reference 1, OEB staff was unable to reconcile most of the average annual saving amounts with the cumulative savings 2022-2026 amounts. For example, Table 1-6-34 shows that an average annual savings 2022-2026 for locates is $3.2M. OEB staff calculated the cumulative saving 2022-2026 to equal $16M (which is $3.2M x 5 years). However, Table 1-6-34 shows cumulative savings 2022-2026 of $12.9M instead of $16M.

Question(s):

a) Please provide supporting calculations that reconcile the amounts in the preamble.

i. Please also provide a breakdown of savings by capital and OM&A for initiatives that contain both types of costs.

b) Please provide forecast incremental productivity savings (not sustained savings) per year for each initiative listed in reference 1 for the 2027-2031 period.

i. Please provide a breakdown between capital and OM&A. For OM&A, please provide a further breakdown by OM&A program if possible.

ii. Please provide and explain assumptions used to derive the forecast incremental productivity savings for each initiative or provide a spreadsheet that shows supporting calculations for each initiative per year.

:

RESPONSE:

a) Please refer to 1-SEC-12 for a breakdown of savings by year and by capital and OM&A and specifically 1-SEC-12 c) for the description of the average and cumulative savings calculation.

b) In the context of this response, Incremental savings are the forecasted benefits that are in addition to the sustained savings realized from actions taken in 2026 or prior. The forecasted incremental savings for the Framework Initiatives are for the Metering Renewal - Technology and MyAlectra portal Framework Initiatives. 1-SEC-12_Attach 1_Framework Initiatives.xlsx provides the incremental and sustained savings for the initiatives while Table 1 below identifies the incremental portion only by capital and OM&A benefit. These incremental benefits expected to result from these initiatives are embedded in the capital and OM&A values forecast in this application, and all other framework initiatives savings are sustained into the forecast. Please refer to 1-SEC-12_Attach 1_Framework Initiatives.xlsx column "O" for the programs associated with each initiative.

Table 1 - Incremental portion of My Alectra portal and metering technology (2027-2031) in $MM

Incremental savings Embedded in the financial plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
Capital Financial Benefit					
Metering Renewal - Technology	2.5	16.2	10.9	12.1	14.6
OM&A Financial Benefit					
MyAlectra Portal Project	1.2	1.9	2.7	3.3	3.8
Total Incremental	**3.8**	**18.1**	**13.6**	**15.4**	**18.4**

:

The following are the assumptions used to derive the forecasted incremental productivity savings to the 2026 baseline (pre-rebasing) for each initiative.

- Metering renewal – Technology:
  - Meter replacement savings are based on the planned meter deployment as per Exhibit 2A, Tab 1, schedule 1, p.269 of the DSP (Table B06 - 23 Meter Volumes by Year in the Recommended 5.5 Year Alternative) and the cost savings per meter.
  - Meter dispensation savings are based on planned volumes of AMI 1.0 meters expected to be granted dispensation from Measurement Canada. These meters are set to expire within two years, and the exemption request is justified by the scheduled replacement under the planned AMI 2.0 deployment strategy. The savings are calculated using the volume of meters set to expire and the testing cost per meter.
  - Incremental savings are meter renewal savings for the meter replacement and meter dispensation, less the 2026 sustained savings.

- My Alectra portal:
  - Total savings based on planned e-billing adoption rate as per Exhibit 4, Tab 2, Schedule 7, p.22 of the Customer Service productivity and cost control. E-bill penetration is expected to rise from a baseline of 39.8% in 2024 to 68.4% by 2031.
  - The savings are based on the incremental adoption rate of e-bills, the volume of bills and the cost of paper bills. Incremental savings are forecasted savings, less the sustained savings in the 2026 forecast.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-30

Departmental Productivity Initiatives

Ref 1: Exhibit 1 / Tab 6 / Schedule 4 / pp. 23-31 (pdf pp. 1504-1512)

Preamble:

In reference 1 (page 23 or pdf page 1504), Alectra Utilities states that in addition to the projects documented under the Framework, Alectra Utilities' culture of employee empowerment and continuous improvement has led business units to conduct smaller productivity initiatives, which yield qualitative benefits, difficult to quantify benefits, or quantifiable benefits below the materiality threshold established for inclusion in the Framework.

One notable area Alectra Utilities has achieved significant productivity is in technology innovation. Table 1-6-35 (reference 1) shows Departmental Productivity Initiatives centered around technology innovation.

Question(s):

a) Please provide estimated incremental productivity savings per year (not sustained savings) for each initiative shown in Table 1-6-35 in reference 1 since the implementation date, if possible.

i. Have the savings been incorporated into the application? If so, please indicate where.

ii. Please provide a breakdown of savings by capital and OM&A. For OM&A savings, please provide a further breakdown by OM&A program if possible.

b) Has Alectra Utilities estimated incremental productivity savings (not sustained savings) for the forecast period?

:

i. If so, please provide estimated incremental productivity savings from each technology innovation initiative per year.
ii. Have the savings been incorporated into the application? If so, please indicate where.
iii. Please provide a breakdown of savings by capital and OM&A. For OM&A savings, please provide a further breakdown by OM&A program if possible.

RESPONSE:

a) Since filing the application, two of the department initiatives listed in Table 1-6-35 have been added as Framework Initiatives, however these are sustained savings. Please refer to 1-SEC-12 and specifically 1-SEC-12_Attach 1_Framework Initiatives.xlsx tab labeled “Newly added FI” for the annual and cumulative savings. These initiatives are both OM&A efficiency benefits and are associated with the finance and customer service programs. Alectra Utilities has not estimated incremental productivity savings (incremental to the 2026 baseline) for the remainder of the department initiatives listed in Table1-6-35.

b) Other than the sustained saving identified in part a) of this response Alectra Utilities has not estimated any incremental productivity savings from the Technology Innovation Department Productivity Initiatives listed in Table 1-6-35.

:

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-31

Facilitating Innovation

Ref 1: Exhibit 1 / Tab 7 / Schedule 1 / pp. 1-13 (pdf pp. 1514-1526)

Question(s):

a) For the innovation initiatives undertaken or planned by Alectra Utilities for the 2020 to 2031 period, please provide a table detailing initiatives with an annual total cost incurred by Alectra Utilities.
   i. Please provide a breakdown of cost by OM&A and capital.

b) Alectra Utilities states that some of the initiatives in reference 1 increased productivity (e.g., Artificial Intelligence (AI) Solution Deployment and Automated Bill Reconciliation). Has Alectra Utilities quantified productivity savings resulting from these innovation initiatives for the 2020 to 2031 period?
   i. If so, please provide incremental productivity savings achieved and forecast incremental productivity savings per year for each initiative (not sustained savings). Please also provide a breakdown of savings by OM&A and capital. For OM&A savings, please provide a further breakdown by OM&A program if possible.
   ii. Please explain whether these savings have been incorporated into the application. If so, please identify where. If not, why not.

RESPONSE:

a) Please see Table 1 and Table 2 below.

:

Table 1 – 2020-2024 Innovation Initiatives

Initatives ($MM)	2020			2021			2022			2023			2024		
	Capital	OMA	Total	Capital	OMA	Total	Capital	OMA	Total	Capital	OMA	Total	Capital	OMA	Total
Home Technologies Rate Based	-	0.10	0.10	-	0.00	0.00	-	(0.54)	(0.54)	-	-	-	-	-	-
Alternate Energy Sources Rate Based	-	0.14	0.14	-	0.07	0.07	-	0.07	0.07	-	0.34	0.34	-	0.03	0.03
York Region's NWA Project	0.00	0.30	0.30	-	0.21	0.21	-	(0.02)	(0.02)	-	(1.28)	(1.28)	-	(0.20)	(0.20)
AlectraDrive @Work	0.04	0.13	0.16	0.17	0.28	0.45	(0.12)	0.09	(0.03)	0.19	0.07	0.26	(0.09)	(0.08)	(0.17)
AlectraDrive @ Home	0.38	0.18	0.56	0.08	0.02	0.10	0.19	0.15	0.34	(0.06)	0.02	(0.04)	(0.19)	(0.03)	(0.22)
Transactive Energy Platform/ Blockchain	0.41	0.03	0.44	0.14	(0.09)	0.05	0.30	(0.01)	0.28	(0.07)	0.16	0.09	0.00	0.01	0.01
DER Control Platform	(0.00)	(0.06)	(0.07)	0.12	0.09	0.21	0.01	0.07	0.08	(0.09)	(0.03)	(0.12)	-	0.10	0.10
Alectra V2X Pilot	-	-	-	-	-	-	-	-	-	-	-	-	0.11	0.01	0.12
AMI 2.0 - Grid Edge Analytics	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.01)	(0.01)
AlectraDrive for Fleets	-	-	-	-	-	-	-	-	-	-	-	-	0.04	0.08	0.12
SEW Customer Engagement eMobility	-	-	-	-	-	-	-	-	-	-	0.06	0.06	0.43	0.16	0.59
Total	**0.82**	**0.81**	**1.64**	**0.51**	**0.57**	**1.09**	**0.38**	**(0.18)**	**0.20**	**(0.03)**	**(0.66)**	**(0.70)**	**0.31**	**0.06**	**0.37**

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1 **Table 2 – 2025-2031 Innovation Initiatives**

Initatives ($MM)	2025			2026			2027			2028			2029			2030			2031		
	Capital	OMA	Total	Capital	OMA	Total	Capital	OMA	Total	Capital	OMA	Total	Capital	OMA	Total	Capital	OMA	Total	Capital	OMA	Total
AlectraDrive @Work	-	0.00	0.00	-	0.00	0.00	-	0.00	0.00	-	0.00	0.00	-	0.00	0.00	-	0.00	0.00	-	0.00	0.00
DER Control Platform	-	(0.01)	(0.01)	-	0.05	0.05	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Alectra V2X Pilot	0.49	0.37	0.86	0.13	0.23	0.36	0.00	0.02	0.02	(0.08)	(0.23)	(0.31)	-	0.10	0.10	-	0.10	0.10	-	0.09	0.09
Customer Non-Wires Solution Design & Development	-	-	-	-	0.43	0.43	0.25	0.23	0.48	0.47	0.01	0.48	0.25	0.01	0.26	0.31	0.01	0.32	0.15	-	0.15
Computer Vision for Utility Operations	0.26	-	0.26	-	-	-	-	-	-	0.17	-	0.17	0.13	-	0.13	-	-	-	-	-	-
Outage Restoration: Enhancing Predictions & Customer Experiences	0.57	-	0.57	-	-	-	-	-	-	0.16	-	0.16	0.16	-	0.16	-	-	-	-	-	-
Enhancing C&I Meter Change Verification	0.13	-	0.13	-	-	-	0.21	0.02	0.23	0.22	0.01	0.23	-	-	-	-	-	-	-	-	-
Enhanced Material Forecasting	0.35	-	0.35	-	-	-	-	-	-	0.16	-	0.16	0.16	-	0.16	-	-	-	-	-	-
AlectraDrive for Fleets	0.24	0.16	0.40	1.08	0.03	1.10	(0.04)	0.18	0.15	(0.10)	(0.32)	(0.42)	-	0.01	0.01	-	0.00	0.00	-	0.00	0.00
SEW Customer Engagement eMobility	0.83	0.13	0.96	0.42	0.22	0.64	0.00	0.05	0.05	-	0.05	0.05	-	-	-	-	-	-	-	-	-
Total	**2.87**	**0.65**	**3.52**	**1.62**	**0.96**	**2.59**	**0.43**	**0.51**	**0.94**	**1.01**	**(0.47)**	**0.54**	**0.70**	**0.12**	**0.82**	**0.31**	**0.11**	**0.42**	**0.15**	**0.10**	**0.24**

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b)

i) While innovation initiative costs are tracked and reported at the initiative level, productivity savings are only quantified and reported where they are material and can be reliably measured. For initiatives that produce material and quantifiable productivity savings, Alectra Utilities reports those savings as Productivity Framework Initiatives, rather than attributing them to individual enabling tools or algorithms. Individual algorithms or digital tools may represent one component of a broader project or initiative that contributes to the reported productivity improvements.

ii) Where benefits exceed Alectra Utilities' materiality threshold for initiatives, they are captured through Alectra Utilities' productivity tracking and reflected in the reported productivity results consistent with Alectra Utilities' productivity framework. Two such examples are:

The AI-Enabled interactive Voice response (IVR) redesign described in Exhibit 1, Tab, Schedule 2 page 4, contributed to the Innovation Customer Service AI Framework Initiative. Please refer to 1-SEC-12_Attach 1_Framework Initiatives.xlsx tab labeled "Innovation" for the Innovation Framework Initiative, sustained into the forecast period for the financial benefits reported under the Customer Service AI initiative. While these savings are incremental to those captured in the application, they do not generate incremental savings in the forecast period.

AI solution deployment contributed to the Microsoft Copilot Productivity Framework Initiative. Please refer to 1-SEC-12_Attach 1_Framework Initiatives.xlsx for Capital and OM&A annual savings of Microsoft Copilot Productivity Framework Initiative which are embedded and sustained into the forecast period (not incremental). These embedded efficiency benefits would be associated with multiple programs as the users of the Microsoft copilot are across the organization.

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Certain algorithm developments are intended to support improved operational decision-making rather than to generate directly measurable productivity savings. While these tools may contribute to decisions that result in savings, the algorithm output is typically one of several inputs to those decisions, and the incremental productivity impact cannot be reliably isolated or attributed solely to the algorithm.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-32

New Future Productivity Initiatives and Savings

Ref 1: Exhibit 1 / Tab 6 / Schedule 4 / Table 1-6-34, pp. 10-11 (pdf pp. 1491-1492)

Preamble:

Reference 1 states that:

> Alectra Utilities has not prepared a detailed productivity plan for the 2027 to 2031 period capable of closing the funding gap implemented within its proposed rate framework, as the full scope of opportunities available to the utility cannot be known or planned so far in advance in an environment of significant technological change. Alectra Utilities has however begun preliminary assessment of a series of longer-term productivity initiatives which it is hopeful will realize material productivity benefits.

Question(s):

a) Please provide a brief description of each new productivity initiative that has been considered but not included in the application or as part of Alectra Utilities' responses to 1-staff-29, 1-staff-30, 1-staff-31.

    i. Please provide Alectra Utilities' preliminary forecast of incremental productivity savings (not sustained savings) for each initiative per year for 2027 and 2028 in Please provide a breakdown of savings by capital and OM&A. For OM&A savings, please provide savings by OM&A program if possible.

RESPONSE:

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Please find below descriptions of projects with opportunities for potential future productivity.

Table 1 – Description of Future Initiatives

Initiative	Description
AMI 2.0 - Grid Edge Analytics	Alectra is planning to implement new technology to harness data and analytics from the Advanced Metering Infrastructure (AMI 2.0). Enhanced grid-edge insights will enable more sophisticated load management and planning for future load expansion, optimizing asset utilization and deferring the need for new infrastructure. Additionally, grid edge analytics supports improved proactive maintenance by providing reliable, granular data from distributed assets throughout Alectra's distribution system.
Enterprise Asset Management	Alectra is planning the implementation of an Enterprise Asset Management (EAM) system. This system is designed to replace manual management processes, providing a centralized and scalable platform capable of managing a large number of assets. It will maintain cradle-to-grave asset information and support the planning and execution of initiatives essential for operating a reliable, cost-effective distribution system.
Meter -to-Cash - CIS - CC&B CCS/C2M upgrade	Alectra is planning to upgrade its customer care and billing system, which is anticipated to realize productivity benefits. The upgrade will ensure that Alectra maintains vendor support from its vendor and other ecosystem partners.
Integrated Network Management	Alectra is planning implementation of an Integrated Network Management (INM) solution, which will unify various siloed planning and operations data into a single canonical model, dramatically reducing the manual effort historically needed to gather, reconcile, and maintain critical distribution system information. By centralizing data and applying continuous quality checks, INM eliminates redundant processes, streamlines reporting, and accelerates key workflows like system studies and asset demographic assessments. This integrated approach not only decreases integration costs but also boosts productivity across system planning, maintenance, and operations by providing accurate data that informs faster, more reliable decision-making.

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Initiative	Description
Planning Tools and Automation	This initiative introduces advanced solutions such as the Techno-economic Stochastic Distribution Planning Tool (TESDP) and the Multi-attribute Time Series Forecasting Tool (MTSF) to automate and optimize Alectra's grid planning activities. Moving beyond static, worst-case assessments, these tools enable dynamic scenario planning, reducing connection timelines and manual analysis. By consolidating the evaluation of Distributed Energy Resources (DERs) and automating interconnection assessments, planners save significant labor hours, minimize errors, and can more rapidly evaluate Non-Wires Alternatives (NWA) as well as the impacts of Non-Wires Solutions (NWS). The result is improved productivity that strengthens both operational efficiency and compliance with evolving regulatory requirements.
Identity & Access Management (IAM) Program	In the ever-evolving digital environment of today, Alectra faces persistent cybersecurity threats that pose risks to our data and operations. A comprehensive Identity and Access Management (IAM) program is essential not only for safeguarding assets but also for adhering to Ontario's Cybersecurity Framework and preserving the trust built with customers and employees. The IAM program will further enhance and secure the environment.

Alectra Utilities has not prepared a preliminary productivity framework forecast for incremental productivity for future initiatives. However**,** please refer to 1-Staff-177 for a preliminary estimate of savings forecasted by the customer service program.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-33

Audited Financial Statements

Ref 1: Exhibit 1 / Appendix 1-6 - 2024 Audited Financial Statements / Note 6 / (pdf p.1554)

Ref 2: Alectra_Attach 2B-1_OEB Appendix 2-BA-Fixed Asset Continuity Schedule_20251121

Preamble:

OEB staff has compiled the following table showing the difference of PP&E between reference 1 and reference 2:

	2023			2024		
($M)	Cost	Accumulated Depreciation	Net Book Value	Cost	Accumulated Depreciation	Net Book Value
Reference 1 (a)	5,335	1,131	4,204	5,776	1,286	4,490
Reference 2 (b)	4,656	1,069	3,587	4,991	1,227	3,764
Variance (a-b)	679	62	617	785	59	726

Question(s):

a) Please reconcile and explain the variances identified in the table above.

RESPONSE:

a) Please see the reconciliation below and the related explanations for each variance:

Table 1, Reconciliation for each variance.

	2023			2024		
($M)	**Cost**	**Acc. Dep.**	**Net Book Value**	**Cost**	**Acc. Dep.**	**Net Book Value**
Ref 1 (Consolidated Financial Statements of Alectra Utilities Corporation)	**5,335**	**1,131**	**4,204**	**5,776**	**1,286**	**4,490**
Less: Balances relating to Solar Sunbelt Partnership and RFSP (Item 1)	(145)	(71)	(74)	(147)	(80)	(67)
Add: Balances relating to intangible assets (Item 2)	315	119	196	335	146	189
Add: Balances relating to customer contributions (deferred revenue) (Item 3)	(823)	(99)	(724)	(954)	(120)	(834)
Less: OMS Impairment (Item 4)	(3)	0	(3)	(3)	0	(3)
Less: Regulatory Adjustments(Item 5)	(23)	(11)	(12)	(16)	(5)	(11)
(Ref 2) Appendix 2-BA	**4,656**	**1,069**	**3,587**	**4,991**	**1,227**	**3,764**

Item 1: Reference 1 relates to the consolidated financial statements of Alectra Utilities Corporation. As noted in the same document under Note 1 (PDF page 1543), the fixed assets of solar divisions, including Ring Fenced Solar Portfolio and Solar Sunbelt General Partnership, are incorporated into the consolidated amounts presented in the Financial Statements.

Item 2: Reference 1 relates to Note 6 of the Financial Statements, which includes only Property, Plant and Equipment and Right of Use Assets. Alectra's Fixed assets also include Intangible Assets as presented in note 7 (PDF page 1556) of the financial statements.

Item 3: Alectra's Fixed assets also include Deferred Revenue, as presented in Note 20 (PDF page 1573) of the financial statements.

Item 4: Alectra recorded an impairment of the OMS for MIFRS purposes, as the system was deployed in only two of the intended five rate zones.

Item 5: Regulatory adjustments represent adjustments made during the year to defer fixed asset balances based on approved OEB deferral accounts balances for MIFRS reporting. These balances relate to accounts 1557, 1531 and 1522.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-34

Audited Financial Statements

Ref 1: Exhibit 1 / Appendix 1-6 - 2024 Audited Financial Statements / Note 13 / (pdf p.1563)

Ref 2: Exhibit 6 / Attachment 6-5 / 2024 Actuarial Report / Appendix A (pdf p.230)

Preamble:

OEB staff has compiled the following table showing the difference of Benefit Cost recognized in Net Income between reference 1 and reference 2:

($M)	2023	2024
Benefit cost recognized in net income Ref 1 (a)	4.0	3.0
Defined benefit cost recognized in income statement Ref 2 (b)	4.4	4.5
Variance (b-a)	0.4	1.5

Question(s):

a) Please reconcile and explain the variance identified in the table above.

RESPONSE:

a) The audited financial statements are presented in millions of dollars with no decimals while the figures presented in the actuarial report are presented in dollars. The differences between the amounts presented in the Audited Financial Statements (Note 13, PDF p. 1563) and the Actuarial Report (Appendix A, PDF p. 230), as noted in references 1(a) and 2(b), are due to rounding adjustments to the financial statements. These rounding adjustments are necessary to ensure that all subtotals and totals add correctly and to reconcile amounts across the statements and notes.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-35

MAADs Commitments
Ref 1: Exhibit 1 / Tab 9 / Schedule 2 / Table 1-9-3 / p. 1 (pdf p. 1674)
Ref 2: Exhibit 1 / Tab 9 / Schedule 4 / pp. 30-31 (pdf pp. 1709-1710)

Preamble:
Alectra Utilities states in reference 1 that ratepayers are expected to experience greater savings in comparison to the status quo from the time of the first anticipated rebasing, ten years following the completion of the consolidation, due to cost savings resulting from synergies.

Reference 2 states that the consolidation has resulted in the total net cash savings (pre-tax) in the 10 years amounting to approximately $340M, with sustained savings of approximately $44.3M per year thereafter. The consolidation has demonstrated that customers are better off than they would have been had the utilities continued to operate as separate entities.

Question(s):

a) Please provide a summary table showing distribution bill impacts, by rate zone, for residential and GS<50 kW rate classes with and without total net synergies for each of the last ten years (2017-2026).

RESPONSE:

a) Alectra questions the probative value of this information, since the achieved MAAD synergies are already embedded into the 2027-2031 capital and OM&A budgets, the

impact of which on 2027 rates is illustrated in response to 1-AMPCO-12 and 1-AMPCO-13.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-36

Incremental Resourcing Requirements by Function
Ref 1: Exhibit 1 / Tab 9 / Schedule 4 / Table 1-9-9 / pp. 5-10 (pdf pp. 1684, 1689)

Question(s):

a) With regards to Alectra Utilities' explanations on consolidating control rooms and business procedures on page 5 in reference 1. Please explain:

   i. why consolidating control rooms down to one at night proved not to be feasible.

   ii. why the consolidation of business procedures required the addition of Planning & Support System Controller responsibilities which had not been present in one of the legacy utilities.

b) With regards to Alectra Utilities' explanation on the de-centralized customer service model on page 8 in reference 1, please explain further why the union negotiations led to a de-centralized model.

c) Please provide a table which shows a breakdown of the 65 unplanned additions by the utility functions by year as categorized in Table 1-9-9 in reference 1.

RESPONSE:

a)

i. Consolidating the two control rooms to one at night is not feasible due to the differences in legacy systems used in the control rooms and the variation in work

practices and procedures between the regions. The single control room and night alternative requires integration of the control room system (e.g. SCADA, OMS) so that staff can be cross trained between the regions. At this time there are differences between the two control rooms with respect to systems, process, and nomenclature, which prevent the level of cross training required to consolidate operations into a single control room at night.

ii. The responsibilities of the Planning & Support System Controller existed at all legacy utilities. In all legacy utilities except one, the Planning & Support System Controller position existed to perform these responsibilities. At the one legacy utility that that did not have this position, the responsibilities were absorbed into the System Control Operator role. At this legacy utility, the Planning & Support System Controller position was created and the responsibilities transferred from the System Control Operator to this position to align with the other legacy utilities allowing for future cross training and potential consolidation of Control Rooms.

b) Provisions resulting from union negotiations, such as work centre protection, limited Alectra's ability to geographically consolidate Customer Service functions while retaining experienced staff in highly complex roles. As a result, the organization was required to manage through a workforce transition period during which many employees either moved into new roles at their current location and required training, or relocated to continue performing existing functions. In this context, a centralized model was determined to be unmanageable without compromising service quality and operational stability.

c) Table 1 provides a detailed breakdown of the 65 unplanned additions by the utility function by year as categorized in Table 1-9-9 in reference 1.

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"Table 1" Unplanned Additions by Utility Function

Function	2017	2018	2019	2020	2021	Total FTEs
Administration	0	0	0	1	0	**1**
Business Transformation	6	0	0	0	0	**6**
Control Room	2	0	6	1	1	**10**
Corporate Relations	3	0	0	0	0	**3**
Customer Service	0	0	3	1	1	**5**
Engineering	1	0	7	2	1	**11**
Finance	1	0	3	1	0	**5**
Human Resources	2	0	0	0	0	**2**
Internal Audit	1	0	0	0	0	**1**
IT	0	3	0	0	0	**3**
Legal	2	1	2	0	0	**5**
Metering	1	2	1	0	0	**4**
Operations	0	0	0	1	0	**1**
Regulatory	2	4	0	0	0	**6**
Supply Chain	0	0	1	1	0	**2**
Total	**21**	**10**	**23**	**8**	**3**	**65**

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-37

Payroll Operating Synergy Savings and Transition Costs

Ref 1: Exhibit 1 / Tab 9 / Schedule 4 / Table 1-9-7 / p. 2 (pdf p. 1681)

Question(s):

a) Please provide a table in the same format as Table 1-9-7 shown in reference 1 to show payroll operating synergy savings achieved per year through the Guelph merger for the period 2019-2026.

   i. Please also provide explanations to support data presented in the table.

b) Please provide tables in the same format as Table 1-9-7 shown in reference 1 to show:

   i. Payroll operating transition cost per year from the initial merger for the 2017-2026 period.

   ii. Payroll operating transition cost per year from the Guelph merger for the 2019-2026 period.

   iii. For b) (i) and b) (ii), please also provide a further cost breakdown by category, as well as explanations to support data presented in the table.

RESPONSE:

a) **"Table 1" - Payroll OPEX Savings – Guelph Merger**

Payroll OPEX Savings ($MM)	2019	2020	2021	2022	2023	2024	2025	2026	Total
Payroll	1.6	1.8	2.3	3.0	3.0	3.5	3.7	3.8	**22.5**
Total	**1.6**	**1.8**	**2.3**	**3.0**	**3.0**	**3.5**	**3.7**	**3.8**	**22.5**

i. Exhibit 1, Tab 9, Schedule 4, page 11, section 4.1.2 provides a detailed explanation supporting the sustained payroll synergies resulting from the Guelph merger.

b)

i. **"Table 2" - Payroll Transition OPEX Costs – Alectra Merger**

Payroll OPEX Transition Costs ($MM)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Severance	15.7	1.5	0.4	1.9	-	-	-	-	-	-	**19.5**
Total	**15.7**	**1.5**	**0.4**	**1.9**	**-**	**-**	**-**	**-**	**-**	**-**	**19.5**

ii. **"Table 3" - Payroll Transition OPEX Costs – Guelph Merger**

Payroll OPEX Transition Costs ($MM)	2019	2020	2021	2022	2023	2024	2025	2026	Total
Severance	2.7	(0.1)	(0.1)	-	-	-	-	-	**2.5**
Total	**2.7**	**(0.1)**	**(0.1)**	**-**	**-**	**-**	**-**	**-**	**2.5**

iii. As indicated in Tables 2 and 3 above, all payroll operating transition costs pertain to severance expenses. Exhibit 1, Tab 9, Schedule 4, pages 11 and 12, provides explanations supporting data presented in Table 2 and 3.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-38

Capital Synergy Savings and Capital Transition Costs for Guelph Merger

Ref 1: Exhibit 1 / Tab 9 / Schedule 4 / p. 30 (pdf p. 1709)

Ref 2: Exhibit 1 / Tab 9 / Schedule 4 / Table 1-9-18 / p. 29 (pdf p. 1708)

Ref 3: Exhibit 1 / Tab 9 / Schedule 4 / Table 1-9-17 / p. 27 (pdf p. 1706)

Question(s):

a) The total capital transition cost of $16M (reference 2) from the Guelph merger is $12.3M higher than the total capital synergy savings of $3.7M (reference 3). Please explain why the capital transition cost is higher than the synergy savings.

b) The total capital transition cost of $16M (reference 2) from the Guelph merger is $12.3M higher than the $6.3M projected in the business case (reference 1). Please explain in detail why the capital transition cost is higher than the transition cost projected in the business case.

RESPONSE:

a) Capital synergy savings from the Guelph merger were limited because Guelph's legacy DSP did not include extensive IT capital expenditures, resulting in fewer opportunities for avoided legacy spend. Please refer to the response to 1-SEC-16, part b) for additional information on legacy planned transition capital. Conversely, the $16M capital transition cost reflects the necessary capital work to complete integration and align Guelph with Alectra's enterprise systems and operating standards, including CIS and ERP consolidations, IT system migration and integration, and GIS/OMS consolidation. The transition total was further increased by budget overruns on the CIS and ERP consolidation projects as elaborated on in the response to part b). Accordingly, capital transition costs were higher than capital synergy savings.

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b) The actual/forecast transition cost of $16M is $6.3M higher than the $9.7M included in business case. The variance is primarily attributable to refinements made during detailed planning, which identified additional technical work, system remediation, and integration requirements not captured in the original assumptions which formed the merger business case.

The largest cost variance is the Guelph CIS Integration, which is projected to exceed the business case estimate by $4.9M. The legacy Guelph CIS system was highly customized, end-of-life, and lacked vendor support, requiring significant remediation, data conversion, and configuration to enable migration into Alectra's CIS platform. Interdependencies with the Guelph water billing exit added further complexity and extended the project timeline, increasing both vendor and internal effort beyond what was initially forecasted.

The Guelph ERP Integration accounts for an additional variance of $1.4M. Full harmonization of Guelph's financial, inventory, and related business processes into Alectra's JDE platform required broader scope, additional technical work, and extended project management support. Process standardization and system alignment activities were introduced during execution, contributing to higher capital requirements than reflected in the business case.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-39

Ref 1: Exhibit 1 / Tab 9 / Schedule 5 / p.1 (pdf p. 1711)
Ref 2: Exhibit 2 / Tab 1 / Schedule 1 / Appendix B09 - Information Technology Systems / p. 372 (pdf Exhibit 2A Part 2, p. 380)

Question(s):

a) Reference 1 states, of the $137.5M in transitional capital investments, "$108.7M ($92.9M from the initial merger + $15.8M from Guelph merger) relate specifically to IT expenditures."

   i. Please provide a table with yearly amounts and details to outline the projects that resulted in the $108.7M expenditure.

   ii. Please create a table similar to table B09 in reference 2, to show separate line items for the transition-related IT expenditures, for each year since the first year of the mergers.

   iii. For the $108.7M, please provide the amounts transferred to fixed assets each year since the mergers, by OEB account.

RESPONSE:

a) Please see 1-SEC-16_Attach 1_Capital Transition Project Schedule.xlsx.

   i. See tab "1-Staff-39 (IT)" for the yearly amounts of the projects that resulted in the $108.7M IT related expenditure amount.

ii. See columns E to O. Note, there are no IT related transition expenditures planned beyond 2026.

iii. See tab “1-Staff-39 (IT)” for the yearly amounts transferred to fixed assets for the projects that resulted in the $108.7M IT related expenditure amount.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-40

Transition Capital

Ref 1: Exhibit 1 / Tab 9 / Schedule 5 / p. 1 (p.1711)

Ref 2: Exhibit 2B, Tab-1, Sch-2, Table 2-1-6, 2-1-7, p. 11

Ref 3: Alectra_Attach 2B-1_OEB Appendix 2-BA-Fixed Asset Continuity Schedule_20251121

Ref 4: Alectra_Exhibit 2A_OEB Appendix 2-AB-Capital Expenditure Summary_20251121

Preamble:

Per reference 1, Alectra Utilities is seeking approval to include the remaining NBV (i.e. $50.3M) transition-related capital expenditures, which is the remaining NBV of the $137.5M transitional capital investments incurred since the mergers, to the 2027 opening rate base. Please see a breakdown of $135M transitional capital investments below:

IT expenditures		Facilities investment	Total
Initial merger	Guelph merger		
$92.9M	$15.8M	$28.8M	$137.5M

Per reference 2, OEB staff has compiled the following table showing that Alectra Utilities has included this transition cost every year from 2017 ~ 2026 totalling $137.5M:

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$M	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Total CapEx (Ref 2) (a)	271.5	278.5	333.6	270.4	277.5	271.1	330.6	334.9	326.7	344.7	
Transition Cost (ref 2) (b)	25.1	42.1	34.1	11.5	7.4	5.5	2.1	1.6	6.1	1.9	137.5
Total CapEx less transition costs (a-b)	246.4	236.4	299.5	258.9	270.1	265.6	328.5	333.3	320.6	342.8	
Net Expenditures (Ref 4)	To be fill in	To be fill in	To be fill in	258.9	270.1	265.6	328.5	333.3	320.5	342.8	

OEB staff notes that this transition capital cost is included in fixed asset continuity schedule (reference 3) but is not included in capital expenditure summary (reference 4).

Question(s):

a) Please provide the OEB's policy or prior OEB decision showing that the transition cost was approved to be included in the rate base in the current application. Please provide EB # and the reference to relevant document.

b) Please fill in highlighted cells from 2017 to 2019 for Net Expenditures and reconcile to Capital Expenditure Summary in reference 4.

c) Please explain why this transition cost was not included in Capital Expenditures summary (Reference 4).

RESPONSE:

a) In Alectra Utilities' two MAADs applications (EB-2016-0025 and EB-2018-0014), the OEB did not make a determination with respect to the inclusion of transition costs in rate base. At page 28 of the OEB's Decision and Order in EB-2016-0025, dated December 8, 2016,

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the OEB did state that "in this application the OEB will not make a determination regarding future rate issues…"

Further, the OEB's 2024 *Handbook to Electricity Distributor and Transmitter Consolidations* (2024 MAADs Handbook, p.14) states that "If a utility has capitalized any assets it has classified as part of the utility's "transition" costs (i.e., capitalized costs intended to integrate operations) these will be subject to review, on a case-by-case basis. The nature of the expenditure and whether it would have occurred regardless of the consolidation will be reviewed, in addition to the typical review for need and prudence. Alectra has provided evidence on this in Exhibit 1, Tab 9, Schedule 5.

For further information regarding Alectra's rationale for the inclusion of these costs in rate base, and references to legacy utility DSP evidence contemplating costs post-merger, please see Alectra's response to 1-SEC-16.

b) Please refer to the response for 2-Staff-45 part d).

c) Transition costs were not included in the capital project summaries because they are distinct from the ongoing capital investment needs of the consolidated organization, and including them in the capital expenditure summary would have distorted the period over period trend analysis. Nonetheless, as noted in the pre-filed evidence at Exhibit 1, Tab 9, Schedule 5 and further explained in 1-SEC-16, but for the merger, these costs would have been required to support the renewal of IT systems and facilities to ensure the safe, reliable and effective ongoing operations of the legacy utilities.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-41

Ref 1: Exhibit 1 / Tab 9 / Schedule 5 / p.1 (p.1711)

Ref 2: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B07 - Facilities Management / p. 287 (pdf Exhibit 2A Part 2, p. 295)

Question(s):

a) Reference 1 states the "remaining $28.8M in capital expenditure primarily corresponds to transition-related facilities investments."

   i. Please provide a table with yearly amounts and details to outline the projects that resulted in the $28.8M expenditure.

   ii. Please create a table similar to table B07 in Ref 2, to show separate line items for the transition-related facilities expenditures, for each year since the first year of the mergers.

   iii. For the $28.8M, please provide the amounts transferred to fixed assets each year since the mergers, by OEB Account.

b) Reference 2, Table B07 shows that a total of $78.8M was spent over 2020 through 2024 on the Kennedy Road Consolidation. Please detail by year, any spending that was related to capital work or capital leases of the Mavis Road or Sandalwood Parkway West properties from 2020 through 2024.

RESPONSE:

a) Please refer to 1-SEC-16_Attach 1_Capital Transition Project Schedule.xlsx

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i. See tab "1-Staff-41 (non-IT)" for the yearly amounts of the projects that resulted in the $28.8M non-IT related expenditure amount.

ii. See columns E to O. There are no non-IT related transition expenditures planned beyond 2026.

iii. See tab "1-Staff-41 (non-IT)" for the yearly amounts transferred to fixed assets for the projects that resulted in the $28.M non-IT related expenditure amount.

b) Table 1 provides the expenditures related to capital work or capital leases for the Mavis Road or Sandalwood Parkway West properties from 2020 through 2024.

"Table 1" - Mavis Road and Sandalwood Parkway Capital Expenditures 2020-2024

Facilities ($MM)	2020	2021	2022	2023	2024	Total
Sandalwood Parkway West	-	0.01	-	-	-	0.01
Mavis Road	-	-	0.00	-	-	0.00
Total	**-**	**0.01**	**0.00**	**-**	**-**	**0.01**

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-42

Capital Synergy Savings and Capital Transition Costs for Initial Merger
Ref 1: Exhibit 1 / Tab 9 / Schedule 7 / pp. 1-2 (pdf pp. 1715-1716)
Ref 2: Exhibit 1 / Tab 3 / Schedule 2 / p. 14 (pdf p. 214)

Preamble:
Alectra Utilities provides several reasons in reference 1 for early termination of the rebasing deferral period (from 2029 to 2027) for the Guelph rate zone including the benefit from sustained synergies and rate impacts.

Reference 1 also states that the 2026 forecasted residential fixed distribution rate for the Guelph rate zone is $35.99; the calculated 2026 harmonized rate on an Alectra Utilities-wide basis is $32.56 or $3.43 lower than the 2026 forecasted residential charge. This harmonization impact for Guelph's residential customers serves to partially offset the impact of rebasing. The 2027 distribution bill impact a typical residential customer in Guelph is $0.07 or 0.2%.

OEB staff notes that for GS<50 kW and GS>50, Regular rate classes, the 2027 distribution bill impacts shown in reference 2 are 38.8% and 23.8% respectively.

Question(s):

a) Please provide the updated 2026 fixed distribution residential rate for the Guelph rate zone and updated 2026 harmonized rate on Alectra Utilities-wide basis, based on the OEB's approved 2026 rates (EB-2025-0055).

b) With the 2027 distribution bill impacts for the GS<50 kW and GS>50, Regular rate classes being significantly higher for the Guelph rate zone (reference 2), please provide additional

information and explanation to demonstrate that these customers benefit from rebasing the Guelph rate zone in 2027 instead of 2029.

RESPONSE:

a) 2026 GRZ fixed distribution residential rate (EB-2025-0055) is $35.99, and 2026 harmonized rate is $32.56. This is unchanged from the pre-filed evidence.

b) As noted in the pre-filed evidence, the sustained synergies achieved from Alectra Utilities' mergers, including the merger of Guelph Hydro Electric System Inc. are $44.3MM per year from 2027 onwards. These benefits accrue to all customers through a lower cost-to-serve. As outlined in Exhibit 8, Alectra Utilities conducted extensive analyses to inform its rate harmonization proposal. Please also see Alectra's response to 8-SEC-102 where it identifies options to harmonize rates over a longer period and 1-CCC-7 that provides the rationale for rebasing the Guelph RZ as part of Alectra's 2027 rebasing application.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-43

Ref 1: Exhibit 2A / Alectra_Exhibit 2A_OEB Appendix 2-AA - Capital Projects Table_20251121

Preamble:

OEB Staff have prepared the following table showing analysis of the system access gross and net expenditures.

System Access ($M)	Actual Expenditure					Bridge		Forecast Period (Planned)				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Gross Expenditures	141	140	119	205	232	253	257	306	313	299	273	296
Total Contributions	-78	-72	-71	-138	-130	-165	-156	-148	-133	-135	-134	-157
Net Expenditures	**63**	**67**	**47**	**67**	**102**	**88**	**101**	**158**	**180**	**164**	**139**	**139**
Contributions as Percent of Gross Expenditures	55%	52%	60%	67%	56%	65%	61%	48%	42%	45%	49%	53%

Question(s):

a) Please confirm or correct the data in the table above.

b) Please explain what contributes to the decrease in contribution amounts from an average of 59.5% over 2020-2026 to an average of 47.6% over 2027-2031.

c) Please provide the capital contribution amounts for each line item in reference 1 for each year, i.e., network metering, customer connections, road authority & transit projects, and transmitter related upgrades.

d) Please provide explanation for any material changes in the level of capital contributions per each line item, year over year.

RESPONSE:

a) Alectra Utilities confirms that the data provided in the table above is correct.

b) The reduction in average contributions as a percentage of System Access gross expenditures over 2027–2031 is primarily due to a shift in the System Access spending mix**.** This is mainly driven by a comparative increase in Network Metering expenditures in the 2027-2031 period versus the historical period, particularly associated with the AMI renewal program, which has no contribution applicability. Without considering Metering investments, the average contribution for 2027-2031 is 60%, which is in line with historical trend.

c) Please find the requested contributions in Table 1, which summarizes System Access capital contribution amounts by project group and year, consistent with Appendix 2-AA and table provided.

Table 1 – System Access capital contribution amounts by project group (2020-2031)

Contributions in $MM	Actual Expenditures					Bridge		Planned Expenditure				
Project Group	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
MIFRS												
SYSTEM ACCESS												
Network Metering	0.0	-0.6	-0.6	-0.7	-0.7	-0.7	-0.6	-0.6	-0.7	-0.6	-0.6	-0.6
Customer Connections	-36.8	-49.4	-48.0	-74.1	-88.9	-80.9	-100.4	-114.7	-112.7	-102.8	-100.6	-123.2
Road Authority and Transit Projects	-41.0	-20.8	-22.5	-62.9	-40.4	-83.3	-55.3	-32.8	-19.3	-31.8	-32.4	-33.0
Transmitter Related Upgrades	-0.5	-1.3	-0.1	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total SYSTEM ACCESS	**-78.3**	**-72.1**	**-71.2**	**-137.8**	**-130.0**	**-164.9**	**-156.3**	**-148.1**	**-132.7**	**-135.2**	**-133.6**	**-156.8**

d) System Access contributions are program dependent and reflect the underlying funding treatment applicable to each activity within the portfolio. The material year over year changes by program are summarized below:

- **Network Metering**: Contributions are consistent over the years, with only limited contribution eligible work associated with customer requests for new services.

- **Customer Connections:** The year-over-year movement in contributions is driven by the timing, scale, and mix of customer driven connection activity. Contribution amounts are determined at the portfolio and project level and can vary materially year over year depending on the presence and timing of large projects and timing of customer deposits that are applied against eligible costs.
    - 2023 had a material increase in contribution ($26MM), consistent with higher ICI and layouts activity and higher volume of subdivisions work.
    - 2024 had a material increase in contribution ($15MM), reflecting continued growth in subdivisions activity and increased investment in large customer-initiated system expansion projects.
    - 2026 had a material increase in contribution ($20MM), driven by higher volume of subdivisions work and execution of large customer-initiated system expansion projects.
    - 2027 had a material increase in contribution ($14MM), driven by higher execution of large customer-initiated system expansion projects while other areas maintain activity levels.
    - 2031 had a material increase in contribution ($23MM), driven by two large transit expansion projects while other areas maintain activity levels.

- **Road Authority and Transit** The year-over-year movement in contributions is primarily driven by transit projects, where contributions are closely tied to the timing, scope and volume of large Metrolinx projects (typically fully funded), and secondarily by road authority work, which presents a steadier contribution profile aligned with municipal cost-sharing arrangements.
    - 2021 had a material decline in contribution ($20MM) largely due to lower execution of transit projects relative to 2020.

- 2023 had a material increase in contribution ($40MM) primarily driven by higher investments in transit projects, with substantial investments for Lakeshore west line and Hurontario Light Rail Transit in Mississauga.
- 2025 had a material increase in contribution ($43MM) primarily driven by higher expenditures for several Metrolinx projects.
- 2026 had a material decrease in contribution ($28MM) reflecting lower planned investments for transit projects compared to 2025.
- Contributions planned from 2027-2031 are relatively stable, with a notable drop in 2028 due to lower planned investments for transit projects as some large Metrolinx projects conclude or transition between phases.

- **Transmitter Related upgrades:** Contributions do not present a material year-over-year trend. Contribution amounts are project specific, and Alectra Utilities has not planned any contribution funded projects in this category over the DSP planning period.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-44

Ref 1: Exhibit 2A / Alectra_Exhibit 2A_OEB Appendix 2-AA - Capital Projects Table_20251121

Preamble:

OEB Staff have prepared the following table showing analysis of the system service gross and net expenditures.

System Service ($M)	Actual Expenditure					Bridge		Forecast Period (Planned)				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Gross Expenditures	28	29	25	20	27	57	62	39	80	152	134	193
Total Contributions	-1	-1	-1	-1	-4	-19	-15	0	-1	-2	-2	-9
Net Expenditures	**27**	**28**	**24**	**19**	**23**	**37**	**47**	**39**	**80**	**150**	**132**	**184**
Contributions as Percent of Gross Expenditures	5%	3%	4%	5%	15%	34%	24%	0%	1%	1%	1%	4%

Question(s):

a) Please confirm or correct the data in the table above.

b) Please explain what contributes to the increased amount of contribution in 2024, 2025, 2026 and 2031.

c) Please provide the capital contribution amounts for each line item in reference 2 for each year.

d) Please provide explanation for any material changes in the level of capital contributions per each line item, year over year.

RESPONSE:

a) Alectra Utilities confirms that the data in the table provided is correct.

b) The higher System Service contribution amounts in 2024, 2025, 2026 and 2031 are primarily attributable to Stations Capacity projects. The contributions are project specific and can vary year over year based on whether a project includes a funding component, and the timing of when contribution amounts are recognized in the actuals or plan.

The 2024, 2025 and 2026 contributions are all primarily driven by Vaughan TS#6, which is multiyear station build with funding. The 2031 contribution is driven by GTAA TS station build. Please refer to Exhibit 2A, Tab 1, Schedule 1, Appendix B13 for further details regarding the projects.

c) Alectra Utilities assumes that Ref 2 is the System Service section of Ref 1. Please find the requested information in Table 1 below, which summarizes System Service capital contribution amounts by project group and year, consistent with Appendix 2-AA and table provided.

Table 1 - System Service capital contribution amounts by project group (2020-2031)

Contributions in $MM	Actual Expenditures					Bridge		Planned Expenditure				
Project Group	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
MIFRS												
SYSTEM SERVICE												
SCADA and Automation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capacity (Lines)	-0.5	-0.2	-0.7	-0.4	0.0	0.0	0.0	0.0	-0.5	-1.8	0.0	0.0
Capacity (Stations)	0.0	0.0	0.0	-0.2	-3.9	-18.4	-14.4	0.0	0.0	0.0	-1.9	-8.5
System Control, Communications and Performance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Safety & Security	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Distributed Energy Resources (DER) Integration	-0.9	-0.6	-0.4	-0.4	0.0	-0.7	-0.7	-0.1	-0.2	0.0	0.0	0.0
Total SYSTEM SERVICE	-1.4	-0.8	-1.1	-1.0	-3.9	-19.1	-15.1	-0.1	-0.7	-1.8	-1.9	-8.5

d) As referenced in Section b, Contributions in Stations and Lines Capacity programs are project specific and can vary yearly depending on whether the underlying work includes a funded component and the timing of when those amounts are recognized.

- **Lines Capacity** work experienced a material decrease in contribution in 2024, with no contributions from 2024 to 2027. This is due to not having funded components in projects that were executed or are planned to be executed in those years. Contributions are planned for 2028 and 2029, driven by planned projects that include funded components, including a new

- feeder in St. Catharines and an investment to add two additional 27.6 kV circuits to supply new greenfield development load in Richmond Hill.

- **Stations Capacity** contributions are material in 2024, 2025, 2026 and 2031. The increase in contribution for these years is associated with the station builds for Vaughan TS#6 and GTAA TS, consistent with the discussion in part (b).

- **DER** Integration had no contributions in 2024 due to the timing of Government agency funded investments in that year.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-45

Capital Expenditure

Ref 1: Exhibit 2 / Alectra_Exhibit 2A_OEB Appendix 2-AB-Capital Expenditure Summary_20251121

Ref 2: Exhibit 2B / Alectra_Attach 2B-1_OEB Appendix 2-BA-Fixed Asset Continuity Schedule_20251121

Ref 3: Exhibit 2B / Tab 1 / Schedule 2 / Tables 2-1-6 and 2-1-7 / pp. 2-3 (pdf pp. 11-12)

Preamble:

OEB staff notes that the historical actuals of each legacy utility from their last rebasing application to 2019 was missing in reference 1.

Question(s):

a) Please provide all legacy utilities' capital expenditure separately in excel worksheet from their last rebasing application to 2031

b) Please update reference 1 to consolidate the total amounts based on (a)

c) Please reconcile (b) to reference 2 and explain the variance between "net capital expenditure" in updated reference 1 and "capital additions" in reference 2

d) Please reconcile (b) to reference 3.

RESPONSE:

a) Please refer to attachment 2-Staff-45-a_b_c-d_Attach 1_2-AB – 2017-2031.xlsx which provides the actual and planned capital expenditures from 2017-2031 by rate zones. Alectra Utilities was formed in 2017 through the amalgamation of several legacy utilities. As a result of differences in historical systems, record-keeping practices, and data availability across the predecessor entities, consistent and reliable information prior to 2017 is not available on a consolidated basis.

b) Attachment 2-Staff-45-a_b_c-d_Attach 1_2-AB – 2017-2031.xlsx provides an updated version of Appendix 2-AB including expenditures details from 2017-2031.

c) Attachment 2-Staff-45-a_b_c-d_Attach 1_2-AB – 2017-2031.xlsx provides the requested reconciliation.

The main reason for differences between capital expenditures and additions is that they do not exhibit a one-to-one relationship in any given year due to timing. A timing lag typically exists between expenditures and additions. This is particularly relevant for multi-year projects, where expenditures may occur in one or more years, while the related assets are placed into service in a subsequent year or upon project completion. Conversely, in-service additions in a given year may exceed current-year capital expenditures where the majority of project costs were incurred in prior years and only limited expenditures occur in the year the assets are placed into service.

In addition, in-service amounts are derived from the Fixed Asset Continuity Schedule (FACS), which includes items such as spares and leases that are not classified as capital expenditures reported by investment category. There are also further differences due to regulatory and accounting adjustments, including variance accounts, which affect in-service additions in FACS and rate base but do not impact capital expenditures reported by investment category. Please refer to response for 2-Staff-143 for further itemized details.

d) Attachment 2-Staff-45-a_b_c-d_Attach 1_2-AB – 2017-2031.xlsx provides the requested reconciliation.

2-Staff-45

Attachment 1
App 2-AB – 2017-2031

Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-46

Alignment with Non-Wires Solutions Policy

Ref 1: Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7, June 2025 / Chapter 4 / pp. 82-83

Ref 2: Exhibit 2A / Tab 1 / Schedule 1 / Tab / 5.3.5 Non-Wires Solutions to Address Energy System Needs / pp.326-341 (pdf Exhibit 2A Part 1 pp. 332-347)

Preamble:

Reference 1 outlines the Government of Ontario's expectations as it relates to grid modernization. Specifically, as it relates to non-wires solutions, reference 1 states:

> Grid modernization is not limited to new hardware. It should also include the better use of existing technologies, whether by applying them in new ways, scaling up their use, or integrating them more effectively into utility operations. It also includes approaches that do not require new infrastructure, such as energy efficiency, demand management, and non-wires solutions that reduce the need for traditional capital projects.

Reference 2 describes Alectra Utilities' preliminary non-wires solutions framework and the proposed non-wires solution that is planned over the 2027 to 2031 distribution system plan period.

Question(s):

a) Considering the Government of Ontario's expectations as it relates to the use of non-wires solutions that reduce the need for traditional capital projects, please explain any factors and/or barriers preventing Alectra Utilities from deploying further non-wires solutions, in addition to that proposed as part of the current application.

b) Please explain in detail how Alectra Utilities' preliminary non-wires solutions framework incorporates all non-wires solution related requirements of the OEB's Non-Wires Solutions Guidelines for Electricity Distributors and Benefit-Cost Analysis Framework for Addressing Electricity System Needs.

   i. Please explain how Alectra Utilities' preliminary Non-Wires Solutions Framework ensures compliance with the OEB's requirement that electricity distributors document their consideration of non-wires solutions when making investment decisions with an expected capital cost of $2M or more.

c) Does Alectra Utilities intend to leverage its preliminary non-wires solutions framework for all potential non-wires solutions (i.e., those with a capital cost of both less and greater than the $2M threshold)?

RESPONSE:

a) Alectra Utilities' ability to deploy both the proposed and potential future NWS is contingent on funding and technical implementation of enabling technologies proposed in this application, including Advanced Distribution Management System, Integrated Network Management, Planning Tools and Automation, and DER Wholesale Market Preparedness, as set out in *Appendix B14 - Enabling Resiliency and Modernization*. These systems will provide the visibility, planning throughput, telemetry/coordination, and operational control required to prudently integrate, monitor, and (where applicable) dispatch DER/DR at scale.

Accordingly, the five station-level NWS projects represent an initial, prudent deployment during the 2027-2031 period, with further scaling expected as these enabling platforms are sequenced and deployed and as market and performance evidence matures.

Alectra Utilities considered NWS options for all significant distribution investments as part of the capital planning process. However, in this application, Alectra Utilities applied the structured preliminary NWS Framework primarily to capacity-driven system needs, with

the objective of identifying opportunities to defer or avoid traditional infrastructure investments. Through the application of this framework to capacity-driven needs, Alectra Utilities identified five station-level needs and associated line capacity needs as candidates for deferral using NWS. The results of the station-level screening are provided in *Interrogatory Response 2A-SEC-40*, and the results of the lines-level screening are provided in *Interrogatory Response 2-ED-07*.

Alectra Utilities further notes that the preliminary NWS Framework is intended to evolve as additional information becomes available, including: (i) improved, location-specific data on DER potential and performance characteristics across operating areas; (ii) improved costing and implementation experience; (iii) enhanced system visibility and DER integration capabilities; and (iv) continued regulatory and market development (please refer to *Exhibit 1A, Tab 1, Schedule 1, 5.3.5 Non-Wires Solutions to Address System Needs,* including *Sections 5.3.5.3 and 5.3.5.4*).

Without limiting the above, key barriers and constraints include the following:

- Applicability by investment category: As described in Section 5.3.5.4 Gate 0 – Portfolio Pre-screen (*Exhibit 1A, Tab 1, Schedule 1, 5.3.5 Non-Wires Solutions to Address System Needs*), NWS is generally not expected to be suitable for addressing System Access, System Renewal, and General Plant where the drivers are not primarily capacity-related and where the underlying need cannot be prudently deferred through DER/DR alternatives.
- Market maturity and resource certainty: The NWS market remains in the early stages of development (please refer to *Exhibit 1A, Tab 1, Schedule 1, 5.3.5 Non-Wires Solutions to Address System Needs, Section 5.3.5.1*). Practical constraints include confirming the availability of uncommitted demand response and DER supply, developing locational constructs (including tariffs where applicable), and validating resource reliability and performance under a range of operating conditions before relying on NWS more broadly.
- Foundational enabling capabilities: The ability to deploy NWS at scale is contingent on foundational grid modernization capabilities proposed in the DSP, including

systems that improve visibility, forecasting, integration, and operational control (e.g., Advanced Distribution Management System, Integrated Network Model, and Planning Tools and Automation). Please refer to *Appendix B14 - Enabling Resiliency and Modernization* in *Exhibit 2A*. These capabilities are required to prudently and safely integrate, monitor, and (where applicable) dispatch DER as alternatives to wires solutions.

- Integration into planning and decision-support: Alectra Utilities will continue to enhance its internal planning processes and decision-support tools (including configuration of its existing optimization platform) to incorporate NWS screening inputs and NWS Benefit-Cost Analysis (BCA) parameters within the same decision-support environment used for capital planning and portfolio optimization.

b) Alectra Utilities developed a preliminary NWS Framework that is consistent with the principles of the OEB's Non-Wires Solutions Guidelines for Electricity Distributors issued on March 28, 2024 (Guidelines) and the OEB's Benefit-Cost Analysis Framework for Addressing Electricity System Needs issued on May 16, 2024 (BCA Framework). The Guidelines specify that applications filed in 2026 (or beyond) should be fully consistent with the BCA Framework (Guidelines, p. 3). Although this application was filed in 2025, Alectra Utilities has made its best efforts to implement this preliminary NWS Framework.

Please refer to *Exhibit 2A, Tab 1, Schedule 1, Section 5.3.5 Non-Wires Solutions to Address System Needs* for Alectra Utilities' description of how the preliminary NWS Framework addresses OEB's requirements related to non-wires solutions set in Guidelines and BCA Framework.

In summary, Alectra Utilities has applied the preliminary NWS Framework as follows:

- NWS consideration: *Exhibit 2A, Tab 1, Schedule 1, Section 5.3.5 Non-Wires Solutions to Address System Needs* describes how NWS was considered in distribution system planning, primary through the gate-based screening process set out in *Section 5.3.5.4 Preliminary NWS Framework*.
- Framework structure and BCA alignment: Alectra Utilities' gate-based process (Gates 0 to 2) is used to identify capacity-related system needs where NWS may be viable and where a BCA, consistent with the BCA Framework, should be undertaken (Gate 3).
- Documentation of consideration for investments ≥ $2MM: Where capacity-related investments with an expected capital cost of $2MM or more were screened and NWS was not advanced, Alectra Utilities documented the screening outcomes and rationale, including for station-level capacity needs. Please refer to *Interrogatory Response 2A-SEC-40* for the station-level evaluation and rationale, and refer to *Interrogatory Response 2-ED-07* for the lines-level evaluation and rationale.
- Business cases for identified NWS candidates: For the five identified capacity-related needs, Alectra Utilities completed and documented a BCA in the NWS BCA Business Case (attached to *Interrogatory Response 2A-SEC-41*) consistent with the BCA Framework.
- Cost recovery and incentive construct: For NWS included in the Application, Alectra Utilities proposed cost recovery through an NWS deferral account and an associated incentive construct using Margin-on-Payments mechanism, as described in *Exhibit 9, Tab 8, Schedule 3, Section 9.3 Non-Wires Solutions Deferral Account (NWSDA)*.

Alectra Utilities notes that, while the OEB has articulated expectations regarding NWS implementation in future filings, the current Application reflects a preliminary NWS framework and initial application focused on capacity-driven needs. In this Application, Alectra Utilities did not apply the preliminary NWS Framework to System Service needs primarily driven by safety, reliability, power quality, efficiency where the needs can plausibly be met by NWS.

c) Alectra Utilities will be compliant with applicable regulations and requirements as set out by the Ontario Energy Board. This currently includes applying the NWS Framework to distribution capital investments with an expected capital cost of $2MM or more, consistent with the OEB's stated threshold for documented consideration.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-47

Proposed Non-Wires Solutions Program
Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / 5.3.5.5 NWS Framework Application in this DSP / pp. 337-340 (pdf Exhibit 2A Part 1 pp. 343-340)
Ref 2: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B13 - Station Capacity / pp. 566-567 (pdf Exhibit 2A Part 2 pp. 574-575)
Ref 3: Exhibit 9 / Tab 8 / Schedule 3 / 9.3 Non-Wires Solution Deferral Account (NWSDA) / pp. 1-3 plus Appendix C (pdf pp. 531-535)

Preamble:
Using its preliminary non-wires solution framework, Alectra Utilities has identified 5 transformer or municipal substation projects that can be deferred by deploying a technology-neutral and competitively sourced non-wires solution. Alectra Utilities is seeking approval to record the OM&A costs in a new deferral account to pay for the non-wires solution.

In reference 1, Alectra Utilities indicates that the non-wires solution program will cost $12M, however in reference 3, Alectra Utilities is proposing to record up to $13.2M in the proposed non-wires solution deferral account. Alectra Utilities is also seeking a 25% margin-on-payment incentive.

Question(s):

a) Has Alectra Utilities completed either a distribution service test (DST) or energy system test (EST), as outlined by the OEB's Benefit-Cost Analysis Framework for Addressing Electricity System Needs?

i. If yes, please provide the benefit-cost analysis, including all input benefit and cost values.

b) If neither a DST nor an EST has been completed, please comment on the cost effectiveness of the proposed non-wires solution.

i. Please include financial details relating to the cost to acquire the non-wires solution and the financial details of the benefits provided (e.g., deferral value, etc.)

c) Please confirm whether Alectra Utilities is seeking $12M or $13.2M for its proposed non-wires solution program.

i. Please identify what proportion of the total cost is allocated to third-party non-wires solutions provider payments and what proportion is allocated to Alectra Utilities' internal program costs.

ii. Please identify the nature of any internal costs (e.g., staff, administration, evaluations, etc.).

d) Is the total proposed $13.2M OM&A budget for the non-wires solution program inclusive or exclusive of the 25% margin-on-payment incentive?

e) Please confirm whether any margin-on-payment incentive amount payable will be recorded in the proposed non-wires solution deferral account for recovery at a later date.

f) Please identify the types of non-wires solutions (e.g., demand response, battery storage, managed electric vehicle charging, etc.) that Alectra Utilities will be deploying as part of the proposed program. In the response, please also explain why each specific non-wires solution was chosen.

g) Has Alectra Utilities secured any third-party funding for the proposed non-wires solution since the filing of the application?

RESPONSE:

a) Alectra Utilities confirms that it has completed the DST consistent with the *BCA Framework for Addressing Electricity System Needs*. Please see the *NWS BCA Business Case* provided in response to *2A-SEC-41*.

   i. The DST results in the *OEB Benefit-Cost Analysis Data Filing Submission Template* format are provided as 2-Staff-47_Attach1_NWS BCA Template.

b) Not applicable. The DST has been completed.

c) Alectra Utilities is seeking approval for a total $13.2 million OM&A budget for the proposed NWS Program, as described in *Exhibit 9, Tab 8, Schedule 3, Section 9.3 Non-Wires Solutions Deferral Account (NWSDA)*. Alectra Utilities notes that $13.2MM reflects the full proposed program budget (third-party payments plus internal incremental program delivery costs), as proposed to be recorded in the NWSDA. The forecast $13.2MM does not include any amounts for incentive payments, such as Margin-on-Payments (MoP). Such amounts would also be recorded in the NWSDA for recovery in addition to the company's actual OM&A costs incurred to acquire DERs and operate and manage the NWS Program. See the response to part e), below.

   i. $12.0 million is allocated to third-party NWS provider payments and $1.2 million is allocated to Alectra Utilities' internal NWS Program costs.

   ii. The internal costs proposed for inclusion in the NWSDA are incremental OM&A costs not included in base rates and directly attributable to implementing the NWS Program, including (as applicable): contracting/procurement and administration, required equipment and system costs to support program delivery, incremental

operation and maintenance activities, evaluation/measurement and verification ("EM&V"), and coordination costs associated with IESO interfaces.

d) The proposed $13.2 million OM&A budget does not include the proposed 25% margin-on-payment incentive.

e) Confirmed. As described in Exhibit 2A, Tab 1, Schedule 1, section 5.3.5.1, p. 327,

> "Alectra Utilities proposes to apply a Margin on Payments (MoP) incentive to third-party DER procurements used as NWS during the DSP plan term. Alectra Utilities proposes a MoP of 25% of payments to third-party DER providers, aligned with the OEB's proposed amendments to the DSC, and subject to the eligibility criteria."

While preparing this response, Alectra Utilities identified an error in the Draft Accounting Order related to the NWSDA, as set out in Exhibit 9, Tab 8, Schedule 3, Appendix C. The Draft Accounting Order describes the amounts to be recorded in the NWSDA as being "net of incentive revenues such as Margin-on-Payments ("MoP") credited against the principal balance" (emphasis added). This treatment would have the effect of reducing the recovery of prudently incurred amounts recorded in the NWSDA and preventing recovery of any MoP related to the procurement of DER. Such an outcome would be inconsistent with Alectra Utilities' intention and the Margin on Payments Incentive Mechanism set out in Section 11 of the Distribution System Code ("DSC").[1]

Consistent with Section 5.3.5 of the DSP and Section 11 of the DSC, Alectra Utilities proposes that the MoP incentive would be recorded in the NWSDA in addition to the OM&A costs associated with acquiring and operating distribution-level NWS.

[1] The MoP incentive mechanism was introduced in the November 25, 2025 amendments to the DSC, which were made subsequent to the filing of this application.

f) Alectra Utilities has not pre-selected specific NWS technologies at this stage. The proposed NWS procurements are intended to be technology-neutral and competitively sourced, to allow proponents to propose the least-cost and best-fit solutions to meet the defined capacity need. Please refer to *Exhibit 2A, Tab 1, Schedule 1, Section 5.3.5.5*.

g) Alectra Utilities has not secured third-party funding for the proposed NWS Program since filing the application.

2-Staff-47

Attachment 1
NWS BCA Template

Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-48

Proposed Non-Wires Solutions Program
Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / 5.3.5.5 NWS Framework Application in this DSP/ pp. 337-340 (pdf Exhibit 2A Part 1 pp. 343-340)

Preamble:
Alectra Utilities indicated that deferral of the 5 transformer or municipal substation capital projects assumes that sufficient non-wires solution capacity is available to cost-effectively and reliably meet the capacity need.

Question(s):

a) Should sufficient non-wires solution capacity not be available, what is Alectra Utilities' plan to ensure that minimum electricity distribution service and reliability be maintained for customers?

RESPONSE:

a) Should sufficient NWS capacity not be available (or cannot be secured on acceptable terms), Alectra Utilities will maintain minimum electricity distribution service and reliability through a combination of actions, as follows:

    1. Advance the deferred traditional solution and/or implement an interim solution. Alectra Utilities would re-evaluate the stations build/upgrade and interim alternatives and, where feasible, advance/accelerate implementation to ensure forecast capacity and contingency requirements are met in accordance with applicable planning criteria and operating standards.

2. Interim operating measures. If a capacity constraint materializes before the permanent or interim solution can be placed in service, Alectra Utilities will re-assess and, where feasible, implement interim targeted controls consistent with safe operating limits and applicable standards. The goal of such measures would be to preserve service to the extent practicable. However, where constraints are binding, they may result in increased operational risk and increased frequency and duration of customer interruptions relative to normal conditions.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-49

Coordination with Electricity Demand Side Management
Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / 5.3.5.5 NWS Application in this DSP / p. 340 (pdf Exhibit 2A Part 1 p. 346)

Preamble:
Alectra Utilities has indicated that it will coordinate with the Independent Electricity System Operator's (IESO) multi-year Electricity Demand Side Management (eDSM) framework and that this coordination will serve as a building block for future Alectra Utilities-led non-wires solutions offerings.

Question(s):

a) Please provide any details regarding how Alectra Utilities plans to leverage the experience gained from coordinating with the IESO's multi-year eDSM framework to serve as the building blocks for future Alectra Utilities-led NWS offerings.

RESPONSE:

a) Alectra Utilities' experience coordinating with the IESO under the multi-year eDSM Framework ("Framework") reflects the fact that the Framework has only recently commenced in 2025 and remains in its early days of implementation. While the Framework establishes long-term provincial energy efficiency and demand response objectives, program delivery and supporting information are still evolving. At this stage, sufficiently localized, distribution-level data has not yet been made available to support detailed coordination, assessment of customer flexibility, or the development of localized price signals. Alectra Utilities has formally requested access to such data to enable more effective alignment with local system needs.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-50

Non-Wires Solutions Enabling Investments
Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B09 - Information Technology Systems / pp. 365-366 (pdf Exhibit 2A Part 2 pp. 373-366)

Preamble:
Alectra Utilities is proposing to spend $1.2M to support the development of customer NWS.

Question(s):

a) Has Alectra Utilities been in communication with any customers who have NWS capacity that may be leveraged?

b) How much customer NWS capacity is Alectra Utilities targeting over the distribution system plan period?

RESPONSE:

a) Alectra Utilities engages regularly with its customers, including customers that own or operate Distributed Energy Resources (DERs) that could potentially form part of a future Non-Wires Solution (NWS). However, Alectra Utilities is not currently in discussions with specific customers to develop or secure customer-provided NWS capacity. As described in Non-Wires Solutions to Address System Needs (Exhibit 2A, Tab 1, Schedule 1, Section 5.3.5, page 326), Alectra Utilities is not yet in a position to identify, procure, administer, or operate customer-provided NWS resources.

The Customer NWS Design and Development investment in Appendix B09 is intended to support delivery of this targeted capacity by developing information resources around

technology capability and market adoption potential to inform the procurement of NWS in the future. See also response to 2-DRC-10 and 2-DRC-11.

b) Alectra Utilities is targeting 30-32 MW of customer-provided NWS capacity over the DSP period, to be procured in the localized constrained areas where NWS is screened as feasible and cost-effective. Please refer to Exhibit 2A, Tab 1, Schedule 1, Section 5.3.5, including Table 5.3.5-3.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-51

Non-Wires Solutions Enabling Investments
Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B09 - Information Technology Systems / p. 379 (pdf Exhibit 2A Part 2 p. 387)

Preamble:
Alectra Utilities has proposed to spend $7.7M of its total $13.8M Business Optimization investment on the optimization of its Copperleaf C55 system to continue enhancing the system to meet and comply with future OEB requirements (e.g., Benefit-Cost Analysis Framework for Addressing Electricity System Needs).

Question(s):

a) Is the proposed $7.7M for the optimization of Copperleaf C55 solely for compliance with the OEB's Benefit-Cost Analysis Framework for Addressing Electricity System Needs or does the scope of this proposed investment include other upgrades to Copperleaf C55?
    a. Please allocate the $7.7M Copperleaf C55 optimization cost across each identified business need.

b) Has Alectra Utilities considered utilizing or purchasing options other than Copperleaf C55 for compliance with the OEB's BCA Framework for Addressing Electricity System Needs?
    a. If so, please detail the options considered, including their expected costs, and any reason(s) why the Copperleaf C55 upgrade was selected as the optimum solution.

c) Please provide a detailed explanation of how Copperleaf C55 will be optimized to ensure compliance with the OEB's Benefit-Cost Analysis Framework for Addressing Electricity System Needs. In the response, please include any pertinent technical materials from the vendor that may be available.

RESPONSE:

a) The proposed investment for the optimization of Copperleaf C55 (Project 151136) includes functionality necessary to meet OEB requirements, including Benefit-Cost Analysis (BCA) and integration of Vulnerability Assessment and System Hardening (VASH) functionality, as well as other enhancements and integrations with multiple enterprise systems (e.g., planning, scheduling, execution and tracking of both capital and operating projects). Please see Exhibit 2A, Tab 1, Schedule 1, Appendix B-09, Section 2.1.4.1 C55 Alectra Utilities: Optimization of Business Practices, pages 356-357 for more information.

Table 1 below provides a breakdown of capital cost and schedule for Project 151136 – C55 Alectra: Optimization of Business Processes by allocation of Capital Planning Enhancement, System Integration and Professional Services. Given the range of functions this investment will support, and the relatively recent introduction of certain OEB requirements (e.g., BCA and VASH functionality), Alectra Utilities is unable to discretely allocate costs to individual functions.

Table 1 – Cost Breakdown for Project 151136 (In $MM)

	2027	2028	2029	2030	2031
Capital Planning Enhancements	0.6	1.2	1.2	0.7	0.4
System Integrations	-	0.4	0.4	0.2	0.2
Professional Services, Change Management, and Labour	0.6	0.6	0.4	0.4	0.4
Total	**1.2**	**2.2**	**2.0**	**1.3**	**1.0**

b) Given the maturity and integration of the Copperleaf C55 system in the utility's planning processes, Alectra Utilities did not consider procuring, implementing, integrating, operating and maintaining other standalone systems to achieve compliance requirements. Alectra Utilities has developed and utilizes an established, refined and mature Asset Management Process as described in detail in 5.3.1 – Asset Management Process Overview in Exhibit 2A, Tab 1, Schedule 1, Page 79.

The Copperleaf Asset Investment Planning & Management (AIPM) system is at the core of Alectra Utilities' Asset Management Process. Integrating both the BCA Framework and VASH Framework functionality into existing core Asset Management Processes was the most efficient approach to meet compliance requirements. For example, the BCA Framework requires Alectra Utilities to consider NWS solutions for each capital investment above $2MM, excluding General Plant investments. Since every capital project and program at Alectra Utilities is already entered into the Copperleaf system, the most efficient and effective approach to integrate NWS into planning is to add the additional steps to the existing Asset Management Process and Copperleaf. Similarly, the VASH Framework requirements specify that electricity distributors incorporate climate resiliency into local distribution companies' asset and investment planning activities, which for Alectra Utilities are the Asset Management Process and Copperleaf system.

c) Since the Phase Two of the Draft BCA Framework is expected in early 2026 and the Final VASH Report and Toolkit was recently released on October 7, 2025, Alectra Utilities does not currently have all the information necessary to develop requirements, implementation plans and scope to provide the detailed explanation of how the BCA and VASH Frameworks will be implemented within Copperleaf. Once the final requirements are published, Alectra Utilities and Copperleaf subject matter experts and developers will work together to develop the solution in Copperleaf that aligns with OEB's methodology, requirements and future directives.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-52

Centricity Project / Grid Modernization Investments

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B14 / p. 614-19 (pdf Exhibit 2A Part 2 pp. 622-627)

Ref 2: Centricity: Empowering Customers in Future Grid Evolution (2030)

Preamble:

Reference 1 states that Grid Modernization investments total $41.1M in capital needed to improve operational efficiency, enable flexible customer connections, and support a more automated and electrified grid with increasing DER uptake.

Reference 2 notes that in August 2025, Alectra Utilities was announced as a recipient of NRCan's Mission Innovation Green-Power Future International Collaboration Grant under the Smart Grid and Energy Storage strategic area for its Centricity project.

Question(s):

a) Please explain the scope and objectives of Centricity, including its anticipated benefits for customers and the distribution system, and describe how its reflected in this application and aligns with Alectra Utilities' Grid Modernization investment segment.

b) Please confirm the total capital and OM&A costs for Centricity per year over the forecast period.

c) Please confirm the sources and amounts of any external funding expected for Centricity's capital and OM&A costs per year over the forecast period and indicate where this external funding has been reflected in this application.

d) Please confirm how any capital and OM&A costs for Centricity not covered by external funding will be treated and indicate where these costs have been reflected in this application per year over the forecast period.

RESPONSE:

a) The Centricity project intends to design and build end-to-end capabilities for Distribution System Operations (planning, operations, and markets). The benefits for the customer and the distribution system include Prosumer empowerment by engagement in a distribution market, end-to-end integration of systems from planning through to real-time operations, and enablement of precise infrastructure planning to deploy resources more effectively. These capabilities are not reflected in this Application.

Centricity aligns with Alectra Utilities' Grid Modernization investment segment by building net new capabilities (described above) on top of investments in Reference 1.

b) The capital expenditure for Project Centricity is expected to be as follows:

Table 1 – Capital Expenditure for Project Centricity

Year	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31
NRCAN Contributions	$225,971.98	$1,892,701.65	$2,500,000	$1,381,326.37	$0	$0

The Centricity Project timelines end on March 31st, 2028. The capital expenditure for Centricity is funded through the NRCAN contribution of $6 Million for the duration of the project. There are no OM&A costs associated with Centricity.

c) Alectra does not expect to incur any additional capital or OM&A costs for Centricity beyond those outlined in the response to part b above.

d) Alectra does not expect to incur any additional capital or OM&A costs for Centricity beyond those outlined in the response to part b above.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-53

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / 5.2.1 DSP Overview / p. 5 (pdf Exhibit 2A Part 1 p. 11)

Preamble:

Regarding the DSP Overview, Alectra Utilities states that "Alectra Utilities completed 51 cable replacement and 57 cable injection projects over the 2020-2024 period, addressing the most pressing and urgent failing cables."

Question(s):

a) Have the accelerated underground (U/G) cable replacement and injection program investments made to date produced a measurable improvement in SAIDI and System Average Interruption Frequency Index (SAIFI) performance metrics?

   i. If no, by when is a measurable improvement anticipated to occur?

   ii. If yes, please quantify the measurable improvements in SAIDI and SAFI performance metrics (e.g. similar to the 15.51 minutes of SAIDI improvement due to investments in automated switches).

RESPONSE:

a) Alectra Utilities did not accelerate underground cable replacement over the 2020 to 2024 period. During that period, Alectra Utilities addressed only the most pressing and urgent failing cables. From 2018 to 2023, the population of deteriorated cables increased by 62%, and Alectra Utilities now manages a backlog of 5,123 km of deteriorated cable. Please refer to Exhibit 2A, Tab 1, Schedule 1, Section 5.3.2, page 222 of 406, which

states that “Compared to the 2014-2018 average CHI of 202,003, the 2019-2024 average CHI has increased by 7% for XLPE cable and accessories.” Overall, Alectra Utilities is not keeping pace, which is evident in the 2019-2024 average CHI.

Exhibit 2A, Tab 1, Schedule 1, Appendix B02 – Section 2.1.1 – XLPE Cables, Page 68 to 69, illustrates various examples where early intervention was urgently required in neighborhoods due to cascading cable failures resulting in frequent and long duration outages. As a result of intervention, the customers have seen appreciable improvement in reliability due to the cable remediation projects.

During the 2027-2031 DSP, Alectra Utilities has proposed to execute on a moderate pace, which will address 665.7 km of cable. Please refer to Exhibit 2A, Tab 1, Schedule 1, Appendix B02 – Underground Asset Renewal, page 82 of 653, Figure B02-14. Area 1 consists of approximately 2,423 km of first generation XLPE cables, which have seen more faults, hence, are more at risk of failures. Alectra Utilities must address these cables to have a measurable improvement in the performance matrix. Considering the pace of cable remediation that Alectra Utilities can feasibly achieve, it would be well beyond the 2027-2031 DSP that a measurable improvement can be realized.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-54

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / 5.1 DSP Overview / p. 5 (pdf Exhibit 2A Part 1 p. 11)
Ref 2: Exhibit 2A / Tab 1 / Schedule 1 / 5.1 DSP Overview / pp. 6-7 (pdf Exhibit 2A Part 1 pp. 12-13)

Preamble:
In reference 1, regarding the DSP Overview, Alectra Utilities states that "Alectra Utilities' Asset Analytics Platform builds on its condition-based asset management process towards predictive analytics, reliability-driven maintenance and integrates multiple data sets to identify emerging reliability hotspots."

Question(s):

a) Is the new data analytics system presently able to produce risk reduction estimates for condition driven renewal capital project and program investments?

   i. If yes, please provide the estimated risk reduction for each renewal investment line item in the present filing above a $1M materiality threshold.

   ii. If no, when will such risk reduction estimates become available? Please describe qualitatively what use Alectra Utilities will be making of the new Assets Analytics Platform until such results are available.

   iii. If no, please explain how the Value Framework assessments of risk mitigation described in the following excerpt from reference 2 is conducted.

   "*Based on the identified investment needs, Alectra Utilities developed and*

evaluated a solution through a consistent and uniform process, based on a Value Framework that assesses the value of an investment (from both a customer and organizational perspective) and risk mitigation."

RESPONSE:

a) The Asset Analytics Platform is not a new addition to this DSP (2020-2024). The platform was developed and deployed during the 2020-2024 DSP period, as stated in reference #1. The platform was leveraged in previous applications before the Ontario Energy Board.

Risk reduction calculation is performed as part of Copperleaf Value Framework and is not part of the Asset Analytics Platform. The benefits and risk reduction value measures are part of the Copperleaf platform described in Ex. 2A-1-1, 5.3.1 p.102-104.

Alectra Utilities provided all capital projects in the DSP period (2027-2031), and all the respective value measures in the response to 2A-SEC-28, part A.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-55

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / 5.2.1 DSP Overview / p. 6 (pdf Exhibit 2A Part 1 p. 12)

Preamble:

Regarding the Balancing Customer Preferences and System Need, Alectra Utilities states that proliferation of distributed energy resources (DERs) is adding complexity and urgency to modernizing the grid.

Question(s):

a) Please list the size and host municipality of all DER additions within Alectra Utilities' service area over the historical and bridge periods.

b) Please provide a list of forecast DER additions in Alectra Utilities' service area over the test period, broken down by host municipality and year. If a list of forecast DERs is not available for the entire test period, please forecast total MW of DER additions by municipality and year in all years for which a detailed list is not available.

RESPONSE:

a) The table below provides the cumulative DER additions (counts and MW) in Alectra Utilities' service area as of December 31, 2024, broken down by municipality. Please note that the "Connected Net Meter" category are predominantly solar PV, and the "Connected Other DER" includes natural gas, biomass, or diesel fuel sources.

Table 1 - Historical Period (Cumulative DER Connections as of December 31, 2024)

Rate Zone	ERZ		BRZ		HRZ		PRZ		GRZ		Total	
Type	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*
Connected FIT	127	23.622	132	32.42	74	11.95	194	35.573	41	8.718	568	112.28
Connected microFIT	718	5.452	858	7.979	1,117	10.125	1,769	14.356	420	3.419	4882	41.33
Connected Net Meter	177	9.328	99	2.038	272	4.62	405	7.06	214	3.075	1167	26.12
Connected Energy Storage	6	7.63	4	4.24	3	0.95	5	6.106	0	0	18	18.93
Connected Other DER	18	29.706	3	3.416	13	53.011	43	49.648	36	42.912	113	178.69
Total Connected DER	**1,046**	**75.74**	**1,096**	**50.09**	**1,479**	**80.66**	**2,416**	**112.74**	**711**	**58.12**	**6,748**	**377**

The table below provides cumulative forecast DER additions during 2025 and 2026:

Table 2 – Cumulative Forecast DER

Rate Zone	ERZ		BRZ		HRZ		PRZ		GRZ		Total	
Type	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*
Connected Net Meter	117.84	2.71	62.15	0.56	168.85	3.40	265.59	3.64	146.57	2.67	761	**12.97**
Connected Energy Storage	0.93	1.01	0.49	0.21	1.33	1.27	2.09	1.36	1.16	0.99	6	**4.84**
Connected other DER	2.17	3.47	1.14	0.72	3.11	4.36	4.89	4.67	2.70	3.42	14	**16.64**
Total Forecasted DER	**121**	**7.19**	**64**	**1.49**	**173**	**9.02**	**273**	**9.67**	**150**	**7.08**	**781**	**34.45**

Note:

"ERZ" refers to the Enersource Rate Zone

"BRZ" refers to the Brampton Rate Zone

"HRZ" refers to the Horizon Rate Zone

"PRZ" refers to the PowerStream Rate Zone

"GRZ" refers to the Guelph Rate Zone

b) The tables below provide forecast DER additions (MW) for the 2027-2031 period, by year and by technology. A table is provided for each year:

Table 3 - 2027

Rate Zone	ERZ		BRZ		HRZ		PRZ		GRZ		Total	
Type	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*
Connected Net Meter	60.08	1.38	31.69	0.29	86.09	1.73	135.41	1.85	74.730	1.36	388	**6.60**
Connected Energy Storage	0.46	0.53	0.24	0.11	0.67	0.67	1.05	0.72	0.578	0.53	3	**2.56**
Connected other DER	1.08	1.76	0.57	0.37	1.55	2.21	2.44	2.37	1.348	1.74	7	**8.45**
Total Connected DER	**62**	**3.67**	**33**	**0.76**	**88**	**4.61**	**139**	**4.94**	**77**	**3.62**	**398**	**17.61**

Table 4 - 2028

Forecasted Connected DER- 2028
Alectra - 2028 Forecast

Rate Zone	ERZ		BRZ		HRZ		PRZ		GRZ		Total	
Type	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*
Connected Net Meter	60.70	1.39	32.01	0.29	86.98	1.75	136.81	1.88	75.50	1.37	392	**6.68**
Connected Energy Storage	0.46	0.55	0.24	0.11	0.67	0.69	1.05	0.74	0.58	0.55	3	**2.65**
Connected other DER	1.08	1.78	0.57	0.37	1.55	2.23	2.44	2.40	1.35	1.75	7	**8.53**
Total Connected DER	**62**	**3.73**	**33**	**0.77**	**89**	**4.68**	**140**	**5.02**	**77**	**3.67**	**402**	**17.87**

Table 5 - 2029

Rate Zone	ERZ		BRZ		HRZ		PRZ		GRZ		Total	
Type	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*
Connected Net Meter	61.48	1.41	32.42	0.29	88.09	1.77	138.55	1.90	76.46	1.39	397	**6.76**
Connected Energy Storage	0.62	0.57	0.33	0.12	0.89	0.72	1.40	0.77	0.77	0.57	4	**2.75**
Connected other DER	1.08	1.80	0.57	0.37	1.55	2.26	2.44	2.42	1.35	1.77	7	**8.62**
Total Connected DER	**63**	**3.78**	**33**	**0.79**	**91**	**4.75**	**142**	**5.09**	**79**	**3.73**	**408**	**18.13**

Table 6 - 2030

Rate Zone	ERZ		BRZ		HRZ		PRZ		GRZ		Total	
Type	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*
Connected Net Meter	62.25	1.43	32.83	0.30	89.20	1.79	140.30	1.92	77.43	1.41	402	**6.84**
Connected Energy Storage	0.62	0.60	0.33	0.12	0.89	0.75	1.40	0.80	0.77	0.59	4	**2.86**
Connected other DER	1.08	1.81	0.57	0.38	1.55	2.28	2.44	2.44	1.35	1.79	7	**8.70**
Total Connected DER	**64**	**3.84**	**34**	**0.80**	**92**	**4.82**	**144**	**5.17**	**80**	**3.78**	**413**	**18.40**

Table 7 - 2031

Rate Zone	ERZ		BRZ		HRZ		PRZ		GRZ		Total	
Type	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*	*# of DER*	*MW*
Connected Net Meter	63.03	1.44	33.24	0.30	90.31	1.81	142.04	1.94	78.39	1.42	407	**6.92**
Connected Energy Storage	0.62	0.62	0.33	0.13	0.89	0.78	1.40	0.83	0.77	0.61	4	**2.96**
Connected other DER	1.24	1.83	0.65	0.38	1.78	2.30	2.79	2.47	1.54	1.81	8	**8.79**
Total Connected DER	**65**	**3.89**	**34**	**0.81**	**93**	**4.89**	**146**	**5.24**	**81**	**3.84**	**419**	**18.68**

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-56

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / 5.2.1 DSP Overview / p. 6 (pdf Exhibit 2A Part 1 p. 12)
Ref 2: Exhibit 1 / Tab 5

Preamble:
Regarding the Balancing Customer Preferences and System Need, Alectra Utilities states that the "DSP demonstrates the minimum level of investment necessary to deliver outcomes for customers."

Question(s):

a) Please summarize the expected outcomes the DSP.

b) Please provide references in the Customer Engagement evidence (Exhibit 1, Tab 5) where customers explicitly or implicitly requested, or prioritized, the outcomes in a).

RESPONSE:

a) The expected DSP outcomes are: Renewing & Replacing Deteriorated Infrastructure, Meeting Growing Electricity Demand and Enabling Resiliency & Modernization. These outcomes are summarized in Ex 2A-1-1 – 5.1 pp. 2-3.

b) **Response prepared by Innovative Research Group**
Both Phase 1 and Phase 2 of the customer engagement were built around the three outcomes referenced in the response to 2-Staff-56-a.

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For instance, page 88 of the Phase 1 Residential report shows how customers were presented with six key themes of Alectra's overall planning approach:

- A systematic review of costs,
- A program to replace deteriorating equipment (this connects to the renewal theme),
- New technologies to give all customers more control (this connects to the modernization theme),
- New technology to modernize the grid (this connects to the modernization theme),
- Upgrading equipment to 'harden' the system (this connects to the resilience theme), and
- Identifying critical investments to meet unexpected surges in demand (this connects to the growth theme).

Page 2 of the executive summary shows that across all four rate classes, 80% to 100% felt that approach is headed in the right direction.

In phase two, Alectra had refined its plan around the three themes referenced in 2-Staff-56-a. Those themes were introduced on page 6 of the Phase 2 Customer Workbook. They were then explored in more detail as customers were asked for their reaction to 6 spending choices that drive those three objectives.

Customers were then asked for an overall reaction to the spending plan. Page 2 of the executive summary shows that across the four rate classes, between 77% to 100% of customers provide social permission responses to Alectra's plan focused on these three outcomes and its resulting rate increases.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-57

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / 5.2.1 DSP Overview / p. 7 (pdf Exhibit 2A Part 1 p. 13)

Question(s):

a) Please provide a table showing the estimated annual probability of condition-related failure for each asset class, broken down by assessed Health Index. Please do not include failure probabilities that are not directly related to asset condition.

b) If the annual probabilities of failure requested above are not available, please explain how Copperleaf determines the pre and post capital expenditure risk profiles of assets that are being replaced or rehabilitated under any of the System Renewal projects and programs. (Note: Risk = Probability x Consequence)

RESPONSE:

Part a) and b):

Alectra Utilities' Asset Management Practice computes baseline risk and residual risk in Copperleaf at a business case level. This method allows Copperleaf's optimization to access the optimal time of intervention considering the investment's total value. Alectra Utilities does not compute annualized failure probabilities for different health index categories.

Copperleaf computes risk as discussed in Exhibit 2A-1-1- Section 5.3.1, Page 103 to 104. The pre- and post- capital investment risk and benefits are based on input from Subject Matter Experts (SME) in the business case that is evaluated by the Value Framework (Ex 2A-1-1 p. 99 Table 5.3.1 – 4).

Alectra Utilities replaces assets that are confirmed to be deteriorated based on inspections and condition assessment. For specific assets, such as switches critical to the safe and reliable operation of the system, Alectra Utilities also considers other relevant drivers for renewal, including equipment obsolescence and vintage designs that pose risks to safe and efficient operations and maintenance.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-58

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / 5.2.1 DSP Overview / pp. 14, 117 (pdf Exhibit 2A Part 1 pp. 20, 123)
Ref 2: CER - Market Snapshot: Zero emission vehicles in Canada—latest trends, including region- and make/model-level insights
Ref 3: Canadian electric vehicle industry insights: Q3 2025 | S&P Global

Preamble:

Regarding the Meeting Growing Electricity Demand section, Alectra Utilities states: Alectra Utilities' service area is one of Canada's largest and fastest-growing data center markets, with 115MW of connected data center load and 425MW of additional data center connections capacity committed by 2031. In addition to the rapid development of AI and cloud computing, Alectra Utilities is obligated to prepare the grid to meet the growing demand stemming from the uptake of electric vehicles, and corresponding charging infrastructure, as well as the transition to heat pumps. Alectra Utilities projects more than 500,000 electric vehicles in its service area by 2031 resulting in an additional 524MW. Alectra Utilities' further states the "EV growth projection from 2022 to 2040 was developed in collaboration with Guidehouse 1 Inc. in 2022."

Question(s):

a) Will the forecast data centre connections impose incremental costs on other customer classes, such as residential customers?

b) As shown in references 2 and 3 EV uptake has declined in 2025. Alectra Utilities' EV forecasts were prepared prior to 2025. What impact does the slow in EV uptake have on Alectra Utilities' load forecasts and capital plans?

RESPONSE:

a) Alectra Utilities implements customer connections as per the Distribution System Code requirements. For customer connection costs, Alectra Utilities conducts an economic evaluation in accordance with Appendix B of the Distribution System Code to determine the capital contribution and expansion deposit. Upon energization of the project, Alectra Utilities reviews the demand over the connection horizon period. If at the end of the customer connection horizon the forecasted demand has not materialized, Alectra Utilities will retain the remaining portion of the expansion deposit.

b) In 2025, Alectra Utilities had 78,158 Electric Vehicles (EVs) registered in Alectra Utilities' service area, which exceeded 2025 projections of 70,908 EVs by 10%. Vehicle sales fluctuate (including EVs) quarterly due to a wide range of drivers, including incentives, economic conditions, customer confidence, supply chain constraints, product cycles and technology introduced into the market. Most recently, the Government of Canada introduced several initiatives to spur EV adoption. On January 16th 2026, the Government of Canada reduced import tariffs on lower-cost EVs into the Canadian market. Furthermore, on February 5th 2026, the Government of Canada announced restoration of EV incentives and further funding of EV charging infrastructure to spur the uptake of EVs. Alectra Utilities considered EV uptake to date and the Government of Canada's commitment to EV incentives, funding for EV charging infrastructure, and its commitment to bring lower-priced EVs to the Canadian marketplace, and determined to maintain the current projections for EV uptake.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-59

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / 5.2.1 DSP Overview / pp. 14-15 (pdf Exhibit 2A Part 1 pp. 20-21)

Preamble:

Regarding the Meeting Growing Electricity Demand section, Alectra Utilities states that, "The utility manages a wide range of legacy assets, infrastructure configurations and obsolete equipment that no longer meet present-day standards including rear-lot services, undersized conductors, direct-buried cables and obsolete station assets. The operation of such assets introduces hazards and high risks to safety for both Alectra employees and customers, as well as the public in general."

Question(s):

a) Please provide quantified risk reduction associated with the proposed test period capital investments in each of the above listed configurations and asset types (i.e. rear-lot services, undersized conductors, direct-buried cables and obsolete station assets).

RESPONSE:

a) Please refer to Table 1 for the Investment Values:

Table 1 – Investment Values

Types	Risk Mitigation ($MM)	Benefit ($MM)	Total Value ($MM)
Direct-buried cables	41.1	1,325.8	1366.9
Rear-lot services	45.1	261.9	307
Undersized conductors	10.4	79.2	89.6
Obsolete station assets	19.0	25.8	44.8

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-60

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / 5.2.1 DSP Overview / pp. 15-17 (pdf Exhibit 2A Part 1 pp. 21-23)

Question(s):

a) For poles, transformers and other identified assets that are subject to Climate Parameters, please revise Table 5.2.1 - 2 to add columns:

   i. to indicate whether Alectra Utilities' current design standards meet or exceed the specified Climate Parameters,

   ii. in cases where a design standard does not meet the Climate Parameter, specify the current design standard value that applies to this parameter, and;

   iii. Alectra Utilities' plan to address the standard deficiency (e.g., accept the risk, risk mitigation plan, increase design standard, etc.).

RESPONSE:

a) i., ii., iii. Alectra Utilities provides Table 1 below which expands on Table 5.2.1-2 with meet or exceed status relative to the Climate Parameters. Alectra Utilities wishes to clarify that for Climate Parameters: Wind Gust Over 121KM/h, Derechos and Ice Storms, Alectra Utilities is unable to provide a status of either Meets or Exceeds as such climate parameters require further assessment of wind, derecho and ice storm severity across a wide range of possible overhead assets installed in Alectra Utilities distribution system.

Alectra Utilities' design standards are fully compliant with CSA Standard C22.3. For overhead systems, Alectra Utilities determines pole class for installation based on specific site conditions, loading conditions and applies pole loading calculations as outlined in CSA 22.3 No 1:25 Overhead Systems. For greater clarity, CSA C22.3 No 1:25 Overhead Systems has been updated to incorporate climate parameters into the prescribed methodology to enhance grid resilience. Alectra Utilities' design standards are developed to CSA Standards. As required by the Electricity Act, 1998, Alectra Utilities demonstrates compliance of designing the electrical distribution system to the CSA Standards through annual audits as required by Electrical Safety Association Regulation 22/04. Alectra Utilities does not propose to exceed such standards in the plans as outlined in the DSP.

Alectra Utilities' grid resilience and modernization investments, as proposed in the DSP, include renewing deteriorated assets built to legacy standards to current CSA standards, which incorporate resilience considerations. Alectra Utilities determined that specific overhead assets that are deteriorated with less strength and built to legacy standards in vulnerable areas are more prone to failure during storms. Alectra Utilities is not proposing to replace existing assets with new infrastructure that exceeds CSA 22.3 standards.

Table 1 - Climate Parameters and Frequency Trends Against Current Material and Construction Standards

Climate Parameter	Trend in Frequency	Standard Meet or Exceeds
Temperature above 32°C	Increasing	Meet
Temperature above 40°C	Increasing	Meet
Precipitation above 20mm	Stable	Meet
Precipitation above 50mm	Increasing	Meet
Wind Gust Below 60KM/h	Stable	Meet
Wind Gust Between 61 and 80KM/h	Increasing	Meet
Wind Gust Between 81 and 100KM/h	Stable	Meet
Wind Gust Between 101 and 120KM/h	Stable	Meet
Wind Gust Over 121KM/h	Increasing	Detailed assessment required
Tornadoes	Increasing	Does not meet
Derechos	Increasing	Detailed assessment required
Ice Storms	Stable	Detailed assessment required

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-61

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / 5.2.3 Performance Measurement for Continuous Improvement / p. 73 (pdf Exhibit 2A Part 1 p. 79)

Preamble:

Alectra Utilities claimed SAIDI improvements of 14.21 minutes and 15.51 minutes for 2023 and 2024 respectively.

Question(s):

a) Please update Table 5.2.3-5 to add rows and columns showing i) actuals from 2023 onwards ii) annual improvement in SAIDI attributable to that year's automated device installations, and ii) capital cost for that year's automated device installation (in nominal dollars).

b) Please clarify if Alectra Utilities is asserting that the automation is directly linked to the SAIDI reductions or if it was one of many factors, which have not been quantified.

c) How does Alectra Utilities assess the marginal value of adding each new automated device?

RESPONSE:

a) Please see the revised table below.

Table 1 - Automated Devices Installed (Table 2-Staff-61)

2023 - 2031 Performance Measure	2023	2024	2025	2026	2027	2028	2029	2030	2031
DA - Target	93	99	95	95	100	100	110	110	110
DA - Actual	93	99	105						
Capital Cost – Actual ($MM)	11.7	15.7	16.1						
Capital Cost – Forecast ($MM)				13.6	14.6	14.9	16.7	17.0	17.3
SAIDI Improvement (minutes)	14.21	15.51	13.55						

Row 1 - In service of automated devices on the distribution system – Target

Row 2 - In service of automated devices on the distribution system – Actual

Alectra Utilities cannot provide the SAIDI improvement for future years. SAIDI improvements are calculated retroactively for each event based on the number of customers restored via automated switching versus the projected duration of a manual restoration. Due to the unpredictable nature of these variables, the utility cannot provide a definitive SAIDI improvement forecast.

b) The reduction of SAIDI by 14.21 minutes and 15.51 minutes in 2023 and 2024 respectively is directly attributable to the installation and effective use of Distribution Automation. In the absence of the automation, an additional 14.21 and 15.51 minutes of interruption would have been experienced by Alectra Utilities customers in 2023 and 2024 respectively.

c) Alectra Utilities assesses the marginal value of added automation device based on the improvement of SAIDI that can be achieved using an incremental device. This improvement will vary based on the number of devices that exist on a given feeder (and the number of customers served by that feeder and its feeder sections). The greatest improvement is generally achieved by the first device, and subsequent devices have reduced improvement potential (all things being equal).As an illustration, Alectra Utilities estimates that each automated device results in savings of 50-80 minutes on restoration time for customers on un-faulted segments of a faulted feeder.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-62

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / 5.2.3 Performance Measurement for Continuous Improvement p. 77 (pdf Exhibit 2A Part 1 p. 83)

Question(s):

a) Please confirm that if equipment fails and does result in a customer interruption, it is the hours of customer interruption that is measured, not the hours the equipment is failed that is measured. For example, in a redundant system, the customer experienced failure may be momentary, while the equipment may be failed for multiple hours. Please Discuss.

RESPONSE:

a) Alectra Utilities confirms that the “Failed Equipment CHI” is based on “Customer Hours of Interruption” and not the hours the equipment is failed for. In the case of a redundant system, where the redundancy is available, the hours of customer interruption is related only to the duration the customer is out of power.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-63

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / 5.3.1 Asset Management Framework Overview p. 109 (pdf Exhibit 2A Part 1 p. 115)

Question(s):

a) Please reconcile the key finding that the "average from all classes resulted in customers collectively asking for no change in spending vs. plan" with the draft plan adjustment to accelerate investment in overhead asset renewal.

b) If the accelerated investment in overhead asset renewal is not implemented and the original plan maintained, what is the net reduction in expenditure for each year of the 2027-2031 period (please break down expenditures into capital, O&M, etc. as appropriate).

RESPONSE:

a) In the second row of Table 5.3.1-5, which pertains to Overhead & Transformer Renewal choices, Alectra Utilities confirms the statement *"The average from all classes resulted in customers collectively asking for no change in spending vs. plan."* was misplaced. Please see the corrected table 5.3.1 -5 below:

Table 1 - Customer Engagement Phase 2 Key Insights (Table 5.3.1 - 1)

DSP Investment Themes	2nd Phase Customer Engagement Choices	Key Findings
Renewing and Replacing Infrastructure	Overhead & Transformer Renewal	All customer classes except for Large Use requested increased spending in this grouping.
	Underground Renewal	All customer classes asked for a slight reduction; the average of all rate classes was a 5% reduction in spending.
	Meter Replacement & Renewal	All customer classes asked for a slight reduction; the average of all rate classes was a 5% reduction in spending.
	Fleet, Facilities & Information Technology	The average response from all rate classes was a 1% reduction.
Meeting Growing Electricity Demand	Meeting Growing Electricity Demand	The average reduction from all rate classes was 2%.
Enabling Resiliency and Modernization	Enabling Resiliency and Modernization	The average from all classes resulted in customers collectively asking for no change in spending vs. plan.

b) In the 2nd phase of customer engagement, customers informed Alectra Utilities of their preference to accelerate investment in overhead asset renewal. As a result, Alectra Utilities was responsive to customers' choices and increased overhead asset renewal by $39.0MM of capital expenditure. Please refer to Table 1 below for the breakdown of $39.0MM reduction if draft plan is maintained.

Table 1 Breakdown of Overhead Asset Renewal Reduction to Draft Plan

Overhead Asset Renewal	2027	2028	2029	2030	2031	Total
Net Reduction (in $MM) from Plan	-16.8	-9.6	-9.9	0.1	-2.8	-39.0

The impact on O&M budgets would be non-material since the accelerated investment in overhead renewal is capital work.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-64

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / 5.3.2 Asset Management Framework Overview / pp. 177-217 (pdf Exhibit 2A Part 1 pp. 183-223)
Ref 2: Kinectrics Inc. Report No: K-418033-RA-001-R000, Asset Depreciation Study for the Ontario Energy Board, July 8, 2010, pp. 9-10

Preamble:
In the referenced Kinectrics report, the Typical Useful Life (TUL) definition states that assets are replaced for a combination of three reasons: Replaced Only When Failed, Replaced Due to Reasons Not Related to Their Performance, and Replaced for Economic Reason.

Question(s):

a) For both 2023 and 2018, please provide new figures (Figure 5.3.2-22 through Figure 5.3.2-24, Figure 5.3.2-38, Figure 5.3.2-41, Figure 5.3.2-44, Figure 5.3.2-45, Figure 5.3.2-58, Figure 5.3.2-59, Figure 5.3.2-63, Figure 5.3.2-65) in tabular and graphic format, showing the breakdown of Health Index (HI) within each of the age distribution bins.

b) For pad mounted switchgear in both 2023 and 2018, please provide a separate Figure 5.3.2-32 in tabular and graphic format, showing the breakdown of HI within each of the age distribution bins.

c) For air-insulated switchgear in both 2023 and 2018, please provide a separate Figure 5.3.2-32 in tabular and graphic format, showing the breakdown of HI within each of the age distribution bins.

RESPONSE:

The tables and figures below show the breakdown of Health Index (HI) within each age range bar for the referenced figures, for 2023 and 2018.

a) **Table 1 - 2023 Age Range Breakdown By HI for Pad-Mounted Distribution Transformers**

Age Range (Years)	Health Index					Total
	VERY POOR	POOR	FAIR	GOOD	VERY GOOD	
0-5	48	35	269	290	10,164	10,806
6-10	108	88	422	1,875	9,166	11,659
11-15	618	117	253	2,630	5,105	8,723
16-20	990	272	285	6,040	6,567	14,154
21-25	1,283	477	285	5,447	5,099	12,591
26-30	753	213	346	2,340	2,675	6,327
31-35	335	165	629	2,156	3,610	6,895
36-40	477	288	859	2,627	3,057	7,308
41-45	315	210	223	1,387	1,149	3,284
46+	410	195	63	694	667	2,029
Unknown	2	2	1	46	58	109

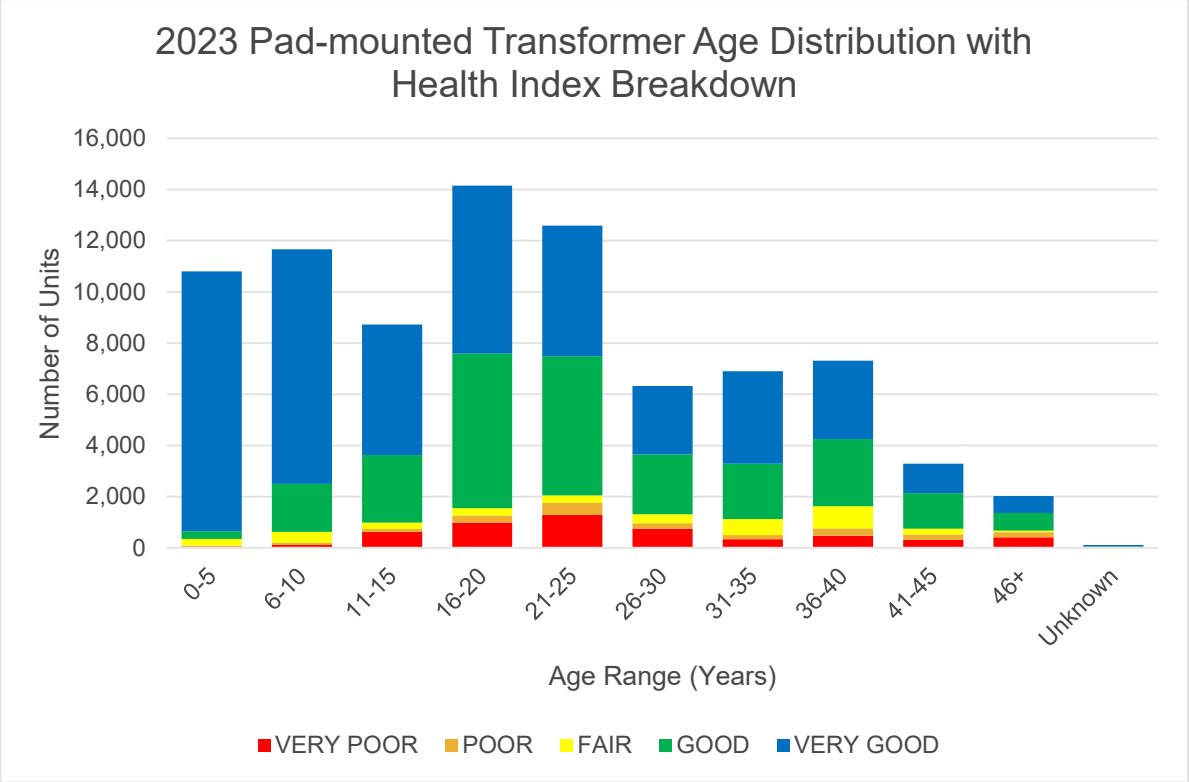

Figure 1 - 2023 Age Range Breakdown By HI for Pad-Mounted Distribution Transformers

Table 2 - 2018 Age Range Breakdown By HI for Pad-Mounted Distribution Transformers

Age Range (Years)	Health Index					Total
	VERY POOR	POOR	FAIR	GOOD	VERY GOOD	
0-5	54	0	385	1,165	9,805	11,409
6-10	31	0	1,163	1,426	6,194	8,814
11-15	126	0	1,345	2,376	11,265	15,112
16-20	268	0	2,305	2,940	7,666	13,179
21-25	234	0	1,202	1,110	3,810	6,356
26-30	91	0	1,523	1,912	2,890	6,416
31-35	164	0	1,606	1,107	3,817	6,694
36-40	149	0	705	256	1,929	3,039
41-45	81	11	350	104	430	976
46+	74	0	135	46	367	622
Unknown	417	0	32	2,292	4,129	6,870

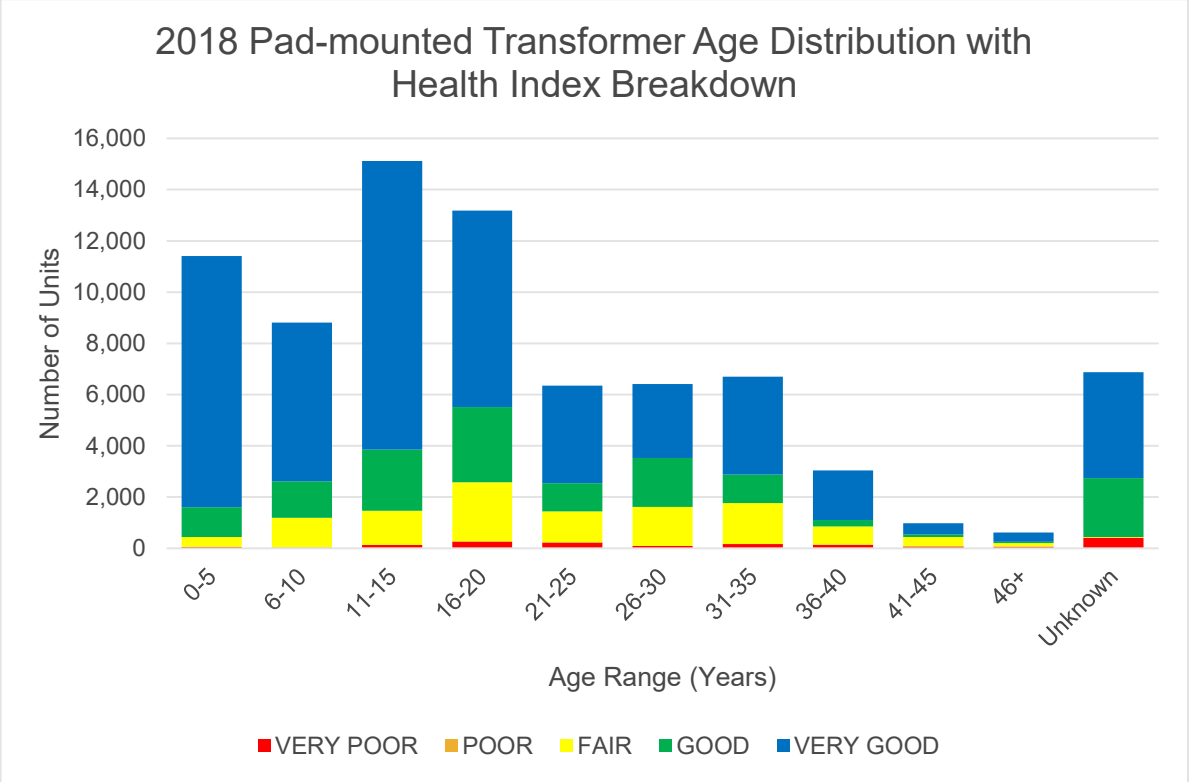

Figure 2 - 2018 Age Range Breakdown By HI for Pad-Mounted Distribution Transformers

Table 3 - 2023 Age Range Breakdown By HI for Pole-Mounted Distribution Transformers

Age Range (Years)	Health Index					Total
	VERY POOR	POOR	FAIR	GOOD	VERY GOOD	
0-5	10	0	10	0	4,961	4,981
6-10	15	0	44	1	4,601	4,661
11-15	13	0	47	1	3,107	3,168
16-20	77	0	113	0	4,153	4,343
21-25	66	12	76	2	3,533	3,689
26-30	63	39	30	227	2,923	3,282
31-35	81	43	22	531	2,061	2,738
36-40	86	22	12	405	1,070	1,595
41-45	59	20	39	398	728	1,244
46-50	55	42	100	267	94	558
51-55	136	52	235	327	0	750
56-60	64	26	86	163	0	339
61+	59	20	65	115	0	259
Unknown	1	9	1	25	164	200

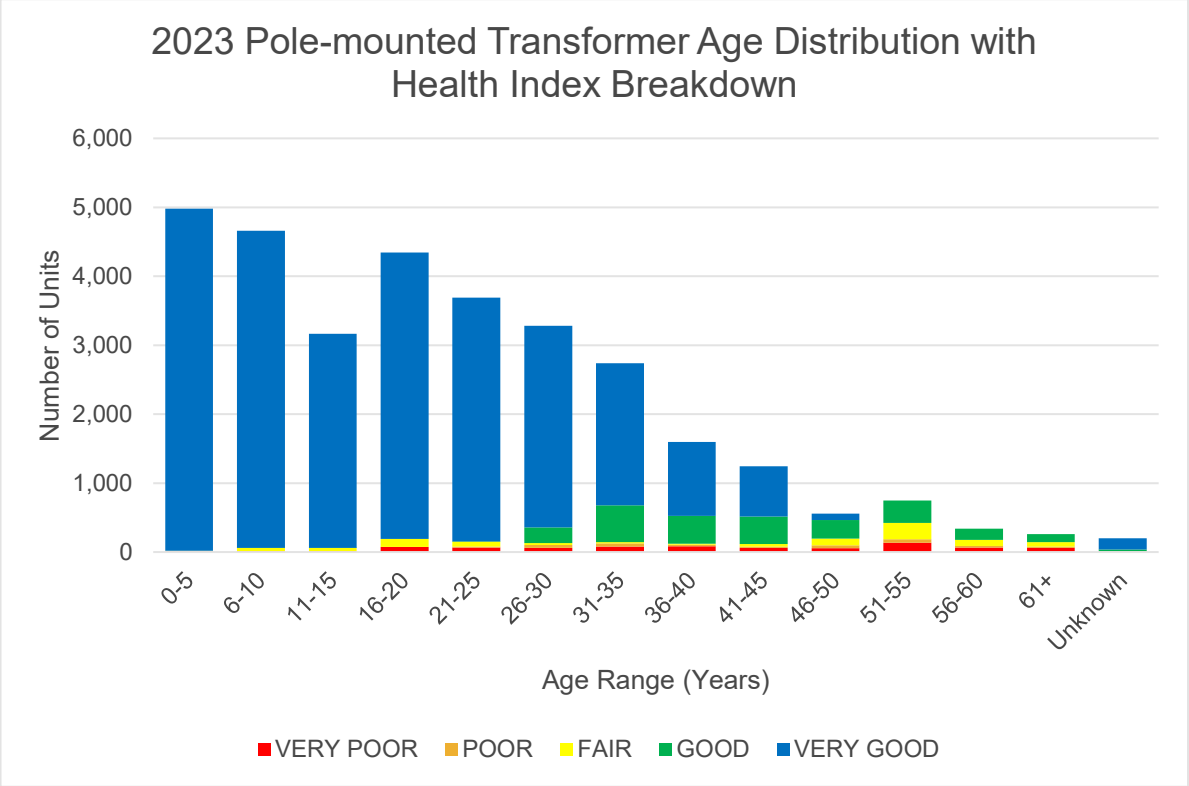

Figure 3 - 2023 Age Range Breakdown By HI for Pole-Mounted Distribution Transformers

Table 4 - 2018 Age Range Breakdown By HI for Pole-Mounted Distribution Transformers

Age Range (Years)	Health Index					Total
	VERY POOR	POOR	FAIR	GOOD	VERY GOOD	
0-5	0	0	0	822	3,936	4,758
6-10	3	0	0	1,318	2,170	3,491
11-15	21	0	0	1,466	3,643	5,130
16-20	27	0	0	2,213	1,995	4,235
21-25	17	0	0	1,926	1,969	3,912
26-30	53	0	0	1,562	1,630	3,245
31-35	75	0	338	594	936	1,943
36-40	38	0	461	235	855	1,589
41-45	51	0	362	107	242	762
46-50	64	96	527	250	98	1,035
51-55	78	180	120	201	0	579
56-60	26	103	37	70	0	236
61+	33	132	15	214	0	394
Unknown	18	0	46	148	602	814

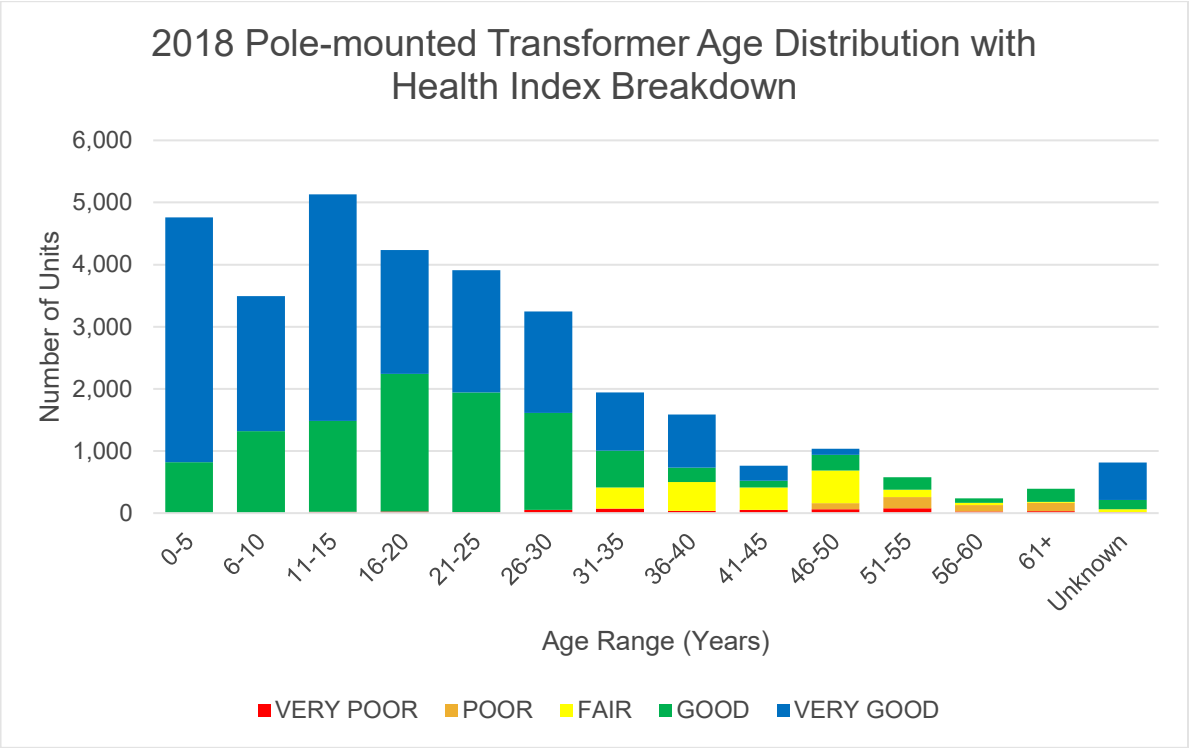

Figure 4 - 2018 Age Range Breakdown By HI for Pole-Mounted Distribution Transformers

Table 5 - 2023 Age Range Breakdown By HI for Vault Distribution Transformers

Age Range (Years)	Health Index					Total
	VERY POOR	POOR	FAIR	GOOD	VERY GOOD	
0-5	3	0	3	0	660	666
6-10	6	0	12	0	1,030	1,048
11-15	8	0	6	0	487	501
16-20	7	4	6	0	582	599
21-25	26	0	12	0	788	826
26-30	15	0	44	0	988	1,047
31-35	52	7	93	287	2,314	2,753
36-40	42	166	131	157	1,747	2,243
41-45	252	51	132	27	1,307	1,769
46+	312	32	12	108	748	1,212
Unknown	0	0	0	0	6	6

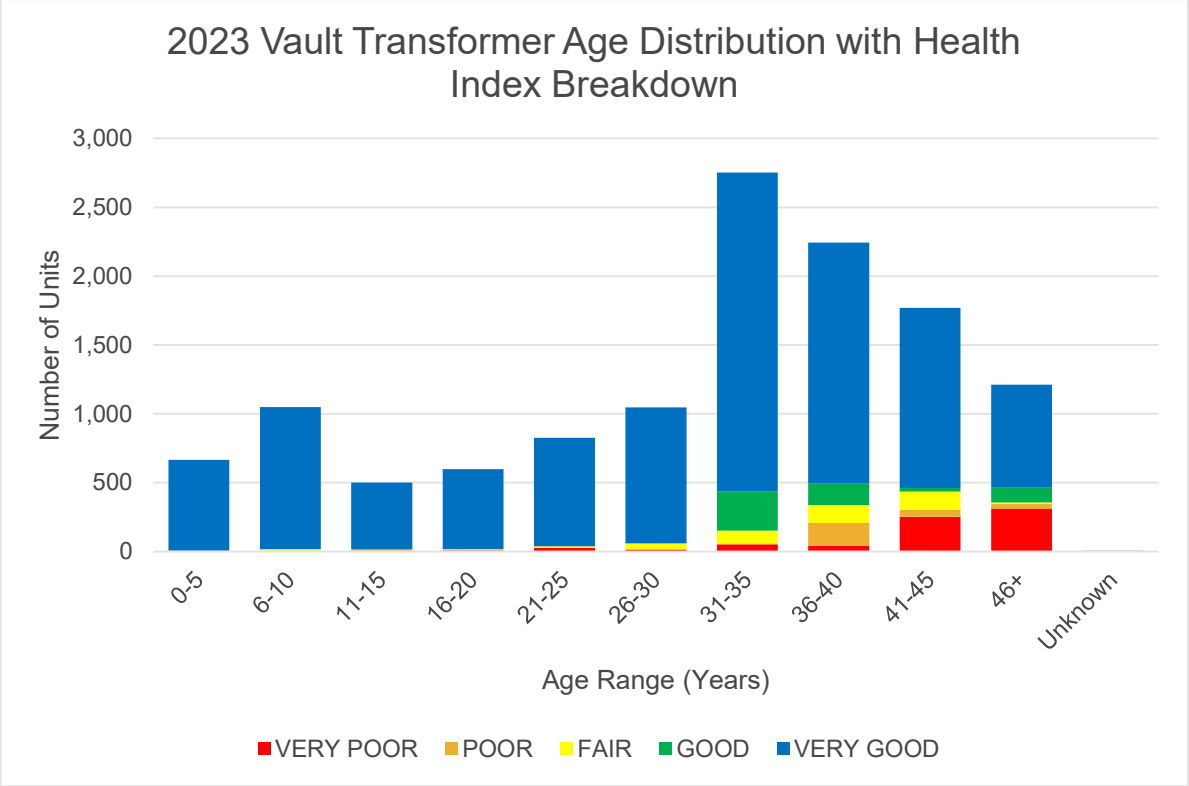

Figure 5 - 2023 Age Range Breakdown By HI for Vault Distribution Transformers

Table 6 - 2018 Age Range Breakdown By HI for Vault Distribution Transformers

Age Range (Years)	Health Index					Total
	VERY POOR	POOR	FAIR	GOOD	VERY GOOD	
0-5	9	0	77	0	941	1,027
6-10	0	0	97	0	422	519
11-15	0	0	229	3	425	657
16-20	6	0	370	7	547	930
21-25	3	0	356	18	799	1,176
26-30	12	9	532	45	2,414	3,012
31-35	9	15	343	125	1,940	2,432
36-40	9	55	324	112	1,493	1,993
41-45	116	6	416	43	403	984
46+	16	15	140	18	379	568
Unknown	0	3	2	0	42	47

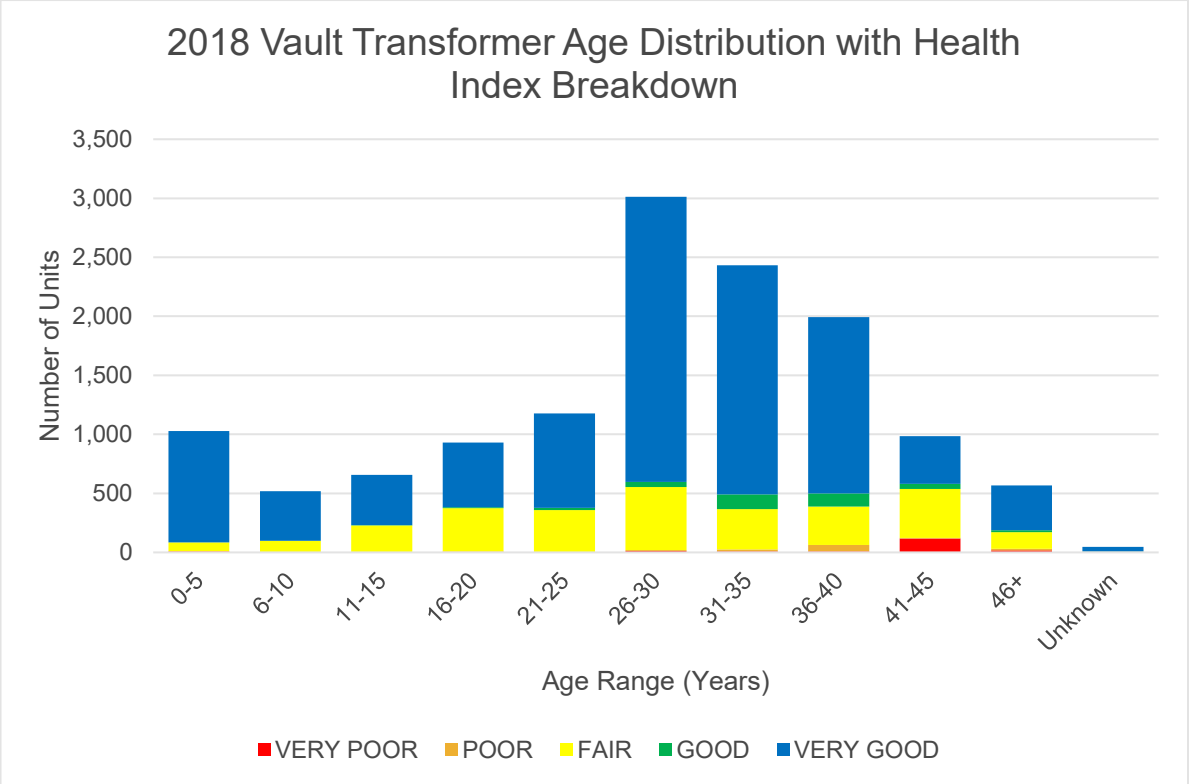

Figure 6 - 2018 Age Range Breakdown By HI for Vault Distribution Transformers

Table 7 - 2023 Age Range Breakdown By HI for Overhead Switches

Age Range (Years)	Health Index					Total
	VERY POOR	POOR	FAIR	GOOD	VERY GOOD	
0-5	4	0	0	0	567	571
6-10	8	0	0	4	670	682
11-15	5	0	0	0	416	421
16-20	7	0	0	7	436	450
21-25	5	0	0	6	302	313
26-30	2	0	0	2	190	194
31-35	2	0	0	3	191	196
36-40	1	0	1	6	84	92
41-45	4	0	13	9	49	75
46-50	3	10	2	23	0	38
51-55	7	3	10	10	0	30
56+	17	1	22	0	0	40
Unknown	1	0	0	1	88	90

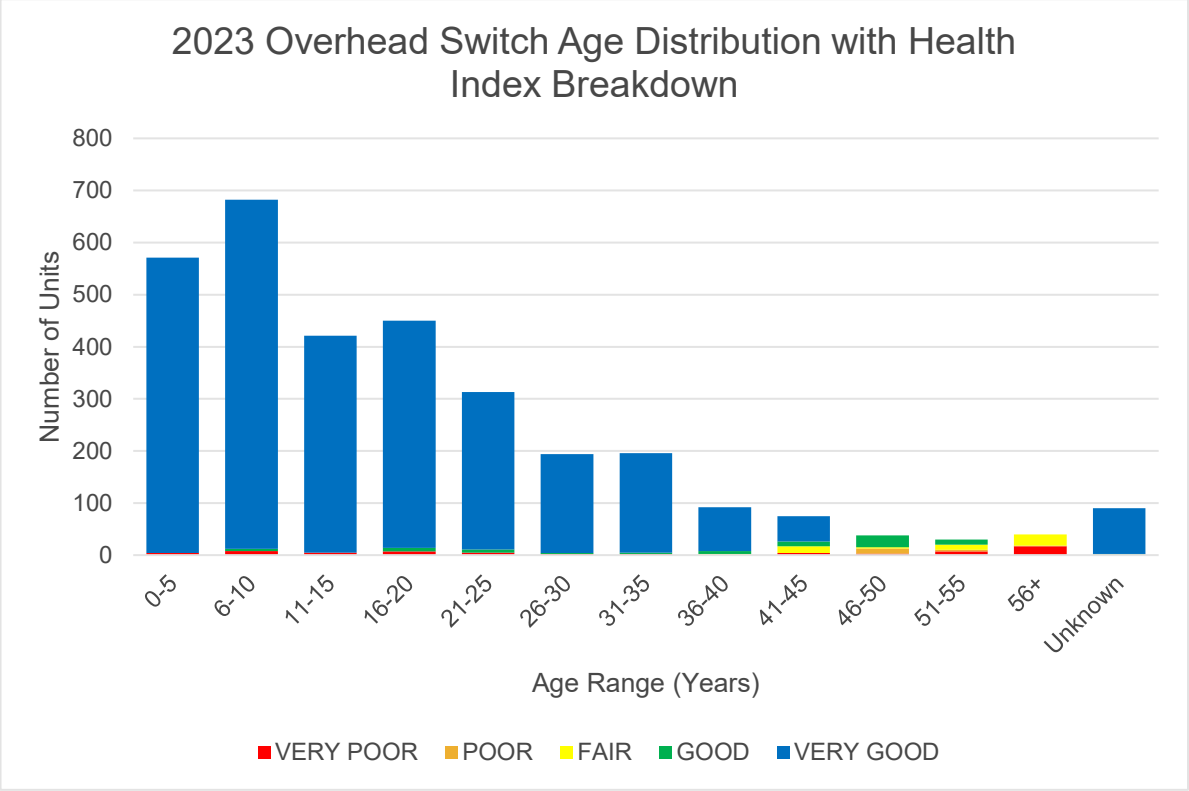

Figure 7 - 2023 Age Range Breakdown By HI for Overhead Switches

Table 8 - 2018 Age Range Breakdown By HI for Overhead Switches

Age Range (Years)	Health Index					Total
	VERY POOR	POOR	FAIR	GOOD	VERY GOOD	
0-5	0	0	0	0	735	735
6-10	0	0	0	0	547	547
11-15	0	0	0	0	657	657
16-20	0	0	0	0	468	468
21-25	0	0	0	0	301	301
26-30	0	0	0	0	437	437
31-35	0	0	0	0	165	165
36-40	0	0	0	59	93	152
41-45	0	0	63	34	0	97
46-50	41	75	0	0	0	116
51-55	74	0	0	0	0	74
56+	140	0	0	0	0	140
Unknown	0	0	0	0	0	0

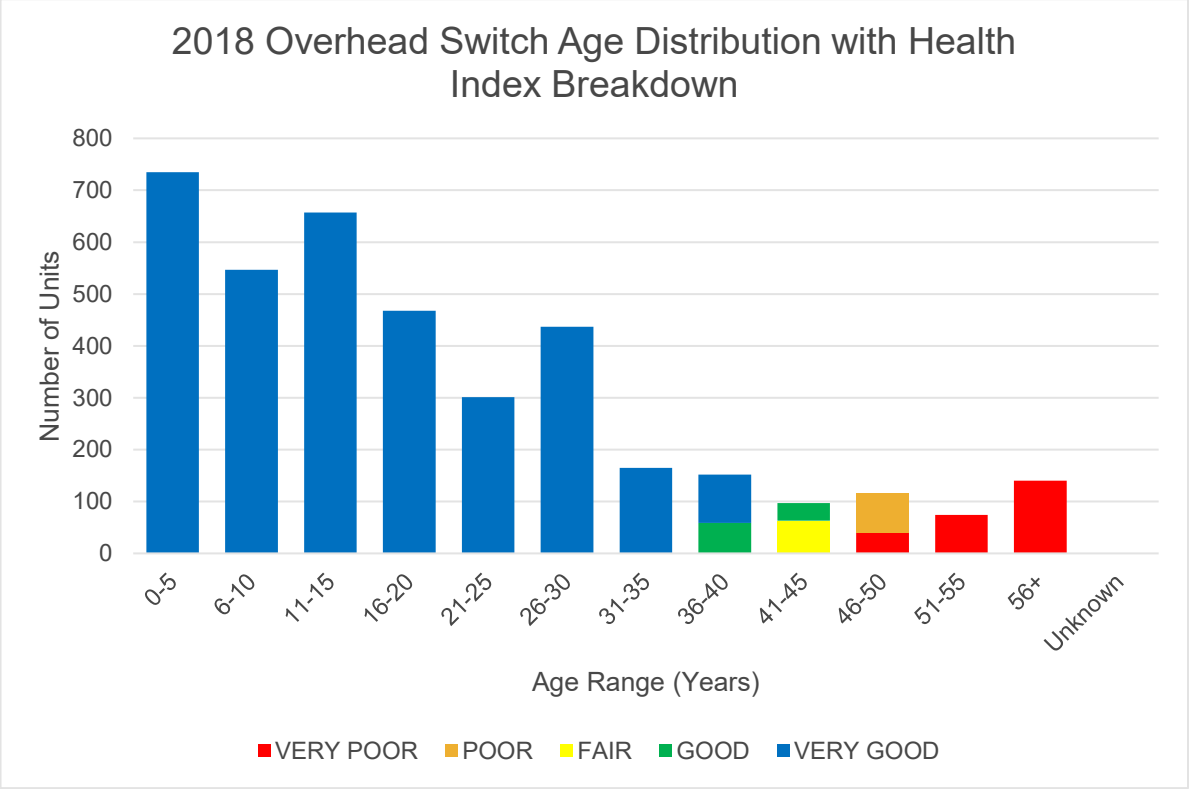

Figure 8 - 2018 Age Range Breakdown By HI for Overhead Switches

Table 9 - 2023 Age Range Breakdown By HI for Overhead Conductors

Age Range (Years)	Health Index					Total (kms)
	VERY POOR	POOR	FAIR	GOOD	VERY GOOD	
0-5	0	0	0	0	1,223	1,223
6-10	0	0	0	0	1,617	1,617
11-15	2	0	0	0	1,749	1,751
16-20	8	0	0	0	3,284	3,293
21-25	2	0	0	0	2,665	2,667
26-30	1	0	0	0	1,872	1,873
31-35	1	0	0	0	2,244	2,245
36-40	0	0	0	0	1,170	1,170
41-45	1	0	0	0	838	840
46-50	5	0	0	0	538	544
51-55	5	0	0	0	456	462
56-60	1	0	0	63	150	214
61-65	0	2	108	42	0	151
66-70	42	97	0	0	0	139
71-75	225	0	0	0	0	225
75+	49	0	0	0	0	49

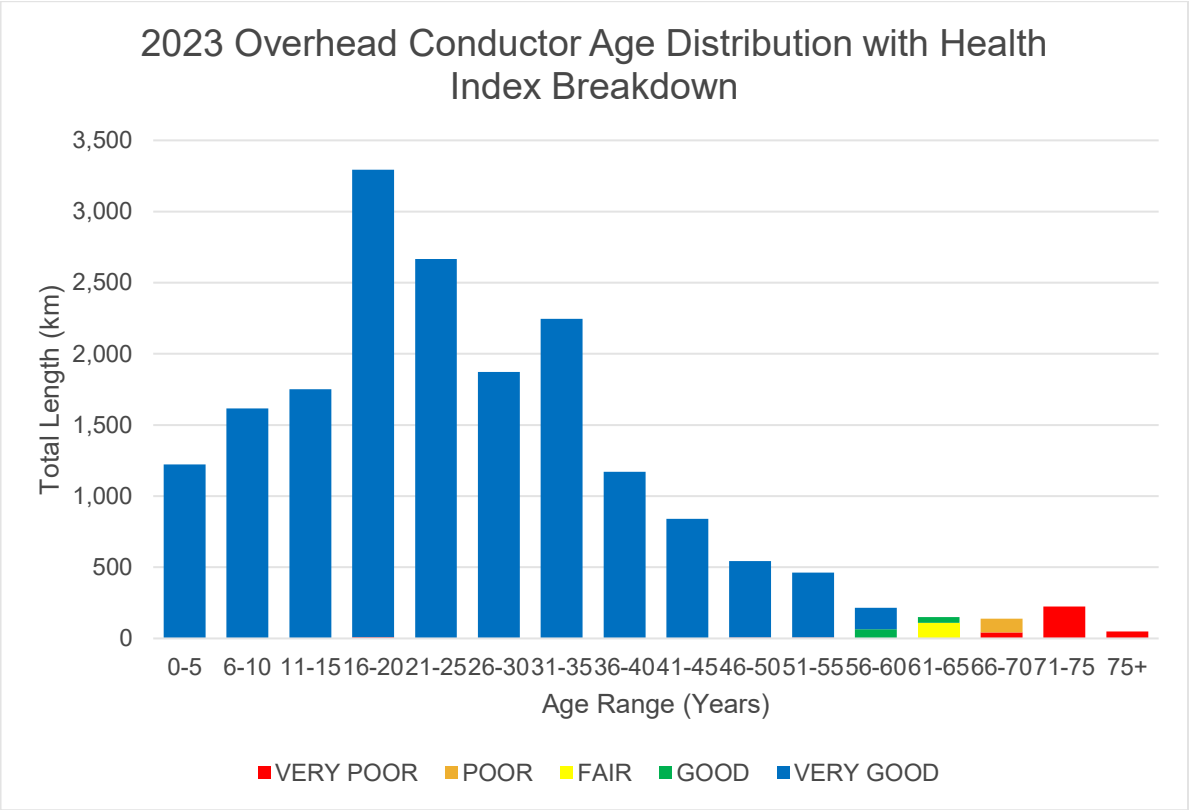

Figure 9 - 2023 Age Range Breakdown By HI for Overhead Conductors

Table 10 - 2018 Age Range Breakdown By HI for Overhead Conductors

Age Range (Years)	Health Index					Total (kms)
	VERY POOR	POOR	FAIR	GOOD	VERY GOOD	
0-5	0	0	0	0	1,419	1,419
6-10	3	0	0	0	1,684	1,687
11-15	12	0	0	0	3,219	3,231
16-20	13	0	0	0	2,588	2,602
21-25	6	0	0	0	1,736	1,742
26-30	8	0	0	0	2,176	2,184
31-35	7	0	0	0	1,091	1,099
36-40	6	0	0	0	795	801
41-45	9	0	0	0	488	497
46-50	9	0	0	0	405	414
51-55	6	0	0	0	189	195
56-60	5	0	0	34	87	126
61-65	9	0	78	31	0	117
66-70	16	157	0	0	0	173
71-75	15	0	0	0	0	15
75+	98	0	0	0	0	98

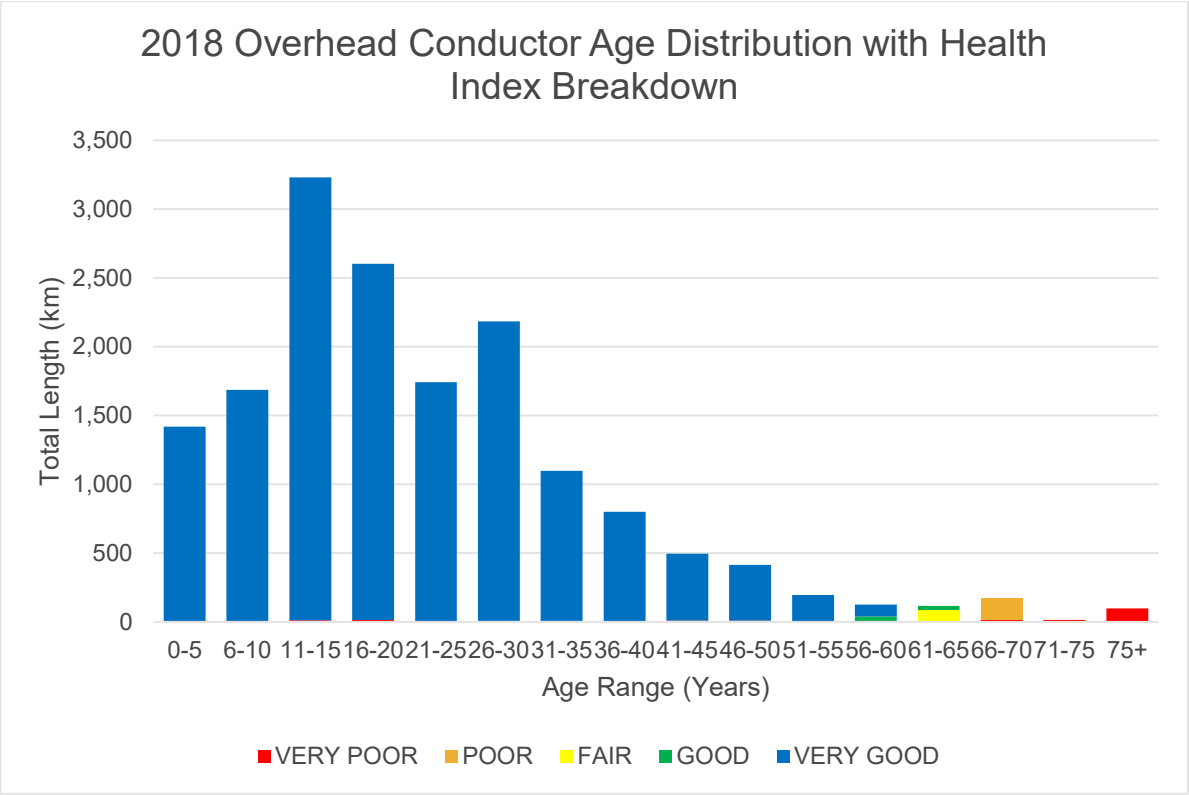

Figure 10 - 2018 Age Range Breakdown By HI for Overhead Conductors

Table 11 - 2023 Age Range Breakdown By HI for Wood Poles

Age Range (Years)	Health Index					Total
	VERY POOR	POOR	FAIR	GOOD	VERY GOOD	
0-5	11	5	0	65	10,522	10,603
6-10	28	11	0	49	11,359	11,447
11-15	50	41	2	144	8,879	9,116
16-20	226	74	10	295	8,266	8,871
21-25	268	178	11	473	7,522	8,452
26-30	401	213	27	944	6,878	8,463
31-35	494	296	78	1,030	5,810	7,708
36-40	340	289	38	901	4,314	5,882
41-45	343	380	77	1,245	2,370	4,415
46-50	345	321	133	1,312	2,117	4,228
51-55	428	264	492	1,876	1,696	4,756
56-60	409	356	500	1,844	440	3,549
61-65	533	280	795	1,408	204	3,220
66-70	754	339	1,562	1,039	32	3,726
71-75	792	367	2,121	698	8	3,986
76+	335	102	327	88	2	854
Unknown	323	95	57	612	4,899	5,986

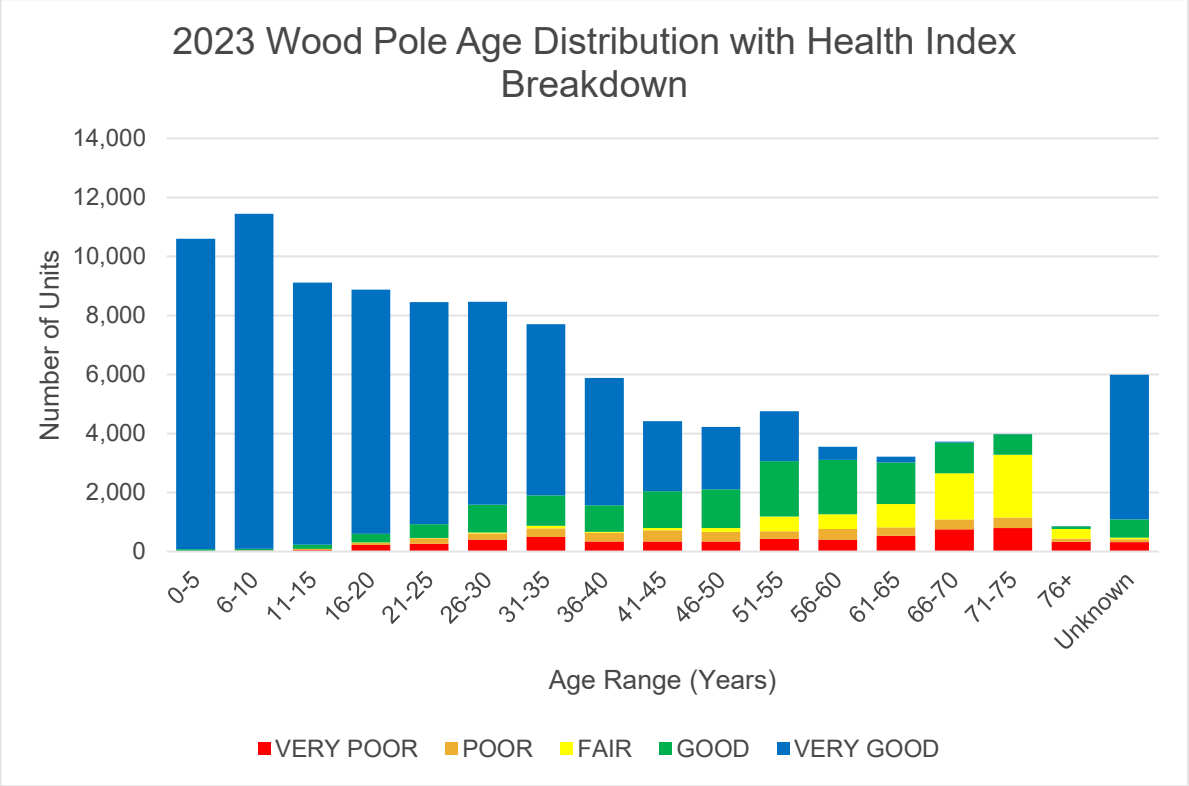

Figure 11 - 2023 Age Range Breakdown By HI for Wood Poles

Table 12 - 2018 Age Range Breakdown By HI for Wood Poles

Age Range (Years)	Health Index					Total
	VERY POOR	POOR	FAIR	GOOD	VERY GOOD	
0-5	185	0	39	2,396	8,458	11,078
6-10	181	0	180	4,635	4,608	9,604
11-15	163	0	206	4,836	4,519	9,724
16-20	244	0	321	5,050	3,868	9,483
21-25	519	0	527	5,284	3,334	9,664
26-30	578	0	627	4,546	3,175	8,926
31-35	453	0	1,312	2,847	2,393	7,005
36-40	489	0	1,499	1,669	1,524	5,181
41-45	390	0	2,576	1,194	742	4,902
46-50	517	167	2,137	1,795	917	5,533
51-55	285	205	1,706	1,354	647	4,197
56-60	325	161	1,929	1,461	181	4,057
61-65	252	1,349	1,703	1,374	130	4,808
66-70	67	1,060	683	331	34	2,175
71-75	13	281	161	35	3	493
76+	13	432	148	28	3	624
Unknown	209	9	1,792	1,417	4,688	8,115

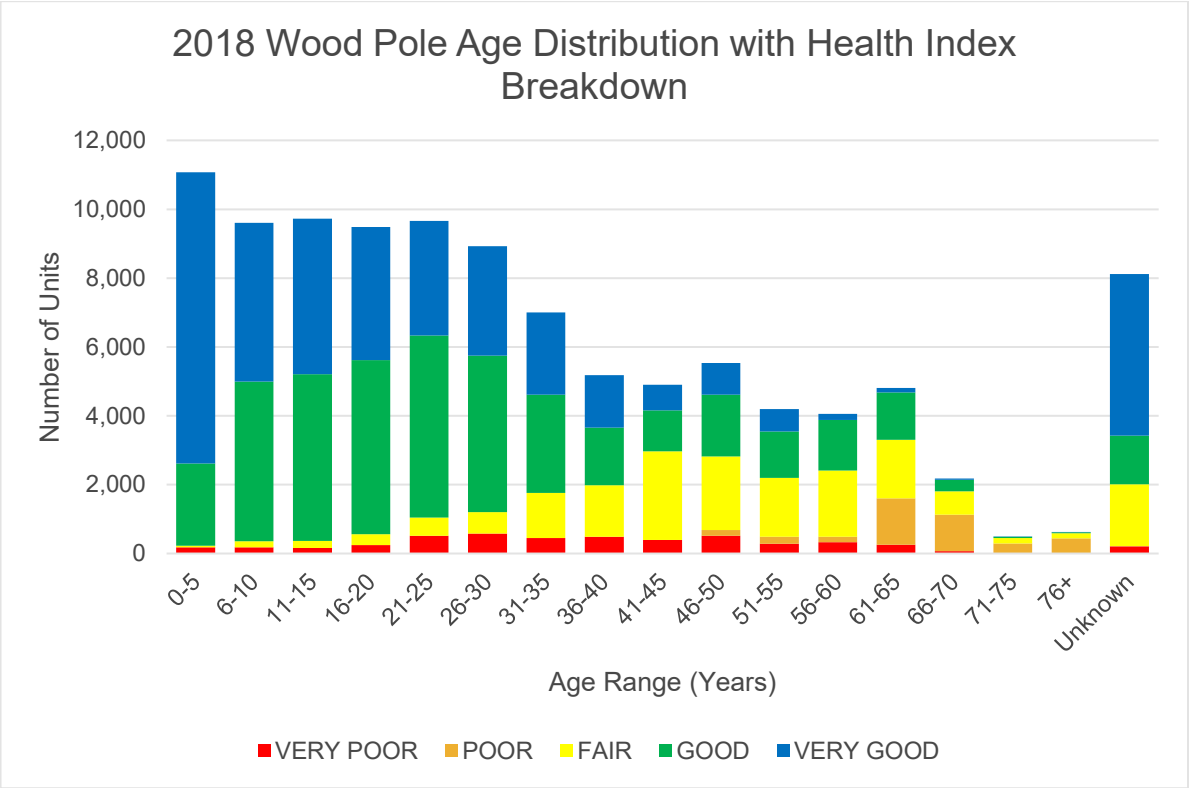

Figure 12 - 2018 Age Range Breakdown By HI for Wood Poles

Table 13 - 2023 Age Range Breakdown By HI for Concrete Poles

Age Range (Years)	Health Index					Total
	VERY POOR	POOR	FAIR	GOOD	VERY GOOD	
0-5	0	0	5	20	3,715	3,740
6-10	4	0	6	31	4,243	4,284
11-15	0	0	3	55	3,077	3,135
16-20	4	0	26	156	3,298	3,484
21-25	8	0	34	213	3,087	3,342
26-30	4	0	36	183	1,861	2,084
31-35	6	0	37	403	1,274	1,720
36-40	15	0	75	286	771	1,147
41-45	21	0	64	128	536	749
46-50	4	0	39	116	794	953
51-55	12	0	128	63	798	1,001
56-60	3	0	149	28	501	681
61-65	3	71	128	64	389	655
66-70	5	22	37	84	17	165
71-75	25	35	2	108	0	170
76-80	15	5	51	3	0	74
81+	168	121	346	0	0	635
Unknown	4	31	93	0	963	1,091

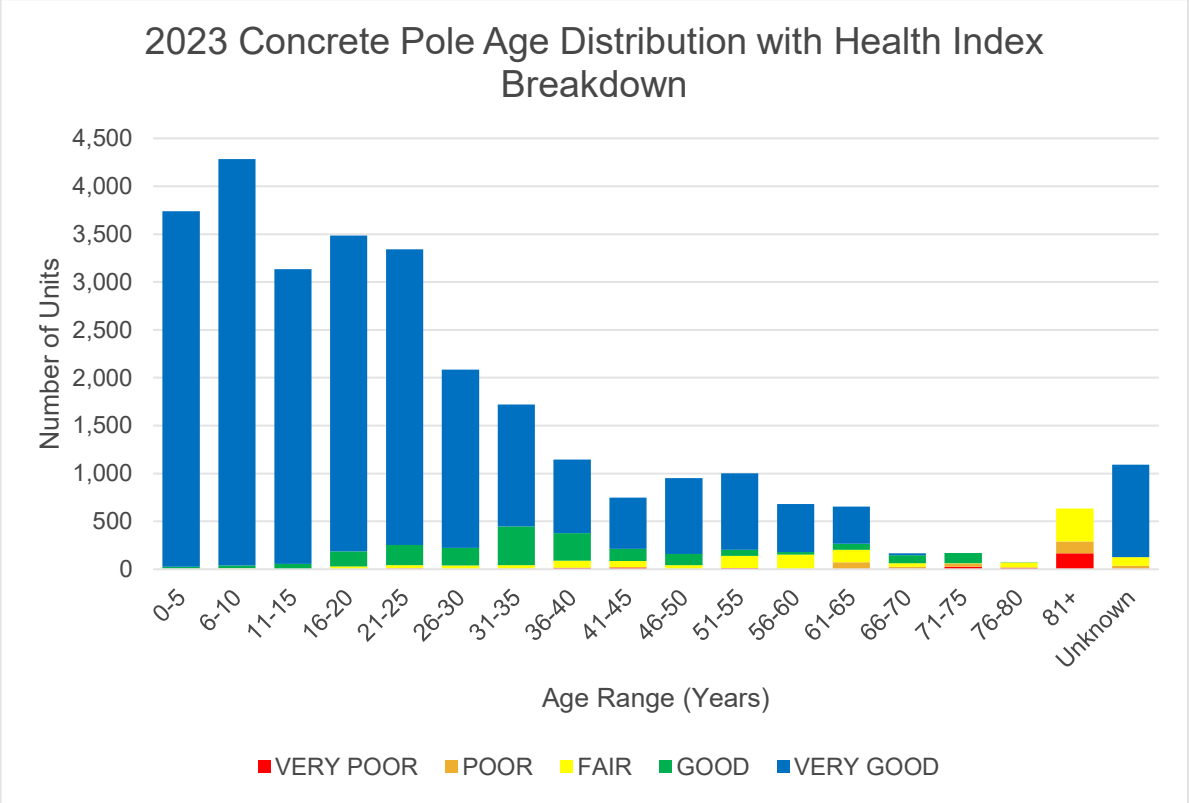

Figure 13 - 2023 Age Range Breakdown By HI for Concrete Poles

Table 14 - 2018 Age Range Breakdown By HI for Concrete Poles

Age Range (Years)	Health Index					Total
	VERY POOR	POOR	FAIR	GOOD	VERY GOOD	
0-5	3	0	6	831	3,304	4,144
6-10	2	0	5	948	2,212	3,167
11-15	11	0	19	916	2,656	3,602
16-20	18	0	15	1,736	1,652	3,421
21-25	26	0	16	1,135	966	2,143
26-30	36	0	76	838	808	1,758
31-35	52	0	34	614	522	1,222
36-40	31	0	14	496	283	824
41-45	17	0	15	696	273	1,001
46-50	28	0	12	867	173	1,080
51-55	53	0	345	353	12	763
56-60	136	0	467	138	2	743
61-65	29	1	151	46	0	227
66-70	1	1	43	2	0	47
71-75	2	77	0	0	0	79
76-80	5	223	0	0	0	228
81+	7	533	0	0	0	540
Unknown	0	0	159	0	192	351

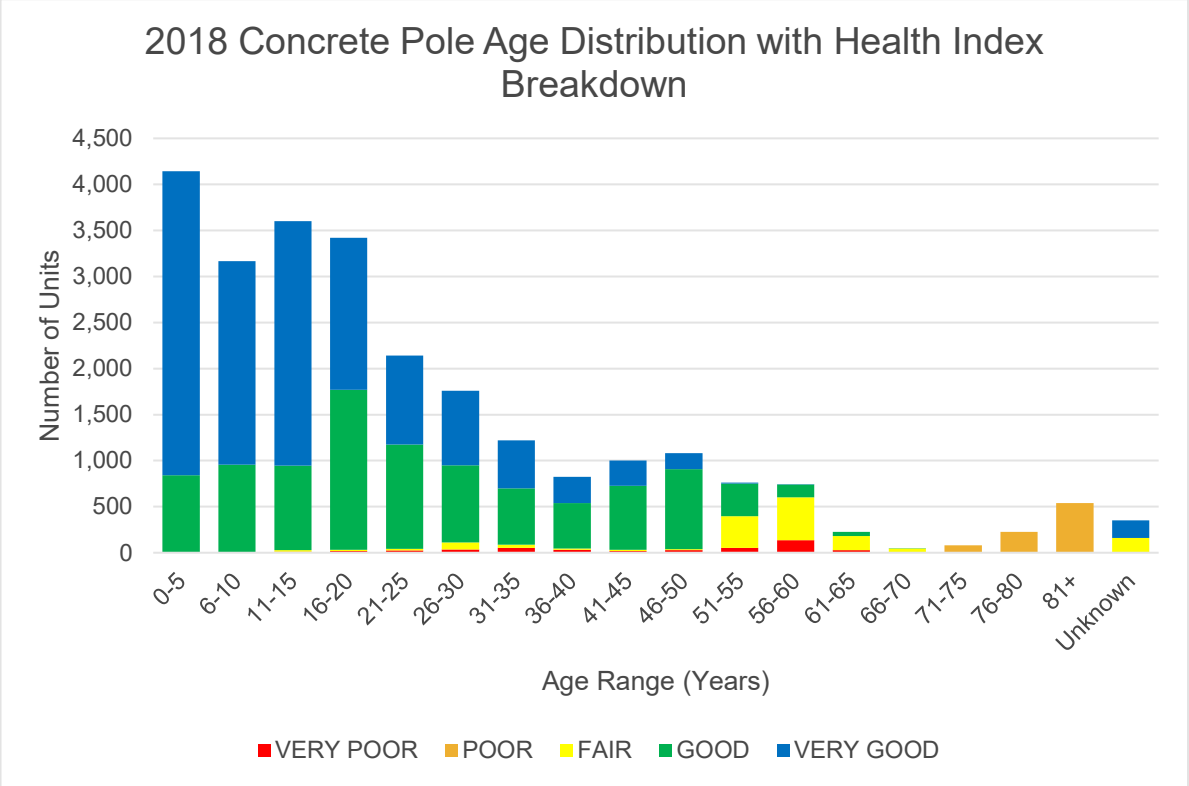

Figure 14 - 2018 Age Range Breakdown By HI for Concrete Poles

Table 15 - 2023 Age Range Breakdown By HI for Primary Underground Cables

Age Range (Years)	Health Index					Total (kms)
	VERY POOR	POOR	FAIR	GOOD	VERY GOOD	
0-5	0	0	0	0	1,965	1,965
6-10	0	0	0	0	2,269	2,269
11-15	0	0	0	0	2,280	2,280
16-20	0	0	0	0	3,319	3,319
21-25	0	0	0	0	3,650	3,650
26-30	0	0	0	60	2,211	2,272
31-35	0	1,215	563	277	931	2,985
36-40	1,248	624	0	31	366	2,270
41-45	959	0	11	41	272	1,284
46-50	610	5	10	40	85	750
51-55	310	0	0	9	67	386
56-60	121	0	0	25	40	187
61+	41	19	10	6	1	78

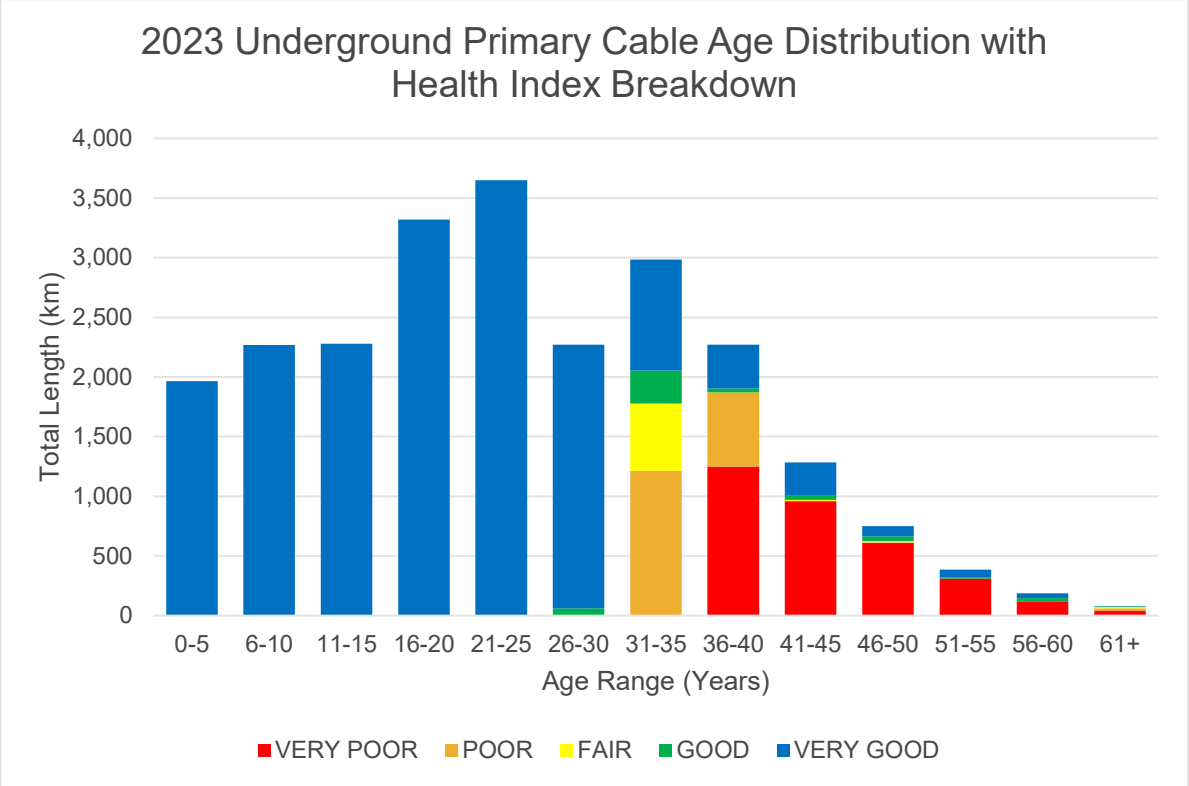

Figure 15 - 2023 Age Range Breakdown By HI for Primary Underground Cables

Table 16 - 2018 Age Range Breakdown By HI for Primary Underground Cables

Age Range (Years)	Health Index					Total (kms)
	VERY POOR	POOR	FAIR	GOOD	VERY GOOD	
0-5	0	0	0	0	2,128	2,128
6-10	0	0	0	0	2,301	2,301
11-15	0	0	0	0	3,322	3,322
16-20	0	0	0	0	3,687	3,687
21-25	0	0	0	0	2,294	2,294
26-30	0	0	0	771	2,251	3,023
31-35	0	502	955	678	186	2,321
36-40	939	257	0	0	215	1,411
41-45	814	0	0	0	61	875
46-50	388	0	0	0	47	435
51-55	190	0	0	0	45	235
56-60	65	0	0	7	14	86
61+	11	6	4	1	0	22

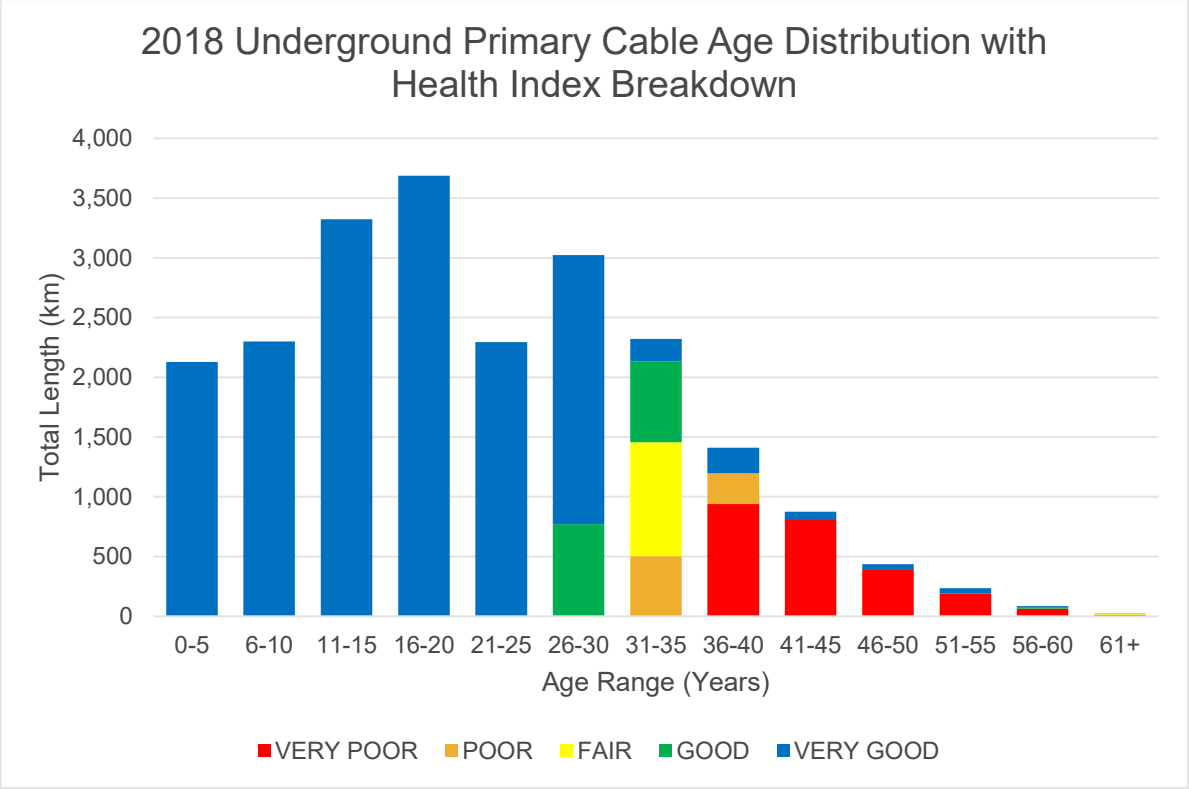

Figure 16 - 2018 Age Range Breakdown By HI for Primary Underground Cables

1 **Table 17 - 2023 Age Range Breakdown By HI for Primary PILC Cables**

Age Range (Years)	Health Index					Total (kms)
	VERY POOR	POOR	FAIR	GOOD	VERY GOOD	
0-5	0	0	0	0	2	2
6-10	0	0	0	0	5	5
11-15	0	0	0	0	12	12
16-20	0	0	0	0	16	16
21-25	0	0	0	0	30	30
26-30	0	0	0	0	53	53
31-35	0	0	0	0	55	55
36-40	0	0	0	0	41	41
41-45	0	0	0	0	47	47
46-50	0	0	0	0	39	39
51-55	0	0	0	0	57	57
56-60	0	0	0	25	37	62
61-70	9	19	10	6	0	45
70+	11	0	0	0	0	11

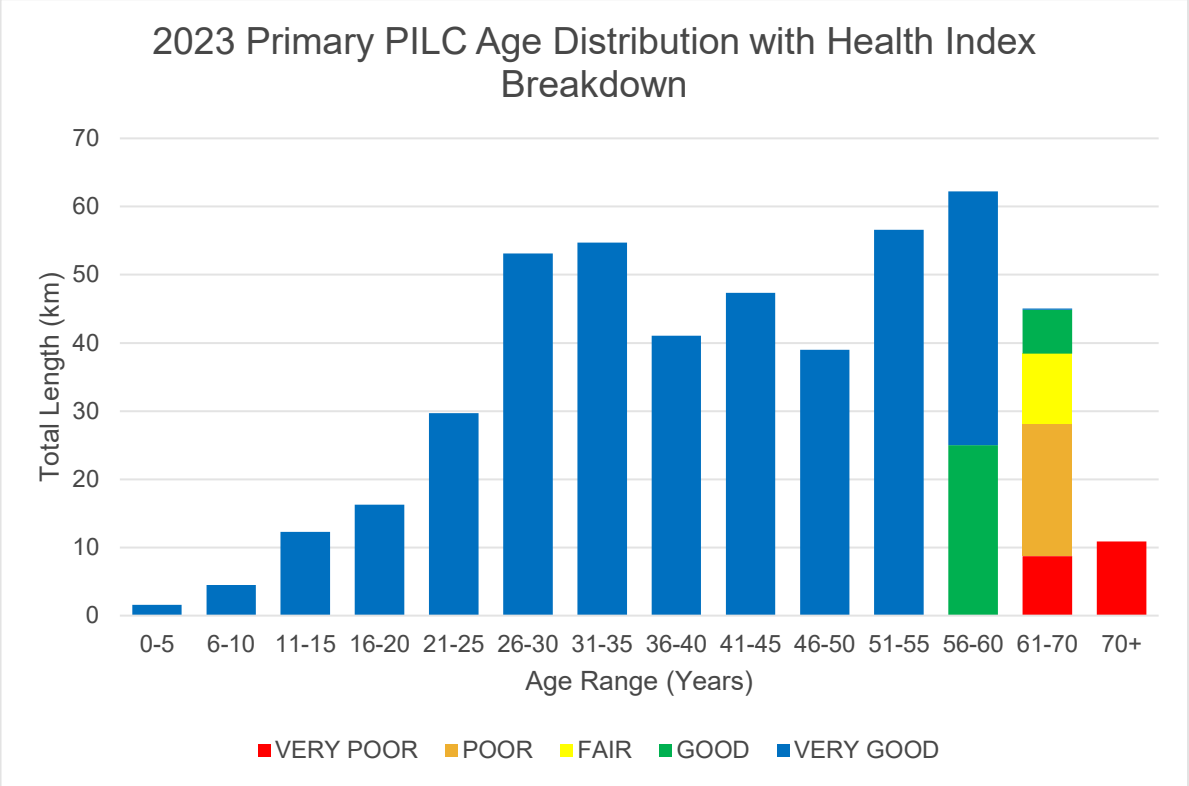

Figure 17 - 2023 Age Range Breakdown By HI for Primary PILC Cables

Table 18 - 2018 Age Range Breakdown By HI for Primary PILC Cables

Age Range (Years)	Health Index					Total (kms)
	VERY POOR	POOR	FAIR	GOOD	VERY GOOD	
0-5	0	0	0	0	1	1
6-10	0	0	0	0	12	12
11-15	0	0	0	0	17	17
16-20	0	0	0	0	30	30
21-25	0	0	0	0	51	51
26-30	0	0	0	0	52	52
31-35	0	0	0	0	42	42
36-40	0	0	0	0	46	46
41-45	0	0	0	0	27	27
46-50	0	0	0	0	44	44
51-55	0	0	0	0	45	45
56-60	0	0	0	7	14	21
61-70	8	6	4	1	0	19
70+	2	0	0	0	0	2

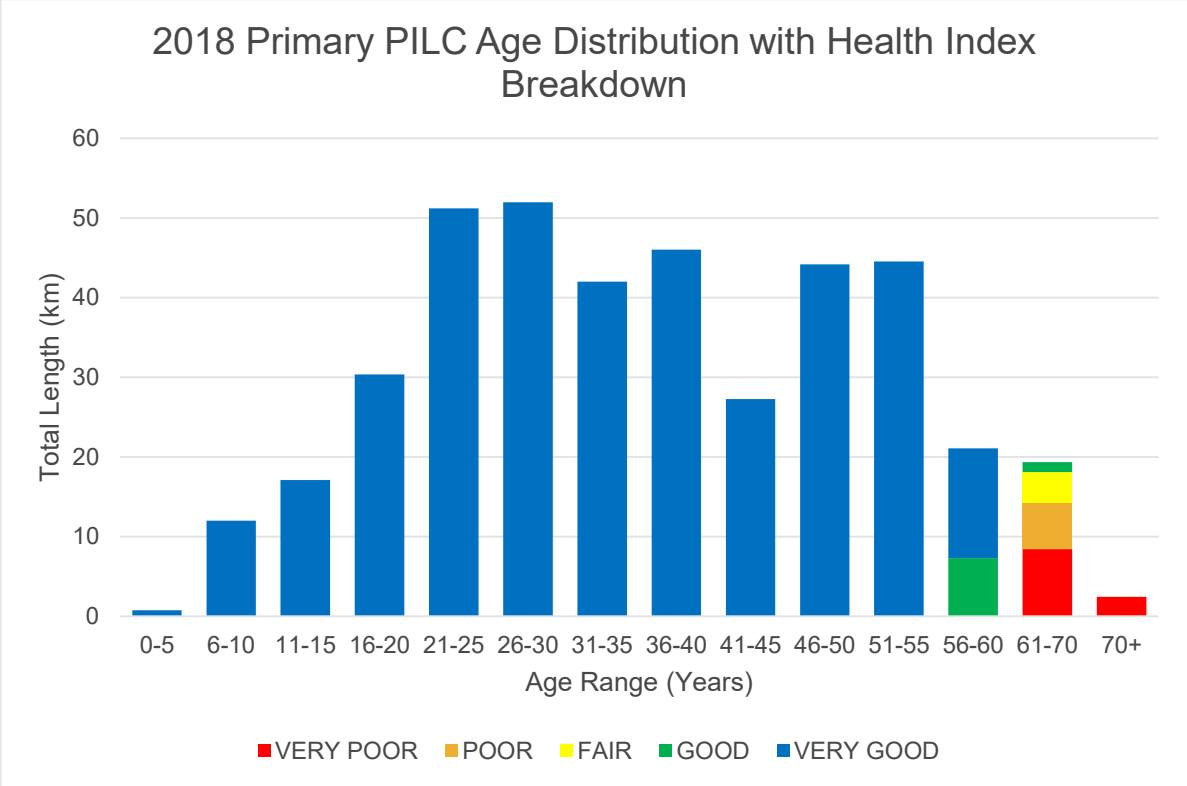

Figure 18 - 2018 Age Range Breakdown By HI for Primary PILC Cables

1 **Table 19 - 2023 Age Range Breakdown By HI for Primary XLPE Cables**

Age Range (Years)	Health Index					Total (kms)
	VERY POOR	POOR	FAIR	GOOD	VERY GOOD	
0-5	0	0	0	0	1,948	1,948
6-10	0	0	0	0	2,238	2,238
11-15	0	0	0	0	2,195	2,195
16-20	0	0	0	0	3,303	3,303
21-25	0	0	0	0	3,620	3,620
26-30	0	0	0	60	2,158	2,219
31-35	0	1,215	563	277	876	2,930
36-40	1,248	624	0	31	325	2,229
41-45	959	0	11	41	225	1,236
46-50	610	5	10	40	46	711
51-55	310	0	0	9	11	330
56-60	121	0	0	0	3	124
61+	22	0	0	0	0	22

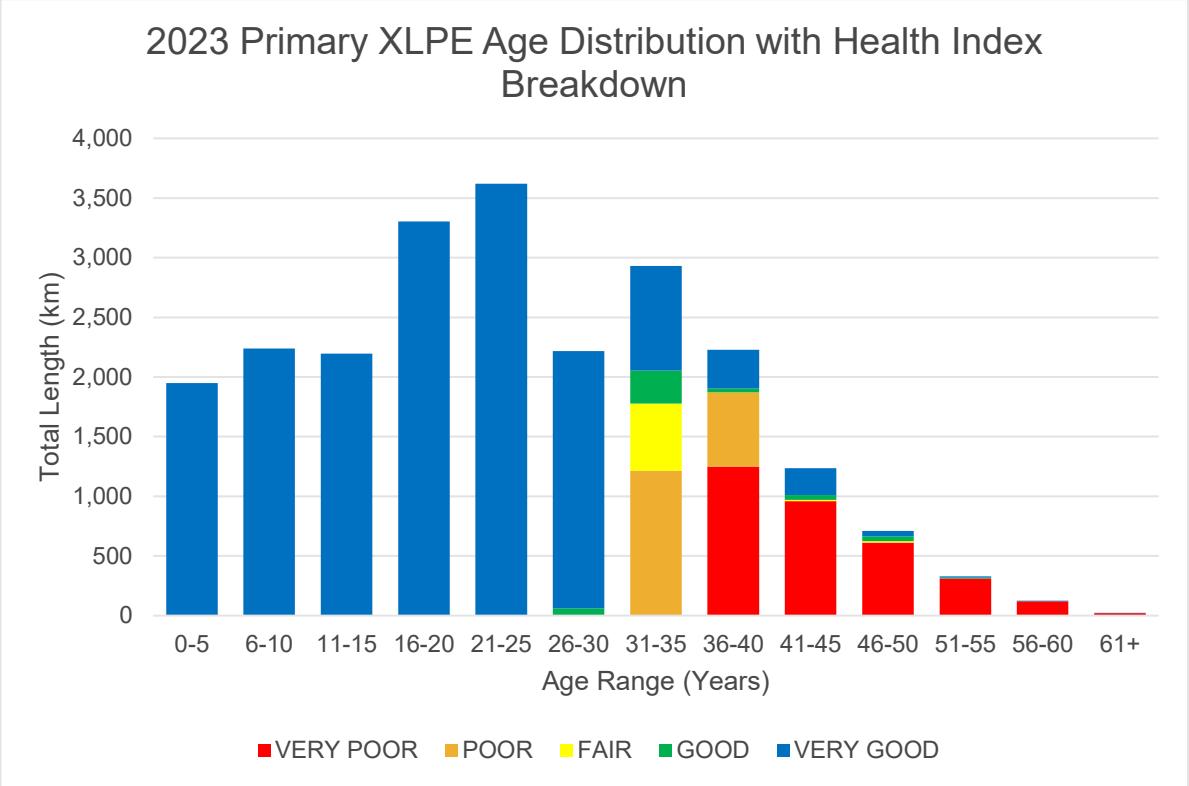

Figure 19 - 2023 Age Range Breakdown By HI for Primary XLPE Cables

Table 20 - 2018 Age Range Breakdown By HI for Primary XLPE Cables

Age Range (Years)	Health Index					Total (kms)
	VERY POOR	POOR	FAIR	GOOD	VERY GOOD	
0-5	0	0	0	0	2,106	2,106
6-10	0	0	0	0	2,219	2,219
11-15	0	0	0	0	3,305	3,305
16-20	0	0	0	0	3,656	3,656
21-25	0	0	0	0	2,243	2,243
26-30	0	0	0	771	2,199	2,971
31-35	0	502	955	678	144	2,279
36-40	939	257	0	0	169	1,365
41-45	814	0	0	0	34	848
46-50	388	0	0	0	3	391
51-55	190	0	0	0	0	190
56-60	65	0	0	0	0	65
61+	0	0	0	0	0	0

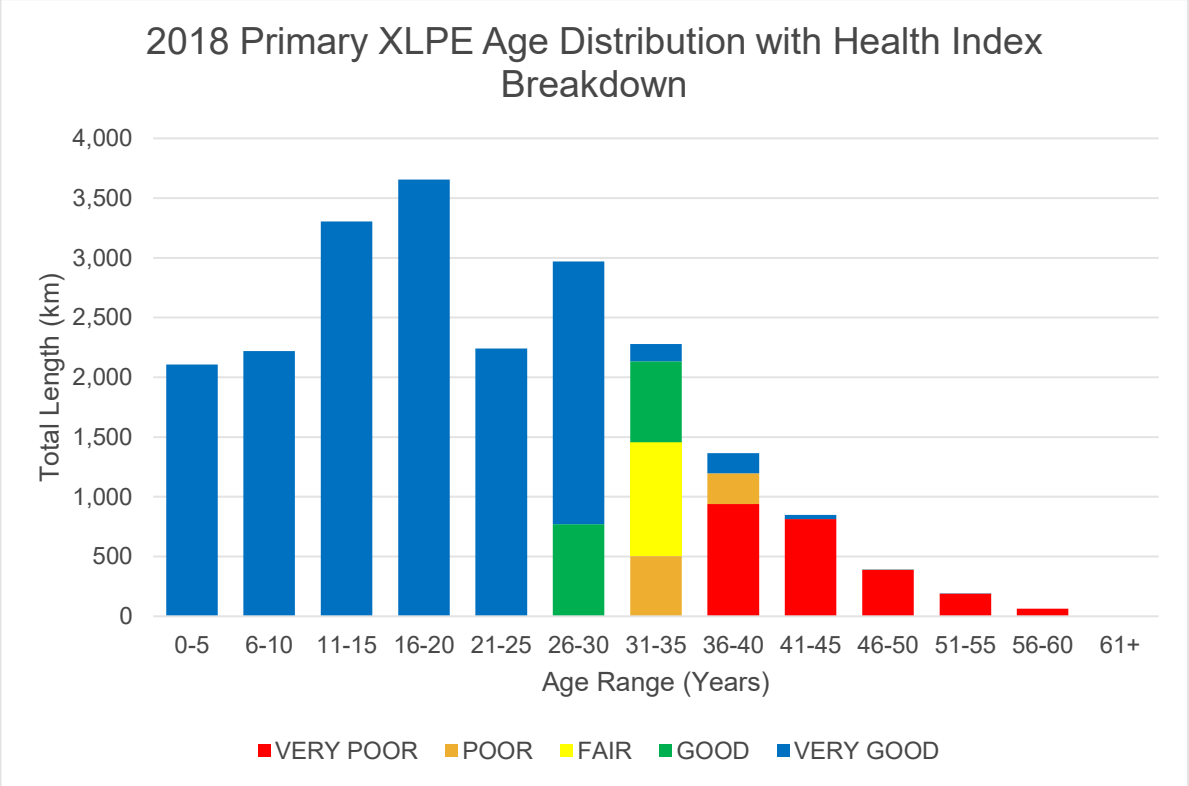

Figure 20 - 2018 Age Range Breakdown By HI for Primary XLPE Cables

Note: Age distribution bins are not applicable to Figure 5.3.2-65 as referenced in the question.

b) **Table 21 - 2023 Age Range Breakdown By HI for Switchgears**

Age Range (Years)	Health Index					Total
	VERY POOR	POOR	FAIR	GOOD	VERY GOOD	
0-5	9	0	10	6	827	852
6-10	5	2	23	8	804	842
11-15	18	0	16	19	358	411
16-20	45	0	39	52	319	455
21-25	65	2	39	27	205	338
26-30	20	13	16	29	87	165
31-35	44	13	23	40	53	173
36-40	29	39	17	26	15	126
41-45	10	0	10	3	5	28
46+	8	0	0	2	2	12
Unknown	6	1	2	6	27	42

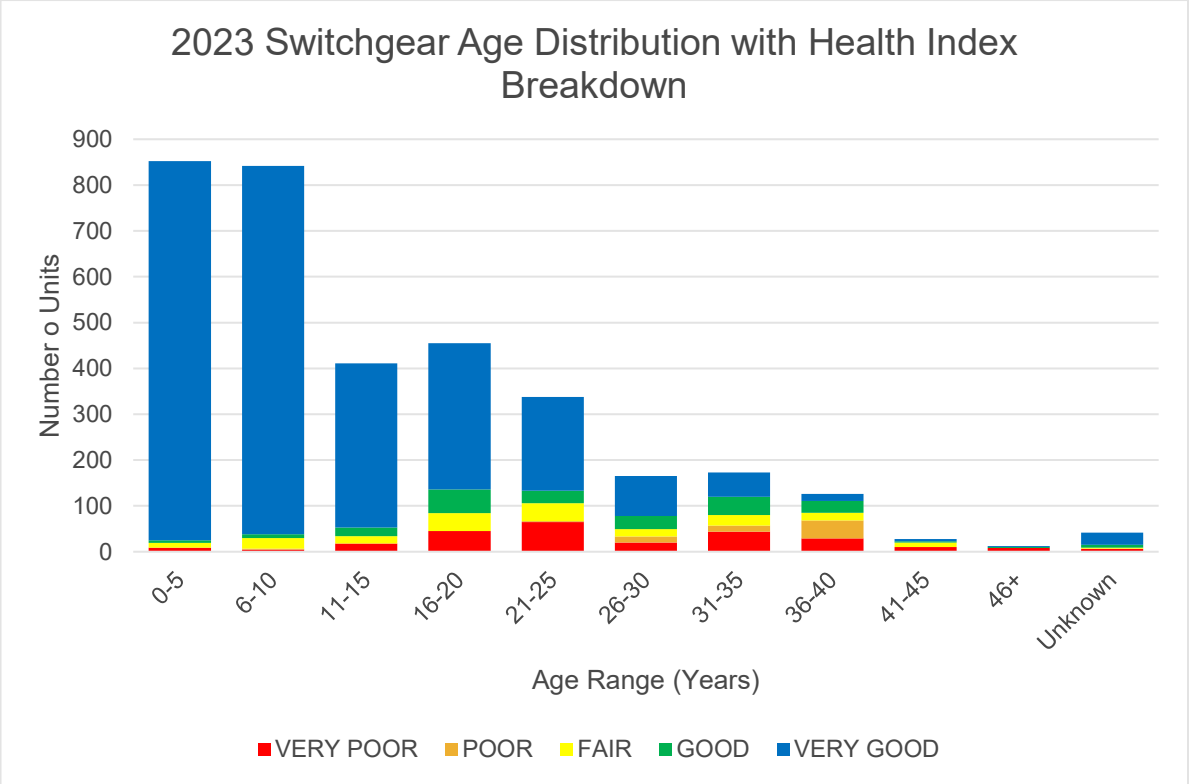

Figure 21 - 2023 Age Range Breakdown By HI for Switchgears

Table 22 - 2018 Age Range Breakdown By HI for Switchgears

Age Range (Years)	Health Index					Total
	VERY POOR	POOR	FAIR	GOOD	VERY GOOD	
0-5	6	0	11	140	767	924
6-10	23	0	17	56	354	450
11-15	45	0	34	15	414	508
16-20	66	0	27	39	293	425
21-25	18	0	28	8	185	239
26-30	48	96	35	11	126	316
31-35	30	156	12	5	84	287
36-40	9	46	4	4	44	107
41-45	5	1	0	0	5	11
46+	3	1	0	2	2	8
Unknown	30	3	3	27	51	114

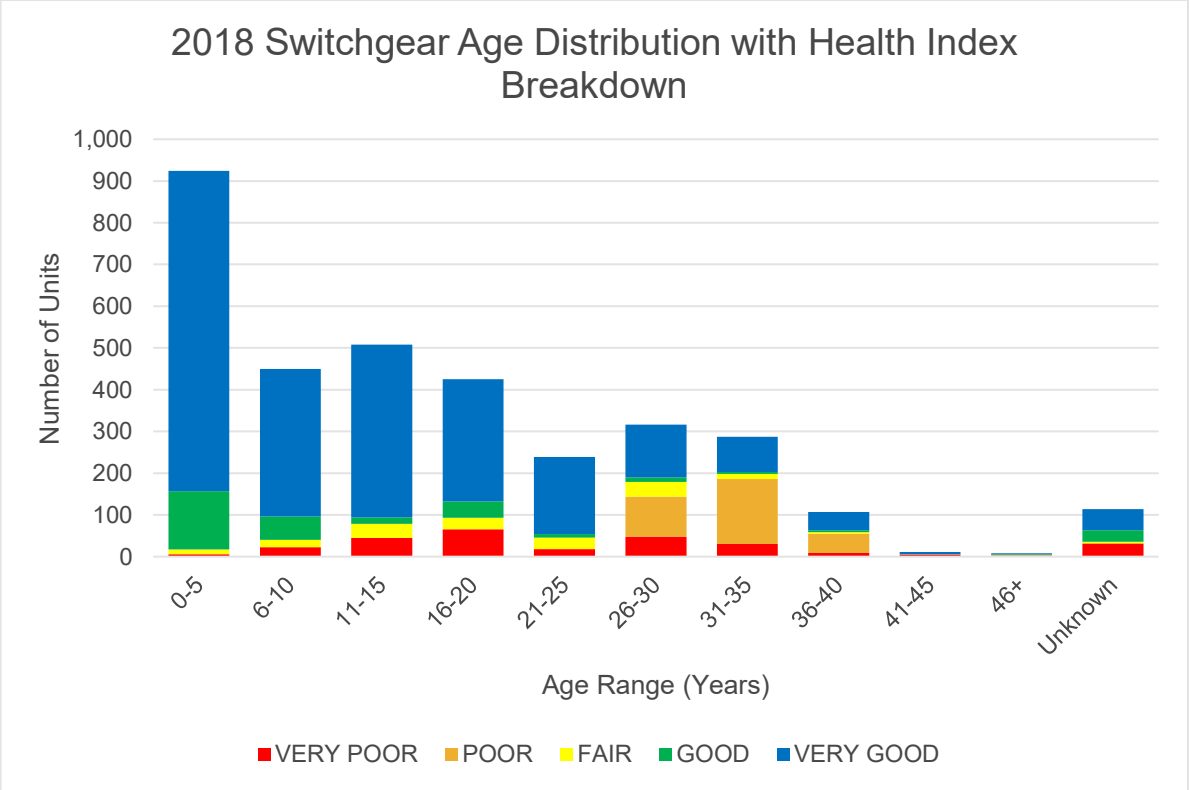

Figure 22 - 2018 Age Range Breakdown By HI for Switchgears

c) **Table 23 - 2023 Age Range Breakdown By HI for Air-Insulated Switchgears**

Age Range (Years)	Health Index					Total
	VERY POOR	POOR	FAIR	GOOD	VERY GOOD	
0-5	2	0	4	6	223	235
6-10	2	0	2	3	172	179
11-15	16	0	8	9	151	184
16-20	36	0	9	12	174	231
21-25	57	0	24	6	114	201
26-30	17	13	7	20	57	114
31-35	44	13	16	28	39	140
36-40	28	31	12	15	8	94
41-45	7	0	3	3	4	17
46+	6	0	0	2	2	10
Unknown	6	0	1	0	7	14

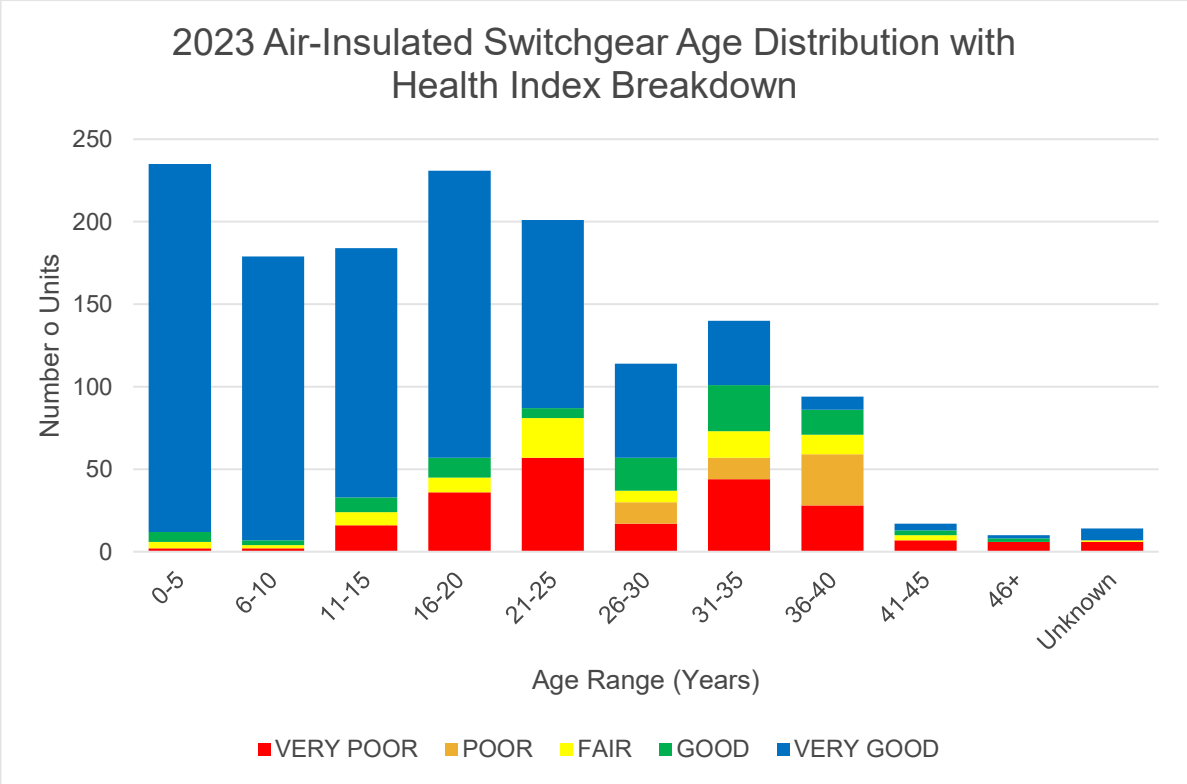

Figure 23 - 2023 Age Range Breakdown By HI for Air-Insulated Switchgears

Table 24 - 2018 Age Range Breakdown By HI for Air-Insulated Switchgears

Age Range (Years)	Health Index					Total
	VERY POOR	POOR	FAIR	GOOD	VERY GOOD	
0-5	2	0	9	2	361	374
6-10	23	0	5	10	204	242
11-15	43	0	12	15	244	314
16-20	61	0	9	18	198	286
21-25	15	0	20	8	156	199
26-30	48	96	29	11	105	289
31-35	30	156	5	5	43	239
36-40	9	46	0	4	18	77
41-45	5	1	0	0	4	10
46+	3	1	0	2	2	8
Unknown	18	3	3	27	40	91

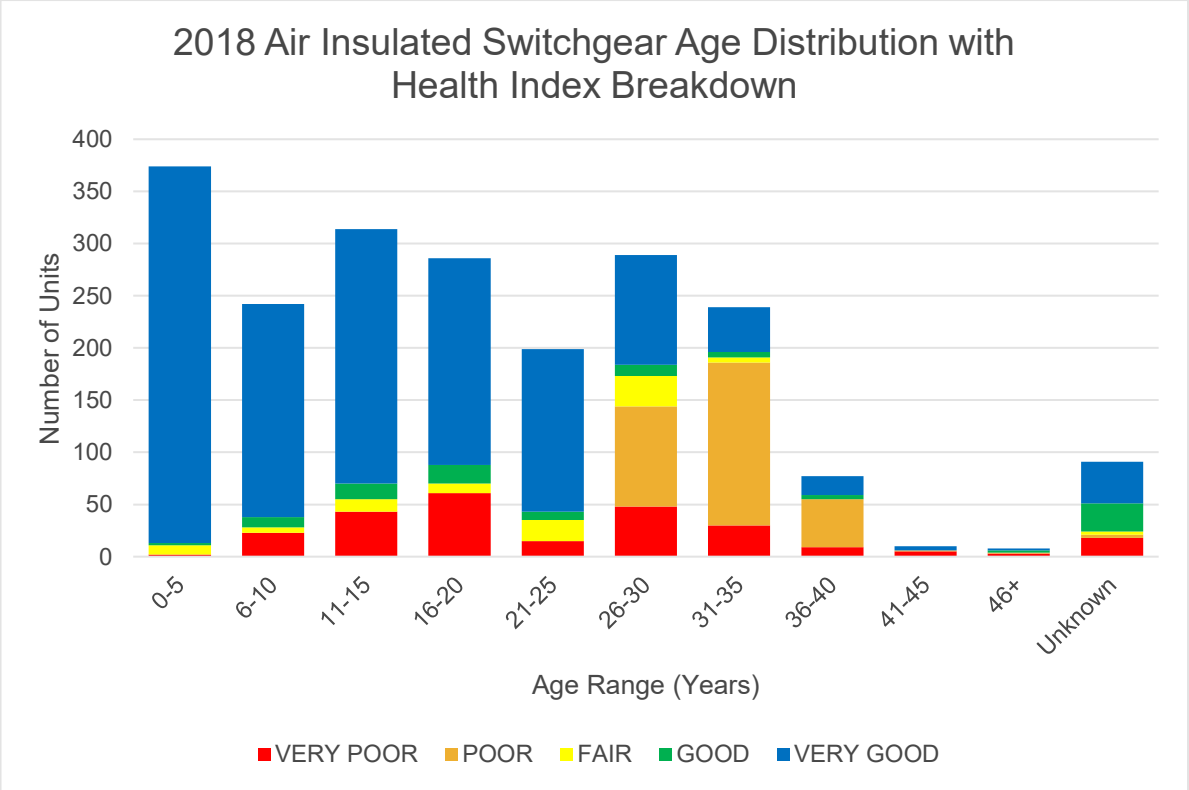

Figure 24: 2018 Age Range Breakdown By HI for Air-Insulated Switchgears

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-65

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / 5.3.2 Overview of Assets Managed / p.190 (pdf Exhibit 2A Part 1 p. 196)

Question(s):

a) Please restate Figure 5.3.2-37, in graphical and tabular format, on a normalized basis wherein the Customer Interruption Time is divided by Customer Hours Served (or Number of Customers as appropriate).

RESPONSE:

a) **Table 1 - Customer Hours of Interruption and SAIDI from Switchgear Failures (2014-2024) (Table 2-Staff-65)**

Year	Customer Hours of Interruption	Annual Average Customers Served	SAIDI (minutes)
2014	25,740	996,930	1.55
2015	19,605	1,009,752	1.16
2016	27,030	1,024,463	1.58
2017	17,131	1,034,326	0.99
2018	43,884	1,046,296	2.52
2019	30,605	1,056,132	1.74
2020	22,981	1,064,615	1.30
2021	69,463	1,075,157	3.88
2022	30,970	1,081,259	1.72
2023	25,338	1,087,917	1.40
2024	42,917	1,093,511	2.35

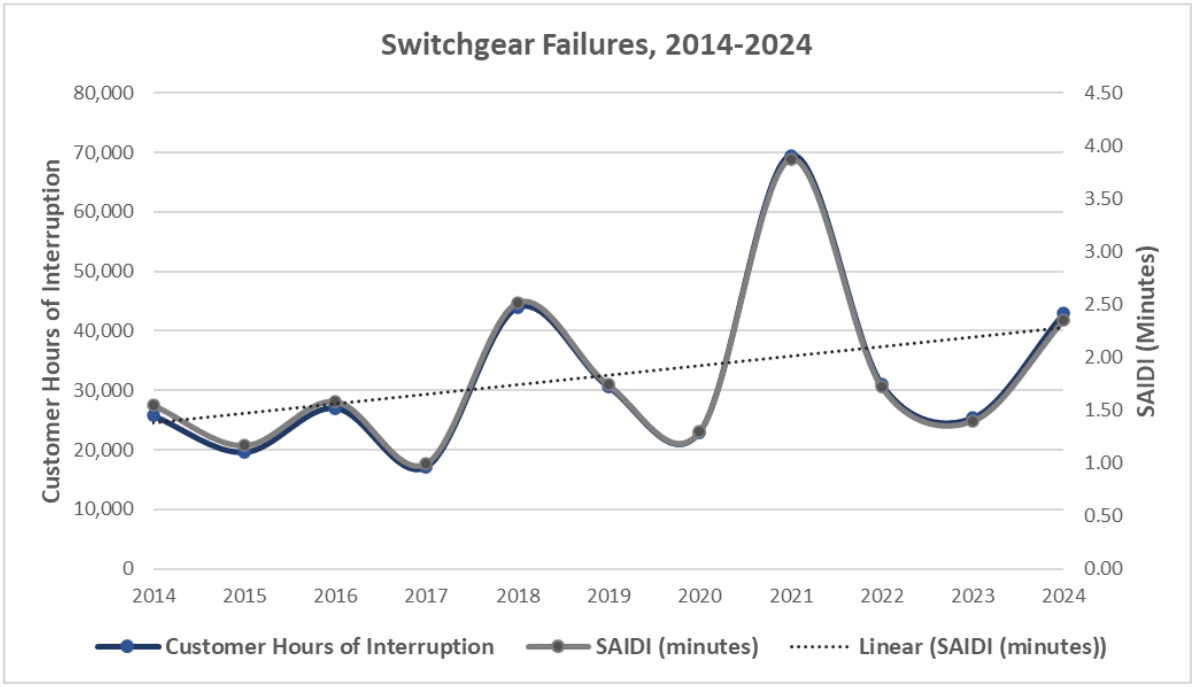

Figure 1 - Switchgear Failures

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-66

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / 5.3.2 Overview of Asset Management / p. 146 (pdf Exhibit 2 Part 1 p. 152)

Preamble:

Regarding the Climate Trends section, Alectra Utilities states that the Derecho, "impacted one-third of all Alectra Utilities customers, resulting in over 100 poles being replaced reactively. Alectra Utilities required 12.5 hours to restore 90% of impacted customers, as entire pole lines required reactive rebuilding."

Question(s):

a) What was the pre-failure Health Index and Pole Strength Test percentage score of the 100 poles lost during the 2022 Derecho?

b) What percentage of the 100 pole failures were caused by trees falling against them or connected wires?

c) For pole failures caused by treefalls, would the pre-failure condition have affected the likelihood of failure?

d) How many poles is Alectra Utilities proposing to replace or upgrade to mitigate customer outages resulting from a similar Derecho event?

e) How have the lessons learned from this incident informed the pole replacement program?

RESPONSE:

a) The Health Index for the 101 poles that were replaced during the 2022 Derecho event are summarized in the table below. The Asset Condition Assessment (ACA) incorporates the results of resistograph testing (i.e., remaining strength) into the calculation of the Health Index; 66% of the poles had pole strength test score.

Table 1 – Health Index for Poles

Health Index Category	Pole Count
Very Good	80
Good	7
Fair	0
Poor	0
Very Poor	9
Not Available	5

b) The pole failures during the 2022 Derecho event were not caused by trees falling against the poles or conductors. Failures occurred due to extreme wind loading that exceeded structural capacity.

c) As noted in response to part b), none of the 101 poles replaced due to the 2022 Derecho event failed due to treefalls. However, under Derecho-level wind conditions, even assets in Good or Very Good condition may fail if climate loading scenarios exceed the loading capacity of the pole. Therefore, pre-event asset conditions alone are not a dependable indicator of performance under extreme wind conditions. See Part d) for more information.

d) According to the Climate Risk and Vulnerability Assessment (detailed in Appendix G - Climate Risk & Vulnerability Assessment) and Alectra Utilities' additional analysis of climate vulnerability of its wood and concrete poles population, there are 29,092 poles potentially vulnerable to adverse weather, with 4,387 being classified as high-risk structurally overloaded poles. Alectra Utilities uses the climate vulnerability status of each pole, and the locational wind severity risk (informed by the climate vulnerability study

summarized in Exhibit 2A, Tab 1, Schedule 1 Section 5.3.2.1 C) to further prioritize replacement of deteriorated poles. Refer to B01 - Overhead Asset Renewal for details on pole replacement pacing over the DSP period.

e) The result of this incident led to Alectra Utilities completing a Climate Risk and Vulnerability Assessment to enable integration of climate resiliency into the Pole Renewal strategy.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-67

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / 5.3.2 Overview of Asset Management / p.149 (pdf Exhibit 2 Part 1 p. 155)

Question(s):

a) Please list all Derechos experienced anywhere in Alectra Utilities' existing service area over the last 20 years.

RESPONSE:

Response Provided by Hatch

a) Please refer to Exhibit 2A, Tab 1, Schedule 1, Appendix G, Climate Risk and Vulnerability Assessment, Section A.5 Derechos, Table A-3: Derecho Events in Alectra Service Zone which provides detailed descriptions of all Derecho Events since 1995.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-68

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / 5.3.2 Overview of Asset Management / p. 151 (pdf Exhibit 2 Part 1 p. 157)

Preamble:

Question(s):

a) Table 5.3.2 - Risk Heat Map Profile for Study Period (2021-2075) provides risk profiles for climate parameter by location. Please provide the quantified annual probabilities associated with each of the qualitative risk profiles in the legend.

RESPONSE:

Response Provided by Hatch

a) The quantified annual probabilities associated with each of the qualitative risk profiles are provided in Appendix C of the Hatch study (Climate Risk and Vulnerability Assessment of the Alectra Utilities' Distribution System), which is available in Exhibit 2A Tab 1 Schedule 1, Appendix G.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-69

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / 5.3.2 Overview of Asset Management / pp. 174, 180-181, 201-202, 218-219, (pdf Exhibit 2 Part 1 pp. 180, 186-187, 207-205, 224-225)

Question(s):

a) Alectra Utilities has provided HI results geographically in figures for distribution transformers, poles and cables. Please provide tabular HI data for each Asset Area and Operating Area as shown on Table 5.3.2 - 8 Asset Inventory (Distribution Assets).

b) Please provide the same data as in a), but as projected in 2031.

RESPONSE:

a) Alectra Utilities presents Table 1 - HI Results for Transformers, Poles, and UG Cables for the granular health index category results per operating area for transformers, poles, and cables.

Table 1 - HI Results for Transformers, Poles, and UG Cables

Asset Category	HI Category	Operating Area				
		Central	East	West	Southwest	Total
Transformers (Pad, Pole, Vault)	Very Poor	2,455	3,247	1,000	145	6,847
	Poor	917	769	890	31	2,607
	Fair	2,908	1,287	600	171	4,966
	Good	10,233	15,903	2,040	397	28,573

Asset Category	HI Category	Operating Area				
		Central	East	West	Southwest	Total
	Very Good	29,239	29,980	20,674	5,476	85,369
Poles (Wood, Concrete)	Very Poor	1,893	795	3,565	128	6,381
	Poor	1,002	455	2,401	38	3,896
	Fair	1,033	525	5,583	348	7,489
	Good	3,766	3,626	6,544	2,028	15,964
	Very Good	26,454	32,576	32,974	8,638	100,642
UG Primary Cables (KM) (XLPE, PILC, EPR)	Very Poor	1,507	961	704	118	3,290
	Poor	738	861	164	99	1,862
	Fair	262	255	59	18	594
	Good	211	201	59	19	490
	Very Good	7,544	6,700	2,282	931	17,458

b) For the asset classes discussed in this question, future projection of the deteriorated population for 2031 is available only for underground cables. The percentage of deteriorated cables is projected to increase from 5,153 km (22%) in 2023 to 7,027 km (30%) in 2031, after considering the implementation of proposed cable renewals as outlined in this DSP. Cable deterioration rate projections for 2024 to 2031 were developed utilizing the most recent ACA demographics as a baseline. Future years' health index demographics of cables are projected by adjusting the age and subsequent ACA results per year.

In Table 2 - Deteriorated Cable Population (2018, 2023, and 2031), Alectra Utilities provides the 2018, 2023, and forecasted 2031 percentage population of deteriorated cables.

Table 2 - Deteriorated Cable Population (2018, 2023, and 2031)

	2018 (Per 2018 ACA)	2023 (Per 2023 ACA)	2031 (Forecasted)
Percentage of Very Poor & Poor Population (%) Cable	15%	22%	30%

For all other asset classes, Alectra Utilities' ACA methodology does not forecast the distribution or quantities of assets by Health Index category into future years. The ACA results are reliant on inputs from the most recent asset attributes captured through inspections, testing, and maintenance activities, which evolve over time as new data is collected.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-70

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / 5.3.2 Overview of Asset Management / p. 222 (pdf Exhibit 2 Part 1 p. 228)

Question(s):

a) Does overhead (OH) Line Hardware in Fig 5.3.2 - 70 include wood poles and concrete poles?

   i. If not, please update the figure to show the relative contribution of each of these asset types to the defective equipment failure interruption hours 2020-2024.

RESPONSE:

a) Yes, the Overhead Line Hardware in Figure 5.3.2-70 includes wood and concrete poles, along with associated overhead components such as insulators, cross-arms, brackets, clamps, conductors, and guying as defined in Appendix B01 – Overhead Asset Renewal, Exhibit 2A, Tab 1, Schedule 1, Page 2 of 653, Lines 6-8.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-71

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / 5.3.2 Overview of Asset Management / pp. 225-226 (pdf Exhibit 2 Part 1 p. 231-232)

Question(s):

a) From Table 5.3.2 - 11 - Typical Asset Failure Modes and Impacts (Station Assets), which of these failure modes can be fully or partly mitigated by repair or refurbishment, and which can only be mitigated by replacing the asset? Please elaborate on the following assets:
   i. Station Power Transformers
   ii. Station Circuit Breakers
   iii. Station Switchgear

RESPONSE:

a) For the purposes of this response, the term “repair” is used to also encompass refurbishment. The required mitigation (repair or replace) for the typical failure modes described below depends on several factors:

1. Firstly, whether the defect was addressed before or after a failure is triggered is an important consideration. Once a failure occurs, the required mitigation will depend on the nature and the extent of damage sustained by the asset. A catastrophic failure of the asset may also result in damage or failure to another asset that it is physically connected to (for example, a bushing on a power transformer).

2. Whether or not spare parts are available also impacts the decision to repair or replace. Equipment sometimes becomes obsolete, meaning that it is no longer manufactured, and replacement components may not be available.

3. The construction type of the asset can also impact the repair/replace decision. For example, with air-insulated switchgear, worn or failed components, such as switchblades or arc chutes, can be easily accessed and repaired. However, with gas-insulated equipment, components may be sealed and therefore inaccessible. Repairs in these cases may not be possible; when they are possible, they are generally more difficult, time-consuming, and costly.

4. In cases where both options (repair or replace) are possible, Alectra Utilities considers the cost-effectiveness of each option. Repair may be cheaper, but the repaired asset may not have the same useful life as a new asset. Consideration is also given to how much longer the Station – or components of the Station – are intended to remain in service.

The tables below summarize the various Failure Modes for Power Transformers, Circuit breakers, and Station Switchgear, and identifies whether mitigation would be achieved via repair or replacement.

i) Station Power Transformers

Table 1 - Power Transformer Failure Modes and Mitigation

Typical Failure Modes	Mitigation (Repair vs Replace)
Bushing failure due to moisture ingress, aging, improper construction, and lightning	If addressed prior to catastrophic failure, a defective bushing itself can be replaced. Once a catastrophic failure occurs, whether the transformer can be repaired or must be replaced depends on the damage sustained.
Defective gasket in oil-filled bushing	If addressed prior to catastrophic failure, a defective bushing gasket can be replaced. Once a catastrophic failure occurs, whether the transformer can be repaired or must be replaced depends on the damage sustained.

Typical Failure Modes	Mitigation (Repair vs Replace)
Oil leaks from failing transformer gaskets	If identified early enough, gaskets can be repaired. Oil plays a critical role in cooling power transformers, so if left unaddressed, failure of the transformer could occur and would need to be replaced.
Paper insulation failure	Once the paper insulation has failed, the transformer will experience a catastrophic internal failure and must be replaced.
Defective breather (all possible causes)	If detected early enough, breathers can be repaired or replaced. Breathers play a critical role in preventing moisture from contaminating the insulating oil of a power transformer, so if the problem is left unaddressed then a catastrophic failure of the transformer may occur, and replacement would be required.
Control circuit or motor failure of onload tap changer	Tap changer control circuitry and motors can be repaired or replaced. If the situation is left unattended, equipment supplied by the power transformer may be damaged by overvoltage or undervoltage.
Overloading and/or failure of transformer cooling	If addressed prior to catastrophic failure, cooling systems – radiators, pumps, etc. - can be repaired. If unaddressed, then failure of the power transformer could occur due to overheating. Whether the transformer could be repaired or must be replaced would depend on the damage sustained.

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ii) Circuit Breakers

Table 2 - Circuit Breaker Failure Modes and Mitigation

Typical Failure Modes	Mitigation (Repair vs Replace)
Breaker fails to open to clear fault (all causes)	The decision to repair or replace would depend upon the extent of damage incurred. The type of breaker and accessibility of components would also influence the decision to repair or replace.
Worn latching mechanism, broken lifting rod, or failed linkage	The decision to repair or replace would depend upon the type of breaker and whether these components can be accessed
Bushing failure	Bushings need to be replaced after failure. If there is also damage to the circuit breaker, then the extent of damage would determine whether the breaker can be repaired or should be replaced.
Loss of insulating medium	If detected and addressed early enough, then repairs can be made. However, if enough of the insulating medium is lost, then the operational integrity of the breaker could be compromised and a failure could occur. Replacement of the breaker would be necessary.
Interrupting medium/ component failure	The decision to repair or replace would depend on how much damage was caused by the failure. Other factors, such as accessibility of components, would also have to be considered.

iii) **Station Switchgear**

Table 3 - Station Switchgear Failure Modes and Mitigation

Typical Failure Modes	Mitigation (Repair vs Replace)
Loose control cable connection	Loose or failed control circuitry can be repaired or replaced.
Broken/cracked interphase barrier or insulators, dirt or debris on insulators	If detected and addressed before failure occurs, these components can be repaired. However, if a failure occurs then the decision to replace or repair part or all of the switchgear would depend on the extent of the damage.
Total cable failure (all possible causes)	Failed cables and accessories such as terminations would have to be replaced.
Dirt or debris on busbar conductors.	If detected and addressed early enough, this condition can be repaired or rectified. However, if a failure were to occur inside the switchgear as a result of the dirt/debris, then the decision to repair or replace all or part of the switchgear would depend on the extent of damage sustained.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-72

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / 5.3.3 Asset Lifecycle Optimization Policies and Practices p. 322 (pdf Exhibit 2A Part 1 p. 328)

Preamble:

Alectra Utilities appears to determine pacing options on the basis of capital budget constraints rather than reliability targets because the base case was originally derived primarily based upon a capital budget constraint.

Question(s):

a) Please discuss what improvements Alectra Utilities would need to make to its Pacing analysis such that Alectra Utilities could target desired system reliability levels rather than asset replacement budget envelopes as described herein by the three pacing options.

RESPONSE:

a) Alectra Utilities set pacing levels in consideration of customer benefit levels (which include reliability), and not budget envelopes. As discussed in Exhibit 2A, Tab 1, Schedule 1, 5.3.3 Asset Lifecyle Optimization Policies and Practices, Page 321, Lines 25 to 28, the volume of assets suggested for replacement is based on economic value which includes reliability benefit to customers.

Additionally, as found in Exhibit 2A, Tab 1, Schedule 1, 5.3.3 Asset Lifecyle Optimization Policies and Practices, Page 322, Lines 2 to 5, the specific pacing strategies were assessed based on risk, customer benefit, and the ability to design and resource the work for execution.

Furthermore, a detailed example is given for poles in Exhibit 2A, Tab 1, Schedule 1, 5.3.3 Asset Lifecyle Optimization Policies and Practices, Page 323, Lines 9 to 15.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-73

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / 5.4.1 Capital Expenditure Summary p. 345 (pdf Exhibit 2A Part 1 p. 351)

Preamble:

OEB Staff notes that grid modernization and automation reduces the consequence of asset failures (e.g., pole failure), therefore it reduces the risk of asset failure for a given asset. As a result, grid modernization and automation investment cost should be partly offset by extending the useful life of assets (e.g., allowing them to advance further down the probability of failure curve before replacement).

Question(s):

a) If grid modernization and automation investments have improved grid reliability and resilience, please discuss the impacts these investments have had on TUL and Estimated Useful Life (EUL) due to reduced risk posed by other asset failures.

b) Please describe how asset failure risk reductions resulting from grid modernization and automation have been translated into Copperleaf based optimization and cost savings for ratepayers.

RESPONSE:

a) Grid modernization and automation investments do not reduce the risk of asset failure, nor affect the underlying physical condition, deterioration mechanisms or move assets along the probability of failure curve.

These investments improve system reliability by reducing outage duration and customer impacts through faster fault detection, isolation, and service restoration. Accordingly, grid modernization and automation investments do not result in changes to the Typical Useful Life (TUL) or End of Useful Life (EUL), nor do they defer or replace the need for condition-based asset renewal because the customers still experience the outage.

b) As provided to response to part (a), grid modernization and automation does not reduce failure risk. Alectra Utilities does capture asset failure reductions under the Reliability benefit in Alectra Utilities Value Framework. The cost savings for ratepayers are calculated using the Value of Lost Load (VOLL). These cost savings are then converted into Reliability value and included in the investments' values.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-74

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / 5.4.1 Capital Expenditure Summary / p.366 (pdf Exhibit 2 Part 1 p. 372)

Preamble:

Regarding the Underground Inspections and Maintenance section, Alectra Utilities states "This program is critical for supporting service reliability in high-density areas where underground assets are prevalent."

Question(s):

a) Will the annual underground inspection and maintenance costs begin to decrease after the residual portfolio of poor condition U/G cables and equipment is reduced over the test period? If not, please explain why not.

RESPONSE:

a) Alectra Utilities expects that annual underground inspection and maintenance costs will be maintained at the pace stated in Exhibit 2A, Tab 1, Schedule 1, Section 5.4.1, page 366 of 406, line 21. Alectra Utilities is mandated, under the ESA minimum inspection requirements for electricity distributors in Ontario, governed by Ontario Reg. 22/04, to maintain all electric distribution equipment in safe operating condition. As Alectra Utilities is required to perform inspections on a 3-year cycle, the utility inspects about 1/3 of its distribution system every year.

   In addition to inspections, Alectra Utilities performs dry ice cleaning to maintain the air-insulated switchgear. This maintenance procedure will continue due to the significant population of air-insulated switchgear remaining in the underground distribution system.

Also included in the underground maintenance costs are the repair of failed secondary cables, which is consistently substantial every year. Alectra Utilities has not made capital investments on the replacement of UG secondary cables.

The remediation of UG primary XLPE cables does not have an impact on the underground inspection and maintenance costs as Alectra Utilities does not currently perform maintenance and testing on cables.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-75

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B01 - Overhead Asset Removal
Ref 2: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B02 - Underground Asset Removal
Ref 3: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B03 - Transformer Renewal
Ref 4: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B13 - Enabling Resiliency & Modernization / IV Grid Modernization

Preamble:

Alectra Utilities outlines transformer asset condition assessment in reference 1 for pad mounted, pole mounted, and vault and submersible type transformers. Alectra Utilities also has identified programs for underground asset renewal, overhead asset renewal and rear lot conversion projects (references 2 to 4). For programs such as overhead powerline rebuilds, voltage conversion, and rear lot conversions, it is typical that any transformers are replaced as part of the project.

Question(s):

a) If transformers are replaced through a program other than transformer renewal, where are the costs for the transformer replacement captured?

b) How does Alectra Utilities coordinate the transformer renewal program with other capital programs to identify the total number of transformers replaced, and the asset condition assessment of transformers planned to be replaced as part of these other programs?

   i. How would this impact the number of transformers replaced per the pacing options for transformer replacement.

RESPONSE:

a) Where a transformer replacement is required as part of another program or project, Alectra Utilities captures the cost of transformer replacement(s) in those other programs and projects (i.e., Overhead Rebuild, Voltage Conversion, Cable Renewal, etc.).

b) For planned work, coordination occurs at three points in time: during development of the scope, during detailed design, and at construction just prior to work execution.

At the development of the scope, the program owner reviews whether the location of the transformer overlaps other associated work. In situations where a transformer overlaps investments, the owners of those investments will convene to determine which project or program scope will contain the transformer replacement. (This may also necessitate additional discussion related to a change in the transformer's location or size, and other changes to the scope of one investment.)

During the detailed design phase, a similar check is completed to ensure that no transformers were missed by the project owners during their review, or if any emerging scope changes have impacted any overlap of transformers. Additionally, the design technicians will check to see if any transformers were replaced reactively during the time between phases. If an overlap is detected, this information is relayed to the project owner.

During the construction phase, before execution, the transformer is checked to ensure that it was not replaced reactively. If it has been replaced reactively, then the transformer is not replaced a second time, as the work is not necessary.

If, during any of the aforementioned coordination points, a transformer that was listed for replacement under the Transformer Renewal program is replaced via another program, then the Transformer Renewal program owner may select another transformer for replacement. In practice, an insignificant number of transformers overlap investments (i.e., programs or projects). Furthermore, Alectra Utilities has 9,454 deteriorated

transformers[1] that require renewal. There is minimal risk that additional transformers that may be replaced due to scope overlaps would materially influence the 4,771 planned[2] transformers over the 2027-2031 period.

[1] Exhibit 2A, Tab 1, Schedule 1, Appendix B03 – Transformer Renewal, Page 127, Line 8
[2] Exhibit 2A, Tab 1, Schedule 1, Appendix B03 – Transformer Renewal, Page 137, Line 8

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-76

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B01 - Overhead Renewal / pp. 2 - 3 (pdf Exhibit 2A Part 2 pp. 10-11)

Question(s):

a) Where are the costs for the decommissioning of the eight stations captured? Please provide the amount per year for station decommissioning.
b) What does Alectra Utilities plan to do with the land currently used for the eight stations after the decommissioning occurs?

RESPONSE:

a) Decommissioning refers to electrically disconnecting these stations from the distribution system and making the stations site safe. The costs associated with these activities are embedded within overall project costs and are not tracked separately.

b) Alectra Utilities has not made a final determination regarding the future use of the eight station properties following decommissioning.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-77

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B01 - Overhead Asset Renewal / p. 2 (pdf Exhibit 2A Part 2 p. 10)

Preamble:

Overhead Line Hardware failures, which includes failure of poles, insulators, clamps, brackets, leads, cross-arms, and guying, were the second largest contributor to Customer Hours of Interruption (CHI). During the 2020 to 2024 period, Overhead Line Hardware caused, on average, 199 outages and 81,228 CHI per year.

Question(s):

a) Please provide the contribution to 2020 - 2024 CHI attributable to failures of each of the listed Overhead Line Hardware components individually: poles, insulators, clamps, brackets, leads, cross-arms and guying.

b) Please confirm that deteriorated insulators, clamps, brackets, leads, cross-arms or guying can be refurbished or replaced at a fraction of the cost of a complete pole replacement. If not confirmed, please explain why not.

c) If the contribution of the individual components to CHI is unknown, please explain how Alectra Utilities designed its renewal program to cost-effectively address the components most responsible for Overhead Line Hardware failures.

RESPONSE:

a) Alectra Utilities' data recording and outage management systems do not track failures in a manner that enables the requested breakdown to be produced. All incidents involving

poles, insulators, clamps, brackets, leads, cross-arms, or guying are captured under the unified "O/H Line Hardware" asset category.

b) The Overhead Asset Renewal Program, together with the Reactive Capital and OM&A programs, prioritizes component-level replacement or repair where individual overhead line hardware elements (e.g., insulators, cross-arms, brackets, fittings) can be addressed independently and doing so effectively mitigates safety and reliability risk. Where inspections identify broader deterioration, incompatibility, or structural limitations such that isolated component replacement would not provide a durable or cost-effective outcome, replacement is addressed at the structure level. This graduated approach ensures that assets are managed at the lowest effective intervention level, consistent with prudent portfolio management and lifecycle cost efficiency.

c) While customer hours of interruption attributed to Overhead Line Hardware reflect realized outage outcomes rather than individual component failures, Alectra’s renewal program is designed to proactively address the components most likely to contribute to future reliability risks. Renewal prioritization is informed by systematic inspection results, detailed condition assessments, and exposure analysis, which identify deteriorated or high-risk components requiring intervention. This forward-looking, risk-based, and condition-informed approach enables Alectra to target investments at the lowest effective intervention level and to address the underlying drivers of failure, rather than relying solely on post-event component attribution.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-78

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B01 - Overhead Asset Renewal / p. 2 (pdf Exhibit 2A Part 2 p. 10)

Preamble:

Table B01 - 1 Overhead Asset Renewal Investment Mix Over the 2025-2031 Period shows that spending on overhead asset replacement during the forecast period totals $396.3M.

Question(s):

a) Please quantify the cumulative risk that will be avoided by completing all planned Overhead Asset Renewal spending over the test period.

RESPONSE:

a) By completing all planned Overhead Asset Renewal Spending over the test period, Alectra Utilities is able to reduce the number of deteriorated assets, harden the system to climate events, and increase the resiliency of the system to manage customer needs and asset failures. This investment will generate a Net Present Value (NPV) of $466MM Benefit and $836MM of risk mitigation (as per Alectra Utilities Value Framework), driven by reliability and financial risk.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-79

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B01 - Overhead Asset Renewal / p. 3 (pdf Exhibit 2A Part 2 p. 11)

Preamble:

Under the Pole Renewal segment, Alectra Utilities plans to replace 5,256 poles over the 2027-2031 period. This target will only help address about half of the deteriorated poles and will result in a sizable reduction to the deteriorated population remaining on the system. For a detailed segment overview, refer to Section II Pole Renewal.

Question(s):

a) How many wood poles does Alectra Utilities plan to replace during the test period under all Renewal programs and projects? For clarity, all programs and projects under which poles will be replaced (e.g., relocations, voltage conversion), not just the Pole Renewal program.
b) How many wood poles does Alectra Utilities plan to replace during the test period under all System Access and System Service programs and projects?
c) What is the total number of wood poles that Alectra Utilities plans to replace under all capital programs and projects during the test period? Please provide a table listing all programs and projects under which poles would be replaced and the pole count to be replaced in each.
d) How many circuit kilometers of overhead line does Alectra Utilities plan to rebuild during the test period under all Access, Renewal and Service projects and programs?

RESPONSE:

a) b) and c) Alectra Utilities operates a distribution system with wood, concrete and composite poles. Alectra Utilities' plans and projections for pole replacements and installations over the 2027 to 2031 period include all pole types. As such, this response includes all types of poles.

Alectra Utilities is unable to estimate the number of poles to be replaced in System Access, as such investments are customer-driven in nature. The specifics related to the location and impacted infrastructure necessary to estimate if poles are required to be replaced are unknown at this time.

The assumed System Renewal and System Service pole replacements are provided in Table 1 below.

Table 1 - Estimated Pole Replacement by Investment for 2027 - 2031 Period

Investment Category	Capital Program/Projects	Primary Investment Driver	Estimated Pole Replacement
System Renewal	Pole Renewal	Failure Risk - Condition	5,256
	Voltage Conversion	Deteriorated Stations	3,650
	Overhead Rebuilds	Failure Risk - Condition	60
	Rear Lot Conversion	Failure Risk – Safety & Climate Vulnerability	370
	# 6 Cu Replacements	Failure Risk – Conductor	80
System Service	System Service	Capacity, Reliability	922
	Total		**10,338**

d) The Distribution System Plan estimates 2,235 km of overhead conductor may be replaced over the 2027 – 2031 period as part of System Renewal, System Access, and System Service.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-80

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B01 - Overhead Asset Renewal / pp. 8, 17 (pdf Exhibit 2A Part 2 pp. 16, 25)

Preamble:

Regarding the Volume of Deteriorated Poles on Alectra Utilities' Distribution System section, Alectra Utilities presents Figure B01 - 7 Trending Analysis of Deteriorated Distribution Assets.

Question(s):

a) Please confirm or correct the following summary.

> Over the six-year period from 2018 to 2023, Alectra Utilities' historical pace of pole replacement led to a 4% increase in the count of poles assessed as being in Poor or Very Poor condition, i.e. 438 poles. Alectra Utilities is proposing to increase its pace of pole replacements from 3,259 poles (over the period 2021-24) to 5,256 poles (over the period 2027-31). Prorating the planned 2027-31 pole replacement count over a four year period to align with the four year 2021-24 period, this means the new rate of replacement under the Pole Renewal project alone is 4,205 every four years, representing an increase of 946 poles per 4 year period, or more than twice the rate at which poles became "Fully Deteriorated" over the 6 year period from 2018 to 2023.

b) Based on any update to the summary in part a, please explain why such a significant increase in pole replacements relative to the rate of pole deterioration is reasonable.

RESPONSE:

a) and b) Alectra Utilities confirms that while the numerical elements of the summary in part (a) are directionally correct, the comparison does not fully reflect the context or rationale for the proposed increase in pole replacements. The planned increase is not intended to match the incremental rate at which poles became deteriorated over the 2018–2023 period, but rather to address a large and growing backlog of deteriorated poles, mitigate escalating public safety and reliability risks, and reduce exposure to storm-related and climate-driven failures.

As of 2023, Alectra Utilities' system includes more than 10,000 deteriorated poles. Poles are not run-to-failure assets due to their critical role in public safety and system reliability. A growing backlog materially increases the likelihood of cascading failures, where the failure of one deteriorated pole precipitates additional failures, property damage, and extended outages.

Alectra Utilities has experienced multiple catastrophic events in recent years, many of which were not related to high wind events. In two of the events, nine poles fell to the ground. In both cases, the failures started with deteriorated assets failing first, causing broad damage, resulting in the need to reactively replace a number of poles that would otherwise not need replacement. Additionally, in both cases the poles damaged third party property and caused lengthy power outages. These incidents demonstrate that deterioration risk is not linear and cannot be managed by simply replacing poles at the same rate at which they newly enter a deteriorated condition.

In addition, a significant subset of deteriorated poles is also climate-vulnerable or structurally overloaded, further increasing failure risk during adverse weather events. These risk factors compound over time and necessitate a renewal pace that exceeds historical deterioration rates in order to stabilize and ultimately reduce system risk.

The proposed increase in pole replacements for the 2027–2031 period was informed by Alectra Utilities' asset management framework, including Copperleaf-supported predictive analytics that prioritize investments based on risk reduction and customer

value, as well as customer engagement feedback indicating a preference to accelerate overhead asset renewal.

Accordingly, while the numerical comparison in part (a) is accurate, it does not capture the risk-based, backlog-reduction, and safety-driven rationale underpinning the proposed increase in pole replacements, which Alectra Utilities considers necessary and reasonable.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-81

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B01 - Overhead Asset Renewal / p. 19 (pdf Exhibit 2A Part 2 p. 27)

Preamble:

Alectra Utilities describes changes to CSA 22.3 standard as follows:

> In 2023, CSA introduced new requirements for pole loading calculations based on updated factors around wind pressure and specific weather conditions for the area where the pole is installed. These changes came into effect as part of the revised CSA C22.3 No.1-15 Overhead Systems under the Canadian Electrical Code. The new requirements are intended to be a more accurate reflection of how poles will perform in real-world situations with increasing severity of weather events.

Question(s):

a) Will adopting the revised CSA 22.3 No. 1 -15 standard increase the average cost of pole replacements?

b) If yes, please quantify the increase in the average cost of pole replacements as attributable to adopting the revised standards, either in dollars or as a percentage of pre-adoption average replacement costs?

RESPONSE:

a) Alectra Utilities is required to adopt the latest CSA 22.3 No. 1, most recently with the 2025 release, in order to remain compliant with the Electrical Safety Authority Ontario Regulation 22/04 audit.

Under this standard, in cases where pole strength needs to be increased to meet the new requirements, a higher strength class pole will be used. Higher strength pole classes are capable of surviving wind storms of greater wind speeds, providing better storm resilience. Generally speaking, higher strength class poles do cost more than lower-class poles, however; they also remain in service longer. In addition, because higher strength class poles typically weigh more than lower-class poles, additional costs may be required to support the installation (i.e. cranes).

b) Alectra Utilities has provided the incremental price increase, as a percentage, for poles of several classes and common heights in Table 1. The poles listed as ‘class 2’ or ‘class J’ were legacy poles Alectra Utilities no longer carries after revision to the CSA standard. The percentage increase is relative to the previous class, i.e. a 55’ class 1 pole is 7% more expensive than class 2, the H1 is 21% more expensive than the class 2. As mentioned above, the requirement for a crane varies by pole weight.

Table 1 - Typical Wood Pole Costs by Type and Class

Height	Legacy Pole Type and Class	Required Pole Type and Class per CSA 22.3 No. 1	Incremental Price Increase %
55'	Wood Class 2 Pole	Wood Class 1 Pole	7%
		Wood Class H1 Pole	21%
60'	Wood Class 2 Pole	Wood Class 1 Pole	15%
		Wood Class H1 Pole	37%
	Concrete Class J	Concrete Class K	10%
		Concrete Class L	19%

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-82

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B01 - Overhead Asset Renewal / p. 21 (pdf Exhibit 2A Part 2 p. 29)

Preamble:

Alectra Utilities states the following regarding impact to changes to CSA C22.3 as follows.

> To comply with updated CSA standards and improve storm resilience, Alectra Utilities may need to replace poles when undertaking other asset renewals, such as switch replacements. The structural capacity of poles may be insufficient to support new equipment under the revised CSA C22.3 No.1-15 non-linear loading requirements. Alectra Utilities will need to replace or reinforce these structures to ensure reliability and compliance with the standard.

Question(s):

a) Has Alectra Utilities evaluated pole reinforcement alternatives such as pole stubbing (to address ground line rot) or carbon-fibre or fibreglass pole wraps (to address above-ground reinforcement requirements driven by pole deterioration, damage or increased load bearing standards)?
   i. If yes, please discuss the evaluation results.
   ii. If no, please explain why not.

RESPONSE:

a) i) Alectra Utilities uses pole reinforcement as an alternative to replacement where it is feasible. This is discussed in Exhibit 2A, Tab 1, Schedule 1, B01 - Overhead Asset Renewal, Page 19 to 20, Line 22 (Page 19) to Line 4 (page 20).

Certain pole reinforcement products can increase the local structural strength of an existing pole and may be effective in addressing specific deterioration mechanisms, such as above-ground decay. However, these products' application is constrained by site conditions, foundation requirements, and constructability limitations, which limit the use to a narrow set of scenarios. For example, if to maintain clearances the pole needs to be five to ten feet taller, no reinforcement product can accomplish this. Accordingly, while pole reinforcement products are used selectively where appropriate, pole replacement remains necessary where compliance with updated standards and long-term reliability and climate resilience objectives cannot be achieved through reinforcement alone.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-83

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B01 - Overhead Asset Renewal / p. 30 (pdf Exhibit 2A Part 2 p. 38)

Question(s):

a) How many Very Good, Good and Fair condition poles is Alectra Utilities planning to replace under this program?

b) Please describe alternative approaches Alectra Utilities has evaluated to mitigate the undersized conductor risk without replacing Very Good, Good and Fair condition poles (thereby losing the remaining service life asset value).

RESPONSE:

a) The reference provided is referring to Alectra Utilities' evaluation to identify poles that are high-risk due to climate trends as part of Alectra Utilities Pole Renewal Program. Alectra Utilities has not included the planned replacement of any Very Good, Good, and Fair condition poles in this program.

b) During the detailed design of projects in the Overhead Rebuild investments a condition assessment of all assets and where possible, existing assets will remain in service where feasible. Projects in this category often involve legacy assets that were not built to current standards. As a result, even poles rated in Very Good, Good, or Fair condition may not comply with current CSA standards and may remain susceptible to failure, requiring replacement.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-84

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B01 - Overhead Asset Renewal / p. 57 (pdf Exhibit 2A Part 2 p. 65)

Preamble:

Alectra Utilities considered three pacing options that address the deteriorating switches.

- Option 1: Renewal of deteriorated assets at the accelerated pace 68 units per year
- Option 2: Renewal of deteriorated assets at a moderate pace 51 units per year (Selected Option)
- Option 3: Renewal of deteriorated assets at a reduced pace 35 units per year

Question(s):

a) Considering that 80 switches have been identified as being in Poor or Very Poor condition, does the selected pace not eliminate all Poor or Very Poor condition switches in less than two years? Please elaborate.

b) Confirm that Option 3 pacing involves replacing all Fair, Poor and Very Poor condition switches before the end of 2030, after which all switches being replaced will be in either Good or Very Good condition? If not confirmed, please explain why not.

c) Given that the selected pace involves ongoing replacement of 51 units per year, does this mean that all Very Poor, Poor, Fair and Good condition switches (a total of 199) and 5 Very Good switches will have been replaced by the end of 2030, and 51 Very Good condition switches will be replaced in 2031?

   i. If yes, please explain why this is a prudent strategy.

   ii. If not, please explain why not.

d) Does the recommended pacing, which involves starting to replace Very Good condition switches in the test period, indicate that Alectra Utilities needs to better calibrate its Asset Condition Assessment implementation? Please explain.

e) If the recommended pacing is intended to upgrade Good and Very Good condition manual switches with automated switches, please explain why a significant portion of this program should not be reclassified as System Service rather than System Renewal investment.

RESPONSE:

a) b) c) While condition is a key driver for renewal, there are multiple other considerations Alectra Utilities considers when making replacement decisions. As stated in Exhibit 2, Tab 1, Schedule 1, Appendix B01- Overhead Renewal, Page 53, Lines 10-12, functional obsolescence or inoperability are other reasons. For example, Alectra Utilities has identified at least 24 devices where the switch remains in good condition, however the automation controls do not function reliably. Alectra Utilities staff have investigated and determined that due to the equipment's age and obsolescence, replacement parts are not available to maintain safe and reliable operation of the asset. As mentioned in Exhibit 2, Tab 1, Schedule 1, Appendix B14 – Enabling Resiliency and Modernization, Page 573, Lines 23-24, automation has led to 14 to 16 minutes in SAIDI savings for customers. Therefore, Alectra Utilities requires ensuring these assets maintain safe and dependable operation to maintain system reliability. Alectra Utilities crews and operators require these switches to operate dependably when critical switching operations are needed to restore power from an outage or transfer loads during critical operating situations. Additionally, Alectra Utilities identified 34 vintage-design switches that pose risks to the safe and efficient maintenance and operation of the unit. Lastly, as provided in Exhibit 2, Tab 1, Schedule 1, Appendix B01- Overhead Renewal, Page 58, Table B01-21, the number of defects provided, Alectra Utilities has updated this table for 2024 and 2025 respectively, in Table 2. As is evident, this number has increased significantly and is over 11 times larger than in 2020.

Table 2 - Overhead Switch Deficiencies (2020-2025)

Year	Overhead Switch Operational Deficiencies		
	Major and Moderate	Minor	Total
2020	2	5	7
2021	8	10	18
2022	24	34	58
2023	43	49	92
2024	62	47	109
2025	55	28	83

When examining switches across the entire asset population, Alectra Utilities currently operates 3,192 switches. Considering the application of switch EUL of 55 years, the population of assets suggest a replacement rate of 58 switches per year. Alectra Utilities wishes to point out that this methodology yields a higher replacement rate than the 51 proposed under the moderate pace. Furthermore, Alectra Utilities has determined that the criticality and importance of switches to the safe and reliable operation of the distribution system as provided in Exhibit 2, Tab 1, Schedule 1, Appendix B01- Overhead Renewal, Page 53, Lines 1-3.

The value framework used to determine the pace of switch renewal is based on a value of lost load framework, ultimately indicating that increased renewal does provide customers with benefits (i.e. reliability). Therefore, while the condition of the switch itself may be fair or better, for the reasons provided above, interoperability functional obsolescence, safe and efficient operation and maintenance of switches and customer reliability benefits, Alectra Utilities deems the investment pacing prudent.

d) As provided in response to parts a) b) and c) above, Alectra Utilities applied multiple factors in the decision-making process to select switch renewal candidates. As the condition of the switch is one of several factors that Alectra Utilities considered, the application of the Health Index methodology, as completed in the 2023 ACA, remains appropriate.

e) As provided in response to parts a) b) and c) above, Alectra Utilities considers multiple replacement drivers for switches, including health deterioration (ACA), functional obsolescence or inoperability. When renewing assets, Alectra Utilities appropriately considers reliability improvements. Alectra Utilities considers the implementation of automated switches driven primarily by reliability and grid flexibility enhancements under the Distribution Automation program. For more details, please see Exhibit 2, Tab 1, Schedule 1, Appendix B14 – Enabling Resiliency and Modernization, Part II SCADA Automation and System Control.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-85

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B01 - Overhead Asset Renewal / p. 60-61 (pdf Exhibit 2A Part 2 pp. 68-69)

Question(s):

a) Regarding the Investment Projects section, Alectra Utilities presents Table B01 - 22 Material Projects and Initiatives. Please quantify the risk that will be mitigated by each of the proposed investments shown in Table B01-22.

RESPONSE:

Alectra Utilities provides Table 1: Material Project Benefits and Risks.

Table 1: Material Project Benefits and Risks

Project Code	Project Name	Benefit ($MM)	Mitigated Risk ($MM)	Total Value ($MM)
Multiple	Pole Renewal	-	481.3	481.3
Multiple	Switch Renewal	-	72.1	72.1
150354	Voltage Conversion - Eastmount MS, Hamilton	76.2	1.2	77.4
150355	Voltage Conversion - Elmwood MS, Hamilton	73.9	2.5	76.4
Multiple	Overhead Asset Renewal-Alectra Initiated Distribution System Projects	44.4	37.4	81.8
152837	Voltage Conversion - (AREA11) - Bromsgrove/Park Royal/Parkwest MS at Truscott/Lewisham Dr, Mississauga	32.4	6	38.4
150317	Voltage Conversion - Deerhurst MS, Hamilton	32	7.3	39.3
150321	Voltage Conversion - Galbraith MS, Hamilton	21.9	7.3	29.2
Multiple	Installation of Tree wire conductor and Wildlife Mitigation products	37.8	1.5	39.3
101832	Joint Use Pole Removal - Alectra East	1.9	50.7	52.6
151952	Overhead Conductor #6 Replacement Feeders PA-F3, PA-F5, PA-F6	8.2	0.4	8.6
151947	Overhead Conductor #6 Replacement Feeder MK-11	7.1	0.5	7.6
152489	Climate Adaptation - Rymal Road, Hamilton - 3612X and 3621X Overhead line undergrounding	11.3	1.3	12.6
150356	Voltage Conversion - (AREA11) - Bromsgrove/Park Royal/Parkwest MS at Constable Rd and Seagull Dr, Mississauga	4.7	3.3	8.0
151161	Joint Use Pole Removal - Alectra West	1.9	0.1	2.0
151470	Joint Use Pole Removal - Central South	1.9	50.7	52.6
151942	Overhead Conductor #6 Replacement Feeder MK-1	4.7	0.5	5.2
150377	Voltage Conversion and Rear Lot - Montgomery Dr, Hamilton	4.7	0.8	5.5
152783	New Build - Lake/Winona CN Rail Overhead Relocate, Hamilton	9.4	0.8	10.2
151936	Overhead conductor #6 Replacement Feeder MK-2	4.7	0.5	5.2

Project Code	Project Name	Benefit ($MM)	Mitigated Risk ($MM)	Total Value ($MM)
151956	Overhead Conductor #6 Replacement Feeder WL-11	5.5	-	5.5
151946	Overhead Conductor #6 Replacement Feeder MK-9	4.7	-	4.7
152985	Hamilton O/H Conductor upgrade - Stirton M86	4.6	1.2	5.8
152982	Hamilton O/H Conductor upgrade - Birmingham M8	3.3	1.3	4.6
151944	Overhead Conductor #6 Replacement Feeder MK-3	3.8	0.5	4.3
150320	Voltage Conversion - Dewitt MS, Hamilton	4.7	0.3	5.0
151139	Voltage Conversion - MS-12 Hansen Rd, Brampton	4.4	2.6	7.0
151539	Joint Use Pole Removal - Alectra Central North	1.9	50.7	52.6
152981	Hamilton O/H Conductor upgrade - Birmingham M7	2.2	1.3	3.5
152241	Overhead #6 Replacement Feeder OT-5	3.8	-	3.8
151951	Overhead Conductor #6 Replacement Feeders OT-3, CP-2	5.2	-	5.2
151945	Overhead Conductor #6 Replacement Feeder MK-5	3.5	-	3.5
152993	Upgrade egress riser poles, hardware and lightning arresters - West	3.8	0.4	4.2
152950	Hamilton O/H Conductor Upgrade - Newton M5 (251X)	2.3	1.1	3.4
152958	Hamilton O/H Conductor upgrade - Mohawk M81 (0812X)	1.8	0.9	2.7
151955	Overhead Conductor #6 Replacement Feeder WT-1	3.8	-	3.8

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-86

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B02 - Underground Asset Renewal / p. 70 (pdf Exhibit 2A Part 2 p. 78)

Question(s):

a) Regarding the Figure B02 - 5 XLPE Cable by Condition and Age, please explain the relatively small proportion of cables in Good and Fair condition vs cables in Very Good, Poor and Very Poor condition.

b) Please discuss how cable injection changes the Health Index of Cable condition by age.

RESPONSE:

a) Alectra Utilities utilizes the cable degradation curves to determine the Health Index. Please refer to Figure 24 in Appendix E – Asset Condition Assessment – 2023, Section 5.6.4.1, page 41. The small range of cable age that corresponds to Fair and Good scores, $50\% \leq HI < 85\%$, explains the relatively small proportion of cables in Good and Fair compared to Very Good, Poor and Very Poor scores.

b) As stated in Exhibit 2A, Tab 1, Schedule 1, Appendix B02 - Underground Asset Renewal, Section 2.1.2, page 71 of 653, Alectra Utilities expects cable rejuvenation to extend the service life of XLPE cables by up to 20 years. Therefore, once cable rejuvenation is completed, Alectra Utilities sets cable age to 20 years, and since this type of cable has an end-of-useful life (EUL) of 40 years, it effectively extends the life of the cable by 20 years. Consequently, the Health Index of the cable improves to Very Good category.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-87

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B02 - Underground Asset Renewal / p 72 (pdf Exhibit 2A Part 2 p. 80)

Question(s):

a) Does Figure B02-7 show the percentage of cables requiring mitigation in the specified years that are ineligible for injection, the percentage of Alectra Utilities' entire XLPE cable portfolio that is ineligible for injection, or something else? Please explain.

RESPONSE:

a) Exhibit 2A, Tab 1, Schedule 1, Appendix B02 - Underground Asset Renewal, page 72 of 653, Figure B02-7 shows the percentage of cables requiring remediation in the specified years that are ineligible for injection. The percentage is calculated by dividing the quantity of cables found ineligible from field inspection and testing by the total quantity of cable injection candidates for each year.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-88

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B02 - Underground Asset Renewal / p. 80 (pdf Exhibit 2A Part 2 p. 88)

Question(s):

a) Alectra Utilities has identified that a sustained and increasing investment is required to prevent this population of deteriorated cables from becoming too large as to hit a tipping point where reactive spending outpaces renewal spending. What is the present ratio of reactive to proactive renewal spending for U/G cables?

RESPONSE:

a) Alectra Utilities has experienced an increasing trend, from 2021 to 2025, in reactive spending due to cable failures. In 2025, the ratio of reactive to proactive cable replacement has reached approximately 1:3.

Reactive spending on cables involves repairing the damaged segment to restore the service to customers, while leaving the rest of the deteriorated cable in-service to be addressed at a later time. The remaining deteriorated segment is more prone to future repeat failures. Such failures impact reliability and are frustrating to customers. Reactive cable repairs are inefficient, time-consuming to locate and to repair.

Alectra Utilities has experienced that without proactive planned renewal of deteriorated cable, the cable is prone to cascading and repetitive failures, raising the need for Alectra Utilities to replace the cable under emergency conditions.

Emergency cable replacement involves open trenching to extract the direct-buried cable, which is very disruptive to the customers, property and driveways.

A recent example is Valleywood Drive in Markham, where customers experienced five cable faults in 2024. These repeated failures created significant frustration in the community, with Alectra Utilities' repeated attempts to repair the deteriorating cable. As a result, Alectra Utilities was required to perform the cable replacement in 2024 under emergency conditions (i.e., unplanned).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-89

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B02 - Underground Asset Renewal / p. 89 (pdf Exhibit 2A Part 2 p. 97)

Preamble:

The air insulated switchgear units were manufactured to specification for normal continuous rated operating voltage of 25kV and tested to operate as high as 28kV to ensure operation at 27.6kV distribution voltage.

Question(s):

a) Please explain how Alectra Utilities ended up with a large portfolio of underrated air-insulated switchgears.

RESPONSE:

a) Like many LDCs, Alectra Utilities' legacy utilities deployed air-insulated switchgear in the distribution system and have been installing them since the early 1970s. Alectra Utilities' oldest air-insulated switchgear was installed on April 10, 1974. The province of Ontario is unique in that it has 27.6 kV distribution system. There was nothing available in the market during the 1970's that meet this voltage rating, except for the 28 kV rated switchgear. Therefore, as the only option at the time, this is the product that was purchased.

   Alectra Utilities keeps 28 kV rated air-insulated switchgear in inventory to reactively replace failed units so that power to the customers is restored quickly. The alternative – switching to a non-air unit – would lead to outages over 12 hours in duration.

To manage the life of these assets, Alectra Utilities continues to perform dry-ice cleaning. This maintenance activity is a “band-aid” solution, as stresses on the equipment ultimately lead to failure.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-90

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B02 - Underground Asset Renewal / pp. 92-93 (pdf Exhibit 2A Part 2 pp. 100-101)

Preamble:

Alectra Utilities states it "has a significant population of oil-insulated switchgear in its underground distribution system. As the name suggests, these units are filled with mineral oil, which operates as the switchgear's insulating medium - a typical oil-filled switchgear unit contains over 1,500 litres of oil."

Question(s):

a) How many oil-insulated switchgears does Alectra Utilities have in its portfolio?

b) How many oil-filled switchgears have failed catastrophically over each year of the Historical and Bridge period?

RESPONSE:

a) Alectra Utilities has 465 oil-insulated switchgears installed in the distribution system.

b) Alectra Utilities had two units that flashed over and leaked oil, one in 2022 and the other in 2023. As stated in the evidence that this IR refers, there is significant risk to public safety and environment when one of these oil-insulated switchgear fails, such as potential oil ignition and fire, and soil contamination. Alectra Utilities still has a significant population of oil switchgears in the system and will experience more of these failures as these assets further deteriorate.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-91

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B02 - Underground Asset Renewal / pp. 92-94 (pdf Exhibit 2A Part 2 p. 100-102)

Preamble:

Leaking units with Polychlorinated Biphenyls (PCB) concentrations above 2 ppm will be prioritized over units that are leaking but have PCB concentrations of less than 2 ppm.

Question(s):

a) Please explain how PCB concentrations above 2 ppm, between 0 and 2 ppm, and 0 ppm change the risk assessment associated with oil leaks. Please provide specific examples of such risk calculations.

RESPONSE:

a) PCB Regulations under the Canadian Environmental Protection Act prohibit the release into the environment of more than one gram of PCB from equipment in use.
A typical oil-insulated padmounted switchgear contains over 1,500 liters of oil. An oil spill with volume of 556 liters and PCB concentration of 2 ppm will release one gram of PCB into the environment. It would take less volume of oil spilled, having higher PCB concentration, to release one gram of PCB into the environment. Therefore, Alectra Utilities prioritizes leaking units which contain higher PCB concentrations because of the higher risk they pose to the public and the environment. For units listed at 0 ppm, there would be no environmental reporting requirements should the oil leak, therefore no additional risk.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-92

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B02 - Underground Asset Renewal / p. 94 (pdf Exhibit 2A Part 2 p. 102)

Preamble:

While solid dielectric switchgears are relatively new, Alectra Utilities has identified issues with several manufacturers' first-generation versions of these switchgears.

Question(s):

a) How many units are affected by these first-generation solid dielectric switchgear issues?

b) What is the total cost to replace all affected first-generation solid dielectric switchgears?

RESPONSE:

a) Alectra Utilities has 224 units that are affected by the first-generation solid dielectric switchgear issues.

b) Based on a conservative assumption that all units will be manual (not automated), the total cost to replace all affected first-generation solid dielectric switchgear is $26.88MM.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-93

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B02 - Underground Asset Renewal / p. 95 (pdf Exhibit 2A Part 2 p. 103)

Preamble:

Alectra Utilities has noticed that since 2023 there has been an increase in units discovered to be leaking SF6 gas. In many cases, repairing the leak involves the unit needing to be replaced, triggering a capital expense.

Question(s):

a) What percentage of switchgear is continuing to be specified as SF6 switchgear in terms of count and dollars?

b) What steps has Alectra Utilities taken to ensure that this problem does not arise in future installations?

RESPONSE

a) Based on the 2023 Asset Condition Assessment (ACA), approximately 17% of the distribution switchgear asset base is classified as SF6 insulated, representing approximately 571 units by count. From a capital investment perspective, SF6 switchgear is expected to represent less than 10% of planned switchgear replacement.

b) To mitigate the risk of SF6 gas leaks in future installations, Alectra Utilities has implemented enhanced specification, monitoring, and vendor accountability measures. New SF6 switchgear installations are equipped with continuous gas monitoring and SCADA alarms to enable early detection of abnormal gas loss. In parallel, Alectra Utilities

has established service agreements with manufacturers requiring field diagnostics and leak testing upon suspected gas loss, with repairs performed where feasible and replacement limited to cases where remediation is not technically viable in the field. These measures ensure that future SF6 installations are actively monitored; defects are addressed early, and exposure to unplanned replacements is minimized.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-94

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B02 - Underground Asset Renewal / pp. 99 and 101 (pdf Exhibit 2A Part 2 pp. 107 and 109)

Question(s):

a) The planned pace of underground switchgear replacement ((3 x 55) plus (2 x 88) = 258 switchgear units) would enable Alectra Utilities to replace the entire portfolio of Very Poor condition units. Please confirm these calculations are correct and update as required.

b) Please confirm if that pace continues into the subsequent test period, all the Poor condition units will be replaced by the end of 2032.

c) Is the longer-term annual pace of switchgear replacement expected to be significantly reduced starting in 2033? Please explain.

RESPONSE:

a) To clarify, as per Exhibit 2A / Tab 1 / Schedule 1 / Appendix B02 / Section 3.1.2 / pp. 95 line 15 to pp. 96 lines 1 - 2, the pacing of switchgear replacement is actually (3x56) + (2x88) = 344 units over the 5-year DSP period.

While condition is a key driver for renewal, there are multiple other factors Alectra Utilities considers when making replacement decision. As stated in Exhibit 2, Tab 1, Schedule 1, Appendix B02 – Underground Asset Renewal, Page 92-95, planned switchgear replacements also include Oil-Insulated Switchgears to address safety and environmental risk, First-Generation Solid Dielectric Switchgear to avoid premature

failures and reliability impact and leaking SF6 Switchgears to mitigate safety risk and SF6 emissions. The quantity of Poor or Very Poor assets will change over the DSP period due to ongoing condition degradation and newly identified deficiencies and therefore Alectra Utilities cannot confirm that all Very Poor condition switchgear will be replaced by 2031.

b) As cited in Exhibit 2A / Tab 1 / Schedule 1 / Appendix B02 / Section 3.3.2 / pp. 99 line 9 / Figure B02-22, as of the 2023 ACA Alectra Utilities has identified 259 pad mounted switchgear in Very Poor condition and an additional 70 units in Poor condition. While the planned replacement pace is expected to address the Very Poor and Poor population during the DSP period, as indicated in part-a) the overall replacement program remains responsive to ongoing condition degradation and newly identified deficiencies and therefore Alectra Utilities cannot confirm that all Poor condition switchgear will be replaced by the end of 2032. As such, replacement prioritization beyond 2032 will continue to be informed by updated inspection results and condition assessment rather than a fixed endpoint. Alectra Utilities will utilize Predictive Analytics as described in Exhibit 2A / Tab 1 / Schedule 1 / Section 5.3.1 / Subsection A.2 / pp. 114 lines 4 -12 to help determine the appropriate pacing in subsequent DSPs.

c) As stated in 2-Staff-94-b, Alectra Utilities will utilize Predictive Analytics as described in Exhibit 2A / Tab 1 / Schedule 1 / Section 5.3.1 / Subsection A.2 / pp. 114 lines 4 -12 to help determine the appropriate pacing in subsequent DSPs.

As demonstrated in Figure 5.3.2-34 Annual Switchgear Replacement Quantities vs Deficiencies, the growth in identified deficiencies between 2021 and 2023 has increased by 52% and exceeded annual replacement quantities, indicating sustained deterioration across the asset population. In addition, increasing customer hours of interruption associated with switchgear failures, as shown in Figure 5.3.2-37 Customer Hours of Interruption from Switchgear Failures, 2014-2024 further supports the need for a continued, risk and condition informed replacement pace.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-95

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B02 - Underground Asset Renewal / p. 108 (pdf Exhibit 2A Part 2 p. 116)

Question(s):

a) What is driving the step increase in spending in 2030 and 2031 compared to historical average, as shown in Table B02 - 14?

b) Will the 2030 and 2031 spending pace continue in future years?

RESPONSE:

a) The ramp-up of investment has been paced and optimized accordingly to enable Alectra Utilities to perform detailed engineering and site-access planning required for complex structures planned for 2029 to 2031. This phased approach provides Alectra Utilities with sufficient time to engineer structures in difficult-to-access areas that require significant permitting and planning for specialized resource mobilization. By grouping these high-complexity projects, Alectra plans to execute them in a timely manner before failures affect safety and system reliability.

b) Alectra Utilities has not yet developed investment plans beyond 2031 and is unable to provide specifics related to the future level of investments required.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-96

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B02 - Underground Asset Renewal / pp. 112-115 (pdf Exhibit 2A Part 2 pp. 120-123)

Question(s):

a) Please quantify the risk that will be mitigated by each of the proposed investments shown in Table B02 - 18.

RESPONSE:

a) Please refer to the Table 1.

Table 1 - Benefit, Risk & Total Value of Investments in Table B02-18

Project Code	Project Name	Benefit ($MM)	Mitigated Risk ($MM)	Total Value ($MM)
Multiple	Switchgear Renewal	-	108	108
151556	Cable and Transformer Replacement - (HAM) - Hollybush - Parkside - Dundas - Spring Creek	124.2	0.2	124.4
Multiple	Cable Replacement Project – Uninjectable Cables	110.8	3.8	114.6
Multiple	Underground Asset Renewal-Alectra Initiated Distribution System Projects	75.8	39.8	115.6
Multiple	Vault Cover Renewal	-	37.5	37.5
152841	Cable Replacement Project - (M27) Hwy 7, Mc Cowan Rd ,16th Ave, Main St Unionville)	63.6	1.0	64.6
151339	Cable Replacement Project - (BA19) - Letitia - Anne - Edgehill - Ferndale, Barrie	54.1	0.2	54.3

Project Code	Project Name	Benefit ($MM)	Mitigated Risk ($MM)	Total Value ($MM)
151301	Cable and Transformer Replacement Project - (HAM) - Rymal - Mud - Upper Centennial - Upper Red Hill Valley	56.3	0.1	56.4
152781	Cable Replacement Project - (A05) - Wellington St W, Bathurst St, Henderson Dr, Yonge St	30.1	1.1	31.2
152665	Cable Replacement Projects - (M15) Fincham Avenue of Markham	54.1	0.2	54.3
152383	Cable Injection - (AREA 39) - Erin Mills Pkwy & Thomas St, Mississauga	36.1	0.9	37
151325	Cable Replacement Project - (M31) - 14th - Old Kennedy - Steeles - Warden, Markham	30.7	1.3	32
151081	Cable and Transformer Replacement Project - (SCH) Courtleigh Rd	26.0	0.8	26.8
152774	Cable Replacement Project - (V15) - Centre St, Keele St, Steeles Ave W, Dufferin St (Vaughan)	22.0	1.1	23.1
151559	Cable and Transformer Replacement - (HAM) - Upper Wentworth - Lincoln M. Alexander - Upper Ottawa - Stonechurch	32.3	0.1	32.4
151879	Cable and Transformer Replacement - (HAM) - Upper Sherman - Stone Church - Nebo - Rymal	26.6	0.1	26.7
151882	Cable Replacement Project - (G3) - Main - Bovaird - Kennedy - Queen, Brampton	39.9	1.4	41.3
152801	Cable Replacement Project - (V36) - Vaughan (Steeles Ave W, Weston Rd, Hwy 7, Pine Valley Dr)	33.4	1.2	34.6
152454	Cable and duct replacement - Golf Club Dr, Hamilton	21.9	0.7	22.6
151285	Cable Replacement Project - (G2) - Sandalwood Pky E and Conestoga Dr Brampton	22.2	1.0	23.2
152789	Cable Replacement (Rear Lot) Project - (AREA23) - Forestwood Dr-Stainton Dr, Mississauga	14.7	2.8	17.5

Project Code	Project Name	Benefit ($MM)	Mitigated Risk ($MM)	Total Value ($MM)
152785	Cable Replacement Project - (AREA26) - Rathburn Rd E/Rockwood Rd. Mississauga	18.0	0.5	18.5
151297	Cable and Transformer Replacement Project - (HAM) - Govenors - Old Ancaster	23.6	0.1	23.7
152502	Cable Replacement Projects - (M15) Sir Constantine Dr & Parkway area of Markham	15.0	0.3	15.3
152666	Cable Injection Project - (M15) Church Street area, Markham	14.5	0.2	14.7
151335	Cable Replacement Project - (BA14) - Tiffin and Hwy 400, Barrie	11.1	0.2	11.3
151276	Cable Injection Project - (SCH) - Vansickle	10.3	0.8	11.1
152786	Cable Replacement Project - (AREA28) - Rathburn Rd E/Chalfield Ln and Meadows Blvd, Mississauga	17.5	0.8	18.3
151332	Cable Replacement Project - (BA20) - Bayfield and Simcoe, Barrie	8.3	0.2	8.5
151299	Cable and Transformer Replacement Project - (HAM) - Millen - Barton - Fruitland	68.5	0.2	68.7
151298	Cable Injection Project - (HAM) - Govenors - Old Ancaster	7.2	0.7	7.9
151336	Cable Replacement Project - (BA22) - Sunnidale and Anne, Barrie	26.8	0.3	27.1
151404	Cable Replacement (Rear Lot) Project - (AREA21) - Miss. Valley & Daralea Hts/Molly Ave, Mississauga	7.8	3.9	11.7
151468	Cable Replacement Project - (V51) - Langstaff - Kipling - Hwy 7 - Hwy 27 – Phase 2, Vaughan	7.9	0.2	8.1
151315	Cable Injection Project - (G5) - County Crt Blvd and Hartford Trail, Brampton	13.6	0.5	14.1
150138	Cable Replacement Project – (BA23-BA24) - Cook St and Steel St, Barrie	7.0	0.2	7.2
151424	Cable Replacement (Rear Lot) Project - (AREA21) - Miss. Valley & Bloor, Mississauga	32.7	2.3	35

Project Code	Project Name	Benefit ($MM)	Mitigated Risk ($MM)	Total Value ($MM)
151306	Cable Injection Project - (HAM) - Upper Wentworth - Lincoln M. Alexander - Upper Ottawa - Stone Church	8.9	0.1	9
151467	Cable Replacement Project - (V17) - Langstaff - Keele - Rutherford - Dufferin, Vaughan	8.3	0.3	8.6
151310	Cable Injection Project - (E4) - Moffat Ave/Torrance Woods/Lockwood Rd, Brampton	7.9	0.2	8.1
151293	Cable and Transformer Replacement Project - (SCH) - Lakeshore - Stanley - Parnell - Chancery	30.0	0.4	30.4
151466	Cable Replacement Project - (V24) - Langstaff - Jane - Rutherford - Keele, Vaughan	8.1	1.4	9.5
152392	Install 27.6kV Dead-front Solid Dielectric Switchgear @ Vault 1879 (Conestoga Drive, north of Sandalwood Pkwy), Brampton	6.0	1.1	7.1
151521	Cable Replacement Project - (A05) - Bathurst - Wellington - Yonge - Henderson, Aurora	18.1	0.3	18.4
151393	GUELPH - Transite Underground Duct Replacement	0.9	15.3	16.2
151323	Cable Injection Project - (L2) - Mountainash Rd/Mountainberry Rd, Brampton	5.2	0.6	5.8
151319	Cable Injection Project - (L3) - Chrysler Dr/Corporation Dr, Brampton	7.2	0.5	7.7
151333	Cable Replacement Project - (BA9) - Little - Fairview - Harvie - Ferndale, Barrie	9.7	0.2	9.9
152743	Cable Injection - (M09) - 16th Ave, Reesor Rd, Hwy 7, Ninth Line - Markham	5.6	0.1	5.7
151330	Cable Replacement Project - (A01) - Henderson - Yonge - Bloomington - Bathurst, Aurora	8.5	0.3	8.8
151363	Cable Injection Project - (M25) - 14th - McCowan - Steeles - Old Kennedy, Markham	13.5	0.2	13.7

Project Code	Project Name	Benefit ($MM)	Mitigated Risk ($MM)	Total Value ($MM)
151176	Cable Replacement Project - (AREA45) - Argentia Rd & Campobello Rd/Kinsmen Gate, Mississauga	4.9	0.4	5.3
152830	Cable Replace-(Barrie 417-F3) St Vincent St,Kempenfelt Dr,Berczy St	10.1	0.2	10.3
152812	PILC Cable Replacement Project - (HAM) - Beach and Ottawa Feeders	5.4	0.2	5.6
151386	Cable and Transformer Replacement - (278) - 31 Greengate Rd Subdivision, Guelph	2.7	0.5	3.2
152697	Cable Replacement Project - (71F2 in Area 27) - Rathburn Rd. E. & Willowbank Trail	2.6	0.4	3
151373	Cable and Transformer Replacement - (923) - 301 - 539 Scottsdale Drive Subdivision, Guelph	2.5	0.1	2.6
151275	Cable Injection Project - (SCH) - QEW - Highway 406 - Martindale Road	11.7	0.8	12.5
151144	Cable and Transformer Replacement - (AREA30) - Rathburn Rd. W, Mississauga	9.7	0.9	10.6
151304	Cable Injection Project - (HAM) - Stone Church - Garth - Lincoln M. Alexander	4.7	0.2	4.9
152746	Cable Injection Project - (M14) - Hwy 7, Box Grove Bypass, 14th Ave, Markham Rd	6.1	0.1	6.2
151385	Cable and Transformer Replacement - (892) - 74 - 176 Janefield Ave Subdivision, Guelph	4.1	0.2	4.3
151320	Cable Injection Project - (I5) - Steelwell Rd/Hedgedale Rd, Brampton	3.1	0.2	3.3
151888	Cable and Transformer Replacement - (906) - 39 - 131 Dovercliffe Dr, Guelph	1.6	0.1	1.7
151887	Cable and Transformer Replacement - (96) - 700 Paisley Rd, Guelph	1.7	0.1	1.8
151322	Cable Injection Project - (N4) - Deerhhurst Dr, Brampton	11.6	0.1	11.7

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-97

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B03 - Transformer Renewal / pp. 116-118 (pdf Exhibit 2A Part 2 pp. 124-126)

Preamble:

Alectra Utilities states "While transformers have historically operated under a run-to-failure strategy due to their relatively low impact on public safety, the environment, and customer reliability,… Alectra Utilities' Asset Condition Assessment (ACA) has identified an increased number of deteriorated transformers. The elevated risk associated with the current level of at-risk transformers underscores the need to shift to a planned replacement strategy. Maintaining a run-to-failure strategy with the increased level of deteriorated transformers heightens the risk of public safety incidents and severe oil leaks requiring costly environmental remediation. Alectra Utilities will pursue planned transformer replacement according to the criteria listed below:"

Question(s):

a) What is the annual probability of condition-based failure of transformers with Health Index values of Very Poor, Poor and Fair? If the answers are different for different types of transformers (e.g., poletop and padmount), please provide separate responses for each type of transformer, in tabular format.

b) How did the Asset Condition Assessment identify an increased number of deteriorated transformers?

c) Please provide the benefit cost analysis that justifies transitioning from a run to fail strategy to a proactive replacement strategy. Please include the changes in

consequences of failure and probability of failure for each of the transformer types included in this program.

d) Has anything other than the number of transformers assessed as having a high probability of failure changed to drive the transformer renewal strategy from "run to fail" to pre-emptive "planned replacement"?
   i. If no, please explain why the strategy should be changed, assuming that individual condition-related transformer failures will continue to pose a "relatively low impact on public safety, the environment, and customer reliability".

e) Has Alectra Utilities calculated the cumulative financial loss to customers by implementing a renewal strategy that will unavoidably reduce the effective service lives of transformers that will be retired prior to failure going forward?
   i. If yes, please provide the financial loss.
   ii. If not, please explain why not.

f) Has Alectra Utilities considered continuing to run Pole Mounted Transformers to failure, except for circumstances of immediate need?

RESPONSE:

a) Alectra Utilities identifies transformers in Very Poor and Poor condition as transformers that exhibit failure modes[1] as provided in Table 5.3.2 – 9 in Exhibit 2A, Tab 1, Schedule 1, 5.3.2 Overview of Asset Managed, Page 175. All the transformers proposed for planned renewal exhibit one or more of the identified failure modes. Refer to response provided in 2-STAFF-57 pertaining to annual probability of condition-based failures of transformers.

[1] Except where transformers are overloaded

b) The 2023 Asset Condition Assessment (ACA) identified an increased number of deteriorated transformers through recent field inspection findings identifying physical deterioration such as oil leaks, corrosion, and enclosure or component degradation. Refer to Exhibit 2A, Tab 1, Schedule 1, Appendix E, Section 5.1.4 Health Index Formula and Results for a detailed explanation on the methodology applied to derive the Asset Condition Assessment for transformers.

c) With regards to benefit cost analysis, refer to response provided to 2-STAFF-104 that provides the Net Present Value of Risks Mitigated and Benefits of transformer renewal program and the Net Value Score which is less the investment cost for the three pacing options provided in response to 2A-SEC-48. There is a significant positive net value score for moderate pacing with Alectra Utilities' proposed plan for transformer renewal.

Alectra Utilities' decision to transition from a predominantly run-to-failure approach to a broader planned replacement reflects the need for timely intervention to address elevated public safety and environmental risk in response to large volume of transformers exhibiting deteriorated condition (Very Poor and Poor condition), such as oil leakage potentially triggering extension environmental remediation and advanced corrosion compromising the enclosure integrity and public safety due to proximity to energized components. Figures 1 and 2 below provide examples of these conditions.

At the end of 2023, Alectra Utilities had 3,994 leaking transformers and 5,267 exhibiting major and moderate corrosion to emphasis the scale of the problem, which cannot be managed effectively through reactive replacement work under run-to-failure approach. Although individual transformer failure may result in limited localized impacts, the cumulative risk across the portfolio is elevated due to higher deteriorated population, leading to increased customer interruptions, operational workload, and costs.

In addition, Figure 3 illustrates the extent of environmental remediation and the significant disruption it causes customers if transformers leaking oil are not replaced upon leak detection. Alectra Utilities has experienced an average remedial cost of $49,700 due

transformer oil leaks, excluding the cost to replace the transformer. Alectra Utilities has determined that the most prudent approach is to identify leaking and severely corroded transformers early to mitigate expensive remediation and public safety risks. Furthermore, planned replacement enables Alectra Utilities to address these conditions in a coordinated, safe, controlled and cost-effective manner.

Pad-Mounted Transformer Oil Leak Example #1	Pad-Mounted Transformer Oil Leak Example #2
Evidence of an oil spill on the ground and surrounding environment.	Evidence of oil running down the surface of the unit but no evidence of an oil spill on the ground.

Figure 1 - Pad-Mounted Transformer Oil Leak Severity Examples

Pad-Mounted Transformer Example #1	Pad-Mounted Transformer Corrosion Example #2
Rusted through (hole); unit is no longer sealed due to corrosion.	Rusting at the weld or seams.

Figure 2 - Pad-Mounted Transformer Corrosion Severity Examples

Figure 3 - Oil Leak Environmental Remediation in Backyard (Mississauga, 2019)

d) Alectra Utilities has always replaced a proportion of its transformer population on a planned basis. The historical spending set out in Table 03 – 1 on Page 117 of Exhibit 2A-Tab1-Schedule 1- Appendix B03 reflects these historical planned investments. The shift in Alectra Utilities' approach to this asset class is in the volume of transformers that the utility plans to replace on a planned basis going forward, due to the increasing level of

at-risk transformers. Refer to Appendix B03 - Transformer Renewal, Page 126, which describes the factors that are driving the increase in planned replacements. This includes the aggregate risk associated with the growing deteriorated population (i.e., safety, environmental, and reliability) that cannot be effectively managed on a run-to-failure strategy. In addition, replacing transformers using a planned approach reduces costs for Alectra Utilities, as mentioned in part (c) above.

e) Alectra Utilities does not believe that the change to a planned replacement strategy will result in a financial loss for customers or the utility. The transition to planned replacement during the 2027-2031 DSP period is not expected to materially change derecognition expense, as most transformers identified for replacement are at or will be at the time of renewal, fully depreciated. In addition, planned replacement reflects mitigation of elevated risks such as compromised enclosure integrity, increased public safety exposure, environmental leakage, and unplanned outages – there is value in mitigating those risks.

f) Alectra Utilities outlined in response to part (a) above that only Very Poor or Poor transformers, which exhibit one or more of the failure modes identified in Table 1, are included in the planned transformer replacement program. The remaining population of transformers that do not exhibit these failure modes will be managed under a run-to-failure strategy. This approach includes Pole-Mounted Transformers.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-98

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B03 - Transformer Renewal / p. 120 (pdf Exhibit 2A Part 2 p. 128)

Question(s):

a) Does Alectra Utilities typically run its vault mounted transformers to fail?

b) Please confirm that the risks associated with vault transformer condition related failures are different than those for pole and pad mounted transformers, so risks that could support planned replacement of specific vault mounted transformers might not justify adopting a planned replacement strategy for pole or pad mounted transformers. Please elaborate on your response.

RESPONSE:

a) Yes, vault-mounted transformers follow a run-to-failure approach except where condition assessment identifies Very Poor or Poor vault transformers exhibiting one or more failure modes detailed in 2-Staff-97, vault-mounted transformers are addressed through planned replacement, as demonstrated in Exhibit 2A Tab 1 Schedule 1 Figure 5.3.3 - 6.

b) Condition-related risks and failure modes exist across vault, pole, and pad-mounted transformers, although the exposure and operational impacts differ by installation type. Vault installations typically present higher worker safety and confined-space risks which can lead to flooding, as detailed in Appendix B03 - Transformer IV Investment Need, while pole and pad-mounted installations can present greater public exposure when enclosure integrity is compromised. These differences inform risk prioritization and execution, rather than whether planned replacement is appropriate. Accordingly, Alectra

Utilities applies a consistent, condition and risk-based approach to replacement decisions across all transformer types, with prioritization reflecting the nature and severity of identified risks.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-99

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B03 - Transformer Renewal / p. 123 (pdf Exhibit 2A Part 2 p. 131)

Question(s):

a) What proportion of the forecast spending shown in Table B03-4 is attributable to Alectra Utilities' proposed change in strategy for transformer replacements from "run to fail" to pre-emptive "planned replacement"? Please provide calculations and discuss your response.

RESPONSE:

a) Alectra Utilities has always replaced a proportion of its transformer population on a planned basis. The historical spending set out in Table B03 – 1 on Page 117 of Exhibit 2A-Tab1-Schedule 1- Appendix B03 reflects these historical planned investments. The shift in Alectra Utilities' approach to this asset class is in the volume of transformers that the utility plans to replace on a planned basis going forward, due to the increasing level of at-risk transformers.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-100

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B03 - Transformer Renewal / p. 124 (pdf Exhibit 2A Part 2 p. 132)

Question(s):

a) What proportion of the planned test period transformer replacement spending increase is due to upgrading the residential transformer standard size from 50 kVA to 100 kVA?

RESPONSE:

a) As described in Appendix B03, the incremental material unit cost associated with the 50kVA to 100kVA standard change is approximately 14%. Alectra Utilities has standardized residential transformer installations at 100kVA to address increasing customer load requirements, whereas the decision to replace transformers and the forecast replacement volumes are driven by condition-based renewal needs to address safety, environmental, and reliability risks.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-101

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B03 - Transformer Renewal / p. 125 (pdf Exhibit 2A Part 2 p. 133)

Question(s):

a) Has the expected public safety consequence associated with individual condition-related transformer failures increased?
   i. if yes, please explain.
   ii. If no, what has changed so that such failures now pose unacceptable public safety risks.

RESPONSE:

a) Alectra Utilities' priority is the management of system-level public safety risk, rather than the severity of any single failure event in isolation. While the expected public safety consequence of an individual condition-related transformer failure has not materially changed, the overall risk profile has increased due to the growing volume of transformers exhibiting deteriorated conditions. Increased oil leaks, prevalence of corrosion, and enclosure degradation increases aggregate exposure to safety-relevant outcomes by raising the likelihood that such conditions are present across the system at any given time. As shown in Exhibit 2A Tab 1 Schedule 1 Figure 5.3.2-29, the population of transformers with identified oil leaks have increased by 55% and transformers with major or moderate corrosion has increased by 45% since 2021, supporting a shift in focus from isolated event consequence to proactive management of cumulative risk.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-102

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B03 - Transformer Renewal / p. 128 (pdf Exhibit 2A Part 2 p. 136)

Preamble:

Alectra Utilities states the "increase in the number of deteriorated transformers compared to the 2018 ACA is primarily due to advancements in the GIS and the collection of more granular asset condition data."

Question(s):

a) Please explain how Alectra Utilities calibrated its asset management tools to ensure that perception bias does not drive unjustified spending to address risks that became more fully understood after Alectra Utilities implemented its new ACA, although the physical realities underlying those risks did not change.

RESPONSE:

a) Alectra Utilities notes that the Asset Condition Assessment (ACA) continues to apply the same health index scoring methodology (i.e., oil leak and rust are the primary condition factors contributing to the Health Index). Refer to Table 1 for Distribution Transformers Health Index Parameters and Weights.

Table 1 – Distribution Transformer Health Index Parameters and Weights

#	Input	Pad-mounted Transformer	Pole-mounted Transformer	Vault Transformer	Scoring Method
1	Corrosion	44%	35%	25%	Step Score
2	Oil Leak	44%	35%	61%	Step Score

#	Input	Pad-mounted Transformer	Pole-mounted Transformer	Vault Transformer	Scoring Method
3	Age	12%	30%	14%	Percentage Score

The increase in identified deteriorated transformers reflects confirmation of physically observable condition deterioration through validated condition data, rather than a change in health index computation methodology or risk tolerance.

It is important to note that Alectra Utilities has implemented standardized inspection guidelines that define clear criteria for classifying deficiencies. These guidelines are designed to minimize subjectivity and ensure consistent, high-quality inspection data. Planned replacement decisions are therefore driven by the growing volume and concentration of deteriorated assets across the asset population, which prevents elevated system-level public safety and environmental risk.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-103

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B03 - Transformer Renewal / p. 129 (pdf Exhibit 2A Part 2 p. 137)

Question(s):

a) For figure B03 - 6, please estimate the proportion of change in number of deteriorated transformers attributable to the change in ACA methodology vs. change in deteriorating physical condition.

b) Please provide the annual outages and outage hours due to condition-based transformer failures from 2018 to the present.

RESPONSE:

a) Alectra Utilities clarifies that the increase in number of deteriorated transformer population was through recent field inspection findings identifying physical deterioration such as oil leaks, corrosion, and enclosure or component degradation. Refer to Exhibit 2A, Tab 1, Schedule 1, Appendix E, Section 5.1.4 Health Index Formula and Results for a detailed explanation on the methodology applied to derive the Asset Condition Assessment for transformers.

b) The outage and customer interruption data presented in the table below reflect unplanned transformer failures, recorded at the point of service interruption. Condition-driven interventions, including replacements due to oil leaks, corrosion, or public safety risks, are typically executed as planned or scheduled outage and are therefore not captured under transformer defective equipment outage statistics. As a result, outage counts and customer interruption hours do not represent the size or severity of the deteriorated

transformer population, nor the risk mitigated through planned replacement. Planned replacement decisions are informed by confirmed asset condition and exposure risk prior to failure, as detailed in Exhibit 2A Tab 1 Schedule 1 Figure 5.3.3 - 6, rather than historical failure outage metrics, to reduce system-level safety, environmental, and reliability risk.

Table 1 – Number of Transformer Failures and Customer Hours of Interruption per year 2018-2025

Year	Number of Outages	Customer Hour Interruptions
2018	330	35,972
2019	280	39,545
2020	393	48,162
2021	334	33,832
2022	331	40,630
2023	348	38,920
2024	321	35,016
2025	306	32,980

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-104

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B03 - Transformer Renewal / p. 141 (pdf Exhibit 2A Part 2 p. 149)

Question(s):

a) Please quantify the risk that will be mitigated by each of the proposed investments shown in Table B02 - 11.

RESPONSE:

a) Alectra Utilities has interpreted that the question refers to the proposed investments shown in Table B03 – 11 instead of Table B02 – 11 based on the page reference provided by OEB Staff.

Please refer to the Table 1 for the value of each of the proposed investments shown in Table B03 – 11:

Table 1 - Value of Proposed Investments

Project Code	Project	Benefit ($MM)	Mitigated Risk ($MM)	Total Value ($MM)
Multiple	Transformer Renewal	0	791.3	791.3
151905	Transformer Room Renewal – Swansea Apts (T305), Hamilton	3.9	1.3	5.3
151906	Transformer Room Renewal – Bentley Place (T553), Hamilton	3.7	0.6	4.3
151907	Transformer Room Renewal – Greenhill Apts (T194), Hamilton	2.6	0.7	3.2

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-105

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B04 - Substation Renewal / pp. 142-184 (pdf Exhibit 2A Part 2 pp. 150-192)

Question(s):

a) When does Alectra Utilities project converting all 4.16kV and 8.32kV distribution?

b) Please identify and quantify all investments in Substation Renewal that are planned to occur over the forecast period for the 4.16kV and 8.32kV distribution, per year.

RESPONSE:

a) Alectra Utilities optimizes its projects every DSP cycle (i.e., 5 years). The sequence of projects (i.e. timing and timeline) in the investment plan is determined through the Asset Management Process, as discussed in Exhibit 2A, Tab 1, Schedule 1, 5.3.1 – Asset Management Framework.

Accordingly, Alectra Utilities cannot provide a timeline of the Voltage Conversion program outside of this DSP, since it will be dependent on future optimization results. However, as part of this DSP voltage conversion of the 4.16kV system in Brampton will be completed, as described in Exhibit 2A-1-1, Appendix B01, Section 4.5, Page 51, Lines 19-24.

b) The table below summarizes Substation Renewal investments for 4.16 kV and 8.32 kV distribution systems that are planned to occur over the forecast period.

Table 1 - Substation Renewal Investments for 4.16 kV and 8.32 kV Distribution Systems

Completion Year	Project	Secondary Voltage (kV)	Project Cost ($)
2029	Spadina MS – installation of Medium Voltage Interrupters	4.16	161,476
	Kenilworth MS – installation of Medium Voltage interrupters	4.16	161,476
	Shawanaga MS67 – Protection upgrade	4.16	222,941
2030	Rockwood MS2 (Guelph) – Protection upgrade	8.32	192,490
	Wentworth MS – installation of Medium Voltage Interrupters	4.16	325,408
	Cope MS – installation of Medium Voltage interrupters	4.16	243,442

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-106

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B04 - Substation Renewal / p. 145 (pdf Exhibit 2A Part 2 p. 153)

Question(s):

a) Please reconcile the reduced spending on this program during the Bridge years with the stated criticality of aggressively increasing spending on this program during the test years to maintain reliability performance.

RESPONSE:

a) Alectra Utilities optimizes its portfolio of projects. The optimization process determines the level of the program spending based on constraints according to the process described in Ex 2A-1-1 5.3.1 – Asset Management Framework Overview.

Alectra Utilities optimization included both the bridge years (2025-2026) and the forecast period (2027-2031). The optimization process paced individual projects within this program with the projected spend level shown in Ex 2A-1-1- Appendix B04, Table B04-1.

Lower planned expenditures during the bridge years don't imply lower criticality or need for renewal in this program. The current pacing addresses these deteriorated assets, mitigates rising failure risks and determines the optimal time for renewal intervention.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-107

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B04 - Substation Renewal / pp. 155-156 (pdf Exhibit 2A Part 2 pp. 163-164)

Question(s):

a) As of January 2026, what percentage of Alectra Utilities' station secondary switching devices (e.g., breakers, reclosers) were protected through electromechanical relays?

b) At the completion of the proposed DSP, what percentage of Alectra Utilities' station secondary switching devices (e.g., Breakers, reclosers) will be protected through electromechanical relays?

RESPONSE:

a) As of January 2026, 15.6% of Alectra Utilities' station secondary switching devices (e.g., breakers, reclosers) were protected by electromechanical relays.

b) At the completion of the proposed DSP, 6.6% of Alectra Utilities' station secondary switching devices (e.g., breakers, reclosers) will be protected by electromechanical relays.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-108

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B04 - Substation Renewal / p. 184 (pdf Exhibit 2A Part 2 p. 192)

Question(s):

a) Are any of the listed investments in Table B04 - 5 associated with a Municipal Station (MS) scheduled for retirement or likely to be retired within the next 10 years? If yes, please explain why the investment is necessary.

b) Please quantify the risk that will be mitigated by each of the proposed investments shown in Table B04 - 5.

RESPONSE:

a) No, none of the proposed investments listed in Table B04 – 5 are for stations that are likely to be retired within the next 10 years.

b) Table 1 provides the Net Present Value (NPV) of benefits and risk mitigation for each proposed investment.

Table 1 - Net Present Value (NPV) of benefits and risk mitigation

Project Code	Project Name	Benefits ($MM)	Mitigated Risk ($MM)	Total Value ($MM)
151100	Station Switchgear Replacement - Rogers MS30 LV1 & LV2	7.5	1.4	8.9
151102	Station Switchgear Replacement - Maingate MS27 LV1 & LV2	6.6	1.3	7.9
151097	Station Switchgear Replacement - Woodlands MS13 LV1 & LV2	9.0	1.0	10

Project Code	Project Name	Benefits ($MM)	Mitigated Risk ($MM)	Total Value ($MM)
150323	Station Switchgear Replacement - Bloor MS38 LV1 & LV2	12.9	1.3	14.2
151101	Station Switchgear Replacement - New Dixie MS45 LV1 & LV2	12.5	1.2	13.7
150715	MS Transformers Refurbishment Multi-Year Program - West	9.2	0.2	9.4
150700	Station Switchgear Replacement - Hamilton MS71 LV1	3.0	1.2	4.2
150701	Station Switchgear Replacement - John MS39 LV1	3.7	1.5	5.2
151548	Station Switchgear Replacement - Aurora MS2	6.0	1.4	7.4
152374	230kV Trench Replacement Program	10.0	6.9	16.9
151510	Station Primary Breaker and Transformer Protection Upgrade - Brampton MS21	4.6	0.6	5.2
150698	Station Switchgear Replacement - City Centre South MS61 LV1	6.8	1.8	8.6
152320	Station Primary Breaker and Transformer Protection Upgrade - Brampton MS19	3.6	0.6	4.2
150515	Sorbweb Oil Containment Systems - 4 Transformers -Multiyear Initiative-Central South	0.4	4.6	5
150611	Transformer Tank and Radiator Reconditioning-Multi-year initiative - East	4.9	0.2	5.1
151980	ProActive Battery Replacement in Alectra Field RTUs	2.8	1.8	4.6

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-109

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B05 - Reactive Capital / p. 205 (pdf Exhibit 2A Part 2 p. 213)

Question(s):

a) In Table B05 - 5, what proportion of the planned reduction in "Equipment failure, imminent failure or safety risk" reactive spending over the test period is due to increased planned spending in pre-emptive transformer renewal, as outlined in Appendix B03? Please discuss.

b) What percentage of the 2022 spending was due to the 2022 Derecho?

RESPONSE:

a) In Table B05-5, 37.4% of the reduction in “Equipment failure, imminent failure or safety risk” reactive spending over the test period of 2027-2031 is due to increased planned spending in transformer renewal. Increases in pre-emptive transformer renewal are targeted at poor and very poor condition transformers which represent approximately 7.3% of Alectra Utilities’ distribution transformer population. Transformer replacements currently represent approximately 37.2% of Alectra Utilities’ reactive capital replacements by investment amount. The amount of reduction forecast is informed by the current amount of reactive capital investment in each region directed towards transformers as well as the relative changes in pre-emptive investment level forecast to be directed towards transformer within each region. Please see Alectra Utilities’ response to 2A-SEC-51, part b),i) for more details on how Alectra determined its forecast for the Equipment failure, imminent failure or safety risk segment.

b) 13% of the 2022 reactive capital spending was due to the 2022 Derecho.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-110

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B06 - Network Metering / p. 232 (pdf Exhibit 2A Part 2 p. 240)

Preamble:

Electra Utilities states "Examination of failed meters and error codes provide some insights about causation. For example, Figure B06 - 11 shows the meter board of an Advanced Metering Infrastructure (AMI) 1.0 that failed due to open circuitry within its transformer."

Question(s):

a) What are the most common causes of AMI meter failures? Please discuss.

b) What is the average replacement time for a failed meter, from the time of failure to the time the replacement is in service?

RESPONSE:

a) Meter failures are identified when the Head End system flags a critical meter issue or the meter stops communicating data. Due to the sealed encasing of the meter and its complex circuitry, Alectra Utilities does not perform detailed analysis of each meter to determine the componentry that has failed. Alectra Utilities does track the general failure modes.

In Alectra Utilities' experience, AMI 1.0 meter failure modes can vary by manufacturer and model. The most common failure mode within Alectra Utilities' AMI 1.0 meter fleet is a non-communicating meter. This typically indicates a failure related to the

communications module, main circuit board or power supply. In some cases, the metering and measurement functions may continue to operate correctly, but the meter is unable to transmit its data to the Head End system.

The second most common failure mode involves "no-display" or "partial-display" conditions. These failures are often related to failure of the display hardware, power supply issues, or internal circuitry. Measurement Canada requires that a meter continue to function in accordance with its approved type specifications. Measurement Canada Standard LMB-EG-07[1] specifies that an approved meter must include "one or more means of indication capable of accurately presenting or displaying the numerical value of each legal unit of measure for which the meter is approved." Therefore, a "no-display" or "partial-display" condition does not meet Measurement Canada requirements and must be replaced.

The third most common failure mode is failed metrology where the meter does not record its data consistently, resulting in missing intervals of consumption data. Metrology failures can arise from issues such as component degradation or power supply issues. Where hourly interval data is not available, the meter data must be estimated for customer billing. Alectra Utilities considers a meter to be in a failed state when more than 10% of the meter data is unavailable.

All types of meter failures are being experienced in higher volumes as the population of AMI 1.0 meters ages.

b) Alectra Utilities has historically strived to replace failed meters within 5 business days of receiving the work request, 90% of the time. This service level has not been achievable with the higher volumes of meter failures experienced since 2022. The utility has

[1] LMB-EG-07 Specifications for Approval of Type of Electricity Meters, Instrument Transformers and Auxiliary Devices

transitioned beyond first-in, first out work management to prioritization by the customer's billing window to minimize the impact of meter failures to customer billing processes.

Where the Head End system identifies a critical meter failure, the work activity is issued immediately. Where the meter has stopped communicating, a delay of five to eight days is undertaken to allow the network mesh the opportunity to heal itself before issuing the work to the field technicians.

In 2025, it took an average of eleven days to replace a failed meter from the time the work order was issued.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-111

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B06 - Network Metering / p. 241 (pdf Exhibit 2A Part 2 p. 249)

Preamble:

AMI 2.0 technology offers simplified communications through fewer devices, as well as opportunities for redundancy not available with AMI 1.0. While AMI 1.0 communications rely on cellular telecommunications, AMI 2.0 can utilize secondary networks including Alectra Utilities' internal WiMAX network.

Question(s):

a) Will the network O&M costs associated with AMI 2.0 be lower than O&M costs associated with AMI 1.0?

   i. If yes, please quantify the cost reduction.

   ii. If not, please explain why not.

RESPONSE:

a) Yes, it is expected that the simplified AMI 2.0 network combined with enhanced network management functionality will result in lower OM&A costs as compared to Alectra Utilities' AMI 1.0 networks.

   Alectra Utilities AMI 1.0 data backhaul expenditures were approximately $1.2MM in 2023 prior to the implementation of AMI 2.0 networks. This expenditure includes approximately

4,815 communication lines to AMI 1.0 devices and licensing related to its communication towers and base stations.

It is forecasted that when the AMI 1.0 networks are fully retired in 2032, as per the 5.5 year mass deployment alternative, that Alectra Utilities' data back haul expenditures will be between $0.3MM to $0.4MM annually.

Furthermore, the ability to utilize secondary communication networks for redundancy combined with AMI 2.0's monitoring and management functionality from the back office is expected to reduce maintenance expenditures.

In 2025, Alectra Utilities avoided approximately 150 field visits to determine the operational status of AMI 2.0 network equipment or to perform a "re-boot" of the device. Instead these activities were completed by the back office team. When the AMI 2.0 network is fully deployed in 2032, this is anticipated to reduce OM&A costs by approximately $0.2MM annually.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-112

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B06 - Network Metering / p. 269 (pdf Exhibit 2A Part 2 p. 277)

Preamble:

Alectra Utilities states "This minor extension to the deployment schedule, which shifts costs related to the installation of 50,000 meters from the latter three years of the DSP period, is not expected to increase overall project costs. Project activities related to the final meter replacements are expected to continue for an additional three to six months, after which the project will be completed. The incremental risk related to meter failures is likewise anticipated to be manageable over this time frame, as Network Metering will continue to prioritize the replacement of its AMI 1.0 meters based on its operational risks."

Question(s):

a) Given that the AMI renewal program has a cyclical nature, with replacements compressed into a 5-year period interspersed with prolonged (15 year) low activity periods, please discuss how does Alectra Utilities manages the volatile labour requirements between the high activity and low inactivity periods. Please consider the balance between in-house and third-party labour in your response.

RESPONSE:

a) Alectra Utilities is staffed internally to manage the majority of its baseline activities which are typically consistent year-over-year. This includes activities related to Alectra Utilities' wholesale meter compliance, revenue meter compliance, new connections and customer

upgrades and, until recently when volumes increased, addressing meter and meter infrastructure failures.

The first priority for internal staff is Network Metering's complex customer installations including wholesale, generation, and polyphase meter installations. Where work requirements exceed resource capacity, single phase meter installations are completed by third-party partners. During its "low activity periods", the Network Metering capital program may be 80% to 90% allocated to internal staff, and 10% to 20% to third party service providers.

This process ensures that Alectra Utilities' Network Metering team is not over-staffed, while managing safety, compliance, and customer experience related to its largest and most complex customers.

In "high activity" periods, Alectra Utilities is required to further rely on third party service providers. In the case of AMI Renewal, this extends beyond meter installations to meter warehousing, meter inventory management, and customer services related to the meter change.

The mass deployment of AMI 1.0 was completed over the 5-year period of 2006 to 2010 to meet the province's Smart Metering Initiative. Alectra Utilities aims to partially mitigate the cyclic nature of future replacement cycles and reduce volatility through: its longer ten-year AMI 2.0 replacement cycle between 2023 to 2032; and, the utilization of open way standards as opposed to proprietary protocols. Itron will be compliant with Wi-Sun standards, which are intended to allow meter inter-operability across AMI providers and networks. In the future, Alectra Utilities meter replacements could potentially be vendor-agnostic based on cost and use case requirements.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-113

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B07 - Facilities Management / pp. 309-310 (pdf Exhibit 2A Part 5 pp. 317-318)

Question(s):

a) In section 7.6 Costs and Savings, Alectra Utilities states “additional capital budget was required to complete the project from the original forecast” and then lists drivers for the increased costs.

   i. Please provide the original budget.

   ii. Please provide the incremental costs for at minimum, each driver listed in section 7.6.

b) Alectra Utilities states a “500kW Solar Plant to power the property” was included in the Kennedy Road project.

   i. What was the total capital costs for the 500kW Solar Plant?

   ii. Please provide the business case and payback calculations for the 500kW Solar Plant. If a formal business case was not constructed, please provide the documentation Alectra Utilities used to support the decision to add the 500kW Solar Plant to the Kennedy Road project.

RESPONSE:

a) Please see response to AMPCO-45 questions A) and C).

b)

i. The total capital costs for the 500kW Solar Plant cost was $1.4 million.

ii. Alectra did not conduct a stand-alone business case for the Solar Plant. However, Alectra did engage Ecovert Sustainability Consultant to evaluate the building's base design Greenhouse Gas ("GHG") emissions in comparison to alternate low-carbon design scenarios. Findings from that analysis included that the Solar Plant would:

- produce estimated savings of $116,638 per year (or a payback period of 10 years); and
- reduce GHGs by 17% annually.

For more detailed information please reference 2-Staff-113_Attach 1_Kennedy Road Solar Plant 500kW PV GHG Analysis – Final.pdf

2-Staff-113

Attachment 1
Kennedy Road Solar Plant 500kW PV GHG Analysis - Final

17 Kennedy Road South, Brampton, ON

GHG Emissions Summary – AES 500kW Solar PV Option

February 25, 2021

Prepared for:

Alectra Utilities Corporation

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GHG EMISSIONS SUMMARY

An energy model was prepared for Alectra Utilities Corporation – Central Operations Centre, located at 174 Kennedy Road South, Brampton, Ontario, to evaluate the base design GHG emissions in comparison to alternate low-carbon design scenarios. The purpose of this analysis was to evaluate the GHG and financial implications of the proposed 500kW (AC) Rooftop Solar PV solution.

The project has a total gross floor area of around 20,500 m^2 and is comprised of several spaces including a two-storey office, commercial kitchen, lounge and break rooms, fleet garage, fleet Centre, and warehouse. Energy simulation was conducted using IES Ve Version 2019.1.0.0 under the Pearson International Airport Weather. The base design energy model is based on the following drawings and documents:

- Architectural drawings dated September 28th, 2020;
- Design-build brief dated November 1st, 2017;
- Mechanical design brief dated April 9th, 2020; and
- Programme requirements Summary dated October 23rd, 2019.

The proposed 500kW AC Solar PV solution is outlined in the table below:

SOLAR ENERGY

- ☐ Key Items-
  - ☐ 500 KW (ac) rooftop solar installation proposed (net meter connected)
  - ☐ Total budgetary cost - $1.25M
  - ☐ Offering to include 20 year PPA
  - ☐ Fixed fees approx. $150,000 per year ($0.15 - 0.18 / kWh)

Result shows that the proposed 500kW (AC) Rooftop Solar PV solution would save **17% GHG emissions** over the current LEED Gold Base Design. Table below compares the GHG intensities of the 174 Kennedy Rd project LEED Gold Base Design, Base Design + 500kW PV, SB-10 Reference, Zero Carbon Design (with 5% on-site renewables), and Zero Carbon design (with 100% on-site renewables). Also, table below includes GHG intensities of two of Alectra's existing facilities. Emission factors are based on the Ontario GHG emissions factors as listed in the Energy Star Technical Reference Guide dated October 2020.

Energy Star Emissions Factors for Ontario (October 2020)	
Natural Gas	1.899 (kg CO_2 e / m^3)
Electricity (Average Rate)	0.020 (kg CO_2 e / kWh)
Exported Electricity (Marginal Rate)	0.394 (kg CO_2 e / kWh)

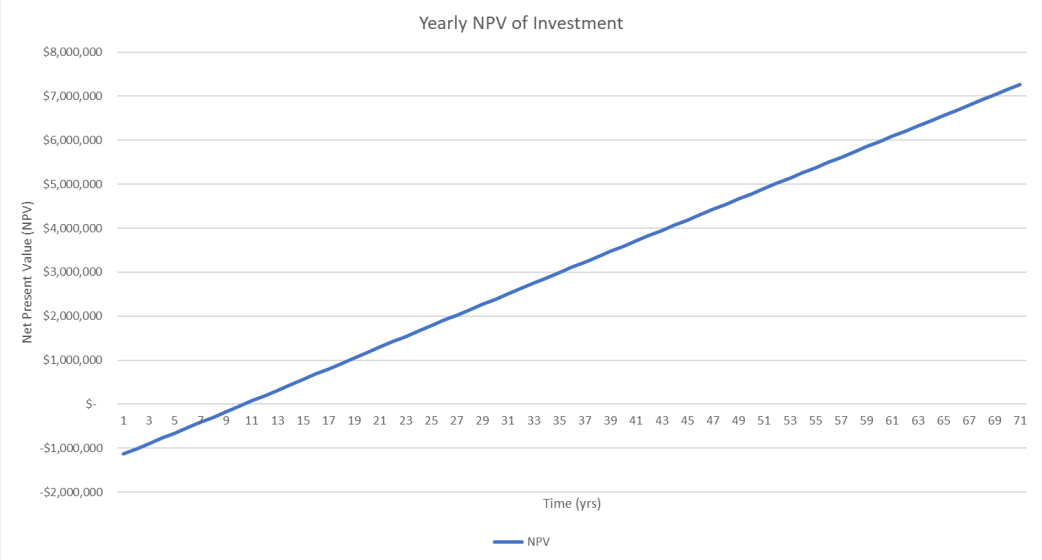
The results outline in the table below show the breakdown of energy consumption and GHG emissions for each scenario.

	Area (m^2)	Electricity Consumption (MWh / Year)	Gas Consumption (MWh / Year)	GHG Emissions (Tonne CO_2 e/ Year)	GHG Intensity (kg CO_2e / m^2 / Year)
174 Kennedy Rd. (SB-10 Reference)	20,512	1,129	959	195.0	9.5
174 Kennedy Rd. LEED Gold Design (Base Design)	20,512	1,967	1030	192.1	9.4
174 Kennedy Rd. LEED Gold Design (Base Design) + 500kW AC PV	20,512	285	1030	159.0	7.8
174 Kennedy Rd. (ZC Design with 5% on-site Renewable)	20,512	1,071	-	27.6	1.3
174 Kennedy Rd. (ZC Design with 100% on-site Renewable)	20,512	321	-	-	-
Mavis & Sandalwood Existing Facilities 5-Years average (2016 to 2020)	25,919	5,602	2097	489.5	18.9

The proposed 500kW AC (640 DC) PV is estimated to generate ~800MWh/year of renewable energy of which 80MWh is estimated to be exported back to the grid (net-metering) credited at the marginal GHG emissions rate. The renewable energy generated results in a 17% reduction in GHG emissions when compared to the original LEED Gold Base Design.

Using the budgetary capital costs of $1.25million (~$2.5/Watt) the 20-year Net Present Value (NPV) is estimated to be $1,293,894. The initial investment would payback ~10 years however through a PPA Alectra would be paying a fixed annual rate over 20-years and not realize the revenue generated from the Solar PV array beyond the 10-year mark. Alectra would benefit from the GHG offsets generated from the renewable energy generation as well as fixed electricity pricing for 800MWh/yr generated on-site.

20-Year NPV Calculation	
Discount Rate	3%
Inflation Rate	2%
Utility Escalation Rate	3%
Carbon Tax Escalation	50$/tonne +15x to max $300/tonne
Capital Investment	$1,250,000
Energy Cost Savings	$116,638/yr
NPV_{20}	$1,293,894
Payback Period	~10 years



RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-114

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B08 - Fleet Renewal / p. 315 (pdf Exhibit 2A Part 2 p. 323)

Preamble:

Alectra Utilities states "Finally, fleet management enables Alectra Utilities to meet its organizational objectives, such as the decarbonization of the utility's fleet assets. When the marketplace has available EVs that meet operational requirements, and are comparable in cost, Alectra Utilities will replace internal combustion engine vehicles with an EV."

Question(s):

a) Does Alectra Utilities plan to operate EVs beyond their initial requirement for battery replacement? Please discuss.

b) Please provide a full lifecycle benefit cost analysis comparing equivalent EV and ICE vehicles for the vehicle category which represents the greatest amount of test period spending.

RESPONSE:

a) Alectra plans to assess this matter on a case-by-case basis. EV battery replacement is a major repair (in some ways analogous to replacing a vehicle's engine).

With any major repairs, Alectra considers vehicle operational need, total repair costs, vehicle age and condition, available replacements and alternatives before deciding on a particular course of action.

b) The table below captures cost analysis between an ICE and EV Pickup Truck for a seven-year life cycle, at which point the vehicle is scheduled for replacement based on Alectra Utilities' replacement criteria for light duty assets. See table below:

Table 1 - Cost Analysis between an ICE and EV Pickup Truck

EV VS ICE Variance Cost Analysis					
Vehicle Type	**Purchase Cost**	**Fuel Source Cost (*)**	**Maintenance & Repair Cost (*)**	**Book Value (*)**	**Total**
ICE Pickup Truck	$60,000	$27,174	$9,800	$0	
EV Pickup Truck	$95,000	$8,400	$3,500	NA	
Variance	**($35,000)**	**18,774**	**6,300**	**$0**	**($9,926)**
Note: (*) Based on a seven-year life cycle					

Currently the benefits of EVs include the avoided greenhouse gas production, along with a reduction in fuel and maintenance costs. Alectra Utilities' EV fleet assets are retentively new, and the utility is still gaining experience with its EV fleet deployment, as is necessary to ensure it can support the utility's operational needs. The average age and kilometers of Alectra Utilities' EVs are 1.3 years and 16,000 km. While more time and accumulated kilometers are required to preform a full lifecycle benefit cost analysis between EVs and ICE vehicles, based on available data, EV Pickup Trucks currently do not produce a net financial benefit due to the upfront EV purchasing cost as shown in table above. This may change over time, if EV purchasing costs reduce in future.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-115

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B08 - Fleet Renewal / p. 318 (pdf Exhibit 2A Part 2 p. 326)

Question(s):

a) Please explain why there is a step change in forecast expenditures between 2026 and 2027.

b) If a primary driver is an upgrade to the new CSA pole standard, please provide the full incremental cost of adopting the new CSA pole standard including these fleet costs.

RESPONSE:

a) The step change from 2026-2027 is due mainly to growth. Please see AMPCO-46 Question D.

b) The upgrade to the new CSA pole standard is not a primary driver to the step change between 2026 and 2027.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-116

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B09 - Information Technology Systems / p. 349 (pdf Exhibit 2A Part 2 p. 357)

Question(s):

a) Alectra Utilities states it is transitioning suite metering to a single software system by the end of the DSP period. Will there be premature suite metering device replacements to communicate with the new software? If so, please provide forecast of yearly amounts and scope of work.

b) Please explain if there is, or will be, any difference to the data available to suite metered customers compared to smart metered customers.

c) Does Alectra Utilities have third party suite metering providers providing services in its service area? If so, does Alectra Utilities have an estimate of the number of properties or customers impacted by these services?

RESPONSE:

a) The consolidation to a single suite meter Head End system will not drive incremental or early suite meter replacements.

b) Suite metered and smart metered customers have access to the same meter data and customer services.

c) Yes, approximately 13,000 suite meters are read by a third-party services provider.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-117

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B09 - Information Technology Systems / p. 352 (pdf Exhibit 2A Part 2 p. 360)

Preamble:

Alectra Utilities states the "benefits that will be realized from the implementation of the Workforce Management (WFM) system are significant. Two of the most significant benefits are in the areas of personnel efficiencies and reliability gains, as summarized below:

- Efficiency gains amongst field, supervisory, and back-office (clerical) are primarily from:
    - Improvements in scheduling, resource allocation, and route optimization that will result in time savings in the planning and scheduling of work, and a reduction in crew travel times. This will result in efficiency gains amongst field staff, supervisory personnel, and staff involved in job scheduling."

Question(s):

a) Please quantify the Net Present Value (NPV) of the expected efficiency gains vs. the planned expenditures necessary to realize those gains.

RESPONSE:

The NPV of the expected efficiency gains associated with the WFM system is approximately $58.3M, compared to a planned project expenditure of approximately $11.5M capital expenditure over 2027-2031.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-118

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B10 - Customer Connections / Table B10 - 2 Summary of Expenditures / p. 395 (pdf Exhibit 2A Part 2 p. 403)

Question(s):

a) Are the capital expenditures for approved Incremental Capital Module (ICM) projects included in table B10?

b) Please provide the gross expenditures, capital contributions, and net expenditures for the "Customer Initiated" expenditures in Table B10.

c) Please provide explanations for material variations of year-to-year expenditures in the historical and bridge years.

d) What drivers are responsible for the significant increase in the annual spending for the forecast period compared to the historical and bridge periods?

e) Please provide a forecast project list with estimated net costs for the forecast period, by year.

RESPONSE:

a) Alectra Utilities confirms that there were no approved Incremental Capital Module (ICM) projects relevant to Table B10 - 2.

b) "Customer Initiated" gross expenditures, capital contributions, and net expenditures

Table 1 - Gross expenditures, Capital contributions, and Net Expenditures

	$ in MM	Customer Initiated		
		Gross	Contributions	Net Expenditures
Historical Spending	2020A	11.6	-3.7	**7.9**
	2021A	24.5	-12.7	**11.8**
	2022A	17.6	-15	**2.6**
	2023A	28.9	-14	**14.9**
	2024A	44.8	-20	**24.8**
Bridge Years	2025A	35.5	-14.5	**21**
	2026	50.3	-32.1	**18.2**
Forecast Spending	2027	82.2	-39.9	**42.3**
	2028	91.3	-34.6	**56.7**
	2029	67.2	-21.4	**45.8**
	2030	41.2	-14.5	**26.7**
	2031	63.6	-32.2	**31.4**

c) The explanations for material variations of year-to-year expenditures in the historical and bridge years are shown in the excel file "*2-Staff-118_Attach1_ Material Variance.xlsx*".

d) The forecasted period spending is higher, especially for 2027, 2028 and 2029 due to several system expansion very large projects that are currently being designed and forecasted for construction in these years. All of these projects are customer driven system expansions for the areas where there is insufficient capacity to connect. The timing of these projects is based on the customer's required connection dates, which were communicated to Alectra Utilities when the projects were initiated. In addition, forecast Customer Initiated investments includes some very large Transit Expansion projects which affect Alectra Utilities' spending in 2028, 2029, 2030 and 2031.

e) Please refer to attachment "*2-Staff-118_Attach 2_Customer Connections Forecasted Project List with Net Costs.xlsx"* forecast project list with estimated net costs for the forecast period, by year.

2-Staff-118

Attachment 1
Material Variance

Please see live Excel

2-Staff-118

Attachment 2
Customer Connections Forecasted Project List with Net Costs

Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-119

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B10 - Customer Connections / Table B10 - 2 / p. 395 (pdf Exhibit 2A Part 2 p. 403)
Ref 2: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B10 - Customer Connections / Table B10 - 3 / p. 400 (pdf Exhibit 2A Part 2 p. 408)

Question(s):

a) Regarding the Investment Projects section, Alectra Utilities presents Table B10 - 3 Very Large Projects (reference 2). Table B10 - 2 in reference 1 shows zero Transit Connections spending for the period from 2025 through 2031, but Table B10 - 3 lists several projects that appear to be Transit Connections related (e.g., Project code 152335 - HaLRT OMSF Expansion and Project Code 153092 - HaLRT - TPSS 4 System Expansion). Please reconcile.

RESPONSE:

a) Table B10-2 presents forecast spending by investment category. For the 2025-2031 period, forecast spending associated with Transit-related expansions is reflected under the Customer Initiated investment category rather than shown as a standalone “Transit Connections” line item.

Table B10-3 provides a project-level listing of very large projects, regardless of the investment category under which the associated costs are captured. As a result, certain projects listed in Table B10-3 (e.g., HaLRT OMSF Expansion and HaLRT TPSS 4 System Expansion) relate to Transit-sponsored initiatives but are categorized as Customer Initiated investments in Table B10-2, consistent with the funding and cost recovery treatment for those projects.

Accordingly, the apparent difference between Tables B10-2 and B10-3 reflects a difference in presentation and categorization, rather than an omission of forecasted Transit-related spending.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-120

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B10 - Customer Connections / pp. 402-403 (pdf Exhibit 2A Part 2 pp. 410-411)

Question(s):

a) Table B10 - 6 shows hundreds of renewable generation (REGEN) connections over the test year period, but Table B10 - 2 shows zero test period spending on REGEN. Please reconcile.

b) If the reason for the discrepancy is capital contributions, please provide table B10 - 7 on a gross basis.

RESPONSE:

a) Costs associated with REGEN connections are typically borne by the connecting customer; therefore, no expenditure was forecasted.

b) As noted above, there is no discrepancy and table B10-7 is correct.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-121

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B12 - Lines Capacity / p. 453 (pdf Exhibit 2A Part 2 p. 461)

Question(s):

a) Regarding the Primary Supply to the Municipal Stations section, Alectra Utilities presents Table B12 - 1 Line Capacity Investment Portfolio Mix by Driver Category. Please explain the timing of the step change from 2027 to 2029 for both forecast spending items I. and II. in Table B12 - 1.

b) What is the estimated risk that some of the proposed Line Capacity spending will be stranded or premature if load growth does not occur as forecast?

RESPONSE:

a) The increase in investment between 2027 and 2029 reflects the forecast timing of line capacity requirements. The increase is primarily driven by Greenfield expansion and Intensification projects that necessitate new feeders and capacity relief as projected loading approaches planning limits.

Higher investments in 2028–2029 are attributable to several major feeder integration and capacity relief projects scheduled for construction during this period. These investments are required to integrate supply from new transformer stations and to relieve loading on existing feeders.

Key projects contributing to the 2028–2029 increase include:

- Building new feeders to incorporate supply from new Markham TS #5 and new Goreway TS #2 to support growth in greenfield areas. The existing feeders are reaching their rated limits and do not have capacity to accommodate future growth.

- Feeder expansion from existing Pleasant TS and Goreway TS to provide capacity relief to the existing feeders resulting from intensification and organic load growth.

- Upgrading feeders in St. Catharines downtown core which is supplied by legacy 500MCM and 350MCM PILC 2 underground feeder cables. These feeders are limited to a 300A rating – half of the standard 600A feeder capacity. The feeders are heavily loaded and lack adequate backup capability, creating capacity and reliability constraints.

- Upgrading, reconfiguration and adding additional feeders within downtown Guelph to coincide with the City's upgrade of the area.

b) Alectra Utilities lines capacity investments are planned in accordance with forecast feeder loading, development activity, and system utilization and are intended to address clearly identified capacity and system reliability needs on the distribution system (see part a) above for the key projects). In addition, these projects enhance system flexibility, through additional tie points and automated switching capability, supporting reliability improvements and the integration of distributed energy resources. Accordingly, the proposed investments present no material risk of being stranded or undertaken prematurely.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-122

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B12 - Lines Capacity / p. 479 (pdf Exhibit 2A Part 2 p. 487)

Question(s):

a) Please identify which of the planned investments in Table B12 - 7 have the highest risk of being stranded or made prematurely should load growth not occur as forecast.

b) Are any of the listed investments intended to serve MS scheduled for retirement or likely to be retired within the next 10 years? If yes, please explain why the investment is necessary.

RESPONSE:

a) Alectra Utilities has determined that the planned Line Capacity upgrades face no material risk of becoming stranded or implemented prematurely. Alectra Utilities capital investment portfolio, specifically the lines capacity projects, are planned in accordance with the forecast feeder loading, development activity, and system utilization and are intended to address clearly identified capacity and system reliability needs on the distribution system. Please refer to *Interrogatory Response 2-Staff-121-b*.

b) None of the listed investments in Table B12-7 are intended to serve MS scheduled for retirement or likely to be retired within the next 10 years.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-123

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B13 - Station Capacity / pp. 484 - 485 (pdf Exhibit 2A Part 2 pp. 492-493)

Question(s):

a) Given Alectra Utilities' intention to ultimately upgrade and standardize its service voltages at 13.8 kV and 27.6 kV, please identify and explain any of the investments listed in Table B13 - 3 that are intended to reinforce or expand MS that serve lower voltage circuits.

RESPONSE:

a) Alectra Utilities confirms that there are no investments in Table B13-3 to reinforce or expand MS that supply lower than 13.8kV.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-124

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B13 - Stations Capacity / p. 564 (pdf Exhibit 2A Part 2 p. 572)
Ref 2: EB-2019-0018 / Exhibit 04 / Tab 01 / Schedule 01 / pp. 370-372
Ref 3: Exhibit 2A OEB Appendix 2-AA

Preamble:

OEB Staff have created the table below to show the planned and actual Capital and Cost Recovery Agreements (CCRA) over the historic period.

$M	2020	2021	2022	2023	2024	2025	2026
2020-2024 DSP (Ref 2)	8.7	1.6	0	0.5	0	NA	NA
Actual (Ref 3)	0.0	5.5	0.7	0.0	0.0	5.7	5.0

Alectra Utilities has forecast CCRA Program Expenditures for 2027 through 2031 at $114.2M.

Question(s):

a) Please confirm or correct the amounts in the table above.

b) Please provide a table listing all actual and forecast CCRA payments to, and credits from, HONI over 2020 - 2030, including the project, payment due date and payment amount.

c) For each actual and forecast cost owing to or credited from HONI over 2020-2030:

i. Please categorize the costs as construction costs or load true-up.
ii. Please provide the agreements between Alectra Utilities and HONI
iii. Please provide any estimates and calculations from HONI (i.e. output of the HONI DCF model). In the absence of estimates from HONI, please provide A lectra Utilities' detailed calculations of the true-up amount.
iv. In cases where Alectra Utilities forecasts a payment during 2027-2031 due to reduced or unrealized load, please explain why the load forecast at the tim e of the agreement with HONI was not realized.
v. Please identify any HONI CCRA payments associated with projects that wer e not identified in one of the regional plans submitted in this application.

RESPONSE:

a) Alectra Utilities provides corrected amounts in Table 1, which is provided in response to part (b), below. Table 1 lists all actual and forecast CCRA payments and credits for the 2020-2031 period. Alectra does not take issue with the 2020-2024 DSP amounts show n in OEB staff's table. Alectra Utilities wishes to clarify that the figures in OEB staff's ta ble for 2025 and 2026 are forecast figures and not actuals per reference 3 as presente. Alectra further clarifies that it recognizes credits resulting from CCRA true-ups as the de recognition of prior periods' contributions paid. These amounts are presented as dispos als of fixed assets and are not included with the in-service additions.

b) See Table 1, below.

Table 1 - CCRA Payments and Credits

Project Name	Payment Date	Actual						Forecast					
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Goreway TS (Brampton) 10 Yr True-Up	12/15/2021		5.5										
Midhurst TS 15 Yr True up	12/31/2022			-0.84									
Winona TS 15 Yr True up	12/31/2022			-1.0									
230KV Underground Cable Supply to Heritage TS (Brampton) Construction Costs	Multi-year[1]											29.2	24.1
Nebo TS 27.6kV (Hamilton) 5Yr True-Up	12/31/2022			0.7									
Newton TS (Hamilton) Construction Costs	Multi-year[1]									8.2	8.1	9.2	
Pleasant TS - H29 H30 Reconductoring - Transmission	Multi-year[1]					0.3	0.8	5.0	5.0				
Kenilworth TS Power factor Correction	12/15/2026				0.2	0.6	2.1	1.0					
Cedar TS (Guelph) [2] 15 Yr True-Up	12/1/2026							0.5					
Arlen MTS (Guelph) [2] 10 Yr True-Up	12/1/2026							0.2					
Campbell TS Metalclad expansion (Guelph)	Multi-year[1]									8.2	8.1	9.2	

Project Name	Payment Date	Actual						Forecast					
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Construction Costs													
Markham TS #5 (Markham) [2] Construction Costs	Multi-year[1]							10.0	10.0				
Total			5.5	-1.14	0.2	0.9	2.9	16.7	15.0	16.3	16.3	47.5	24.1

[1] Payments for construction will be made over a multiyear construction period and are planned for December of forecast year as presented.

[2] Payments for 2025 were forecast, however, no payments were made. True-up payments for Cedar TS and Arlen MTS have not yet been finalized. Discussions regarding Markham TS #5 project are ongoing with Hydro One, however, no payments were made in 2025.

c)

(i) Please refer to Table 1 in response to part (b), specifically the “Project Name” co lumn, which identifies whether each item is a construction cost or a load true-up.

(ii) CCRA agreements for Goreway TS, Nebo TS, Arlen MTS, Cedar TS, Winona T S, Midhurst TS and Kenilworth TS are provided in Attachment 1 [2-Staff-124_Att ach 1 CCRA Goreway–Nebo–Arlen–Cedar–Winona-Midhurst-Kenilworth]. Agree ments for Markham MTS #5, Campbell TS, Newton TS and H29/H30 re conduct oring, and the 230kV Supply to the planned new Heritage MTS, have not yet bee n prepared and are therefore not available.

(iii) Load true-up calculations for Goreway TS, Nebo TS, Winona and Midhurst as provided by HONI, are provided in Attachment 2 [2-Staff-124_Attach 2 Load True Up Goreway –Nebo–Cedar–Arlen–Winona-Midhurst]. Load true-up contributions for Cedar TS and Arlen MTS have not been finalized and Alectra Utilities is working with Hydro One to settle these true-ups in 2026. In the interim, Alectra Utilities prepared estimated true-up calculations for Cedar TS and Arlen MTS, which are also included in Attachment 2.

Load true calculations are not required for the future Campbell TS expansion pro ject, as the scope is to add a new metalclad switchgear to provide additional Low Voltage feeders at the station.

Alectra Utilities does not yet have the DCF model outputs from HONI for the futu re projects (Markham MTS #5, Newton TS, H29/H30 reconductoring and Line to supply Heritage TS). Alectra Utilities has developed capital contribution estimate s for these future projects based on budgetary project costs using the modelling spreadsheet provided by HONI. The related capital contribution calculations are provided in Attachment 3 [2-Staff-124_Attach 3 Capital Contribution Calculations Markham 5 – Newton – H29/H30 Reconductoring- Line to Heritage].

(iv) Alectra Utilities has not identified nor included any CCRA payments in 2027-2031 period which are driven by reduced or unrealized load.

(v) Alectra Utilities notes that the HONI CCRA payments for Goreway TS, Nebo TS, Arlen MTS and Cedar TS between 2020 to 2025 are Load True-up payments, which are not within the scope of Regional Planning and are not identified in Regional Planning reports.

Capacity needs have been identified at Pleasant and Jim Yarrow TS. Please refer to Appendix H - GTA West Region Scoping Assessment Outcome Report, November 28, 2024, p15(3). New Heritage TS is a recently identified project which addresses capacity needs at Pleasant and Jim Yarrow. The new line project to supply the new Heritage TS is included in the GTA West IRRP (currently underway).

Capacity needs at Campbell TS and Newton TS are identified in regional plans submitted with this Application. For Campbell TS, please refer to Exhibit 2A, Tab 1, Schedule 1, Appendix H KWCG – Needs Assessment [April 09. 2024], and Kitchener/Waterloo/Cambridge/Guelph Scoping Assessment Outcome Report, July 8, 2024. For Newton TS, please refer to Exhibit 2A, Tab 1, Schedule 1, Appendix H Burlington to Nanticoke Integrated Regional Resource Plan [December 18, 2024]. The specific projects are included in the Kitchener-Waterloo-Cambridge-Guelph (KWCG) and Hamilton subregion IRRPs (currently underway).

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Attachment 1
CCRA Goreway–Nebo–Arlen–Cedar–Winona–Midhurst-Kenilworth

CCRA – Goreway TS

Revised Schedule "B" (Goreway TS Expansion)

SCHEDULE B REVISION DATE

Date: October 5, 2012

READY FOR SERVICE DATE

Actual date: May 23, 2010

TRANSFORMATION CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Transformation Connection Pool Work: $23,489,005.00

Estimate of Transformation Connection Pool Work Capital Contribution: $9,511,200.00

Actual Engineering and Construction Cost of the Transformation Connection Pool Work: $23,871,000

Actual Transformation Connection Pool Work Capital Contribution: $9,823,700

Capital Contribution Includes the Cost of Capacity Not Needed by the Customer: N/A

LINE CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Line Connection Pool Work: $376,493.00

Estimate of Line Connection Pool Work Capital Contribution: $0

Actual Engineering and Construction Cost of the Line Connection Pool Work: $0

Actual Line Connection Pool Work Capital Contribution: $0

Capital Contribution Includes the Cost of Capacity Not Needed by the Customer: $0

NETWORK CUSTOMER ALLOCATED WORK

Estimate of the Engineering and Construction Cost of the Network Customer Allocated Work: $284,764.00

Actual Engineering and Construction Cost of the Network Customer Allocated Work: $273,000

NETWORK POOL WORK (NON-RECOVERABLE FROM CUSTOMER):

The estimated Engineering and Construction Cost of the Network Pool Work (Non-Recoverable from Customer) is $0.00. Subject to Section 14.2 of the Standard Terms and Conditions, Hydro One will perform this work at its own expense.

WORK CHARGEABLE TO CUSTOMER

Estimate of the Engineering and Construction Cost of the Work Chargeable To Customer:

Revenue metering instrument transformers: $328,091.00

Cable duct banks: To be covered by a separate agreement

Actual Engineering and Construction Cost of the Work Chargeable to Customer: $321,000

MANNER OF PAYMENT OF THE ESTIMATE OF CAPITAL CONTRIBUTIONS AND WORK CHARGEABLE TO CUSTOMER

The Customer shall pay Hydro One the estimate of the Transformation Connection Pool Work Capital Contribution, the Estimate of Line Connection Pool Work Capital Contribution, the estimate of the Network Customer Allocated Work Capital Contribution and the estimate of the Engineering and Construction Cost of the Work Chargeable to Customer by making the progress payments specified below on or before the Payment Milestone Date specified below. Hydro One will invoice the Customer for each progress payment 30 days prior to the Payment Milestone Date.

Payment Milestone Date	Transformation Pool Work Capital Contribution	Line Pool Work Capital Contribution	Network Customer Allocated Work Capital Contribution	Work Chargeable To Customer	Total Payment Required
Jan. 15, 2009	$2,377,800.00	0	0	82,022.75	2,459,822.75
June 15, 2009	$2,377,800.00	0	0	82,022.75	2,459,822.75
Jan. 15, 2010	$2,377,800.00	0	0	82,022.75	2,459,822.75
June 15, 2010	$2,377,800.00	0	0	82,022.75	2,459,822.75
June 15, 2011	$312,500.00	0	0	-$7,091.00	$305,409.00

TRANSFORMATION CONNECTION REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Annual Period Ending On:	New Load** (MW) (1)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [A] (Note 1)	Adjusted Load Forecast (MW) [B]	Transformation Connection Revenue (k$) for True-Up, based on [A] or [B], whichever is applicable
1st Anniversary of In Service Date	19.1	19.1	19.1	369.6
2nd Anniversary of In Service Date	25.2	25.2	25.2	487.8
3rd Anniversary of In Service Date	31.0	31.0	31.0	599.2
4th Anniversary of In Service Date	37.0	37.0	37.0	713.9
5th Anniversary of In Service Date	43.1	43.1	43.1	832.1
6th Anniversary of In Service Date	49.4	49.4	49.4	953.8
7th Anniversary of In Service Date	55.9	55.9	55.9	1079.2
8th Anniversary of In Service Date	62.5	62.5	62.5	1208.4
9th Anniversary of In Service Date	69.4	69.4	69.4	1341.4
10th Anniversary of In Service Date	76.5	76.5	76.5	1478.4
11th Anniversary of In Service Date	83.8	83.8	83.8	1619.5
12th Anniversary of In Service Date	91.3	91.3	91.3	1764.9
13th Anniversary of In Service Date	99.1	99.1	99.1	1914.4
14th Anniversary of In Service Date	107.1	107.1	107.1	2068.8
15th Anniversary of In Service Date	115.0	115.0	115.0	2220.8
16th Anniversary of In Service Date	119.3	119.3	119.3	2305.6
17th Anniversary of In Service Date	119.3	119.3	119.3	2305.6
18th Anniversary of In Service Date	119.3	119.3	119.3	2305.6
19th Anniversary of In Service Date	119.3	119.3	119.3	2305.6
20th Anniversary of In Service Date	119.3	119.3	119.3	2305.6
21st Anniversary of In Service Date	119.3	119.3	119.3	2305.6
22nd Anniversary of In Service Date	119.3	119.3	119.3	2305.6
23rd Anniversary of In Service Date	119.3	119.3	119.3	2305.6
24th Anniversary of In Service Date	119.3	119.3	119.3	2305.6
25th Anniversary of In Service Date	119.3	119.3	119.3	2305.6

(1) Average monthly peak load for anniversary year, based on PLI of 0.78.

LINE CONNECTION REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Annual Period Ending On:	New Load** - (MW) (1)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [C]	Adjusted Load Forecast (MW) [D]	Line Connection Revenue (k$) for True-Up, Based on [C] or [D], whichever is applicable
1st Anniversary of In Service Date	19.1	19.1	0	0
2nd Anniversary of In Service Date	25.2	25.2	0	0
3rd Anniversary of In Service Date	31.0	31.0	0	0
4th Anniversary of In Service Date	37.0	37.0	0	0
5th Anniversary of In Service Date	43.1	43.1	0	0
6th Anniversary of In Service Date	49.4	49.4	0	0
7th Anniversary of In Service Date	55.9	55.9	0	0
8th Anniversary of In Service Date	62.5	62.5	0	0
9th Anniversary of In Service Date	69.4	69.4	0	0
10th Anniversary of In Service Date	76.5	76.5	0	0
11th Anniversary of In Service Date	83.8	83.8	0	0
12th Anniversary of In Service Date	91.3	91.3	0	0
13th Anniversary of In Service Date	99.1	99.1	0	0
14th Anniversary of In Service Date	107.1	107.1	0	0
15th Anniversary of In Service Date	115.0	115.0	0	0
16th Anniversary of In Service Date	119.3	119.3	0	0
17th Anniversary of In Service Date	119.3	119.3	0	0
18th Anniversary of In Service Date	119.3	119.3	0	0
19th Anniversary of In Service Date	119.3	119.3	0	0
20th Anniversary of In Service Date	119.3	119.3	0	0
21st Anniversary of In Service Date	119.3	119.3	0	0
22nd Anniversary of In Service Date	119.3	119.3	0	0
23rd Anniversary of In Service Date	119.3	119.3	0	0
24th Anniversary of In Service Date	119.3	119.3	0	0
25th Anniversary of In Service Date	119.3	119.3	0	0

(1) Average monthly peak load for anniversary year, based on PLI of 0.78.

NETWORK REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Annual Period Ending On:	New Load** - (MW)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [C]	Adjusted Load Forecast (MW) [D]	Network Revenue (k$) for True-Up, Based on [C] or [D], whichever is applicable
1st Anniversary of In Service Date	19.1	19.1	0.3	8.1
2nd Anniversary of In Service Date	25.2	25.2	0.4	10.7
3rd Anniversary of In Service Date	31.0	31.0	0.5	13.1
4th Anniversary of In Service Date	37.0	37.0	0.6	15.6
5th Anniversary of In Service Date	43.1	43.1	0.7	18.2
6th Anniversary of In Service Date	49.4	49.4	0.8	20.9
7th Anniversary of In Service Date	55.9	55.9	0.9	23.7
8th Anniversary of In Service Date	62.5	62.5	1.0	26.5
9th Anniversary of In Service Date	69.4	69.4	1.1	29.4
10th Anniversary of In Service Date	76.5	76.5	1.2	32.4
11th Anniversary of In Service Date	83.8	83.8	1.3	35.5
12th Anniversary of In Service Date	91.3	91.3	1.4	38.7
13th Anniversary of In Service Date	99.1	99.1	1.5	42.0
14th Anniversary of In Service Date	107.1	107.1	1.6	45.3
15th Anniversary of In Service Date	115.0	115.0	1.8	48.7
16th Anniversary of In Service Date	119.3	119.3	1.8	50.5
17th Anniversary of In Service Date	119.3	119.3	1.8	50.5
18th Anniversary of In Service Date	119.3	119.3	1.8	50.5
19th Anniversary of In Service Date	119.3	119.3	1.8	50.5
20th Anniversary of In Service Date	119.3	119.3	1.8	50.5
21st Anniversary of In Service Date	119.3	119.3	1.8	50.5
22nd Anniversary of In Service Date	119.3	119.3	1.8	50.5
23rd Anniversary of In Service Date	119.3	119.3	1.8	50.5
24th Anniversary of In Service Date	119.3	119.3	1.8	50.5
25th Anniversary of In Service Date	119.3	119.3	1.8	50.5

****** New Load based on Customer's Load Forecast which includes Part of New Load Exceeding Normal Capacity of Existing Load Facilities. "Overload" derived in accordance with Section 6.7.9 of the Transmission System Code and the OEB-Approved Connection Procedures. Any Customer load below the Normal Capacity of the Existing Load Facilities transferred to the New or Modified Facilities will not be credited towards the Transformation Connection Revenue Requirements, Line Connection Revenue Requirements or the Network Connection Revenue Requirements. The discounted cash flow calculation for Network Revenue requirements will be based on Incremental Network Load which is New Load less the amount of load, if any, that has been by-passed by the Customer at any of Hydro One's connection facilities.

Connection and Cost Recovery Agreement

between

Hydro One Brampton Networks Inc.

and

Hydro One Networks Inc.

for

Goreway TS Expansion

February 2008

Hydro One Brampton Networks Inc. (the "Customer") has requested and **Hydro One Networks Inc.** ("Hydro One") has agreed to build a new 230/27.6-27.6 kV, 75/100/125 MVA DESN (the "Project") on the terms and conditions set forth in this Agreement dated January 18, 2008 (the "Agreement") and the attached Standard Terms and Conditions for Low Risk Transmission Customer Connection Projects V3 09-2007 (the "Standard Terms and Conditions" or "T&C"). Schedules "A" and "B" attached hereto and the Standard Terms and Conditions are to be read with and form part of this Agreement.

Project Summary

The 27.6 kV loads in the East Brampton area are reaching transformation facilities' available capacity. The Customer has advised Hydro One that it will require new transformation capacity to supply 27.6 kV loads and has requested that Hydro One build a new 230/27.6-27.6 kV 75/100/125 MVA DESN at Hydro One's Goreway TS ("Goreway TS Expansion Project").

Term: The term of this Agreement commences on the date first written above and terminates on the 25th anniversary of the In Service Date.

Special Circumstances: The Customer acknowledges the station loading is limited by the 230 kV supply cables rating of 420 MVA based on single contingency.

In addition to the circumstances described in Section 5 of the Standard Terms and Conditions, the Ready for Service Date is subject to:

(a) the Customer executing and delivering this Agreement to Hydro One by no later than January 21, 2008, (the "Execution Date");

Subject to Section 31, this Agreement constitutes the entire agreement between the parties with respect to the subject matter of this Agreement and supersedes all prior oral or written representations and agreements concerning the subject matter of this Agreement.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by the signatures of their proper authorized signatories, as of the day and year first written above.

HYDRO ONE NETWORKS INC.

Jim Patterson
Manager - Customer Business Relations
I have the authority to bind the Corporation.

HYDRO ONE BRAMPTON NETWORKS INC.

Roger Albert
President
I have the authority to bind the Corporation.

Schedule "A" (*Project Title*)

PROJECT SCOPE

New or Modified Connection Facilities: Hydro One will design, construct, own and operate a new 75/100/125 MVA, 230/27.6-27.6 kV DESN to be located at the existing Goreway TS site.

Connection Point: 230 kV transmission circuits, V73RS and V76R

Ready for Service Date: May 1, 2010

HYDRO ONE CONNECTION WORK

Part 1:Transformation Connection Pool Work

Hydro One will:

Hydro One will design and build a new 230/27.6-27.6 kV DESN at Goreway TS as described below:

1. General Requirements

- Obtain approvals and permits as required for the station facilities. These include, and are not necessarily limited to those related to noise, soil removals, drainage, and landscaping.
- Carry out acceptance checks, testing and commissioning of station equipment and associated systems.
- Revise drawings, as required.
- Provide landscaping as per City, zoning and other requirements.
- Expand the existing station fence.

2. 230 kV Switchyard

The new HV switchyard will be integrated into existing HV facilities. The scope of work includes the following:

- Modify the exiting 230 kV line entrance and buswork as required to accommodate connection to the new transformers.
- Provide and install two (2) 230 kV motorized disconnect switches to meet the requirements of the line tap and to interrupt the maximum transformer magnetizing current.
- Provide and install two (2) 75/100/125 MVA, 230/27.6-27.6 kV transformers with a minimum summer 10-day LTR of 170 MVA.
- Provide and install transformer coolers and conservator tanks.
- Provide and install spill containment around the two transformers.
- Provide and install six (6) HV station class surge arresters, one for each phase of the HV bushings.
- Provide and install all required insulators, support structures, foundations and 230 kV cabling connecting the above equipment.

3. 27.6 kV Switching Facilities

All electrical equipment in the 27.6 kV switchyard is to be installed in bays of outdoor switching structure. The LV switchyard will be designed to allow for underground egress of the twelve feeders. Scope of work includes the following:

- Provide and install twelve (12) LV station class surge arresters.
- Provide and install four (4) 1.5 ohm transformer neutral grounding reactors.
- Provide and install two (2) main buses.
- Provide and install four (4) LV transformer breakers each with two isolating switches.
- Provide and install one (1) bus-tie breaker with two isolating switches.

- Provide and install twelve (12) 1200 Ampere feeder breakers, each with six (6) isolating switches.
- Provide and install buses between the main buses and the feeder breakers and future capacitor breakers.
- Provide and install six (6) feeder tie switches.
- Provide and install twelve (12) potential transformers for protection purposes.
- Provide and install twelve (12) sets of feeder buses connecting the feeder breakers, the feeder tie switches and the Customer's feeders.
- Provide and install all required insulators, support structures, foundations and LV cabling connecting the above equipment.

4. AC and DC Station Service Systems

- Provide and install a complete AC Station Service System including two (2) pad-mounted Station Service Transformers with associated fusing, insulators, transfer switches, breakers, disconnect switches, panels and cabling.
- Provide a complete DC Station Service System along with 125 VDC sealed battery, charger, DC distribution panels and cabling.

5. Protection, Control and Teleprotections Systems

- Provide and install a pre-fabricated & pre-wired P&C building.
- Provide cross tripping facilities between the existing 27.6 kV and 44 kV DESNs and the new DESN and for the interface between the new facility and the existing line protection associated with circuits V73RS and V76R.
- Review and revise, as required, the line protections on V73RS and V76R at Rexdale TS, Sithe Goreway GS, Cardiff TS, Bramalea TS and the existing Goreway TS.
- Provide SCADA telemetry quantities to OGCC.
- Provide SCADA telemetry quantities to IESO.
- Provide under-frequency load shedding relay, as required.
- Witness P&C building manufacturer commissioning
- Commission all P&C devices associated with the new facilities as well as at existing facilities connected to 230 kV circuits, V73RS and V76R.

6. Grounding and Lightning Protection

- Provide and install station ground grid in the new switchyard.
- Provide grounding for the new sections of station fence.
- Provide standard grounding for the power transformers, HV and LV surge arresters, HV and LV switches, breakers and all steel structures.
- Provide perimeter grounding for the P&C building and connect to the grounding bus inside the P&C building.
- Review and upgrade lightning protection at the TS, as required.

7. Exclusions/Assumptions

Cost estimates are based on the following assumptions:

- There will be no requirement for Environmental Assessment.
- Noise assessment is required
- Geotechnical Investigation exists for the existing portion of the station and this estimate assumes the same soil conditions for the extension of the station
- Excavated soil is not contaminated.
- No 230 kV lines are involved in this work.

Part 2:Line Connection Pool Work

Hydro One will:

- Move the 230 kV underground termination facilities on the TS site to make room for the new 230 kV buswork extension to the DESN.

NOTE: Once this new DESN has been completed, the installed capacity for all DESNs at Goreway TS will exceed the capacity of the supply circuits (420 MVA), V73RS and V76R. When the combined loading on all DESNs at Goreway TS reaches the capacity of the supply circuits, transmission reinforcement will be required.

Part 3:Network Customer Allocated Work

Hydro One will:

- Review and revise, as required, the line protections on V73RS and V76R at Richview TS and Claireville TS

Part 4:Network Pool Work (Non-Recoverable from Customer)

Hydro One will:

- Not Applicable

Part 5: Work Chargeable to Customer

Hydro One will:

1. Revenue Metering Instrument Transformers

- Specify, supply, install and connect twelve (12) Revenue Canada approved revenue metering potential transformers (PTs) and twelve (12) free standing Revenue Canada approved revenue metering current transformers (CTs) on LV bus structures. The bus structure is to be modified to accommodate the installation.
- Provide four (4) metering junction boxes on the structure supporting the revenue metering CTs.
- Supply, install and terminate the secondary cables from the instrument transformer terminal boxes to metering junction boxes and to the metering cabinets provided by the Customer.
- Install and terminate 120 VAC Station Service cables from AC Station Service Distribution panel to the metering cabinets provided by the Customer.
- Install and terminate telephone service cables from telecom cable interface box to metering cabinets provided by the Customer.
- Install the structure supporting the Customer's metering cabinets to a location outside the P&C building.
- Providing spare instrument transformers are NOT included in the scope of work.

2. Feeder Duct Banks

- Expectation is that Hydro One will be asked by the Customer to provide and install feeder duct banks from the feeder breakers to just outside the station fence. This work is NOT covered by this agreement and will be dealt with by a separate agreement.

CCRA - Goreway TS

Part 6: Scope Change

For the purposes of this Part 6 of Schedule "A", the term "Non-Customer Initiated Scope Change(s)" means one or more changes that are required to be made to the Project Scope as detailed and documented in Parts 1 to 5 of this Schedule "A" such as a result of any one or more of the following:

- any environmental assessment(s);
- any IESO requirements identified in the System Impact Assessment or any revisions thereto.

Any change in the Project Scope as detailed and documented in Parts 1 to 5 of this Schedule "A" whether they are initiated by the Customer or are Non-Customer Initiated Scope Changes, may result in a change to the Project costs estimated in Schedule "B" of this Agreement and the Project schedule, including the Ready for Service Date.

All Customer initiated scope changes to this Project must be in writing to Hydro One.

Hydro One will advise the Customer of any cost and schedule impacts of any Customer initiated scope changes. Hydro One will advise the Customer of any Material cost and/or Material schedule impacts of any Non-Customer Initiated Scope Changes.

Hydro One will not implement any Customer initiated scope changes until written approval has been received from the Customer accepting the new pricing and schedule impact.

Hydro One will implement all Non-Customer initiated scope changes until the estimate of the Engineering and Construction Cost of all of the Non-Customer initiated scope changes made by Hydro One reaches 10% of the total sum of the estimates of the Engineering and Construction Cost of:

(i) the Transformation Connection Pool Work,;
(ii) the Line Connection Pool Work;
(iii) Network Pool Work
(iv) Network Customer Allocated Work; and
(v) the Work Chargeable to Customer.

At that point, no further Non-Customer initiated scope changes may be made by Hydro One without the written consent of the Customer accepting new pricing and schedule impact. If the Customer does not accept the new pricing and schedule impact, Hydro One will not be responsible for any delay in the Ready for Service Date as a consequence thereof.

CUSTOMER CONNECTION WORK

The Customer will:

- Provide and install four (4) Revenue Metering cabinets and associated metering equipment and cabling.
- Order a landline telephone service for IESO MV90 access and ensure that the service is available at least two weeks prior to in-service date.
- Accept responsibility for the registration of the revenue metering installations. The IESO registration work must be completed at least two weeks prior to the in-service date.
- Accept responsibility for purchasing any spare equipment associated with the revenue metering.
- Provide and install feeder duct banks outside the station fence.

- Provide and install 27.6 kV feeder cables and make connection to NEMA pads at feeder disconnect switch.

NOTES:

The Estimate of the Engineering and Construction Cost of the Transformation Connection Pool Work and the Estimate of Transformation Connection Pool Work Capital Contribution do not include any amounts associated with the easements and other land rights to be obtained by Hydro One from third parties for the Transformation Connection Pool Work. The actual cost of obtaining those easements and other land rights will be reflected in the Actual Engineering and Construction Cost of the Transformation Connection Pool Work and the Actual Transformation Connection Pool Work Capital Contribution.

EXISTING LOAD:

	A	B
Existing Load Facility	**Existing Load (MW)[1,]**	**Normal Capacity (MW)[2]**
Goreway TS T5/T6	181	181
Bramalea TS[3]	82.5	82.5

Notes:

1. Existing Load (Annual Peak Load) means the Customer's Assigned Capacity at the Existing Load Facility as of the date of this Agreement (Section 3.0.3 of the *Transmission System Code).*
2. Any station load above the Normal Capacity of the Existing Load Facility (Overload) will be determined in accordance with Section 6.7.9 of the *Transmission System Code* and Hydro One's Connection Procedures. If the Overload is transferred to the New or Modified Connection Facilities, the Overload will be credited to the Line Connection Revenue, Transformation Connection Revenue or Network Revenue requirement, whichever is applicable.
3. The Customer utilises 82.5MW, which represents 50% of the total capacity at Bramalea TS.
4. Average monthly peak load will be calculated based on PLI of 0.78.

OTHER RELEVANT CONSIDERATIONS: NONE

EXCEPTIONAL CIRCUMSTANCES RE. NETWORK CONSTRUCTION OR MODIFICATIONS: (Yes/No). NONE

MISCELLANEOUS

Customer Connection Risk Classification: Low Risk

True-Up Points: **Low Risk** (a) following the fifth and tenth anniversaries of the In Service Date; and

(b) following the fifteenth anniversary of the In Service Date if the Actual Load is 20% higher or lower than the Load Forecast at the end of the tenth anniversary of the In Service Date.

Customer's GST Registration Number: 864867635RT0001

Documentation Required (after In Service Date): Final Feeder Egress Drawings

Ownership: Hydro One will own all equipment provided by Hydro One as part of the Hydro One Connection Work.

Approval Date (if Section 92 required to be obtained by Hydro One): N/A

Security Requirements: Specify amount or Nil

Security Date:

Easement Required from Customer: NO

Easement Date: N/A

Easement Lands: N/A

Easement Term: N/A

Approval Date (for OEB leave to construct):

Revenue Metering: IESO compliant revenue metering to be provided by the Customer

Customer Notice Info:

Hydro One Brampton Networks Inc.
175 Sandalwood Pkwy., West
Brampton, Ontario L7A 1E8

Attention: Roger Albert, President & CEO
Fax #: (905) 840-1305

CCRA - Goreway TS

Schedule "B" (*Project Title*)

TRANSFORMATION CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Transformation Connection Pool Work: $23,489,005.00

Estimate of Transformation Connection Pool Work Capital Contribution: $9,511,200.00

Actual Engineering and Construction Cost of the Transformation Connection Pool Work: To be provided 180 days after the Ready for Service Date

Actual Transformation Connection Pool Work Capital Contribution: To be provided 180 days after the Ready for Service Date

Capital Contribution Includes the Cost of Capacity Not Needed by the Customer:

LINE CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Line Connection Pool Work: $376,493.00

Estimate of Line Connection Pool Work Capital Contribution: N/A

Actual Engineering and Construction Cost of the Line Connection Pool Work: To be provided 180 days after the Ready for Service Date

Actual Line Connection Pool Work Capital Contribution: To be provided 180 days after Ready for Service Date

Capital Contribution Includes the Cost of Capacity Not Needed by the Customer:

NETWORK CUSTOMER ALLOCATED WORK

Estimate of the Engineering and Construction Cost of the Network Customer Allocated Work: $284,764.00

Actual Engineering and Construction Cost of the Network Customer Allocated Work: To be provided 180 days after Ready for Service Date

NETWORK POOL WORK (NON-RECOVERABLE FROM CUSTOMER):

The estimated Engineering and Construction Cost of the Network Pool Work (Non-Recoverable from Customer) is $0.00. Subject to Section 14.2 of the Standard Terms and Conditions, Hydro One will perform this work at its own expense.

CCRA - Goreway TS

WORK CHARGEABLE TO CUSTOMER

Estimate of the Engineering and Construction Cost of the Work Chargeable To Customer:

Revenue metering instrument transformers: $328,091.00

Cable duct banks: To be covered by a separate agreement

Actual Engineering and Construction Cost of the Work Chargeable to Customer: To be provided 180 days after Ready for Service Date

MANNER OF PAYMENT OF THE ESTIMATE OF CAPITAL CONTRIBUTIONS AND WORK CHARGEABLE TO CUSTOMER

The Customer shall pay Hydro One the estimate of the Transformation Connection Pool Work Capital Contribution, the Estimate of Line Connection Pool Work Capital Contribution, the estimate of the Network Customer Allocated Work Capital Contribution and the estimate of the Engineering and Construction Cost of the Work Chargeable to Customer by making the progress payments specified below on or before the Payment Milestone Date specified below. Hydro One will invoice the Customer for each progress payment 30 days prior to the Payment Milestone Date.

Payment Milestone Date	Transformation Pool Work Capital Contribution	Line Pool Work Capital Contribution	Network Customer Allocated Work Capital Contribution	Work Chargeable To Customer	Total Payment Required
Jan. 15, 2009	2,377,800.00	0	0	82,022.75	2,459,822.75
June 15, 2009	2,377,800.00	0	0	82,022.75	2,459,822.75
Jan. 15, 2010	2,377,800.00	0	0	82,022.75	2,459,822.75
June 15, 2010	2,377,800.00	0	0	82,022.75	2,459,822.75

CCRA - Goreway TS

TRANSFORMATION CONNECTION REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Annual Period Ending On:	New Load** (MW) (1)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [A] (Note 1)	Adjusted Load Forecast (MW) [B]	Transformation Connection Revenue (k$) for True-Up, based on [A] or [B], whichever is applicable
1st Anniversary of In Service Date	18.6	18.6	18.6	359.3
2nd Anniversary of In Service Date	24.8	24.8	24.8	478.6
3rd Anniversary of In Service Date	30.5	30.5	30.5	589.8
4th Anniversary of In Service Date	36.4	36.4	36.4	704.2
5th Anniversary of In Service Date	42.6	42.6	42.6	822.1
6th Anniversary of In Service Date	48.8	48.8	48.8	943.5
7th Anniversary of In Service Date	55.3	55.3	55.3	1068.6
8th Anniversary of In Service Date	62.0	62.0	62.0	1197.4
9th Anniversary of In Service Date	68.8	68.8	68.8	1330.1
10th Anniversary of In Service Date	75.9	75.9	75.9	1466.8
11th Anniversary of In Service Date	83.2	83.2	83.2	1607.5
12th Anniversary of In Service Date	90.7	90.7	90.7	1752.5
13th Anniversary of In Service Date	98.4	98.4	98.4	1901.9
14th Anniversary of In Service Date	106.4	106.4	106.4	2055.7
15th Anniversary of In Service Date	114.3	114.3	114.3	2208.7
16th Anniversary of In Service Date	119.3	119.3	119.3	2305.6
17th Anniversary of In Service Date	119.3	119.3	119.3	2305.6
18th Anniversary of In Service Date	119.3	119.3	119.3	2305.6
19th Anniversary of In Service Date	119.3	119.3	119.3	2305.6
20th Anniversary of In Service Date	119.3	119.3	119.3	2305.6
21st Anniversary of In Service Date	119.3	119.3	119.3	2305.6
22nd Anniversary of In Service Date	119.3	119.3	119.3	2305.6
23rd Anniversary of In Service Date	119.3	119.3	119.3	2305.6
24th Anniversary of In Service Date	119.3	119.3	119.3	2305.6
25th Anniversary of In Service Date	119.3	119.3	119.3	2305.6

(1) Average monthly peak load for anniversary year, based on PLI of 0.78.

CCRA - Goreway TS

LINE CONNECTION REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Annual Period Ending On:	New Load** - (MW) (1)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [C]	Adjusted Load Forecast (MW) [D]	Line Connection Revenue (k$) for True-Up, Based on [C] or [D], whichever is applicable
1st Anniversary of In Service Date	18.6	18.6	1.5	10.9
2nd Anniversary of In Service Date	24.8	24.8	2.0	14.4
3rd Anniversary of In Service Date	30.5	30.5	2.5	17.8
4th Anniversary of In Service Date	36.4	36.4	3.0	21.2
5th Anniversary of In Service Date	42.6	42.6	3.5	24.8
6th Anniversary of In Service Date	48.8	48.8	4.0	28.4
7th Anniversary of In Service Date	55.3	55.3	4.5	32.2
8th Anniversary of In Service Date	62.0	62.0	5.1	36.1
9th Anniversary of In Service Date	68.8	68.8	5.7	40.1
10th Anniversary of In Service Date	75.9	75.9	6.2	44.2
11th Anniversary of In Service Date	83.2	83.2	6.8	48.5
12th Anniversary of In Service Date	90.7	90.7	7.5	52.8
13th Anniversary of In Service Date	98.4	98.4	8.1	57.3
14th Anniversary of In Service Date	106.4	106.4	8.8	62.0
15th Anniversary of In Service Date	114.3	114.3	9.4	66.6
16th Anniversary of In Service Date	119.3	119.3	9.8	69.5
17th Anniversary of In Service Date	119.3	119.3	9.8	69.5
18th Anniversary of In Service Date	119.3	119.3	9.8	69.5
19th Anniversary of In Service Date	119.3	119.3	9.8	69.5
20th Anniversary of In Service Date	119.3	119.3	9.8	69.5
21st Anniversary of In Service Date	119.3	119.3	9.8	69.5
22nd Anniversary of In Service Date	119.3	119.3	9.8	69.5
23rd Anniversary of In Service Date	119.3	119.3	9.8	69.5
24th Anniversary of In Service Date	119.3	119.3	9.8	69.5
25th Anniversary of In Service Date	119.3	119.3	9.8	69.5

(1) Average monthly peak load for anniversary year, based on PLI of 0.78.

CCRA - Goreway TS

NETWORK REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Annual Period Ending On:	New Load** - (MW)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [C]	Adjusted Load Forecast (MW) [D]	Network Revenue (k$) for True-Up, Based on [C] or [D], whichever is applicable
1st Anniversary of In Service Date	18.6	18.6	0.3	8.3
2nd Anniversary of In Service Date	24.8	24.8	0.4	11.0
3rd Anniversary of In Service Date	30.5	30.5	0.5	13.6
4th Anniversary of In Service Date	36.4	36.4	0.6	16.2
5th Anniversary of In Service Date	42.6	42.6	0.7	18.9
6th Anniversary of In Service Date	48.8	48.8	0.8	21.7
7th Anniversary of In Service Date	55.3	55.3	0.9	24.6
8th Anniversary of In Service Date	62.0	62.0	1.0	27.5
9th Anniversary of In Service Date	68.8	68.8	1.1	30.6
10th Anniversary of In Service Date	75.9	75.9	1.2	33.7
11th Anniversary of In Service Date	83.2	83.2	1.3	37.0
12th Anniversary of In Service Date	90.7	90.7	1.5	40.3
13th Anniversary of In Service Date	98.4	98.4	1.6	43.7
14th Anniversary of In Service Date	106.4	106.4	1.7	47.3
15th Anniversary of In Service Date	114.3	114.3	1.8	50.8
16th Anniversary of In Service Date	119.3	119.3	1.9	53.0
17th Anniversary of In Service Date	119.3	119.3	1.9	53.0
18th Anniversary of In Service Date	119.3	119.3	1.9	53.0
19th Anniversary of In Service Date	119.3	119.3	1.9	53.0
20th Anniversary of In Service Date	119.3	119.3	1.9	53.0
21st Anniversary of In Service Date	119.3	119.3	1.9	53.0
22nd Anniversary of In Service Date	119.3	119.3	1.9	53.0
23rd Anniversary of In Service Date	119.3	119.3	1.9	53.0
24th Anniversary of In Service Date	119.3	119.3	1.9	53.0
25th Anniversary of In Service Date	119.3	119.3	1.9	53.0

** New Load based on Customer's Load Forecast which includes Part of New Load Exceeding Normal Capacity of Existing Load Facilities. "Overload" derived in accordance with Section 6.7.9 of the Transmission System Code and the OEB-Approved Connection Procedures. Any Customer load below the Normal Capacity of the Existing Load Facilities transferred to the New or Modified Facilities will not be credited towards the Transformation Connection Revenue Requirements, Line Connection Revenue Requirements or the Network Connection Revenue Requirements. The discounted cash flow calculation for Network Revenue requirements will be based on Incremental Network Load which is New Load less the amount of load, if any, that has been by-passed by the Customer at any of Hydro One's connection facilities.

Standard Terms and Conditions for Load Customer Transmission Customer Connection Projects

1. Each party represents and warrants to the other that:

(a) it is duly incorporated, formed or registered (as applicable) under the laws of its jurisdiction of incorporation, formation or registration (as applicable);
(b) it has all the necessary corporate power, authority and capacity to enter into the Agreement and to perform its obligations hereunder;
(c) the execution, delivery and performance of the Agreement by it has been duly authorized by all necessary corporate and/or governmental and/or other organizational action and does not (or would not with the giving of notice, the lapse of time or the happening of any other event or condition) result in a violation, a breach or a default under or give rise to termination, greater rights or increased costs, amendment or cancellation or the acceleration of any obligation under (i) its charter or by-law instruments; (ii) any Material contracts or instruments to which it is bound; or (iii) any laws applicable to it;
(d) any individual executing this Agreement, and any document in connection herewith, on its behalf has been duly authorized by it to execute this Agreement and has the full power and authority to bind it;
(e) the Agreement constitutes a legal and binding obligation on it, enforceable against it in accordance with its terms;
(f) it is registered for purposes of Part IX of the *Excise Tax Act* (Canada). The GST registration number for Hydro One is 87086-5821 RT0001 and the GST registration number for the Customer is as specified in Schedule "A" of the Agreement; and
(g) no proceedings have been instituted by or against it with respect to bankruptcy, insolvency, liquidation or dissolution.

Part A: Hydro One Connection Work and Customer Connection Work

2. The Customer and Hydro One shall perform their respective obligations outlined in the Agreement in a manner consistent with Good Utility Practice and the Transmission System Code, in compliance with all Applicable Laws, and using duly qualified and experienced people.

3. The parties acknowledge and agree that:

(a) Hydro One is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Hydro One Connection Work and those required for the construction, Connection and operation of the New or Modified Connection Facilities;

(b) the Customer shall perform the Customer Connection Work, at its own expense;

(c) except as specifically provided in the Agreement, the Customer is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Customer Connection Work and those required for the construction, Connection and operation of the Customer's Facilities including, but not limited to, where applicable, leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998*;

(d) the Customer is responsible for installing equipment and facilities such as protection and control equipment to protect its own property, including, but not limited to the Customer's Facilities;

(e) the Customer shall provide Hydro One with Project data required by Hydro One, including, but not limited to (i) the same technical information that the Customer provided the IESO during any connection assessment and facility registration process associated with the Customer's Facilities in the form outlined in the applicable sections of the IESO's public website and (ii) technical specifications (including electrical drawings) for the Customer's Facilities;

(f) Hydro One may participate in the commissioning, inspection or testing of the Customer's Connection Facilities at a time that is mutually agreed by Hydro One and the Customer and the Customer shall ensure that the work performed by the Customer and others required for successful commissioning, inspection or testing of protective equipment is completed as required to enable Hydro One witnessing and testing to confirm satisfactory performance of such systems;

(g) unless otherwise provided herein, Hydro One's responsibilities under the Agreement with respect to the Connection of the New or Modified Connection Facilities to Hydro One's transmission system shall be limited to the performance of the Hydro One Connection Work;

(h) Hydro One is not permitted to Connect any new, modified or replacement Customer's Facilities unless any required Connection authorizations, certificate of inspection or other applicable approval have been issued or given by the Ontario Electrical Safety Authority in relation to such facilities;

(i) Hydro One may require that the Customer provide Hydro One with test certificates certifying that the Customer's Facilities have passed all relevant tests and comply with the *Transmission System Code***,** the Market Rules, Good Utility Practice, the standards of all applicable reliability organizations and any Applicable

Laws, including, but not limited to any certificates of inspection that may be required by the Ontario Electrical Safety Authority;

(j) in addition to the Hydro One Connection Work described in Schedule "A", Hydro One shall: provide the Customer with such technical parameters as may be required to assist the Customer in ensuring that the design of the Customer's Facilities is consistent with the requirements applicable to Hydro One's transmission system and the basic general performance standards for facilities set out in the *Transmission System Code*, including Appendix 2 thereof; and

(k) if Hydro One requires access to the Customer's Facilities for the purposes of performing the Hydro One Connection Work or the Customer requires access to Hydro One's Facilities for the purposes of the Customer Connection Work, the parties agree that Section 27.13 of the Connection Agreement shall govern such access and is hereby incorporated in its entirety by reference into, and forms an integral part of the Agreement. All references to "this Agreement" in Section 27.13 shall be deemed to be a reference to the Agreement;

(l) the Customer shall enter into a Connection Agreement with Hydro One or amend its existing Connection Agreement with Hydro One at least 14 calendar days prior to the Connection;

(m) Hydro One shall use commercially reasonable efforts to ensure that any applications required to be filed to obtain any permits or approvals required under Applicable Laws for the Hydro One Connection Work are filed in a timely manner; and

(n) the Customer shall use commercially reasonable efforts to ensure that any applications required to be filed to obtain any permits or approvals required under Applicable Laws for the Customer Connection Work or for the construction, Connection and operation of the Customer's Facilities are filed in a timely manner.

4. The following aspects of the Hydro One Connection Work and Hydro One's rights and requirements hereunder are solely for the purpose of Hydro One ensuring that the Customer Facilities to be connected to Hydro One's transmission system do not materially reduce or adversely affect the reliability of Hydro One's transmission system and do not adversely affect other customers connected to Hydro One's transmission system, Hydro One's:

(i) specifications of the protection equipment on the Customer's side of the Connection Point;
(ii) acceptance of power system components on the Customer's side of the Connection Point;
(iii) acceptance of the technical specifications (including electrical drawings) for the Customer's Facilities and/or the Customer Connection Work; and
(iv) participation in the commissioning, inspection or testing of the Customer's Facilities,

The Customer is responsible for installing equipment and facilities such as protection and control equipment to protect its own property, including, but not limited to the Customer's Facilities.

5. Hydro One shall use commercially reasonable efforts to complete the Hydro One Connection Work by the Ready for Service Date specified in Schedule "A" provided that:

(a) the Customer is in compliance with its obligations under the Agreement;
(b) any work required to be performed by third parties has been performed in a timely manner and in a manner to the satisfaction of Hydro One, acting reasonably;
(c) there are no delays resulting from Hydro One not being able to obtain outages from the IESO required for any portion of the Hydro One Connection Work or from the IESO making changes to the Hydro One Connection Work or the scheduling of all or a portion of the Hydro One Connection Work ;
(d) Hydro One does not have to use its employees, agents and contractors performing the Hydro One Connection Work or the Network Pool Work elsewhere on its transmission system or distribution system due to an Emergency (as that term is defined in the *Transmission System Code*) or a Force Majeure Event;
(e) Hydro One is able to obtain the materials and labour required to perform the Hydro One Connection Work with the expenditure of Premium Costs where required;
(f) where Hydro One needs to obtain leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998*, such leave is obtained on or before the date specified as the Approval Date in Schedule "A" of the Agreement;
(g) where applicable, Hydro One received the easement described in Section 24 hereof by the Easement Date specified in Schedule "A" of the Agreement;
(h) Hydro One has received or obtained prior to the dates upon which Hydro One requires any or one or more of the following under Applicable Laws in order to perform all or any part of the Hydro One Connection Work:
    (i) environmental approvals, permits or certificates;
    (ii) land use permits from the Crown; and
    (iii) building permits and site plan approvals;
(j) Hydro One is able, using commercially reasonable efforts, to obtain all necessary land rights on terms substantially similar to the form of the easement that

is attached hereto as Appendix "B" of these Standard Terms and Conditions for the Project, prior to the dates upon which Hydro One needs to commence construction of the Hydro One Connection Work in order to meet the Ready for Service Date;

(k) there are no delays resulting from Hydro One being unable to obtain materials or equipment required from suppliers in time to meet the project schedule for any portion of the Hydro One Connection Work provided that such delays are beyond the reasonable control Hydro One; and

(l) the Customer executed the Agreement on or before the date specified as the Execution Date.

The Customer acknowledges and agrees that the Ready for Service Date may be materially affected by difficulties with obtaining or the inability to obtain all necessary land rights and/or environmental approvals, permits or certificates.

6. Upon completion of the Hydro One Connection Work:

(a) Hydro One shall own, operate and maintain all equipment specified in Schedule "A" of the Agreement under the heading "Ownership"; and

(b) other than equipment referred to in (a) above that shall be owned, operated and maintained by Hydro One, all other equipment provided by Hydro One as part of the Hydro One Connection Work or provided by the Customer as part of the Customer Connection Work shall be owned, operated and maintained by the Customer.

The Customer acknowledges that:

(i) ownership and title to the equipment referred to in (a) above shall throughout the Term and thereafter remain vested in Hydro One and the Customer shall have no right of property therein; and

(ii) any portion of the equipment referred to in (a) above that is located on the Customer's property shall be and remain the property of Hydro One and shall not be or become fixtures and/or part of the Customer's property.

7. The Customer acknowledges and agrees that Hydro One is not responsible for the provision of power system components on the Customer's Facilities, including, without limitation, all transformation, switching, metering and auxiliary equipment such as protection and control equipment.

All of the power system components on the Customer's side of the Connection Point including, without limitation, all transformation, switching and auxiliary equipment such as protection and control equipment shall be subject to the acceptance of Hydro One with regard to Hydro One's requirements to permit Connection of the New or Modified Connection Facilities to Hydro One's transmission system, and shall be installed, maintained and operated in accordance with all Applicable Laws, codes and standards, including, but not limited to, the *Transmission System Code*, at the expense of the Customer.

8. Where Hydro One has equipment for automatic reclosing of circuit breakers after an interruption for the purpose of improving the continuity of supply, it shall be the obligation of the Customer to provide adequate protective equipment for the Customer's facilities that might be adversely affected by the operation of such reclosing equipment. The Customer shall provide such equipment as may be required from time to time by Hydro One for the prompt disconnection of any of the Customer's apparatus that might affect the proper functioning of Hydro One's reclosing equipment.

9. The Customer shall provide Hydro One with copies of the documentation specified in Schedule "A" of the Agreement under the heading "Documentation Required", acceptable to Hydro One, within 120 calendar days after the Ready for Service Date. The Customer shall ensure that Hydro One may retain this documentation for Hydro One's ongoing planning, system design, and operating review. The Customer shall also maintain and revise such documentation to reflect changes to the Customer's Facilities and provide copies to Hydro One on demand and as specified in the Connection Agreement.

Part B: Transformation Connection Pool Work and/or Line Connection Pool Work and/or Network Customer Allocated Work

10.1 To the extent that the Pool Funded Cost of the Hydro One Connection Work is not recoverable by Transformation Connection Revenue for the Transformation Connection Pool Work and/or Line Connection Revenue for the Line Connection Pool Work and/or Network Revenue for the Network Customer Allocated Work during the Economic Evaluation Period, the Customer agrees to pay Hydro One a Capital Contribution towards the Pool Funded Cost of the Transformation Connection Pool Work and/or a Capital Contribution towards the Pool Funded Cost of the Line Connection Pool Work and/or a Capital Contribution towards the Pool Funded Cost of the Network Customer Allocated Work and any amounts payable to Hydro One under Subsection 12 (a) (i) hereof.

An estimate of the Engineering and Construction Cost (not including Taxes) of the Transformation Connection Pool Work and/or Line Connection Pool Work and/or Network Customer Allocated Work is provided in Schedule "B" of the Agreement.

An estimate of the Capital Contribution for each of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work is specified in Schedule "B" of the Agreement (plus Taxes). The Customer shall pay Hydro One the estimated Capital Contribution(s) in the manner specified in Schedule "B" of the Agreement.

Within 180 calendar days after the Ready for Service Date, Hydro One shall provide the Customer with a new Schedule "B" to replace Schedule "B" of the Agreement attached hereto which shall identify the following:

(i) the actual Engineering and Construction Cost of the Transformation Connection Pool Work;
(ii) the actual Engineering and Construction Cost of the Line Connection Pool Work;
(iii) the actual Engineering and Construction Cost of the Network Customer Allocated Work;
(iv) the actual Engineering and Construction Cost of the Work Chargeable to Customer;
(v) the actual Capital Contribution required to be paid by the Customer for each of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work; and
(vi) the revised Transformation Connection Revenue and/or Line Connection Revenue requirements and/or Network Revenue requirements based on the Load Forecast or the Adjusted Load Forecast, whichever is applicable.

The new Schedule "B" shall be made a part hereof as though it had been originally incorporated into the Agreement.

If an estimate of a Capital Contributions paid by the Customer exceeds the actual Capital Contribution required to be paid by the Customer for any or all of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work, Hydro One shall refund the difference to the Customer (plus Taxes) within 30 days following the issuing of the new Schedule "B". If the estimate of a Capital Contribution paid by the Customer is less than the actual Capital Contributions required to be paid by the Customer for any or all of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work, the Customer shall pay Hydro One the difference (plus Taxes) within 30 days following the issuing of the new Schedule "B".

10.2 Hydro One shall not include the following amounts in the Capital Contributions referenced in Section 10.1, any capital contribution for:

(a) a Connection Facility that was otherwise planned by Hydro One except for advancement costs;
(b) capacity added to a Connection Facility in anticipation of future load growth not attributable to the Customer; or
(c) the construction of or modifications to Hydro One's Network Facilities that may be required to accommodate the New or Modified Connection other than Network Customer Allocated Work unless Hydro One has indicated in Schedule "A" of the Agreement that exceptional circumstances exist so as to reasonably require the Customer to make a Capital Contribution.

10.3 Notwithstanding Sub-section 10.2(c) above, if Hydro One indicates in Schedule "A" of the Agreement that exceptional circumstances exist so as to reasonably require the Customer to make a Capital Contribution towards the Network Pool Work, Hydro One shall not, without the prior written consent of the Customer, refuse to commence or diligently perform the Network Pool Work pending direction from the OEB under section 6.3.5 of the *Transmission System Code* provided that the Customer provides Hydro One with a security deposit in accordance with Section 20 of these Standard Terms and Conditions.

Until such time as Hydro One has actually begun to perform the Network Pool Work, the Customer may request, in writing, that Hydro One not perform the Network Pool Work and Hydro One shall promptly return to the Customer any outstanding security deposit related to the Network Pool Work.

10.4 If the Customer has made a Capital Contribution under Section 10.1 hereof and where this Capital Contribution includes the cost of capacity on the Connection Facility not needed by the Customer as indicated in Schedule "B" of the Agreement, Hydro One shall provide the Customer with a refund, calculated in accordance with Section 6.2.25 of the *Transmission System Code* if that capacity is assigned to another Load Customer within five (5) years of the In Service Date.

11. Hydro One shall perform a True-Up, based on Actual Load:

(a) at the True-Up Points specified in Schedule "A" of the Agreement; and
(b) the time of disconnection where the Customer voluntarily and permanently disconnects the Customer's Facilities from Hydro One's transmission facilities and the prior to the final True-Up Point identified in (a) above.

For True-Up purposes, if the Customer does not pay a Capital Contribution, Hydro One shall provide the Customer with an Adjusted Load Forecast.

Hydro One shall perform True-Ups in a timely manner. Within 30 calendar days following completion of each of the True-Ups referred to in 11(a), Hydro One shall provide the Customer with the results of the True-Up.

12(a) If the result of a True-Up performed in accordance with Section 11 above is that the Actual Load and Updated Load Forecast is:

(i) less than the load in the Load Forecast or the Adjusted Load Forecast, whichever is applicable, and therefore does not generate the forecasted Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue required for the Economic Evaluation Period, the Customer shall pay Hydro One an amount equal to the shortfall adjusted to reflect the time value of money within 30 days after the date of Hydro One's invoice therefor; and

(ii) more than the load in the Load Forecast or the Adjusted Load Forecast, whichever is applicable, and therefore generates more than the forecasted Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue required for the Economic Evaluation Period, Hydro One shall post the excess Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue as a credit to the Customer in a notional account. Hydro One shall apply this credit against any shortfall in subsequent True-Up calculations. Where the Customer paid a Capital Contribution in accordance with Section 10.1 hereof, Hydro One shall rebate the Customer an amount that is the lesser of the credit balance in the notional account adjusted to reflect the time value of money, and the Capital Contribution adjusted to reflect the time value of money by no later than 30 days following the final True-Up calculation.

12(b) All adjustments to reflect the time value of money to be performed under Subsection 12(a) above shall be performed in accordance with the OEB-Approved Connection Procedures. As of the date of this Agreement, the time value of money is determined using Hydro One's after-tax cost of capital as used in the original economic evaluation performed in accordance with the requirements of the *Transmission System Code.*

13.1 With respect to the installation of embedded generation (as determined in accordance with Section 11.1 of the *Transmission System Code)* during the applicable True-Up period Hydro One shall comply with the requirements of Section 6.5.8 of the *Transmission System Code* when carrying out True-Up calculations if the Customer is a Distributor or the requirements of Section 6.5.9 of the Transmission System Code when carrying out True-Up calculations if the Customer is a Load Customer other than a Distributor.

13.2 With respect to energy conservation, energy efficiency, load management or renewable energy activities that occurred during the applicable True-Up period Hydro One shall comply with the requirements of Section 6.5.10 of the *Transmission System Code* when carrying out True-Up calculations provided that the Customer demonstrates to the reasonable satisfaction of Hydro One (such as by means of an energy study or audit) that the amount of any reduction in the Customer's load has resulted from energy conservation, energy efficiency, load management or renewable energy activities that occurred during the applicable True-Up period.

14. Hydro One shall provide the Customer with all information pertaining to the calculation of all Engineering and Construction Costs, Capital Contributions and True-Ups that the Customer is entitled to receive in accordance with the requirements of the *Transmission System Code*.

Part C: Work Chargeable to Customer, Network Pool Work and Premium Costs

15.1 The Customer shall pay Hydro One's Engineering and Construction Cost (plus Taxes) of the Hydro One Connection Work described asWork Chargeable to Customer in Schedule "A" of the Agreement which is estimated to be the amounts specified in Schedule "B" of the Agreement in the manner specified in Schedule "B" of the Agreement.

Hydro One shall identify the actual Engineering and Construction Cost of the Work Chargeable to Customer in the revised Schedule "B" provided to the Customer in accordance with Section 10.1 of this Agreement. Any difference between the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes) and the amount already paid by the Customer shall be paid within 30 days after the issuance of the revised Schedule "B" by:

(a) Hydro One to the Customer, if the amount already paid by the Customer exceeds the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes); or
(b) the Customer to Hydro One, if the amount already paid by the Customer is less than the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes).

15.2 Subject to Sections 10.3 and 18 hereof, Hydro One shall perform the Hydro One Connection Work described as Network Pool Work in Part 3 of Schedule "A" of the Agreement at Hydro One's sole expense.

16. As the Project is schedule-driven and as the estimated costs specified in Schedule "B" of the

Agreement are based upon normal timelines for delivery of material and performance of work, in addition to the amounts that the Customer is required to pay pursuant to Section 10.1 and 15.1 above, the Customer agrees to pay Hydro One's Premium Costs if the Customer causes or contributes to any delays, including, but not limited to, the Customer failing to execute the Agreement by the Execution Date specified in Schedule "A" of the Agreement.

Hydro One shall obtain the Customer's approval prior to Hydro One authorizing the purchase of materials or the performance of work that attracts Premium Costs. The Customer acknowledges that its failure to approve an expenditure of Premium Costs may result in further delays and Hydro One shall not be liable to the Customer as a result thereof. Hydro One shall invoice the Customer for expenditures of Premium Costs approved by the Customer within 180 calendar days after the Ready for Service Date.

Part D: Right of Customer to By-Pass Existing Load Facilities

17.1 **Obligation to Notify Hydro One of Customer's Intent to Bypass an Existing Load Facility:** If the Customer chooses to exercise its rights under the *Transmission System Code* and the Agreement to bypass the Existing Load Facility, the Customer shall notify Hydro One, in writing, at least 30 days prior to transferring load from the Existing Load Facility Hydro One will then proceed in accordance with Section 6.7 of the *Transmission System Code*.

17.2 **Hydro One has not received a Notice of Customer Intent to Bypass an Existing Load Facility and Customer has Transferred Existing Load:** Where Hydro One determines that the Customer has transferred load from the Existing Load Facility without notifying Hydro One or the OEB, Hydro One will notify the Customer, all other load customers served by the connection facility and the OEB of a potential by-pass situation in accordance with the OEB-Approved Connection Procedures. If the Customer does not intend to by-pass the Existing Load Facility, the Customer must in accordance with the OEB-Approved Connection Procedures:

i. notify Hydro One and the OEB within 30 days of receiving Hydro One's notification of potential by-pass, that it has no intention of by-passing Hydro One's Existing Load Facility;
ii. transfer the load back to the Existing Load Facility within an agreed time period; and
iii. compensate Hydro One for the lost revenues.

17.3 The Customer agrees that Sections 17.1 and 17.2 above shall also be a term of the Connection Agreement.

Part E: Cancellation or Termination of Project and Early Termination of Agreement for Breach

18. Notwithstanding any other term of the Agreement, if at any time prior to the In-Service Date, the Project is cancelled or the Agreement is terminated for any reason whatsoever other than breach of the Agreement by Hydro One, the Customer shall pay Hydro One's Engineering and Construction Cost (plus Taxes) of the Line Connection Pool Work, the Transformation Connection Pool Work, the Network Pool Work, the Network Customer Allocated Work and the Work Chargeable to Customer incurred on and prior to the date that the Project is cancelled or the Agreement is terminated, including the preliminary design costs and all costs associated with the winding up of the Project, including, but not limited to, storage costs, vendor cancellation costs, facility removal expenses and any environmental remediation costs.

If the Customer provides written notice to Hydro One that it is cancelling the Project, Hydro One shall have 10 Business Days to provide written notice to the Customer listing the individual items listed as materials which it agrees to purchase. Hydro One shall deduct the actual cost of those individual items of materials being purchased by Hydro One from the Engineering and Construction Costs referred to above.

If Hydro One does not require all or part of the materials, the Customer may exercise any of the following options or a combination thereof:

(i) where materials have been ordered but all or part of the materials have not been received by Hydro One, the Customer shall have the right to require Hydro One, at the Customer's sole expense, to continue with the purchase of the materials and transfer title to those materials on an "as is, where is basis" to the Customer upon the Customer paying Hydro One's Engineering and Construction Costs (plus Taxes) provided that the Customer exercises this option within 15 Business Days of the termination or cancellation; or
(ii) where all or part of the materials have been received by Hydro One but have not been installed, the Customer shall have the right to require Hydro One, at the Customer's sole expense, to transfer title to the materials on an "as is, where is basis" to the Customer upon the Customer paying Hydro One's Engineering and Construction Costs (plus Taxes) provided that the Customer exercises this option within 15 Business Days of the termination or cancellation. The Customer shall also be responsible for any warehousing costs associated with the storage of the materials to the date of transfer; or

(iii) where all or part of the materials have been received by Hydro One and have been installed, the Customer shall have the right to require Hydro One, at the Customer's sole expense, to: transfer title to the materials on an "as is, where is basis" to the Customer upon the later of (A) the Customer paying Hydro One's Engineering and Construction Costs (plus Taxes); and (B) the date that Hydro One removes the materials from its property at the risk of the Customer; provided that the Customer exercises this option within 15 Business Days of the termination or cancellation. The Customer shall also be responsible for any Engineering and Construction Costs (plus Taxes) associated with the removal of the materials that have been installed by Hydro One.

The Customer shall pay Hydro One's Engineering and Construction Costs (plus Taxes) which become payable under this Section 18 within 30 calendar days after the date of invoice.

Part F: Sale, Lease, Transfer or Other Disposition of Customer's Facilities

19. In the event that the Customer sells, leases or otherwise transfers or disposes of the Customer's Facilities to a third party during the Term of the Agreement, the Customer shall cause the purchaser, lessee or other third party to whom the Customer's Facilities are transferred or disposed to enter into an assumption agreement with Hydro One to assume all of the Customer's obligations in the Agreement; and notwithstanding such assumption agreement unless Hydro One agrees otherwise, in writing, the Customer shall remain obligated under Sections 10.1 12, 15.1 and 16 hereof. The Customer further acknowledges and agrees that in the event that all or a portion of the Customer's Facilities are shut down, abandoned or vacated for any period of time during the Term of the Agreement, the Customer shall remain obligated under Sections 10.1, 12, 15.1 and 16 for the said time period.

Part G: Security Requirements

20. If Hydro One requires that the Customer furnish security, which at the Customer's option may be in the form of cash, letter of credit or surety bond, the Customer shall furnish such security in the amount and by the dates specified in Schedule "A" of the Agreement. Hydro One shall return the security deposit to the Customer as follows:

(i) security deposits in the form of cash shall be returned to the Customer, together with Interest, less the amount of any Capital Contribution owed by the Customer once the Customer's Facilities are connected to Hydro One's New or Modified Connection Facilities; and

(ii) security deposits in any other form shall be returned to the Customer once the Customer's Facilities are connected to Hydro One's New or Modified Connection Facilities and any Capital Contribution has been paid.

Notwithstanding the foregoing, Hydro One may keep all or a part of the security deposit: (a) where and to the extent that the Customer fails to pay any amount due under the Agreement within the time stipulated for payment; or (b) in the circumstances described in the OEB-Approved Connection Procedures.

Part H: Disputes

21. Prior to the existence of OEB-Approved Connection Procedures either party may refer a Dispute to the OEB for a determination. Once there are OEB-Approved Connection Procedures, all disputes, including, but not limited to, disputes related to:

(a) the cost and the allocation of the costs under this Agreement;
(b) the cost and the allocation of costs of the Hydro One Connection Work and notwithstanding Hydro One's decision not to allocate or to allocate any part of the costs of this work to the Customer at this time; or
(c) any other costs and the allocation of any other costs associated with, related to, or arising out of the connection of the Project to Hydro One's transmission system or Hydro One's policies in respect of connections generally,

shall be dealt with in accordance with the dispute resolution procedure set out in the OEB-Approved Connection Procedures.

22. Before and after the existence of OEB-Approved Connection Procedures, if a dispute arises while Hydro One is constructing the New or Modified Connection Facilities, Hydro One shall not cease the work or slow the pace of the work without leave of the OEB.

23. Hydro One shall refund to the Customer or the Customer shall pay to Hydro One any portion of Capital Contributions, as the case may be, which the OEB subsequently determines should not have been allocated to the Customer or should have been allocated to the Customer by Hydro One but were not, as the case may be, or should have been allocated in a manner different from that allocated by Hydro One in this Agreement.

Part I: Easement

24. If specified in Schedule "A" that an easement(s) is required from the Customer, the Customer shall grant an easement to Hydro One substantially in the form of the easement attached hereto as Appendix "B" of these

Standard Terms and Conditions for the property(ies) described as the Easement Lands in Schedule "A" on or before the date specified as the Easement Date in Schedule "A" (hereinafter referred to as the "Easement") with good and marketable title thereto, free of all encumbrances, first in priority except as noted herein, and in registerable form, in consideration of the sum of $2.00.

Part J: Events of Default

25. Each of the following events shall constitute an "Event of Default" under the Agreement:

(a) failure by the Customer to pay any amount due under the Agreement, including any amount payable pursuant to Sections 10.1, 12, 15.1, 16 or 18 within the time stipulated for payment;
(b) breach by the Customer or Hydro One of any Material term, condition or covenant of the Agreement; or
(c) the making of an order or resolution for the winding up of the Customer or Hydro One or of their respective operations or the occurrence of any other dissolution, bankruptcy or reorganization or liquidation proceeding instituted by or against the Customer or Hydro One.

For greater certainty, a dispute shall not be considered an Event of Default under this Agreement. However, a Party's failure to comply, within a reasonable period of time, with the terms of a determination of such a dispute by the OEB or with a decision of a court of competent jurisdiction with respect to a determination made by the OEB shall be considered an Event of Default under the Agreement.

26. Upon the occurrence of an Event of Default by the Customer hereunder (other than those specified in Section 25(c) of the Agreement, for which no notice is required to be given by Hydro One), Hydro One shall give the Customer written notice of the Event of Default and allow the Customer 30 calendar days from the date of receipt of the notice to rectify the Event of Default, at the Customer's sole expense. If such Event of Default is not cured to Hydro One's reasonable satisfaction within the 30 calendar day period, Hydro One may, in its sole discretion, exercise the following remedy in addition to any remedies that may be available to Hydro One under the terms of the Agreement, at common law or in equity: deem the Agreement to be repudiated and, after giving the Customer at least 10 calendar days' prior written notice thereof, recover, as liquidated damages and not as a penalty, the following:

(i) the sum of the amounts payable by the Customer pursuant to Sections 10.1, 12, 15.1 and where applicable, Section 16 less any amounts already paid by the Customer in accordance with Section 10.1, 12, 15.1 and 16 if this clause is invoked after the In-Service Date; or

(ii) the amounts payable under Section 16 and 18 less any amounts already paid by the Customer in accordance with Sections 10.1, 15.1 and 16 if this clause is invoked prior to the In-Service Date.

27. Upon the occurrence of an Event of Default by Hydro One hereunder (other than those specified in Section 25(c), the Customer shall give Hydro One written notice of the Event of Default and shall allow Hydro One 30 calendar days from the date of receipt of the notice to rectify the Event of Default at Hydro One's sole expense. If such Event of Default is not cured to the Customer's reasonable satisfaction within the 30 calendar day period, the Customer may pursue any remedies available to it at law or in equity, including at its option the termination of the Agreement.

28. All rights and remedies of Hydro One and the Customer provided herein are not intended to be exclusive but rather are cumulative and are in addition to any other right or remedy otherwise available to Hydro One and the Customer respectively at law or in equity, and any one or more of Hydro One's and the Customer's rights and remedies may from time to time be exercised independently or in combination and without prejudice to any other right or remedy Hydro One or the Customer may have or may not have exercised. The parties further agree that where any of the remedies provided for and elected by the non-defaulting party are found to be unenforceable, the non-defaulting party shall not be precluded from exercising any other right or remedy available to it at law or in equity.

Part K: Changes to Transmission Rates

29. In the event that the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate is rescinded or the methodology of determination or components is materially changed, the Parties agree to negotiate a new mechanism for the purposes of the Agreement, provided that such new mechanism will not result in an increase in the amounts of Capital Contribution or Security Deposits payable by the Customer to Hydro One hereunder. The Parties shall have 90 calendar days from the effective date of rescission or fundamental change of the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate to agree to a new mechanism that is, to the extent possible, fair to the parties and constitutes a reasonably comparable replacement for the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate. If the Parties are unable to successfully negotiate a replacement within that 90 calendar day period, this shall be considered a dispute under the terms

of this Agreement and the parties shall follow the dispute resolution procedure set out in the OEB-Approved Connection Procedures.

Any settlement on a new mechanism pursuant to this Section 29 shall apply retroactively from the date on which the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate was rescinded or fundamentally changed. Until such time as a new mechanism is determined hereunder, any amounts to be paid by the Customer under the Agreement shall be based on the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate in effect prior to the effective date of any such changes.

Part L: Incorporation of Liability and Force Majeure Provisions

30. PART III: LIABILITY AND FORCE MAJEURE (with the exception of Section 15.5 thereof) and Sections 1.1.12 and 1.1.17 of the Connection Agreement are hereby incorporated in their entirety by reference into, and form an integral part of the Agreement. Unless the context otherwise requires, all references in PART III: LIABILITY AND FORCE MAJEURE TO "this Agreement" shall be deemed to be a reference to the Agreement and all references to the "the Transmitter" shall be deemed to be a reference to Hydro One.

For the purposes of this Section 30, the Parties agree that the reference to:

(i) the Transmitter in lines 3 and 4 of Section 15.1 means the Transmitter or any party acting on behalf of the Transmitter such as contractors, subcontractors, suppliers, employees and agents; and
(ii) the Customer in lines 3 and 4 of Section 15.2 means the Customer or any party acting on behalf of the Customer such as contractors, subcontractors, suppliers, employees and agents.

Part M: General

31. This Agreement is subject to the *Transmission System Code* and the OEB-Approved Connection Procedures. If any provision of this Agreement is inconsistent with the:

(a) *Transmission System Code,* the said provision shall be deemed to be amended so as to comply with the *Transmission System Code;*
(b) OEB-Approved Connection Procedures the said provision shall be deemed to be amended so as to comply with the OEB-Approved Connection Procedures; and
(c) Connection Agreement made between the parties, associated with the new customer connection facilities, on the same subject matter, the Connection Agreement governs.

32. The failure of either party hereto to enforce at any time any of the provisions of the Agreement or to exercise any right or option which is herein provided shall in no way be construed to be a waiver of such provision or any other provision nor in any way affect the validity of the Agreement or any part hereof or the right of either party to enforce thereafter each and every provision and to exercise any right or option. The waiver of any breach of the Agreement shall not be held to be a waiver of any other or subsequent breach. Nothing shall be construed or have the effect of a waiver except an instrument in writing signed by a duly authorized officer of the party against whom such waiver is sought to be enforced which expressly waives a right or rights or an option or options under the Agreement.

33. Other than as specifically provided in the Agreement, no amendment, modification or supplement to the Agreement shall be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of the Agreement.

34. Any written notice required by the Agreement shall be deemed properly given only if either mailed or delivered to the Secretary, Hydro One Networks Inc., 483 Bay Street, North Tower, 15th Floor, Toronto, Ontario M5G 2P5, fax no: (416) 345-6240 on behalf of Hydro One, and to the person at the address specified in Schedule "A" of the Agreement on behalf of the Customer.

A faxed notice shall be deemed to be received on the date of the fax if received before 3 p.m. on a business day or on the next business day if received after 3 p.m. or a day that is not a business day. Notices sent by courier or registered mail shall be deemed to have been received on the date indicated on the delivery receipt. The designation of the person to be so notified or the address of such person may be changed at any time by either party by written notice.

35. The Agreement shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of the Province of Ontario and the laws of Canada applicable therein.

36. The Agreement may be executed in counterparts, including facsimile counterparts, each of which shall be deemed an original, but all of which shall together constitute one and the same agreement.

37. The Customer shall provide Hydro One with a copy of the Customer's final monthly bills associated

with the transmission of electricity from the Existing Load Facilities and/or the Customer's Facilities or authorize the IESO to provide Hydro One with same. Hydro One agrees to use this information solely for the purpose of the Agreement.

38. **Invoices and Interest:** Invoiced amounts are due 30 days after invoice issuance. All overdue amounts including, but not limited to amounts that are not invoiced but required under the terms of this Agreement to be paid in a specified time period, shall bear interest at 1.5% per month compounded monthly (19.56 percent per year) for the time they remain unpaid.

39. The obligation to pay any amount due hereunder, including, but not limited to, any amounts due under Sections 10.1, 12, 15.1, 16, 18 or 23 shall survive the termination of the Agreement.

Appendix "A": Definitions

In the Agreement, unless the context otherwise requires, terms which appear therein without definition, shall have the meanings respectively ascribed thereto in the *Transmission System Code* and unless there is something in the subject matter or context inconsistent therewith, the following words shall have the following meanings:

"Actual Load" means the actual load delivered by Hydro One to the Customer up to the True-Up Point in excess of the Normal Capacity of the Existing Load Facilities.

"Assigned Capacity" is calculated in accordance with Section 6.2.2 of the *Transmission System* Code.

"Adjusted Load Forecast" means a Load Forecast that has been adjusted to the point where the present value of the Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue equals the present value of the Pool Funded Cost of the Transformation Connection Pool Work and/or the Pool Funded Cost of the Line Connection Pool Work and/or the Pool Funded Cost of the Network Customer Allocated Work.

"Agreement" means the Connection Cost Recovery Agreement, Schedules "A" and "B" attached thereto and these Standard Terms and Conditions.

"Applicable Laws" means any and all applicable laws, including environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments or decrees or any requirement or decision or agreement with or by any government or governmental department, commission board, court authority or agency.

"Approval Date" means for the purpose of Subsection 5(f) of the Terms and Conditions, the date specified in Schedule "A" of the Agreement.

"Capital Contribution" means a capital contribution calculated using the economic evaluation methodology set out in the *Transmission System Code*.

"Connect and Connection" has the same meaning ascribed to the term "Connect" in the *Transmission System Code.*

"Connection Agreement" means the form of connection agreement appended to the *Transmission System Code* as Appendix 1, Version 1.

"Connection Facilities" has the meaning set forth in the *Transmission System Code.*

"Connection Point" has the meaning set forth in the *Transmission System Code* and for this project, is as specified in Schedule "A" of the Agreement.

"Customer Connection Work" means the work to be performed by the Customer, at its sole expense, which is described in Schedule "A" of the Agreement.

"Customer Connection Risk Classification" is as specified in Schedule "A" of the Agreement.

"Customer's Facilities" has the meaning set forth in the *Transmission System Code*, and includes, but is not limited to any new, modified or replaced Customer's Facilities.

"Customer's Property(ies)" means any lands owned by the Customer in fee simple or where the Customer has easement rights.

"Dispute" means a dispute between the Parties with respect to any of the matters listed in Section 6.1.4 of the *Transmission System Code* where either Party is alleging that the other is seeking to impose a term that is inconsistent or contrary to the *Ontario Energy Board Act*, the *Electricity Act, 1998*, Hydro One's transmission licence or the *Transmission System Code* or refusing to include a term or condition that is required to give effect to the Code.

"Distributor" has the meaning set forth in the *Transmission System Code.*

"Economic Evaluation Period" means the period of five (5) years for high risk connection, ten (10) years for a medium-high risk connection, fifteen (15) years for a medium-low risk connection and twenty-five years for a low risk connection commencing on the In Service Date whichever is applicable to the Customer as specified in Schedule "A" of the Agreement.

"Engineering and Construction Cost" means Hydro One's charge for equipment, labour and materials at Hydro One's standard rates plus Hydro One's standard overheads as well as interest during construction using Hydro One's capitalization rate in effect during the construction period.

"*Electricity Act,* 1998" means the *Electricity Act, 1998* being Schedule "A" of the *Energy Competition Act,* S.O. *1998*, c.15, as amended.

"Existing Load" in relation to the Customer and each of the Existing Load Facilities is equal to the Customer's Assigned Capacity at each of the Existing Load Facilities on the date of this Agreement.

"Existing Load Facility or Existing Load Facilities" means the connection facility(ies) owned by Hydro One

as specified in the Existing Load Table in Schedule "A" of the Agreement where the Customer has Existing Load.

"Force Majeure Event" has the meaning ascribed thereto in the Connection Agreement.

"**GST**" means the Goods and Services Tax.

"Hydro One Connection Work" means the work to be performed by Hydro One, which is described in Schedule "A" of the Agreement.

"Hydro One Facilities" means Hydro One's structures, lines, transformers, breakers, disconnect switches, buses, voltage/current transformers, protection systems, telecommunication systems, cables and any other auxiliary equipment used for the purpose of transmitting electricity.

"Hydro One's Property(ies)" means any lands owned by Hydro One in fee simple or where Hydro One now or hereafter has obtained easement rights.

"IESO" means the Independent Electricity System Operator continued under the *Electricity Act, 1998.*

"In Service Date" has the same meaning ascribed to the term "comes into service" in the *Transmission System Code.*

"Incremental Network Load" means the Customer's New Load less the amount of load, if any, that has been by-passed by the Customer at any of Hydro One's connection facilities.

"Interest" means the interest rates specified by the OEB to be applicable to security deposits in the form of cash as specified in Subsection 6.3.11(b) in the *Transmission System Code*.

"Line Connection Pool Work" means the Hydro One Connection Work specified in Schedule "A" of the Agreement under the heading "Line Connection Pool Work".

"Line Connection Revenue" means the amount of line connection revenue attributable to that part of the Customer's New Load to be received by Hydro One through the monthly collection of the Line Connection Service Rate during the Economic Evaluation Period.

"**Line Connection Service Rate"** means the line connection service rate approved by the OEB in Hydro One's Rate Order from time to time, or any mechanism instituted in accordance with Section 29.

"Load Customer" has the meaning set forth in the *Transmission System Code.*

"Load Forecast" means the initial load forecast of the New Load in excess of the Normal Capacity of the Existing Load Facilities used in the initial economic evaluation for the Economic Evaluation Period.

"Material" relates to the essence of the contract, more than a mere annoyance to a right, but an actual obstacle preventing the performance or exercise of a right.

"Network Customer Allocated Work" means the construction of or modifications to Network Facilities specified in Schedule "A" of the Agreement under the heading "Network Customer Allocated Work" that are minimum connection requirements.

"Network Facilities" has the meaning set forth in the *Transmission System Code.*

"Network Pool Work" means the Hydro One Connection Work specified in Schedule "A" of the Agreement under the heading "Network Pool Work".

"Network Revenue" means the amount of network revenue attributable to the Incremental Network Load to be received by Hydro One through the monthly collection of the Network Service Rate during the Economic Evaluation Period.

"Network Service Rate" " means the network service rate approved by the OEB in Hydro One's Rate Order from time to time, or any mechanism instituted in accordance with Section 29.

"New Load" means the load at the New or Modified Connection Facility that is in excess of, for each of the Existing Load Facilities, the lesser of the Existing Load or the Normal Capacity.

"New or Modified Connection Facilities" means the facilities owned by Hydro One as specified in Schedule "A" of the Agreement.

"Normal Capacity" means, where the Customer is:

(a) the only Load Customer supplied by an Existing Load Facility, the total normal supply capacity of the Existing Load Facility as determined in accordance with the OEB-Approved Connection Procedures; and
(b) one of two or more Load Customers served by an Existing Load Facility, the Customer's pro-rated share of the total normal supply capacity of the Existing Load Facility as determined in accordance with the OEB-Approved Connection Procedures.

"OEB" means the Ontario Energy Board.

"OEB-Approved Connection Procedures" means Hydro One's connection procedures as approved by the OEB from time to time.

"Ontario Energy Board Act" means the *Ontario Energy Board Act* being Schedule "B" of the *Energy Competition Act,* S.O. *1998*, c. 15, as amended.

"Pool-Funded Cost" means the present value of the Engineering and Construction Cost and projected on-going maintenance and other related incremental costs (including, but not limited to applicable taxes, and net of tax benefits), of each of the Transformation Connection Pool Work, the Line Connection Pool Work and/or the Network Customer Allocated Work calculated in accordance with the principles, criteria and methodology set out in Appendices 4 and 5 of the Transmission System Code.

"Premium Costs" means those costs incurred by Hydro One in order to maintain or advance the Ready for Service Date, including, but not limited to, additional amounts expended for materials or services due to short time-frame for delivery; and the difference between having Hydro One's employees, agents and contractors perform work on overtime as opposed to during normal business hours.

"**Rate Order"** has the meaning ascribed thereto in the *Transmission System Code.*

"Ready for Service Date" means the date upon which the Hydro One Connection Work is fully and completely constructed, installed, commissioned and energised to the Connection Point. The Customer's disconnect switches must be commissioned prior to this date in order to use them as isolation points.

"Standard Terms and Conditions" means these Standard Terms and Conditions for Low Risk Transmission Customer Connection Projects and Appendices "A" and "B" attached hereto.

"Taxes" means all property, municipal, sales, use, value added, goods and services, harmonized and any other non-recoverable taxes and other similar charges (other than taxes imposed upon income, payroll or capital).

"Transformation Connection Pool Work" means the Hydro One Connection Work specified in Schedule "A" of the Agreement under the heading "Transformation Connection Pool Work".

"Transformation Connection Revenue" means the amount of transformation connection revenue attributable to that part of the Customer's New Load to be received by Hydro One through the monthly collection of the Transformation Connection Service Rate during the Economic Evaluation Period.

"**Transformation Connection Service Rate"** means the line connection service rate approved by the OEB in Hydro One's Rate Order from time to time, or any mechanism instituted in accordance with Section 29.

"Transmission System Code" or "Code" means the code of standards and requirements issued by the OEB on July 25, 2005 that came into force on August 20, 2005 as published in the Ontario Gazette, as it may be amended, revised or replaced in whole or in part from time to time.

"Transmitter's Facilities" has the meaning ascribed thereto in the *Transmission System Code.*

"True-Up" means the calculation to be performed by Hydro One, as a transmitter, at each True-Up Point in accordance with the requirements of Subsection 6.5.4 of the *Transmission System Code.*

"True-Up Point" means the points of time based upon the Customer Connection Risk Classification when Hydro One is required to perform a True-Up as described in Section 11 of these Terms and Conditions.

"Updated Load Forecast" means the load forecast of the New Load in excess of the Normal Capacity of the Existing Load Facilities for the remainder of the Economic Evaluation Period.

"Work Chargeable to Customer" means the Hydro One Connection Work specified in Part 4 of Schedule "A" of the Agreement under the heading "Work Chargeable to Customer".

Appendix "B": Form of Easement

INTEREST / ESTATE TRANSFERRED

The Transferor is the owner in fee simple and in possession of _____

_____

_____ (the **"Lands"**).

The Transferee has erected, or is about to erect, certain Works (as more particularly described in paragraph 1(a) hereof) in, through, under, over, across, along and upon the Lands.

1 The Transferor hereby grants and conveys to Hydro One Networks Inc, its successors and assigns the rights and easement, free from all encumbrances and restrictions, the following unobstructed and exclusive rights, easements, rights-of-way, covenants, agreements and privileges in perpetuity (the **"Rights"**) in, through, under, over, across, along and upon that portion of the Lands of the Transferor described herein and shown highlighted on Schedule "A" hereto annexed (the **"Strip"**) for the following purposes:

(a) To enter and lay down, install, construct, erect, maintain, open, inspect, add to, enlarge, alter, repair and keep in good condition, move, remove, replace, reinstall, reconstruct, relocate, supplement and operate and maintain at all times in, through, under, over, across, along and upon the Strip an electrical transmission system and telecommunications system consisting in both instances of a pole structures, steel towers, anchors, guys and braces and all such aboveground or underground lines, wires, cables, telecommunications cables, grounding electrodes, conductors, apparatus, works, accessories, associated material and equipment, and appurtenances pertaining to or required by either such system (all or any of which are herein individually or collectively called the **"Works"**) as in the opinion of the Transferee are necessary or convenient thereto for use as required by Transferee in its undertaking from time to time, or a related business venture.

(b) To enter on and selectively cut or prune, and to clear and keep clear, and remove all trees (subject to compensation to Owners for merchantable wood values), branches, bush and shrubs and other obstructions and materials in, over or upon the Strip, and without limitation, to cut and remove all leaning or decayed trees located on the Lands whose proximity to the Works renders them liable to fall and come in contact with the Works or which may in any way interfere with the safe, efficient or serviceable operation of the Works or this easement by the Transferee.

(c) To conduct all engineering, legal surveys, and make soil tests, soil compaction and environmental studies and audits in, under, on and over the Strip as the Transferee in its discretion considers requisite.

(d) To erect, install, construct, maintain, repair and keep in good condition, move, remove, replace and use bridges and such gates in all fences which are now or may hereafter be on the Strip as the Transferee may from time to time consider necessary.

(e) Except for fences and permitted paragraph 2(a) installations, to clear the Strip and keep it clear of all buildings, structures, erections, installations, or other obstructions of any nature (hereinafter collectively called the **"obstruction"**) whether above or below ground, including removal of any materials and equipment or plants and natural growth, which in the opinion of the Transferee, endanger its Works or any person or property or which may be likely to become a hazard to any Works of the Transferee or to any persons or property or which do or may in any way interfere with the safe, efficient or serviceable operation of the Works or this easement by the Transferee.

(e) To enter on and exit by the Transferor's access routes and to pass and repass at all times in, over, along, upon and across the Strip and so much of the Lands as is reasonably required, for Transferee, its respective officers, employees, agents, servants, contractors, subcontractors, workmen and permittees with or without all plant machinery, material, supplies, vehicles and equipment for all purposes necessary or convenient to the exercise and enjoyment of this easement and

(f) To remove, relocate and reconstruct the line on or under the Strip.

2. The Transferor agrees that:

(a) It will not interfere with any Works established on or in the Strip and shall not, without the Transferee's consent in writing, erect or cause to be erected or permit in, under or upon the Strip any obstruction or plant or permit any trees, bush, shrubs, plants or natural growth which does or may interfere with the Rights granted herein. The Transferor agrees it shall not, without the Transferee's consent in writing, change or permit the existing configuration, grade or elevation of the Strip to be changed and the Transferor further agrees that no excavation or opening or work which may disturb or interfere with the existing surface of the Strip shall be done or made unless consent therefore in writing has been obtained from Transferee, provided however, that the Transferor shall not be required to obtain such permission in case of emergency. Notwithstanding the foregoing, in cases where in the reasonable discretion of the Transferee, there is no danger or likelihood of danger to the Works of the Transferee or to any persons or property and the safe or serviceable operation of this easement by the Transferee is not interfered with, the Transferor may at its expense and with the prior written approval of the Transferee, construct and maintain roads, lanes, walks, drains, sewers, water pipes, oil and gas pipelines, fences (not to exceed 2 metres in height) and service cables on or under the Strip (the "**Installation**") or any portion thereof; provided that prior to commencing such Installation, the Transferor shall give to the Transferee thirty (30) days notice in writing thereof to enable the Transferee to have a representative present to inspect the proposed Installation during the performance of such work, and provided further that Transferor comply with all instructions given by such representative and that all such work shall be done to the reasonable satisfaction of such representative. In the event of any unauthorised interference aforesaid or contravention of this paragraph, or if any authorised interference, obstruction or Installation is not maintained in accordance with the Transferee's instructions or in the Transferee's reasonable opinion, may subsequently interfere with the Rights granted herein, the Transferee may at the Transferor's expense, forthwith remove, relocate, clear or correct the offending interference, obstruction, Installation or contravention complained of from the Strip, without being liable for any damages caused thereby.

(b) notwithstanding any rule of law or equity, the Works installed by the Transferee shall at all times remain the property of the Transferee, notwithstanding that such Works are or may become annexed or affixed to the Strip and shall at anytime and from time to time be removable in whole or in part by Transferee.

(c) no other easement or permission will be transferred or granted and no encumbrances will be created over or in respect to the Strip, prior to the registration of a Transfer of this grant of Rights.

(d) the Transferor will execute such further assurances of the Rights in respect of this grant of easement as may be requisite.

(e) the Rights hereby granted:

(i) shall be of the same force and effect to all intents and purposes as a covenant running with the Strip.

(ii) is declared hereby to be appurtenant to and for the benefit of the Works and undertaking of the Transferee described in paragraph 1(a).

3. The Transferee covenants and agrees to obtain at its sole cost and expense all necessary postponements and subordinations (in registrable form) from all current and future prior encumbrancers, postponing their respective rights, title and interests to the Transfer of Easement herein so as to place such Rights and easement in first priority on title to the Lands.

4. There are no representations, covenants, agreements, warranties and conditions in any way relating to the subject matter of this grant of Rights whether expressed or implied, collateral or otherwise except those set forth herein.

5. No waiver of a breach or any of the covenants of this grant of Rights shall be construed to be a waiver of any succeeding breach of the same or any other covenant.

6. The burden and benefit of this transfer of Rights shall run with the Strip and the Works and undertaking of the Transferee and shall extend to, be binding upon and enure to the benefit of the parties hereto and their respective heirs, executors, administrators, successors and assigns.

IN WITNESS WHEREOF the Transferor has hereunto set his hand and seal to this Agreement, this ___ day of _____ _____, 200__.

SIGNED, SEALED AND DELIVERED
In the presence of)
)
_____(seal)
Signature of Witness)
)
)
)
_____)
Signature of Witness

_____)
Transferor's Signature

_____(seal)
Transferor's Signature

SIGNED, SEALED AND DELIVERED)
In the presence of)
)
)
)
_____)
Signature of Witness

Consent Signature & Release of
Transferor's Spouse, if non-owner.

_____(seal)

CHARGEES

THE CHARGEE of land described in a Charge/Mortgage of Land dated _____

Between _____ and _____

and registered as Instrument Number _____ on _____ does

hereby consent to this Easement and releases and discharges the rights and easement herein from the said

Charge/Mortgage of Land.

Name	Signature(s)	Date of Signatures Y M D

Per:

_____

_____

I/We have authority to bind the Corporation

CCRA – Nebo TS

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) - LOAD

between

Horizon Utilities Corporation Inc.

and

Hydro One Networks Inc.

for

Nebo TS - Increase 230/27.6 kV Station Capacity

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) – LOAD

Horizon Utilities Corporation Inc. (the "Customer") has requested and Hydro One Networks Inc. ("Hydro One") has agreed to increase the capacity of the 230/27.6 kV Nebo TS (the "Project") on the terms and conditions set forth in this Agreement dated April 12, 2012 (the "Agreement") and the attached Standard Terms and Conditions for Load Customer Transmission Customer Connection Projects V3 9-2007 R5 (the "Standard Terms and Conditions" or "T&C"). Schedules "A" and "B" attached hereto and the Standard Terms and Conditions are to be read with and form part of this Agreement.

Project Summary

The 230/27.6 kV Nebo Transformer Station (TS) supplies Horizon Utilities and Hydro One Distribution at 27.6 kV. The 27.6 kV load at Nebo TS has exceeded the capacity of the 215.5/27.6 kV facilities. The Customer has advised Hydro One that it will need additional capacity at Nebo TS to supply its future 27.6 kV load growth. Hydro One Distribution has also requested additional capacity at Nebo TS.

Hydro One will increase the capacity by replacing the existing two 215.5/28 kV 50/67/83 MVA T1 and T2 transformers (T1/T2 DESN) with two 215.5/28-28 kV 75/100/125 MVA transformers, and installing six new feeder breakers at Nebo TS to supply the Customer and Hydro One Distribution.

Term: The term of this Agreement commences on the date first written above and terminates on the 25th anniversary of the In Service Date

Special Circumstances:

The Customer acknowledges that the cost of the Project will be shared between the Customer and Hydro One Distribution. Twenty seven percent (27%) of the incremental capacity of Nebo TS 215.5/27.6 kV T1/T2 DESN is to be allocated to the Customer, with the remainder allocated to Hydro One Distribution. Costs are to be shared in accordance with the proportion of assigned capacity and as described in Schedule B.

Hydro One acknowledges that the Customer bears no responsibility whatsoever for the portion of the costs payable by and revenues to be received from Hydro One Distribution in respect of the Project.

In addition to the circumstances described in Section 5 of the Standard Terms and Conditions, the Ready for Service Date is subject to:

(a) The Customer executing and delivering this Agreement to Hydro One by no later than April 30, 2012 (the "Execution Date").
(b) Hydro One receives the delivery of the 215.5/28-28 kV 75/100/125 MVA transformers at the Nebo TS site by February 28, 2013.
(c) Outages are available as required.
(d) All necessary approvals being obtained as outlined in this CCRA.

Subject to Section 31, this Agreement constitutes the entire agreement between the parties with respect to the subject matter of this Agreement and supersedes all prior oral or written representations and agreements concerning the subject matter of this Agreement.

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) – LOAD

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by the signatures of their proper authorized signatories, as of the day and year first written above.

HYDRO ONE NETWORKS INC.

~~Brad Colden~~ Laura Formusa
~~Manager - Customer Business Relations~~ President + CEO
I have the authority to bind the Corporation.

HORIZON UTILITIES CORPORATION INC.

~~Max~~ Cananzi
President and Chief Executive Officer
I have the authority to bind the Corporation.

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) – LOAD

Schedule "A"
Nebo TS - Increase 230/27.6-27.6 kV Station Capacity

PROJECT SCOPE

New or Modified Connection Facilities: Hydro One will design, construct, own and operate the facilities for the following project scope to increase the capacity at Nebo TS:

- Replace the existing two 215.5/28 kV 50/67/83 MVA T1 and T2 transformers with two 215.5/28-28 kV 75/100/125 MVA transformers.
  The increased transformer capacity (estimated as 64 MVA - to be confirmed once the transformers are delivered) will be shared 27% and 73% between the Customer and Hydro One Distribution respectively.
- Install 6 new 27.6 kV feeder breaker positions at Nebo TS.
  Two of the six new feeder positions will be for the Customer, the remaining four feeder positions for Hydro One Distribution.
- Reconfigure and reconnect the existing switchgear to the 215.5/28-28 kV 75/100/125 MVA transformers.
- The work required at Hydro One facilities includes engineering, procurement of equipment; installation of equipment, update as built drawings, and carryout acceptance checks, testing and commissioning of station equipment and associated systems commissioning.
- Witnessing of the work required at in the interface of the Customer's facilities at Nebo TS T1/T2 DESN.

Connection Point:
The connection point is where the 27.6 kV feeder breakers at Nebo TS connect to the Customer's feeders.

Ready for Service Date: October 31, 2013

HYDRO ONE CONNECTION WORK

Part 1: Transformation Connection Pool Work

Hydro One will:
Construct the facilities as described below:

1. **General Requirement**
   Obtain approvals and permits as required for the station facilities related to noise, soil removals, drainage, and landscaping.

2. **Transformers**
- Install two 215.5/28-28 kV 75/100/125 MVA 3 phase dual low voltage (LV) winding transformers as per CSA standards with a summer 10 day Limited Time Rating (LTR) of 170 MVA (to be confirmed once the transformers are delivered) to replace the existing two 215.5/28 kV 50/67/83 MVA transformers (T1 and T2) at Nebo TS. The 215.5/28-28 kV 75/100/125 MVA transformer winding connections are:

High voltage (HV) windings: Wye connected solidly grounded. Low voltage (LV) windings: zig-zag connected. The LV winding neutral will be grounded through the neutral reactor.
- Install four (4) neutral current limiting reactors 1.5 ohm, one for each neutral of the LV winding.
- Install six (6) HV station class surge arrestors, one for each phase of the HV winding.
- Install twelve (12) LV station class surge arrestors, one for each phase of the LV winding.

- Removal of:
  - The existing 215.5/28 kV 50/83MVA T1 and T2 transformers.
  - The existing surge arresters associated with 215.5/28 kV 50/83MVA T1 and T2 transformers.
  - The grounding transformers associated with 215.5/28 kV 50/83MVA T1/T2 transformers.

- Environmental Scope of work includes
  - Obtaining Noise Certificate of Approval
  - Obtaining amendment to current Drainage Certificate of Approval
  - Environmental monitoring

- Assumptions:
  - No major work is required on the existing oil spill containment.
  - No sound barriers or other noise mitigating measures are required.

There may be an impact on the project cost and the Ready for Service date if there are variances in the above assumptions.

3. 230 kV Switching Facilities

Install two 230 kV 3 phase motor operated air break disconnect switches equipped with 3-pole grounding switches.

4. 27.6 kV Switching Facilities

The scope of work includes the following:
- Reconfigure the existing LV switchyard for connecting to the 215.5/28-28 kV 75/100/125 MVA dual LV winding transformers. The LV system will be suitable for 3 phase-4 wire supply.
- Install two (2) LV transformer breakers and associated isolating switches.
- Install six (6) new feeder breakers and associated isolating switches.
  Two of the six new feeder breaker positions will be for the Customer, the remaining four feeder breaker positions will be for Hydro One Distribution.
- Install sets of instrument transformers (potential and current transformers) for protection purposes.
- Install required bus work, insulators, support structures, foundations and cabling connecting the above equipment.

5. AC and DC Station Service Systems

AC and DC station services will be expanded to accommodate the new facilities.

6. Protection, Control and Teleprotections Systems
- Review and revise, as required, the protection settings at the terminal stations of the 230 kV transmission lines Q24HM and Q29HM.
- Install new protections for:

  - Two 75/100/125 MVA 215.5/28-28 kV transformers
  - Two new transformer LV breakers.
  - Six new feeder and control circuits for the six new circuit breakers.
- Modify existing bus protections
- Modify existing transformer LV breaker protections
- Modify teleprotection interface equipment for transmission lines Q24HM and Q29HM
- Provide SCADA communications to the Hydro One's Ontario Grid Control Centre (OGCC), and the Independent Electricity System Operator (IESO).
- Provide under-frequency load shedding relaying, as required.

7. Property

It is assumed that no additional property is required to install the new equipment under this project.

8. Exclusions/Assumptions

Cost estimates are based on the following assumptions:

- Sound attenuation measures are not included in the scope of work as their need has yet to be verified.
- Soil conditions and resistivity at the site are good.
- Excavated soil is not contaminated. If it is contaminated, cost for remedial action will be added to the Project cost and assigned to the Customer and Hydro One Distribution.
- Permits and approvals associated with the distribution feeders are the responsibility of the Customer

Part 2: Line Connection Pool Work

Not applicable

Part 3: Network Customer Allocated Work

Hydro One will:

- Review and revise tele-protection settings for the 230 kV transmission lines Q24HM and Q29HM as required to accommodate the modified connection facility.
- Modify existing master SCADA at Hydro One's Ontario Grid Control Centre (OGCC) to provide control of the new or modified connection facility

Part 4: Network Pool Work (Non-Recoverable from Customer)

Not Applicable.

Part 5: Work Chargeable to Customer

Hydro One will:

1. Revenue Metering

1.1 Revenue Metering for Customer Feeders

Revenue metering for the customer's two new feeders is not included in Hydro One's scope of work. The Customer is responsible for revenue metering for its feeders. It is assumed that the

Customer will install the feeder revenue metering and the metering cabinet outside the Nebo TS fence line.

The Customer will:

- Be responsible for procuring and installing the revenue metering system, including associated instrument transformers, revenue meters, cabling, and metering cabinets, for its feeders.
- Be responsible for the registration of the revenue metering installation with the IESO. The registration of the revenue metering must be completed 2 weeks before the Ready for Service date.

1.2 Metering for Transformer LV buses

Revenue metering for transformer LV buses is allocated to Hydro One Distribution and is not included in this CCRA.

2. Feeder Egress Duct (s)

The Customer is responsible for the feeder egress associated with its feeders within Nebo TS. As requested by Customer, Hydro One will install underground feeder egress duct(s) within the Nebo TS fence, to the nearest fence line, for the two new feeders. Hydro One will retain ownership of the ducts installed by Hydro One within Nebo TS while the Customer will be responsible for any maintenance, repairs or replacement of the ducts.

Part 6: Scope Change

For the purposes of this Part 6 of Schedule "A", the term "Non-Customer Initiated Scope Change(s)" means one or more changes that are required to be made to the Project Scope as detailed and documented in Parts 1 to 5 of this Schedule "A" such as a result of any one or more of the following:

- any environmental assessment(s);
- requirement for Hydro One to obtain approval under Section 92 (leave to construct) of the Ontario Energy Board Act if the transmission line route selected by Hydro One is greater than 2 km in length;
- Hydro One having to expropriate property under the Ontario Energy Board Act;
- conditions included by the OEB in any approval issued by the OEB under Section 92 of the Ontario Energy Board Act or any approval issued by the OEB to expropriate under the Ontario Energy Board Act; and
- any IESO requirements identified in the System Impact Assessment or any revisions thereto.

Any change in the Project Scope as detailed and documented in Parts 1 to 5 of this Schedule "A" whether they are initiated by the Customer or are Non-Customer Initiated Scope Changes, may result in a change to the Project costs estimated in Schedule "B" of this Agreement and the Project schedule, including the Ready for Service Date.

All Customer initiated scope changes to this Project must be in writing to Hydro One.

Hydro One will advise the Customer of any cost and schedule impacts of any Customer initiated scope changes. Hydro One will advise the Customer of any Material cost and/or Material schedule impacts of any Non-Customer Initiated Scope Changes.

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) – LOAD

Hydro One will not implement any Customer initiated scope changes until written approval has been received from the Customer accepting the new pricing and schedule impact.

Hydro One will implement all Non-Customer initiated scope changes until the estimate of the Engineering and Construction Cost of all of the Non-Customer initiated scope changes made by Hydro One reaches 10% of the total sum of the estimates of the Engineering and Construction Cost of:

(i) the Transformation Connection Pool Work;
(ii) the Line Connection Pool Work;
(iii) Network Pool Work;
(iv) Network Customer Allocated Work; and
(v) the Work Chargeable to Customer.

At that point, no further Non-Customer initiated scope changes may be made by Hydro One without the written consent of the Customer accepting new pricing and schedule impact. If the Customer does not accept the new pricing and schedule impact, Hydro One will not be responsible for any delay in the Ready for Service Date as a consequence thereof.

CUSTOMER CONNECTION WORK

The Customer will:

- Be responsible for providing its feeders and connecting to the breakers at the Nebo TS.
- Be responsible for the cost of feeder egress required within the station fence.
- Provide and install the drop leads to make connection to the NEMA pads at the feeder disconnect switches.
- Provide feeder protection settings for implementation by Hydro One three months prior to the Ready for Service Date.
- Be responsible for relocating the existing feeders, and arranging outages as required.
- Provide a landline telephone service for IESO access and ensure that the service is available at least 2 weeks before the Ready for Service Date.
- Be responsible for the on-going cost of the landline telephone service.
- Provide and install all facilities associated with revenue metering in accordance with IESO requirements.
- Be responsible for the on-going cost of revenue metering.
- Accept responsibility for the registration of the revenue metering installations. The IESO registration work must be completed at least two weeks prior to the Ready for Service date.
- Accept responsibility for purchasing and storing any spare equipment associated with the revenue metering installation.

EXISTING LOAD:

	A	B		
Existing Load Facility	**Existing Load (MW)[1,]**	**Normal Capacity (MW)[2]**		
Nebo TS 230/27.6 kV T1/T2 DESN	30.1 MW	30.1 MW		

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) – LOAD

Notes:

1. Existing Load means the Customer's Assigned Capacity at the Existing Load Facility as of the date of this Agreement (Section 3.0.3 of the Transmission System Code).
2. Any station load above the Normal Capacity of the Existing Load Facility (Overload) will be determined in accordance with Section 6.7.9 of the Transmission System Code and Hydro One's Connection Procedures. If the Overload is transferred to the New or Modified Connection Facilities, the Overload will be credited to the Line Connection Revenue, Transformation Connection Revenue or Network Revenue requirement, whichever is applicable.

   Existing Nebo TS 230/27.6 kV 50/67/83 MVA (T1/T2 DESN) normal capacity = 106 MVA (95.4 MW @ 0.9 pf).
   Customer assigned existing capacity = 33.5 MVA (30.1 MW@ 0.9 pf)

OTHER RELEVANT CONSIDERATIONS:
None

EXCEPTIONAL CIRCUMSTANCES RE. NETWORK CONSTRUCTION OR MODIFICATIONS:
None

MISCELLANEOUS

Customer Connection Risk Classification: Low Risk

True-Up Points:

a) following the fifth and tenth anniversaries of the In Service Date; and,
b) following the fifteenth anniversary of the In Service Date if the Actual Load is 20% higher or lower than the Load Forecast at the end of the tenth anniversary of the In Service Date.

Customer's HST Registration Number: [redacted]

Documentation Required (after In Service Date): Customer will provide the final feeder egress drawings.

Ownership: Hydro One will own all equipment provided by Hydro One as part of the Hydro One Connection Work

Approval Date (if Section 92 required to be obtained by Hydro One):
Not applicable

Security Requirements: Nil

Security Date: Not applicable

Easement Required from Customer: No

Easement Date: Not applicable

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) – LOAD

Easement Lands: Not applicable

Easement Term: Not applicable

Approval Date (for OEB leave to construct): Not applicable

Revenue Metering: IESO compliant revenue metering to be provided by the Customer.

Customer Notice Info:

HORIZON UTILITIES CORPORATION INC.

Attention: Kathy Lerette
Vice President Utility Operations
Horizon Utilities Corporation
P.O. Box 2249 LCD 1,
55 John Street North
Hamilton
Ontario., L8N 3E4

Fax # (905) 522-3076

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) – LOAD

Schedule "B"
Nebo TS 230/27.6-27.6 kV DESN - Increase Station Capacity

Costs of the Project, associated with Pool Work, are being apportioned between the Customer and Hydro One Distribution based on the Customer having 27% of the 64 MVA (57.6 MW @ 0.9 power factor) incremental capacity at Nebo TS and Hydro One Distribution having 73%. As such, the Customer will be responsible for 27% of the Transformation Connection Pool and Network Pool cost of the Project.

The capacity for the Customer's use, based on the load forecast provided by the Customer, at Nebo TS 230/27.6 kV T1/T2 DESN upon the Project Ready for Service Date:

Capacity based on existing facilities:	30.1 MW (33.5 MVA @ 0.9 pf)
Capacity (incremental) under this Project:	15.6 MW (17.3 MVA @ 0.9 pf)
Total:	45.7MW (50.8 MVA @ 0.9 pf)

The 27.6 kV feeder positions at Nebo TS 230/27.6 kV T1/T2 DESN for the Customer's use are:

Feeder positions that supply existing load:	2
Feeder positions under this Project:	2
Total feeder positions:	4

TRANSFORMATION CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Transformation Connection Pool Work:

Total Cost: $17,612,500.00 plus HST in the amount of $2,289,625.00
Cost Allocated to the Customer: $4,755,400.00 plus HST in the amount of $618,202.00

Estimate of Transformation Connection Pool Work Capital Contribution:
$2,304,200.00 plus HST in the amount of $299,546.00

Actual Engineering and Construction Cost of the Transformation Connection Pool Work:
To be provided 180 days after the Ready for Service Date

Actual Transformation Connection Pool Work Capital Contribution:
To be provided 180 days after the Ready for Service Date

Capital Contribution Includes the Cost of Capacity Not Needed by the Customer:
Not applicable

LINE CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Line Connection Pool Work:

Total Cost: $0
Cost Allocated to the Customer: $0

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) – LOAD

Estimate of Line Connection Pool Work Capital Contribution:
$0

Actual Engineering and Construction Cost of the Line Connection Pool Work:
To be provided 180 days after the Ready for Service Date

Actual Line Connection Pool Work Capital Contribution:
To be provided 180 days after Ready for Service Date

Capital Contribution Includes the Cost of Capacity Not Needed by the Customer:
$0 plus HST in the amount of $0

NETWORK CUSTOMER ALLOCATED WORK

Estimate of the Engineering and Construction Cost of the Network Customer Allocated Work:
Total Cost: $31,700.00 plus HST in the amount of $4,121.00.
Cost Allocated to the Customer: $8,550.00 plus HST in the amount of $1,112.00.

Estimate of the Network Pool Work Capital Contribution:
$0

Actual Engineering and Construction Cost of the Network Customer Allocated Work:
To be provided 180 days after Ready for Service Date

NETWORK POOL WORK (NON-RECOVERABLE FROM CUSTOMER):

The estimated Engineering and Construction Cost of the Network Pool Work (Non-Recoverable From Customer) is $0. Subject to Sections 10.3 and 18 of the Standard Terms and Conditions, Hydro One will perform this work at its own expense.

WORK CHARGEABLE TO CUSTOMER

Estimate of the Engineering and Construction Cost of the Work Chargeable To Customer:
$115,600.00 plus HST in the amount of $15,028.00 (For feeder egress duct. See Note below)

Note:

- Cost stated above is for the underground feeder egress duct(s) within the Nebo TS fence for Customer's two new feeders.

Actual Engineering and Construction Cost of the Work Chargeable To Customer:
To be provided 180 days after Ready for Service Date

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) – LOAD

MANNER OF PAYMENT OF THE ESTIMATE OF CAPITAL CONTRIBUTIONS AND WORK CHARGEABLE TO CUSTOMER

The Customer shall pay Hydro One the estimate of the Transformation Connection Pool Work Capital Contribution, the Estimate of Line Connection Pool Work Capital Contribution, the estimate of the Network Customer Allocated Work Capital Contribution and the estimate of the Engineering and Construction Cost of the Work Chargeable to Customer by making the progress payments specified below on or before the Payment Milestone Date specified below. Hydro One will invoice the Customer for each progress payment 30 days prior to the Payment Milestone Date.

Payment Milestone Date	Transformation Pool Work Capital Contribution*	Line Pool Work Capital Contribution*	Network Customer Allocated Work Capital Contribution*	Work Chargeable To Customer*	Total Payment Required*
July 13, 2011**	$40,000.00	-	-	-	$40,000.00
May 18, 2012	$930,000.00	-	-	-	$930,000.00
February 28, 2013	$1,334,200.00	-	-	$115,600.00	$1,449,800.00

* Payments specified above do not include HST. Above specified payments and applicable HST will be included in the invoices to Customer.

** Purchase Order # 18740 dated July 13, 2011 for $40,000.00 provided by Customer.

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) – LOAD

TRANSFORMATION CONNECTION REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Annual Period Ending On:	New Load** (MW)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [A] (Note)	Adjusted Load Forecast (MW) [B]	Transformation Connection Revenue (k$) for True-Up, based on [A] or [B], whichever is applicable
October 31, 2014	7.0	7.0	7.0	157.3
October 31, 2015	8.5	8.5	8.5	189.2
October 31, 2016	9.0	9.0	9.0	199.9
October 31, 2017	9.3	9.3	9.3	206.7
October 31, 2018	9.6	9.6	9.6	213.6
October 31, 2019	9.9	9.9	9.9	220.6
October 31, 2020	10.2	10.2	10.2	227.6
October 31, 2021	10.5	10.5	10.5	234.7
October 31, 2022	10.8	10.8	10.8	241.9
October 31, 2023	11.1	11.1	11.1	248.5
October 31, 2024	11.2	11.2	11.2	249.6
October 31, 2025	11.2	11.2	11.2	249.6
October 31, 2026	11.2	11.2	11.2	249.6
October 31, 2027	11.2	11.2	11.2	249.6
October 31, 2028	11.2	11.2	11.2	249.6
October 31, 2029	11.2	11.2	11.2	249.6
October 31, 2030	11.2	11.2	11.2	249.6
October 31, 2031	11.2	11.2	11.2	249.6
October 31, 2032	11.2	11.2	11.2	249.6
October 31, 2033	11.2	11.2	11.2	249.6
October 31, 2034	11.2	11.2	11.2	249.6
October 31, 2035	11.2	11.2	11.2	249.6
October 31, 2036	11.2	11.2	11.2	249.6
October 31, 2037	11.2	11.2	11.2	249.6
October 31, 2038	11.2	11.2	11.2	249.6

Note: New load is a weighted average of the annual peak loads for the two calendar years during each anniversary year multiplied by a Peak Load Index (PLI) of 0.719. PLI is defined as the average of the ratio of the average monthly peak load to the annual peak load. Adjusted load forecast takes account of the load capped at the level of assigned capacity.

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) – LOAD

LINE CONNECTION REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES : NOT APPLICABLE

Annual Period Ending On:	New Load** - (MW)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [C] (Note)	Adjusted Load Forecast (MW) [D]	Line Connection Revenue (k$) for True-Up, Based on [C] or [D], whichever is applicable
October 31, 2014				
October 31, 2015				
October 31, 2016				
October 31, 2017				
October 31, 2018				
October 31, 2019				
October 31, 2020				
October 31, 2021				
October 31, 2022				
October 31, 2023				
October 31, 2024				
October 31, 2025				
October 31, 2026				
October 31, 2027				
October 31, 2028				
October 31, 2029				
October 31, 2030				
October 31, 2031				
October 31, 2032				
October 31, 2033				
October 31, 2034				
October 31, 2035				
October 31, 2036				
October 31, 2037				
October 31, 2038				

Note: New load is a weighted average of the annual peak loads for the two calendar years during each anniversary year multiplied by a Peak Load Index (PLI) of 0.719. PLI is defined as the average of the ratio of the average monthly peak load to the annual peak load. Adjusted load forecast takes account of the load capped at the level of assigned capacity.

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) – LOAD

NETWORK REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Annual Period Ending On:	New Load** - (MW)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [C] (Note)	Adjusted Load Forecast (MW) [D]*	Network Revenue (k$) for True-Up, Based on [C] or [D], whichever is applicable
October 31, 2014	7.0	7.0	0.01	0.6
October 31, 2015	8.5	8.5	0.02	0.7
October 31, 2016	9.0	9.0	0.02	0.8
October 31, 2017	9.3	9.3	0.02	0.8
October 31, 2018	9.6	9.6	0.02	0.8
October 31, 2019	9.9	9.9	0.02	0.9
October 31, 2020	10.2	10.2	0.02	0.9
October 31, 2021	10.5	10.5	0.02	0.9
October 31, 2022	10.8	10.8	0.02	1.0
October 31, 2023	11.1	11.1	0.02	1.0
October 31, 2024	11.2	11.2	0.02	1.0
October 31, 2025	11.2	11.2	0.02	1.0
October 31, 2026	11.2	11.2	0.02	1.0
October 31, 2027	11.2	11.2	0.02	1.0
October 31, 2028	11.2	11.2	0.02	1.0
October 31, 2029	11.2	11.2	0.02	1.0
October 31, 2030	11.2	11.2	0.02	1.0
October 31, 2031	11.2	11.2	0.02	1.0
October 31, 2032	11.2	11.2	0.02	1.0
October 31, 2033	11.2	11.2	0.02	1.0
October 31, 2034	11.2	11.2	0.02	1.0
October 31, 2035	11.2	11.2	0.02	1.0
October 31, 2036	11.2	11.2	0.02	1.0
October 31, 2037	11.2	11.2	0.02	1.0
October 31, 2038	11.2	11.2	0.02	1.0

Note: New load is a weighted average of the annual peak loads for the two calendar years during each anniversary year multiplied by a Peak Load Index (PLI) of 0.719. PLI is defined as the average of the ratio of the average monthly peak load to the annual peak load. Adjusted load forecast takes account of the load capped at the level of assigned capacity.

*Adjusted load forecast for revenue true up being less than 0.1 MW is rounded to the 2nd decimal place.

** New load based on Customer's Load Forecast which includes Part of New Load Exceeding Normal Capacity of Existing Load Facilities. "Overload" derived in accordance with Section 6.7.9 of the Transmission System Code and the OEB-Approved Connection Procedures. Any Customer load below the Normal Capacity of the Existing Load Facilities transferred to the New or Modified Facilities will not be credited towards the Transformation Connection Revenue Requirements, Line Connection Revenue Requirements or the Network Connection Revenue Requirements. The discounted cash flow calculation for Network Revenue requirements will be based on Incremental Network Load which is New Load less the amount of load, if any, that has been by-passed by the Customer at any of Hydro One's connection facilities.

Standard Terms and Conditions for Load Customer Transmission Customer Connection Projects

1. Each party represents and warrants to the other that:

(a) it is duly incorporated, formed or registered (as applicable) under the laws of its jurisdiction of incorporation, formation or registration (as applicable);
(b) it has all the necessary corporate power, authority and capacity to enter into the Agreement and to perform its obligations hereunder;
(c) the execution, delivery and performance of the Agreement by it has been duly authorized by all necessary corporate and/or governmental and/or other organizational action and does not (or would not with the giving of notice, the lapse of time or the happening of any other event or condition) result in a violation, a breach or a default under or give rise to termination, greater rights or increased costs, amendment or cancellation or the acceleration of any obligation under (i) its charter or by-law instruments; (ii) any Material contracts or instruments to which it is bound; or (iii) any laws applicable to it;
(d) any individual executing this Agreement, and any document in connection herewith, on its behalf has been duly authorized by it to execute this Agreement and has the full power and authority to bind it;
(e) the Agreement constitutes a legal and binding obligation on it, enforceable against it in accordance with its terms;
(f) it is registered for purposes of Part IX of the *Excise Tax Act* (Canada). The HST registration number for Hydro One is [redacted] and the HST registration number for the Customer is as specified in Schedule "A" of the Agreement; and
(g) no proceedings have been instituted by or against it with respect to bankruptcy, insolvency, liquidation or dissolution.

Part A: Hydro One Connection Work and Customer Connection Work

2. The Customer and Hydro One shall perform their respective obligations outlined in the Agreement in a manner consistent with Good Utility Practice and the Transmission System Code, in compliance with all Applicable Laws, and using duly qualified and experienced people.

3. The parties acknowledge and agree that:

(a) Hydro One is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Hydro One Connection Work and those required for the construction, Connection and operation of the New or Modified Connection Facilities;

(b) the Customer shall perform the Customer Connection Work, at its own expense;

(c) except as specifically provided in the Agreement, the Customer is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Customer Connection Work and those required for the construction, Connection and operation of the Customer's Facilities including, but not limited to, where applicable, leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998*;

(d) the Customer is responsible for installing equipment and facilities such as protection and control equipment to protect its own property, including, but not limited to the Customer's Facilities;

(e) the Customer shall provide Hydro One with Project data required by Hydro One, including, but not limited to (i) the same technical information that the Customer provided the IESO during any connection assessment and facility registration process associated with the Customer's Facilities in the form outlined in the applicable sections of the IESO's public website and (ii) technical specifications (including electrical drawings) for the Customer's Facilities;

(f) Hydro One may participate in the commissioning, inspection or testing of the Customer's Connection Facilities at a time that is mutually agreed by Hydro One and the Customer and the Customer shall ensure that the work performed by the Customer and others required for successful commissioning, inspection or testing of protective equipment is completed as required to enable Hydro One witnessing and testing to confirm satisfactory performance of such systems;

(g) unless otherwise provided herein, Hydro One's responsibilities under the Agreement with respect to the Connection of the New or Modified Connection Facilities to Hydro One's transmission system shall be limited to the performance of the Hydro One Connection Work;

(h) Hydro One is not permitted to Connect any new, modified or replacement Customer's Facilities unless any required Connection authorizations, certificate of inspection or other applicable approval have been issued or given by the Ontario Electrical Safety Authority in relation to such facilities;

(i) Hydro One may require that the Customer provide Hydro One with test certificates certifying that the Customer's Facilities have passed all relevant tests and comply with the *Transmission System Code*, the Market Rules, Good Utility Practice, the standards of all applicable reliability organizations and any Applicable

Laws, including, but not limited to any certificates of inspection that may be required by the Ontario Electrical Safety Authority;

(j) in addition to the Hydro One Connection Work described in Schedule "A", Hydro One shall: provide the Customer with such technical parameters as may be required to assist the Customer in ensuring that the design of the Customer's Facilities is consistent with the requirements applicable to Hydro One's transmission system and the basic general performance standards for facilities set out in the *Transmission System Code*, including Appendix 2 thereof; and

(k) if Hydro One requires access to the Customer's Facilities for the purposes of performing the Hydro One Connection Work or the Customer requires access to Hydro One's Facilities for the purposes of the Customer Connection Work, the parties agree that Section 27.13 of the Connection Agreement shall govern such access and is hereby incorporated in its entirety by reference into, and forms an integral part of the Agreement. All references to "this Agreement" in Section 27.13 shall be deemed to be a reference to the Agreement;

(l) the Customer shall enter into a Connection Agreement with Hydro One or amend its existing Connection Agreement with Hydro One at least 14 calendar days prior to the Connection;

(m) Hydro One shall use commercially reasonable efforts to ensure that any applications required to be filed to obtain any permits or approvals required under Applicable Laws for the Hydro One Connection Work are filed in a timely manner; and

(n) the Customer shall use commercially reasonable efforts to ensure that any applications required to be filed to obtain any permits or approvals required under Applicable Laws for the Customer Connection Work or for the construction, Connection and operation of the Customer's Facilities are filed in a timely manner.

4. The following aspects of the Hydro One Connection Work and Hydro One's rights and requirements hereunder are solely for the purpose of Hydro One ensuring that the Customer Facilities to be connected to Hydro One's transmission system do not materially reduce or adversely affect the reliability of Hydro One's transmission system and do not adversely affect other customers connected to Hydro One's transmission system, Hydro One's:

(i) specifications of the protection equipment on the Customer's side of the Connection Point;
(ii) acceptance of power system components on the Customer's side of the Connection Point;
(iii) acceptance of the technical specifications (including electrical drawings) for the Customer's Facilities and/or the Customer Connection Work; and
(iv) participation in the commissioning, inspection or testing of the Customer's Facilities,

The Customer is responsible for installing equipment and facilities such as protection and control equipment to protect its own property, including, but not limited to the Customer's Facilities.

5. Hydro One shall use commercially reasonable efforts to complete the Hydro One Connection Work by the Ready for Service Date specified in Schedule "A" provided that:

(a) the Customer is in compliance with its obligations under the Agreement;
(b) any work required to be performed by third parties has been performed in a timely manner and in a manner to the satisfaction of Hydro One, acting reasonably;
(c) there are no delays resulting from Hydro One not being able to obtain outages from the IESO required for any portion of the Hydro One Connection Work or from the IESO making changes to the Hydro One Connection Work or the scheduling of all or a portion of the Hydro One Connection Work ;
(d) Hydro One does not have to use its employees, agents and contractors performing the Hydro One Connection Work or the Network Pool Work elsewhere on its transmission system or distribution system due to an Emergency (as that term is defined in the *Transmission System Code*) or a Force Majeure Event;
(e) Hydro One is able to obtain the materials and labour required to perform the Hydro One Connection Work with the expenditure of Premium Costs where required;
(f) where Hydro One needs to obtain leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998,* such leave is obtained on or before the date specified as the Approval Date in Schedule "A" of the Agreement;
(g) where applicable, Hydro One received the easement described in Section 24 hereof by the Easement Date specified in Schedule "A" of the Agreement;
(h) Hydro One has received or obtained prior to the dates upon which Hydro One requires any or one or more of the following under Applicable Laws in order to perform all or any part of the Hydro One Connection Work:
  (i) environmental approvals, permits or certificates;
  (ii) land use permits from the Crown; and
  (iii) building permits and site plan approvals;
(j) Hydro One is able, using commercially reasonable efforts, to obtain all necessary land rights on terms substantially similar to the form of the easement that

is attached hereto as Appendix "B" of these Standard Terms and Conditions for the Project, prior to the dates upon which Hydro One needs to commence construction of the Hydro One Connection Work in order to meet the Ready for Service Date;

(k) there are no delays resulting from Hydro One being unable to obtain materials or equipment required from suppliers in time to meet the project schedule for any portion of the Hydro One Connection Work provided that such delays are beyond the reasonable control Hydro One; and

(l) the Customer executed the Agreement on or before the date specified as the Execution Date.

The Customer acknowledges and agrees that the Ready for Service Date may be materially affected by difficulties with obtaining or the inability to obtain all necessary land rights and/or environmental approvals, permits or certificates.

6. Upon completion of the Hydro One Connection Work:

(a) Hydro One shall own, operate and maintain all equipment specified in Schedule "A" of the Agreement under the heading "Ownership"; and

(b) other than equipment referred to in (a) above that shall be owned, operated and maintained by Hydro One, all other equipment provided by Hydro One as part of the Hydro One Connection Work or provided by the Customer as part of the Customer Connection Work shall be owned, operated and maintained by the Customer.

The Customer acknowledges that:

(i) ownership and title to the equipment referred to in (a) above shall throughout the Term and thereafter remain vested in Hydro One and the Customer shall have no right of property therein; and

(ii) any portion of the equipment referred to in (a) above that is located on the Customer's property shall be and remain the property of Hydro One and shall not be or become fixtures and/or part of the Customer's property.

7. The Customer acknowledges and agrees that Hydro One is not responsible for the provision of power system components on the Customer's Facilities, including, without limitation, all transformation, switching, metering and auxiliary equipment such as protection and control equipment.

All of the power system components on the Customer's side of the Connection Point including, without limitation, all transformation, switching and auxiliary equipment such as protection and control equipment shall be subject to the acceptance of Hydro One with regard to Hydro One's requirements to permit Connection of the New or Modified Connection Facilities to Hydro One's transmission system, and shall be installed, maintained and operated in accordance with all Applicable Laws, codes and standards, including, but not limited to, the *Transmission System Code*, at the expense of the Customer.

8. Where Hydro One has equipment for automatic reclosing of circuit breakers after an interruption for the purpose of improving the continuity of supply, it shall be the obligation of the Customer to provide adequate protective equipment for the Customer's facilities that might be adversely affected by the operation of such reclosing equipment. The Customer shall provide such equipment as may be required from time to time by Hydro One for the prompt disconnection of any of the Customer's apparatus that might affect the proper functioning of Hydro One's reclosing equipment.

9. The Customer shall provide Hydro One with copies of the documentation specified in Schedule "A" of the Agreement under the heading "Documentation Required", acceptable to Hydro One, within 120 calendar days after the Ready for Service Date. The Customer shall ensure that Hydro One may retain this documentation for Hydro One's ongoing planning, system design, and operating review. The Customer shall also maintain and revise such documentation to reflect changes to the Customer's Facilities and provide copies to Hydro One on demand and as specified in the Connection Agreement.

Part B: Transformation Connection Pool Work and/or Line Connection Pool Work and/or Network Customer Allocated Work

10.1 To the extent that the Pool Funded Cost of the Hydro One Connection Work is not recoverable by Transformation Connection Revenue for the Transformation Connection Pool Work and/or Line Connection Revenue for the Line Connection Pool Work and/or Network Revenue for the Network Customer Allocated Work during the Economic Evaluation Period, the Customer agrees to pay Hydro One a Capital Contribution towards the Pool Funded Cost of the Transformation Connection Pool Work and/or a Capital Contribution towards the Pool Funded Cost of the Line Connection Pool Work and/or a Capital Contribution towards the Pool Funded Cost of the Network Customer Allocated Work and any amounts payable to Hydro One under Subsection 12 (a) (i) hereof.

An estimate of the Engineering and Construction Cost (not including Taxes) of the Transformation Connection Pool Work and/or Line Connection Pool Work and/or Network Customer Allocated Work is provided in Schedule "B" of the Agreement.

An estimate of the Capital Contribution for each of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work is specified in Schedule "B" of the Agreement (plus Taxes). The Customer shall pay Hydro One the estimated Capital Contribution(s) in the manner specified in Schedule "B" of the Agreement.

Within 180 calendar days after the Ready for Service Date, Hydro One shall provide the Customer with a new Schedule "B" to replace Schedule "B" of the Agreement attached hereto which shall identify the following:

(i) the actual Engineering and Construction Cost of the Transformation Connection Pool Work;
(ii) the actual Engineering and Construction Cost of the Line Connection Pool Work;
(iii) the actual Engineering and Construction Cost of the Network Customer Allocated Work;
(iv) the actual Engineering and Construction Cost of the Work Chargeable to Customer;
(v) the actual Capital Contribution required to be paid by the Customer for each of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work; and
(vi) the revised Transformation Connection Revenue and/or Line Connection Revenue requirements and/or Network Revenue requirements based on the Load Forecast or the Adjusted Load Forecast, whichever is applicable.

The new Schedule "B" shall be made a part hereof as though it had been originally incorporated into the Agreement.

If an estimate of a Capital Contributions paid by the Customer exceeds the actual Capital Contribution required to be paid by the Customer for any or all of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work, Hydro One shall refund the difference to the Customer (plus Taxes) within 30 days following the issuing of the new Schedule "B". If the estimate of a Capital Contribution paid by the Customer is less than the actual Capital Contributions required to be paid by the Customer for any or all of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work, the Customer shall pay Hydro One the difference (plus Taxes) within 30 days following the issuing of the new Schedule "B".

10.2 Hydro One shall not include the following amounts in the Capital Contributions referenced in Section 10.1, any capital contribution for:

(a) a Connection Facility that was otherwise planned by Hydro One except for advancement costs;
(b) capacity added to a Connection Facility in anticipation of future load growth not attributable to the Customer; or
(c) the construction of or modifications to Hydro One's Network Facilities that may be required to accommodate the New or Modified Connection other than Network Customer Allocated Work unless Hydro One has indicated in Schedule "A" of the Agreement that exceptional circumstances exist so as to reasonably require the Customer to make a Capital Contribution.

10.3 Notwithstanding Sub-section 10.2(c) above, if Hydro One indicates in Schedule "A" of the Agreement that exceptional circumstances exist so as to reasonably require the Customer to make a Capital Contribution towards the Network Pool Work, Hydro One shall not, without the prior written consent of the Customer, refuse to commence or diligently perform the Network Pool Work pending direction from the OEB under section 6.3.5 of the *Transmission System Code* provided that the Customer provides Hydro One with a security deposit in accordance with Section 20 of these Standard Terms and Conditions.

Until such time as Hydro One has actually begun to perform the Network Pool Work, the Customer may request, in writing, that Hydro One not perform the Network Pool Work and Hydro One shall promptly return to the Customer any outstanding security deposit related to the Network Pool Work.

10.4 If the Customer has made a Capital Contribution under Section 10.1 hereof and where this Capital Contribution includes the cost of capacity on the Connection Facility not needed by the Customer as indicated in Schedule "B" of the Agreement, Hydro One shall provide the Customer with a refund, calculated in accordance with Section 6.2.25 of the *Transmission System Code* if that capacity is assigned to another Load Customer within five (5) years of the In Service Date.

11. Hydro One shall perform a True-Up, based on Actual Load:

(a) at the True-Up Points specified in Schedule "A" of the Agreement; and
(b) the time of disconnection where the Customer voluntarily and permanently disconnects the Customer's Facilities from Hydro One's transmission facilities and the prior to the final True-Up Point identified in (a) above.

For True-Up purposes, if the Customer does not pay a Capital Contribution, Hydro One shall provide the Customer with an Adjusted Load Forecast.

Hydro One shall perform True-Ups in a timely manner. Within 30 calendar days following completion of each of the True-Ups referred to in 11(a), Hydro One shall provide the Customer with the results of the True-Up.

12(a) If the result of a True-Up performed in accordance with Section 11 above is that the Actual Load and Updated Load Forecast is:

(i) less than the load in the Load Forecast or the Adjusted Load Forecast, whichever is applicable, and therefore does not generate the forecasted Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue required for the Economic Evaluation Period, the Customer shall pay Hydro One an amount equal to the shortfall adjusted to reflect the time value of money within 30 days after the date of Hydro One's invoice therefor; and

(ii) more than the load in the Load Forecast or the Adjusted Load Forecast, whichever is applicable, and therefore generates more than the forecasted Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue required for the Economic Evaluation Period, Hydro One shall post the excess Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue as a credit to the Customer in a notional account. Hydro One shall apply this credit against any shortfall in subsequent True-Up calculations. Where the Customer paid a Capital Contribution in accordance with Section 10.1 hereof, Hydro One shall rebate the Customer an amount that is the lesser of the credit balance in the notional account adjusted to reflect the time value of money, and the Capital Contribution adjusted to reflect the time value of money by no later than 30 days following the final True-Up calculation.

12(b) All adjustments to reflect the time value of money to be performed under Subsection 12(a) above shall be performed in accordance with the OEB-Approved Connection Procedures. As of the date of this Agreement, the time value of money is determined using Hydro One's after-tax cost of capital as used in the original economic evaluation performed in accordance with the requirements of the *Transmission System Code.*

13.1 With respect to the installation of embedded generation (as determined in accordance with Section 11.1 of the *Transmission System Code)* during the applicable True-Up period Hydro One shall comply with the requirements of Section 6.5.8 of the *Transmission System Code* when carrying out True-Up calculations if the Customer is a Distributor or the requirements of Section 6.5.9 of the Transmission System Code when carrying out True-Up calculations if the Customer is a Load Customer other than a Distributor.

13.2 With respect to energy conservation, energy efficiency, load management or renewable energy activities that occurred during the applicable True-Up period Hydro One shall comply with the requirements of Section 6.5.10 of the *Transmission System Code* when carrying out True-Up calculations provided that the Customer demonstrates to the reasonable satisfaction of Hydro One (such as by means of an energy study or audit) that the amount of any reduction in the Customer's load has resulted from energy conservation, energy efficiency, load management or renewable energy activities that occurred during the applicable True-Up period.

14. Hydro One shall provide the Customer with all information pertaining to the calculation of all Engineering and Construction Costs, Capital Contributions and True-Ups that the Customer is entitled to receive in accordance with the requirements of the *Transmission System Code.*

Part C: Work Chargeable to Customer, Network Pool Work and Premium Costs

15.1 The Customer shall pay Hydro One's Engineering and Construction Cost (plus Taxes) of the Hydro One Connection Work described asWork Chargeable to Customer in Schedule "A" of the Agreement which is estimated to be the amounts specified in Schedule "B" of the Agreement in the manner specified in Schedule "B" of the Agreement.

Hydro One shall identify the actual Engineering and Construction Cost of the Work Chargeable to Customer in the revised Schedule "B" provided to the Customer in accordance with Section 10.1 of this Agreement. Any difference between the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes) and the amount already paid by the Customer shall be paid within 30 days after the issuance of the revised Schedule "B" by:

(a) Hydro One to the Customer, if the amount already paid by the Customer exceeds the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes); or
(b) the Customer to Hydro One, if the amount already paid by the Customer is less than the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes).

15.2 Subject to Sections 10.3 and 18 hereof, Hydro One shall perform the Hydro One Connection Work described as Network Pool Work in Part 3 of Schedule "A" of the Agreement at Hydro One's sole expense.

16. As the Project is schedule-driven and as the estimated costs specified in Schedule "B" of the

Agreement are based upon normal timelines for delivery of material and performance of work, in addition to the amounts that the Customer is required to pay pursuant to Section 10.1 and 15.1 above, the Customer agrees to pay Hydro One's Premium Costs if the Customer causes or contributes to any delays, including, but not limited to, the Customer failing to execute the Agreement by the Execution Date specified in Schedule "A" of the Agreement.

Hydro One shall obtain the Customer's approval prior to Hydro One authorizing the purchase of materials or the performance of work that attracts Premium Costs. The Customer acknowledges that its failure to approve an expenditure of Premium Costs may result in further delays and Hydro One shall not be liable to the Customer as a result thereof. Hydro One shall invoice the Customer for expenditures of Premium Costs approved by the Customer within 180 calendar days after the Ready for Service Date.

Part D: Right of Customer to By-Pass Existing Load Facilities

17.1 **Obligation to Notify Hydro One of Customer's Intent to Bypass an Existing Load Facility:** If the Customer chooses to exercise its rights under the *Transmission System Code* and the Agreement to bypass the Existing Load Facility, the Customer shall notify Hydro One, in writing, at least 30 days prior to transferring load from the Existing Load Facility Hydro One will then proceed in accordance with Section 6.7 of the *Transmission System Code*.

17.2 **Hydro One has not received a Notice of Customer Intent to Bypass an Existing Load Facility and Customer has Transferred Existing Load:** Where Hydro One determines that the Customer has transferred load from the Existing Load Facility without notifying Hydro One or the OEB, Hydro One will notify the Customer, all other load customers served by the connection facility and the OEB of a potential by-pass situation in accordance with the OEB-Approved Connection Procedures. If the Customer does not intend to by-pass the Existing Load Facility, the Customer must in accordance with the OEB-Approved Connection Procedures:

i. notify Hydro One and the OEB within 30 days of receiving Hydro One's notification of potential by-pass, that it has no intention of by-passing Hydro One's Existing Load Facility;
ii. transfer the load back to the Existing Load Facility within an agreed time period; and
iii. compensate Hydro One for the lost revenues.

17.3 The Customer agrees that Sections 17.1 and 17.2 above shall also be a term of the Connection Agreement.

Part E: Cancellation or Termination of Project and Early Termination of Agreement for Breach

18. Notwithstanding any other term of the Agreement, if at any time prior to the In-Service Date, the Project is cancelled or the Agreement is terminated for any reason whatsoever other than breach of the Agreement by Hydro One, the Customer shall pay Hydro One's Engineering and Construction Cost (plus Taxes) of the Line Connection Pool Work, the Transformation Connection Pool Work, the Network Pool Work, the Network Customer Allocated Work and the Work Chargeable to Customer incurred on and prior to the date that the Project is cancelled or the Agreement is terminated, including the preliminary design costs and all costs associated with the winding up of the Project, including, but not limited to, storage costs, vendor cancellation costs, facility removal expenses and any environmental remediation costs.

If the Customer provides written notice to Hydro One that it is cancelling the Project, Hydro One shall have 10 Business Days to provide written notice to the Customer listing the individual items listed as materials which it agrees to purchase. Hydro One shall deduct the actual cost of those individual items of materials being purchased by Hydro One from the Engineering and Construction Costs referred to above.

If Hydro One does not require all or part of the materials, the Customer may exercise any of the following options or a combination thereof:

(i) where materials have been ordered but all or part of the materials have not been received by Hydro One, the Customer shall have the right to require Hydro One, at the Customer's sole expense, to continue with the purchase of the materials and transfer title to those materials on an "as is, where is basis" to the Customer upon the Customer paying Hydro One's Engineering and Construction Costs (plus Taxes) provided that the Customer exercises this option within 15 Business Days of the termination or cancellation; or
(ii) where all or part of the materials have been received by Hydro One but have not been installed, the Customer shall have the right to require Hydro One, at the Customer's sole expense, to transfer title to the materials on an "as is, where is basis" to the Customer upon the Customer paying Hydro One's Engineering and Construction Costs (plus Taxes) provided that the Customer exercises this option within 15 Business Days of the termination or cancellation. The Customer shall also be responsible for any warehousing costs associated with the storage of the materials to the date of transfer; or

(iii) where all or part of the materials have been received by Hydro One and have been installed, the Customer shall have the right to require Hydro One, at the Customer's sole expense, to: transfer title to the materials on an "as is, where is basis" to the Customer upon the later of (A) the Customer paying Hydro One's Engineering and Construction Costs (plus Taxes); and (B) the date that Hydro One removes the materials from its property at the risk of the Customer; provided that the Customer exercises this option within 15 Business Days of the termination or cancellation. The Customer shall also be responsible for any Engineering and Construction Costs (plus Taxes) associated with the removal of the materials that have been installed by Hydro One.

The Customer shall pay Hydro One's Engineering and Construction Costs (plus Taxes) which become payable under this Section 18 within 30 calendar days after the date of invoice.

Part F: Sale, Lease, Transfer or Other Disposition of Customer's Facilities

19. In the event that the Customer sells, leases or otherwise transfers or disposes of the Customer's Facilities to a third party during the Term of the Agreement, the Customer shall cause the purchaser, lessee or other third party to whom the Customer's Facilities are transferred or disposed to enter into an assumption agreement with Hydro One to assume all of the Customer's obligations in the Agreement; and notwithstanding such assumption agreement unless Hydro One agrees otherwise, in writing, the Customer shall remain obligated under Sections 10.1 12, 15.1 and 16 hereof. The Customer further acknowledges and agrees that in the event that all or a portion of the Customer's Facilities are shut down, abandoned or vacated for any period of time during the Term of the Agreement, the Customer shall remain obligated under Sections 10.1, 12, 15.1 and 16 for the said time period.

Part G: Security Requirements

20. If Hydro One requires that the Customer furnish security, which at the Customer's option may be in the form of cash, letter of credit or surety bond, the Customer shall furnish such security in the amount and by the dates specified in Schedule "A" of the Agreement. Hydro One shall return the security deposit to the Customer as follows:

(i) security deposits in the form of cash shall be returned to the Customer, together with Interest, less the amount of any Capital Contribution owed by the Customer once the Customer's Facilities are connected to Hydro One's New or Modified Connection Facilities; and

(ii) security deposits in any other form shall be returned to the Customer once the Customer's Facilities are connected to Hydro One's New or Modified Connection Facilities and any Capital Contribution has been paid.

Notwithstanding the foregoing, Hydro One may keep all or a part of the security deposit: (a) where and to the extent that the Customer fails to pay any amount due under the Agreement within the time stipulated for payment; or (b) in the circumstances described in the OEB-Approved Connection Procedures.

Part H: Disputes

21. Prior to the existence of OEB-Approved Connection Procedures either party may refer a Dispute to the OEB for a determination. Once there are OEB-Approved Connection Procedures, all disputes, including, but not limited to, disputes related to:

(a) the cost and the allocation of the costs under this Agreement;
(b) the cost and the allocation of costs of the Hydro One Connection Work and notwithstanding Hydro One's decision not to allocate or to allocate any part of the costs of this work to the Customer at this time; or
(c) any other costs and the allocation of any other costs associated with, related to, or arising out of the connection of the Project to Hydro One's transmission system or Hydro One's policies in respect of connections generally,

shall be dealt with in accordance with the dispute resolution procedure set out in the OEB-Approved Connection Procedures.

22. Before and after the existence of OEB-Approved Connection Procedures, if a dispute arises while Hydro One is constructing the New or Modified Connection Facilities, Hydro One shall not cease the work or slow the pace of the work without leave of the OEB.

23. Hydro One shall refund to the Customer or the Customer shall pay to Hydro One any portion of Capital Contributions, as the case may be, which the OEB subsequently determines should not have been allocated to the Customer or should have been allocated to the Customer by Hydro One but were not, as the case may be, or should have been allocated in a manner different from that allocated by Hydro One in this Agreement.

Part I: Easement

24. If specified in Schedule "A" that an easement(s) is required from the Customer, the Customer shall grant an easement to Hydro One substantially in the form of the easement attached hereto as Appendix "B" of these

Standard Terms and Conditions for the property(ies) described as the Easement Lands in Schedule "A" on or before the date specified as the Easement Date in Schedule "A" (hereinafter referred to as the "Easement") with good and marketable title thereto, free of all encumbrances, first in priority except as noted herein, and in registerable form, in consideration of the sum of $2.00.

Part J: Events of Default

25. Each of the following events shall constitute an "Event of Default" under the Agreement:

(a) failure by the Customer to pay any amount due under the Agreement, including any amount payable pursuant to Sections 10.1, 12, 15.1, 16 or 18 within the time stipulated for payment;
(b) breach by the Customer or Hydro One of any Material term, condition or covenant of the Agreement; or
(c) the making of an order or resolution for the winding up of the Customer or Hydro One or of their respective operations or the occurrence of any other dissolution, bankruptcy or reorganization or liquidation proceeding instituted by or against the Customer or Hydro One.

For greater certainty, a dispute shall not be considered an Event of Default under this Agreement. However, a Party's failure to comply, within a reasonable period of time, with the terms of a determination of such a dispute by the OEB or with a decision of a court of competent jurisdiction with respect to a determination made by the OEB shall be considered an Event of Default under the Agreement.

26. Upon the occurrence of an Event of Default by the Customer hereunder (other than those specified in Section 25(c) of the Agreement, for which no notice is required to be given by Hydro One), Hydro One shall give the Customer written notice of the Event of Default and allow the Customer 30 calendar days from the date of receipt of the notice to rectify the Event of Default, at the Customer's sole expense. If such Event of Default is not cured to Hydro One's reasonable satisfaction within the 30 calendar day period, Hydro One may, in its sole discretion, exercise the following remedy in addition to any remedies that may be available to Hydro One under the terms of the Agreement, at common law or in equity: deem the Agreement to be repudiated and, after giving the Customer at least 10 calendar days' prior written notice thereof, recover, as liquidated damages and not as a penalty, the following:

(i) the sum of the amounts payable by the Customer pursuant to Sections 10.1, 12, 15.1 and where applicable, Section 16 less any amounts already paid by the Customer in accordance with Section 10.1, 12, 15.1 and 16 if this clause is invoked after the In-Service Date; or

(ii) the amounts payable under Section 16 and 18 less any amounts already paid by the Customer in accordance with Sections 10.1, 15.1 and 16 if this clause is invoked prior to the In-Service Date.

27. Upon the occurrence of an Event of Default by Hydro One hereunder (other than those specified in Section 25(c), the Customer shall give Hydro One written notice of the Event of Default and shall allow Hydro One 30 calendar days from the date of receipt of the notice to rectify the Event of Default at Hydro One's sole expense. If such Event of Default is not cured to the Customer's reasonable satisfaction within the 30 calendar day period, the Customer may pursue any remedies available to it at law or in equity, including at its option the termination of the Agreement.

28. All rights and remedies of Hydro One and the Customer provided herein are not intended to be exclusive but rather are cumulative and are in addition to any other right or remedy otherwise available to Hydro One and the Customer respectively at law or in equity, and any one or more of Hydro One's and the Customer's rights and remedies may from time to time be exercised independently or in combination and without prejudice to any other right or remedy Hydro One or the Customer may have or may not have exercised. The parties further agree that where any of the remedies provided for and elected by the non-defaulting party are found to be unenforceable, the non-defaulting party shall not be precluded from exercising any other right or remedy available to it at law or in equity.

Part K: Changes to Transmission Rates

29. In the event that the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate is rescinded or the methodology of determination or components is materially changed, the Parties agree to negotiate a new mechanism for the purposes of the Agreement, provided that such new mechanism will not result in an increase in the amounts of Capital Contribution or Security Deposits payable by the Customer to Hydro One hereunder. The Parties shall have 90 calendar days from the effective date of rescission or fundamental change of the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate to agree to a new mechanism that is, to the extent possible, fair to the parties and constitutes a reasonably comparable replacement for the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate. If the Parties are unable to successfully negotiate a replacement within that 90 calendar day period, this shall be considered a dispute under the terms

of this Agreement and the parties shall follow the dispute resolution procedure set out in the OEB-Approved Connection Procedures.

Any settlement on a new mechanism pursuant to this Section 29 shall apply retroactively from the date on which the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate was rescinded or fundamentally changed. Until such time as a new mechanism is determined hereunder, any amounts to be paid by the Customer under the Agreement shall be based on the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate in effect prior to the effective date of any such changes.

Part L: Incorporation of Liability and Force Majeure Provisions

30. PART III: LIABILITY AND FORCE MAJEURE (with the exception of Section 15.5 thereof) and Sections 1.1.12 and 1.1.17 of the Connection Agreement are hereby incorporated in their entirety by reference into, and form an integral part of the Agreement. Unless the context otherwise requires, all references in PART III: LIABILITY AND FORCE MAJEURE TO "this Agreement" shall be deemed to be a reference to the Agreement and all references to the "the Transmitter" shall be deemed to be a reference to Hydro One.

For the purposes of this Section 30, the Parties agree that the reference to:

(i) the Transmitter in lines 3 and 4 of Section 15.1 means the Transmitter or any party acting on behalf of the Transmitter such as contractors, subcontractors, suppliers, employees and agents; and
(ii) the Customer in lines 3 and 4 of Section 15.2 means the Customer or any party acting on behalf of the Customer such as contractors, subcontractors, suppliers, employees and agents.

Part M: General

31. This Agreement is subject to the *Transmission System Code* and the OEB-Approved Connection Procedures. If any provision of this Agreement is inconsistent with the:

(a) *Transmission System Code,* the said provision shall be deemed to be amended so as to comply with the *Transmission System Code;*
(b) OEB-Approved Connection Procedures the said provision shall be deemed to be amended so as to comply with the OEB-Approved Connection Procedures; and
(c) Connection Agreement made between the parties, associated with the new customer connection facilities, on the same subject matter, the Connection Agreement governs.

32. The failure of either party hereto to enforce at any time any of the provisions of the Agreement or to exercise any right or option which is herein provided shall in no way be construed to be a waiver of such provision or any other provision nor in any way affect the validity of the Agreement or any part hereof or the right of either party to enforce thereafter each and every provision and to exercise any right or option. The waiver of any breach of the Agreement shall not be held to be a waiver of any other or subsequent breach. Nothing shall be construed or have the effect of a waiver except an instrument in writing signed by a duly authorized officer of the party against whom such waiver is sought to be enforced which expressly waives a right or rights or an option or options under the Agreement.

33. Other than as specifically provided in the Agreement, no amendment, modification or supplement to the Agreement shall be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of the Agreement.

34. Any written notice required by the Agreement shall be deemed properly given only if either mailed or delivered to the Secretary, Hydro One Networks Inc., 483 Bay Street, North Tower, 15th Floor, Toronto, Ontario M5G 2P5, fax no: (416) 345-6240 on behalf of Hydro One, and to the person at the address specified in Schedule "A" of the Agreement on behalf of the Customer.

A faxed notice shall be deemed to be received on the date of the fax if received before 3 p.m. on a business day or on the next business day if received after 3 p.m. or a day that is not a business day. Notices sent by courier or registered mail shall be deemed to have been received on the date indicated on the delivery receipt. The designation of the person to be so notified or the address of such person may be changed at any time by either party by written notice.

35. The Agreement shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of the Province of Ontario and the laws of Canada applicable therein.

36. The Agreement may be executed in counterparts, including facsimile counterparts, each of which shall be deemed an original, but all of which shall together constitute one and the same agreement.

37. The Customer shall provide Hydro One with a copy of the Customer's final monthly bills associated

with the transmission of electricity from the Existing Load Facilities and/or the Customer's Facilities or authorize the IESO to provide Hydro One with same. Hydro One agrees to use this information solely for the purpose of the Agreement.

38. **Invoices and Interest:** Invoiced amounts are due 30 days after invoice issuance. All overdue amounts including, but not limited to amounts that are not invoiced but required under the terms of this Agreement to be paid in a specified time period, shall bear interest at 1.5% per month compounded monthly (19.56 percent per year) for the time they remain unpaid.

39. The obligation to pay any amount due hereunder, including, but not limited to, any amounts due under Sections 10.1, 12, 15.1, 16, 18 or 23 shall survive the termination of the Agreement.

Appendix "A": Definitions

In the Agreement, unless the context otherwise requires, terms which appear therein without definition, shall have the meanings respectively ascribed thereto in the *Transmission System Code* and unless there is something in the subject matter or context inconsistent therewith, the following words shall have the following meanings:

"Actual Load" means the actual load delivered by Hydro One to the Customer up to the True-Up Point in excess of the Normal Capacity of the Existing Load Facilities.

"Assigned Capacity" is calculated in accordance with Section 6.2.2 of the *Transmission System* Code.

"Adjusted Load Forecast" means a Load Forecast that has been adjusted to the point where the present value of the Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue equals the present value of the Pool Funded Cost of the Transformation Connection Pool Work and/or the Pool Funded Cost of the Line Connection Pool Work and/or the Pool Funded Cost of the Network Customer Allocated Work.

"Agreement" means the Connection Cost Recovery Agreement, Schedules "A" and "B" attached thereto and these Standard Terms and Conditions.

"Applicable Laws" means any and all applicable laws, including environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments or decrees or any requirement or decision or agreement with or by any government or governmental department, commission board, court authority or agency.

"Approval Date" means for the purpose of Subsection 5(f) of the Terms and Conditions, the date specified in Schedule "A" of the Agreement.

"Capital Contribution" means a capital contribution calculated using the economic evaluation methodology set out in the *Transmission System Code.*

"Connect and Connection" has the same meaning ascribed to the term "Connect" in the *Transmission System Code.*

"Connection Agreement" means the form of connection agreement appended to the *Transmission System Code* as Appendix 1, Version 1.

"Connection Facilities" has the meaning set forth in the *Transmission System Code.*

"Connection Point" has the meaning set forth in the *Transmission System Code* and for this project, is as specified in Schedule "A" of the Agreement.

"Customer Connection Work" means the work to be performed by the Customer, at its sole expense, which is described in Schedule "A" of the Agreement.

"Customer Connection Risk Classification" is as specified in Schedule "A" of the Agreement.

"Customer's Facilities" has the meaning set forth in the *Transmission System Code*, and includes, but is not limited to any new, modified or replaced Customer's Facilities.

"Customer's Property(ies)" means any lands owned by the Customer in fee simple or where the Customer has easement rights.

"Dispute" means a dispute between the Parties with respect to any of the matters listed in Section 6.1.4 of the *Transmission System Code* where either Party is alleging that the other is seeking to impose a term that is inconsistent or contrary to the *Ontario Energy Board Act*, the *Electricity Act, 1998*, Hydro One's transmission licence or the *Transmission System Code* or refusing to include a term or condition that is required to give effect to the Code.

"Distributor" has the meaning set forth in the *Transmission System Code.*

"Economic Evaluation Period" means the period of five (5) years for high risk connection, ten (10) years for a medium-high risk connection, fifteen (15) years for a medium-low risk connection and twenty-five years for a low risk connection commencing on the In Service Date whichever is applicable to the Customer as specified in Schedule "A" of the Agreement.

"Engineering and Construction Cost" means Hydro One's charge for equipment, labour and materials at Hydro One's standard rates plus Hydro One's standard overheads as well as interest during construction using Hydro One's capitalization rate in effect during the construction period.

"*Electricity Act*, 1998" means the *Electricity Act, 1998* being Schedule "A" of the *Energy Competition Act,* S.O. *1998*, c.15, as amended.

"Existing Load" in relation to the Customer and each of the Existing Load Facilities is equal to the Customer's Assigned Capacity at each of the Existing Load Facilities on the date of this Agreement.

"Existing Load Facility or Existing Load Facilities" means the connection facility(ies) owned by Hydro One

as specified in the Existing Load Table in Schedule "A" of the Agreement where the Customer has Existing Load.

"Force Majeure Event" has the meaning ascribed thereto in the Connection Agreement.

"**HST**" means the Harmonized Sales Tax.

"Hydro One Connection Work" means the work to be performed by Hydro One, which is described in Schedule "A" of the Agreement.

"Hydro One Facilities" means Hydro One's structures, lines, transformers, breakers, disconnect switches, buses, voltage/current transformers, protection systems, telecommunication systems, cables and any other auxiliary equipment used for the purpose of transmitting electricity.

"Hydro One's Property(ies)" means any lands owned by Hydro One in fee simple or where Hydro One now or hereafter has obtained easement rights.

"IESO" means the Independent Electricity System Operator continued under the *Electricity Act, 1998*.

"In Service Date" has the same meaning ascribed to the term "comes into service" in the *Transmission System Code*.

"Incremental Network Load" means the Customer's New Load less the amount of load, if any, that has been by-passed by the Customer at any of Hydro One's connection facilities.

"Interest" means the interest rates specified by the OEB to be applicable to security deposits in the form of cash as specified in Subsection 6.3.11(b) in the *Transmission System Code*.

"Line Connection Pool Work" means the Hydro One Connection Work specified in Schedule "A" of the Agreement under the heading "Line Connection Pool Work".

"Line Connection Revenue" means the amount of line connection revenue attributable to that part of the Customer's New Load to be received by Hydro One through the monthly collection of the Line Connection Service Rate during the Economic Evaluation Period.

"**Line Connection Service Rate"** means the line connection service rate approved by the OEB in Hydro One's Rate Order from time to time, or any mechanism instituted in accordance with Section 29.

"Load Customer" has the meaning set forth in the *Transmission System Code*.

"Load Forecast" means the initial load forecast of the New Load in excess of the Normal Capacity of the Existing Load Facilities used in the initial economic evaluation for the Economic Evaluation Period.

"Material" relates to the essence of the contract, more than a mere annoyance to a right, but an actual obstacle preventing the performance or exercise of a right.

"Network Customer Allocated Work" means the construction of or modifications to Network Facilities specified in Schedule "A" of the Agreement under the heading "Network Customer Allocated Work" that are minimum connection requirements.

"Network Facilities" has the meaning set forth in the *Transmission System Code*.

"Network Pool Work" means the Hydro One Connection Work specified in Schedule "A" of the Agreement under the heading "Network Pool Work".

"Network Revenue" means the amount of network revenue attributable to the Incremental Network Load to be received by Hydro One through the monthly collection of the Network Service Rate during the Economic Evaluation Period.

"Network Service Rate" " means the network service rate approved by the OEB in Hydro One's Rate Order from time to time, or any mechanism instituted in accordance with Section 29.

"New Load" means the load at the New or Modified Connection Facility that is in excess of, for each of the Existing Load Facilities, the lesser of the Existing Load or the Normal Capacity.

"New or Modified Connection Facilities" means the facilities owned by Hydro One as specified in Schedule "A" of the Agreement.

"Normal Capacity" means, where the Customer is:

(a) the only Load Customer supplied by an Existing Load Facility, the total normal supply capacity of the Existing Load Facility as determined in accordance with the OEB-Approved Connection Procedures; and

(b) one of two or more Load Customers served by an Existing Load Facility, the Customer's pro-rated share of the total normal supply capacity of the Existing Load Facility as determined in accordance with the OEB-Approved Connection Procedures.

"OEB" means the Ontario Energy Board.

"OEB-Approved Connection Procedures" means Hydro One's connection procedures as approved by the OEB from time to time.

"Ontario Energy Board Act" means the *Ontario Energy Board Act* being Schedule "B" of the *Energy Competition Act*, S.O. *1998*, c. 15, as amended.

"Pool-Funded Cost" means the present value of the Engineering and Construction Cost and projected on-going maintenance and other related incremental costs (including, but not limited to applicable taxes, and net of tax benefits), of each of the Transformation Connection Pool Work, the Line Connection Pool Work and/or the Network Customer Allocated Work calculated in accordance with the principles, criteria and methodology set out in Appendices 4 and 5 of the Transmission System Code.

"Premium Costs" means those costs incurred by Hydro One in order to maintain or advance the Ready for Service Date, including, but not limited to, additional amounts expended for materials or services due to short time-frame for delivery; and the difference between having Hydro One's employees, agents and contractors perform work on overtime as opposed to during normal business hours.

"Rate Order" has the meaning ascribed thereto in the *Transmission System Code.*

"Ready for Service Date" means the date upon which the Hydro One Connection Work is fully and completely constructed, installed, commissioned and energised to the Connection Point. The Customer's disconnect switches must be commissioned prior to this date in order to use them as isolation points.

"Standard Terms and Conditions" means these Standard Terms and Conditions for Low Risk Transmission Customer Connection Projects and Appendices "A" and "B" attached hereto.

"Taxes" means all property, municipal, sales, use, value added, goods and services, harmonized and any other non-recoverable taxes and other similar charges (other than taxes imposed upon income, payroll or capital).

"Transformation Connection Pool Work" means the Hydro One Connection Work specified in Schedule "A" of the Agreement under the heading "Transformation Connection Pool Work".

"Transformation Connection Revenue" means the amount of transformation connection revenue attributable to that part of the Customer's New Load to be received by Hydro One through the monthly collection of the Transformation Connection Service Rate during the Economic Evaluation Period.

"Transformation Connection Service Rate" means the line connection service rate approved by the OEB in Hydro One's Rate Order from time to time, or any mechanism instituted in accordance with Section 29.

"Transmission System Code" or "Code" means the code of standards and requirements issued by the OEB on July 25, 2005 that came into force on August 20, 2005 as published in the Ontario Gazette, as it may be amended, revised or replaced in whole or in part from time to time.

"Transmitter's Facilities" has the meaning ascribed thereto in the *Transmission System Code.*

"True-Up" means the calculation to be performed by Hydro One, as a transmitter, at each True-Up Point in accordance with the requirements of Subsection 6.5.4 of the *Transmission System Code.*

"True-Up Point" means the points of time based upon the Customer Connection Risk Classification when Hydro One is required to perform a True-Up as described in Section 11 of these Terms and Conditions.

"Updated Load Forecast" means the load forecast of the New Load in excess of the Normal Capacity of the Existing Load Facilities for the remainder of the Economic Evaluation Period.

"Work Chargeable to Customer" means the Hydro One Connection Work specified in Part 4 of Schedule "A" of the Agreement under the heading "Work Chargeable to Customer".

Appendix "B": Form of Easement

INTEREST / ESTATE TRANSFERRED

The Transferor is the owner in fee simple and in possession of _____
_____
_____ (the **"Lands"**).

The Transferee has erected, or is about to erect, certain Works (as more particularly described in paragraph 1(a) hereof) in, through, under, over, across, along and upon the Lands.

1 The Transferor hereby grants and conveys to Hydro One Networks Inc, its successors and assigns the rights and easement, free from all encumbrances and restrictions, the following unobstructed and exclusive rights, easements, rights-of-way, covenants, agreements and privileges in perpetuity (the **"Rights"**) in, through, under, over, across, along and upon that portion of the Lands of the Transferor described herein and shown highlighted on Schedule "A" hereto annexed (the **"Strip"**) for the following purposes:

(a) To enter and lay down, install, construct, erect, maintain, open, inspect, add to, enlarge, alter, repair and keep in good condition, move, remove, replace, reinstall, reconstruct, relocate, supplement and operate and maintain at all times in, through, under, over, across, along and upon the Strip an electrical transmission system and telecommunications system consisting in both instances of a pole structures, steel towers, anchors, guys and braces and all such aboveground or underground lines, wires, cables, telecommunications cables, grounding electrodes, conductors, apparatus, works, accessories, associated material and equipment, and appurtenances pertaining to or required by either such system (all or any of which are herein individually or collectively called the **"Works"**) as in the opinion of the Transferee are necessary or convenient thereto for use as required by Transferee in its undertaking from time to time, or a related business venture.

(b) To enter on and selectively cut or prune, and to clear and keep clear, and remove all trees (subject to compensation to Owners for merchantable wood values), branches, bush and shrubs and other obstructions and materials in, over or upon the Strip, and without limitation, to cut and remove all leaning or decayed trees located on the Lands whose proximity to the Works renders them liable to fall and come in contact with the Works or which may in any way interfere with the safe, efficient or serviceable operation of the Works or this easement by the Transferee.

(c) To conduct all engineering, legal surveys, and make soil tests, soil compaction and environmental studies and audits in, under, on and over the Strip as the Transferee in its discretion considers requisite.

(d) To erect, install, construct, maintain, repair and keep in good condition, move, remove, replace and use bridges and such gates in all fences which are now or may hereafter be on the Strip as the Transferee may from time to time consider necessary.

(e) Except for fences and permitted paragraph 2(a) installations, to clear the Strip and keep it clear of all buildings, structures, erections, installations, or other obstructions of any nature (hereinafter collectively called the **"obstruction"**) whether above or below ground, including removal of any materials and equipment or plants and natural growth, which in the opinion of the Transferee, endanger its Works or any person or property or which may be likely to become a hazard to any Works of the Transferee or to any persons or property or which do or may in any way interfere with the safe, efficient or serviceable operation of the Works or this easement by the Transferee.

(e) To enter on and exit by the Transferor's access routes and to pass and repass at all times in, over, along, upon and across the Strip and so much of the Lands as is reasonably required, for Transferee, its respective officers, employees, agents, servants, contractors, subcontractors, workmen and permittees with or without all plant machinery, material, supplies, vehicles and equipment for all purposes necessary or convenient to the exercise and enjoyment of this easement and

(f) To remove, relocate and reconstruct the line on or under the Strip.

2. The Transferor agrees that:

(a) It will not interfere with any Works established on or in the Strip and shall not, without the Transferee's consent in writing, erect or cause to be erected or permit in, under or upon the Strip any obstruction or plant or permit any trees, bush, shrubs, plants or natural growth which does or may interfere with the Rights granted herein. The Transferor agrees it shall not, without the Transferee's consent in writing, change or permit the existing configuration, grade or elevation of the Strip to be changed and the Transferor further agrees that no excavation or opening or work which may disturb or interfere with the existing surface of the Strip shall be done or made unless consent therefore in writing has been obtained from Transferee, provided however, that the Transferor shall not be required to obtain such permission in case of emergency. Notwithstanding the foregoing, in cases where in the reasonable discretion of the Transferee, there is no danger or likelihood of danger to the Works of the Transferee or to any persons or property and the safe or serviceable operation of this easement by the Transferee is not interfered with, the Transferor may at its expense and with the prior written approval of the Transferee, construct and maintain roads, lanes, walks, drains, sewers, water pipes, oil and gas pipelines, fences (not to exceed 2 metres in height) and service cables on or under the Strip (the **"Installation"**) or any portion thereof; provided that prior to commencing such Installation, the Transferor shall give to the Transferee thirty (30) days notice in writing thereof to enable the Transferee to have a representative present to inspect the proposed Installation during the performance of such work, and provided further that Transferor comply with all instructions given by such representative and that all such work shall be done to the reasonable satisfaction of such representative. In the event of any unauthorised interference aforesaid or contravention of this paragraph, or if any authorised interference, obstruction or Installation is not maintained in accordance with the Transferee's instructions or in the Transferee's reasonable opinion, may subsequently interfere with the Rights granted herein, the Transferee may at the Transferor's expense, forthwith remove, relocate, clear or correct the offending interference, obstruction, Installation or contravention complained of from the Strip, without being liable for any damages caused thereby.

(b) notwithstanding any rule of law or equity, the Works installed by the Transferee shall at all times remain the property of the Transferee, notwithstanding that such Works are or may become annexed or affixed to the Strip and shall at anytime and from time to time be removable in whole or in part by Transferee.

(c) no other easement or permission will be transferred or granted and no encumbrances will be created over or in respect to the Strip, prior to the registration of a Transfer of this grant of Rights.

(d) the Transferor will execute such further assurances of the Rights in respect of this grant of easement as may be requisite.

(e) the Rights hereby granted:

(i) shall be of the same force and effect to all intents and purposes as a covenant running with the Strip.

(ii) is declared hereby to be appurtenant to and for the benefit of the Works and undertaking of the Transferee described in paragraph 1(a).

3. The Transferee covenants and agrees to obtain at its sole cost and expense all necessary postponements and subordinations (in registrable form) from all current and future prior encumbrancers, postponing their respective rights, title and interests to the Transfer of Easement herein so as to place such Rights and easement in first priority on title to the Lands.

4. There are no representations, covenants, agreements, warranties and conditions in any way relating to the subject matter of this grant of Rights whether expressed or implied, collateral or otherwise except those set forth herein.

5. No waiver of a breach or any of the covenants of this grant of Rights shall be construed to be a waiver of any succeeding breach of the same or any other covenant.

6. The burden and benefit of this transfer of Rights shall run with the Strip and the Works and undertaking of the Transferee and shall extend to, be binding upon and enure to the benefit of the parties hereto and their respective heirs, executors, administrators, successors and assigns.

IN WITNESS WHEREOF the Transferor has hereunto set his hand and seal to this Agreement, this ___ day of _____ _____, 200__.

SIGNED, SEALED AND DELIVERED
In the presence of)
)
_____(seal)
Signature of Witness)
)
)
)
_____)
Signature of Witness

_____)
Transferor's Signature

_____(seal)
Transferor's Signature

SIGNED, SEALED AND DELIVERED)
In the presence of)
)
)
)
_____)
Signature of Witness

Consent Signature & Release of
Transferor's Spouse, if non-owner.

_____(seal)

CHARGEES

THE CHARGEE of land described in a Charge/Mortgage of Land dated _____

Between _____ and _____

and registered as Instrument Number _____ on _____ does

hereby consent to this Easement and releases and discharges the rights and easement herein from the said

Charge/Mortgage of Land.

Name	Signature(s)	Date of Signatures Y M D
	Per:	
	_____	
	_____	
	I/We have authority to bind the Corporation	

CCRA – Arlen MTS

Revised Schedule "B" (*Arlen MTS*)

REVISION DATE:

March 25, 2013

READY FOR SERVICE DATE:

November 30, 2011

TRANSFORMATION CONNECTION POOL WORK
Estimate of the Engineering and Construction Cost of the Transformation Connection Pool Work: None

Estimate of Transformation Connection Pool Work Capital Contribution: None

Actual Engineering and Construction Cost of the Transformation Connection Pool Work: Not applicable

Actual Transformation Connection Pool Work Capital Contribution: Not Applicable

Capital Contribution Includes the Cost of Capacity Not Needed by the Customer: None

LINE CONNECTION POOL WORK
Estimate of the Engineering and Construction Cost of the Line Connection Pool Work: $1,688,000

Estimate of Line Connection Pool Work Capital Contribution: None

Actual Engineering and Construction Cost of the Line Connection Pool Work: $974,445

Actual Line Connection Pool Work Capital Contribution: None

Capital Contribution Includes the Cost of Capacity Not Needed by the Customer:

WORK CHARGEABLE TO CUSTOMER
Estimate of the Engineering and Construction Cost of the Work Chargeable To Customer: $314,000.
Actual Engineering and Construction Cost of the Work Chargeable To Customer: $106,136.49

Schedule "B" (*Arlen MTS*)-CONT'D

MANNER OF PAYMENT OF THE ESTIMATE OF CAPITAL CONTRIBUTIONS AND WORK CHARGEABLE TO CUSTOMER

The Customer shall pay Hydro One the estimate of the Transformation Connection Pool Work Capital Contribution, the Estimate of Line Connection Pool Work Capital Contribution, the estimate of the Network Customer Allocated Work Capital Contribution and the estimate of the Engineering and Construction Cost of the Work Chargeable to Customer by making the progress payments specified below on or before the Payment Milestone Date specified below. Hydro One will invoice the Customer for each progress payment 30 days prior to the Payment Milestone Date.

Payment Milestone Date	Transformation Pool Work Capital Contribution	Line Pool Work Capital Contribution	Network Customer Allocated Work Capital Contribution	Work Chargeable To Customer	Total Payment Required
June 30, 2012		None		$314,000	$314,000

LINE CONNECTION REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Period: One year following the anniversary of the Ready for Service date and annually thereafter	New Load** - (MW)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [C]	Adjusted Load Forecast (MW) [D]	Line Connection Revenue (k$) for True-Up, Based on [C] or [D], whichever is applicable
1st Anniversary - 2012	0	0	0.0	0.0
2nd Anniversary -2013	0	0	0.0	0.0
3rd Anniversary -2014	0	0	0.0	0.0
4th Anniversary -2015	3.9	3.9	2.2	30.0
5th Anniversary -2016	8.1	8.1	4	62.5
6th Anniversary – 2017	12.3	12.3	6	94.3
7th Anniversary – 2018	16.8	16.8	8.1	128.7
8th Anniversary – 2019	21.2	21.2	10.1	162.6
9th Anniversary – 2020	25.7	25.7	12.2	197.3
10th Anniversary – 2021	29.3	29.3	13.7	224.4
11th Anniversary – 2022	32.5	32.5	15.2	249.2
12th Anniversary -2023	35.8	35.8	16.7	274.3
13th Anniversary – 2024	39.1	39.1	18.2	300.0
14th Anniversary – 2025	42.5	42.5	19.8	326.1
15th Anniversary - 2026	46.5	46.5	21.7	356.3

16th Anniversary -2027	48.0	48.0	22.1	368.2
17th Anniversary -2028	48.7	48.7	22.5	373.7
18th Anniversary -2029	49.5	49.5	22.8	379.2
19th Anniversary -2030	50.2	50.2	23.1	384.9
20th Anniversary -2031	50.4	50.4	23.2	386.3
21st Anniversary -2032	50.4	50.4	23.2	386.3
22nd Anniversary -2033	50.4	50.4	23.2	386.3
23rd Anniversary -2034	50.4	50.4	23.2	386.3
24th Anniversary – 2035	50.4	50.4	23.2	386.3
25th Anniversary - 2036	50.4	50.4	23.2	386.3

Note: New Load is a weighted average of the annual peak loads for the two calendar years during each anniversary year multiplied by a Peak Load Index (PLI) of 0.87. PLI is defined as the average of the ratio of the average monthly peak load to the annual peak load.

****** New Load based on Customer's Load Forecast which includes Part of New Load Exceeding Normal Capacity of Existing Load Facilities. "Overload" derived in accordance with Section 6.7.9 of the Transmission System Code and the OEB-Approved Connection Procedures. Any Customer load below the Normal Capacity of the Existing Load Facilities transferred to the New or Modified Facilities will not be credited towards the Transformation Connection Revenue Requirements, Line Connection Revenue Requirements or the Network Connection Revenue Requirements. The discounted cash flow calculation for Network Revenue requirements will be based on Incremental Network Load which is New Load less the amount of load, if any, that has been by-passed by the Customer at any of Hydro One's connection facilities.

Connection and Cost Recovery Agreement

between

Guelph Hydro Electric Systems Inc.

and

Hydro One Networks Inc.

for

Arlen MTS – Line Connection

Guelph Hydro Electric Systems Inc. (the "Customer") has requested and **Hydro One Networks Inc.** ("Hydro One") has agreed to the construction of Arlen MTS Line Connection (the "**Project**") on the terms and conditions set forth in this Agreement dated May 17, 2011 (the "**Agreement**") and the attached Standard Terms and Conditions for Low Risk Transmission Customer Connection Projects V3 09 -2007 (the "**Standard Terms and Conditions**" or "**T&C**"). Schedules "A" and "B" attached hereto and the Standard Terms and Conditions are to be read with and form part of this Agreement.

Project Summary

The Customer is building a new 115/13.8 kV, 30/40/50 MVA DESN transformer station (Arlen MTS) located on the south-east corner of Crawley Road and Clair Road West in the City of Guelph to serve the Customer's southern service area (the "New Facility"), which shall be owned by the Customer. The Customer has requested Hydro One to build a double circuit 115 kV line tap from Hydro One's B5G and B6G circuits to the New Facility.

Term: The term of this Agreement commences on the date first written above and terminates on the 25th anniversary of the In Service Date.

Special Circumstances:

Before the upgrade to Burlington TS is complete and under high voltage commands, necessary control actions shall be taken by the Customer to avoid over-loading the transformers at Burlington TS, in accordance with the loading restriction stated in Guelph Hydro System Impact Assessment dated October 26, 2010, Section 4.5.1 (pg. 20) System State 1.

In addition to the circumstances described in Section 5 of the Standard Terms and Conditions, the Ready for Service Date is subject to:

(a) the Customer executing and delivering this Agreement to Hydro One by no later than Friday May 20, 2011, (the "Execution Date"); and

Subject to Section 31, this Agreement constitutes the entire agreement between the parties with respect to the subject matter of this Agreement and supersedes all prior oral or written representations and agreements concerning the subject matter of this Agreement.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by the signatures of their proper authorized signatories, as of the day and year first written above.

HYDRO ONE NETWORKS INC.

Approved by:

Myles D'Arcey
Senior VP. Customer Operations
Date: MAY 30, 2011
I have the authority to bind the Corporation.

GUELPH HYDRO ELECTRIC SYSTEMS INC.

Arlen Molyneaux
Director of Engineering
Date: May 17, 2011
I have the authority to bind the Corporation.

Schedule "A" (*Arlen MTS*)

PROJECT SCOPE

New or Modified Connection Facilities: Hydro One will construct a double circuit 115 kV tap from 115 kV lines B5G and B6G to the New Facility and provide transfer trip protection from Hanlon TS, Cedar TS (T1 and T2), and Arlen MTS to Burlington TS.

Connection Point: 115 kV transmission circuits B5G and B6G located on the west side of Crawley Road and south of Clair Road West in the City of Guelph.

Ready for Service Date: December 16, 2011

HYDRO ONE CONNECTION WORK

Part 1: Transformation Connection Pool Work

NONE

Part 2: Line Connection Pool Work

2.1 Protection changes

Hydro One will:

- Review & revise protections at Burlington TS and other stations as required.
- Provide recommended line backup settings to the Customer.
- Provide new operating plates and revise operating diagrams on Hydro One facilities only.
- Carry out commissioning & acceptance tests on Hydro One facilities.
- Conduct review of Customer Interface Documents and review compliance with the Transmission System Code.
- Review COVER Documents.

2.1 SCADA quantities

Hydro One will:

- Make modifications at OGCC, if required, to accommodate ICCP.
- Provide communications protocol details.
- Provide a points list of the required telemetry quantities.
- Collect the required telemetry quantities (device status, measured quantities and alarms) which will be provided by the Customer.

The quantities and device statuses, as set out and defined in Parts 2.2 to 2.5 below, shall be monitored and transmitted continually to Hydro One by the Customer:

2.2 Analogue Quantities

(a) Where HV voltages are monitored
  (I) HV active power (MW) and reactive power (MVAR) flows and directions for each transformer
  (II) Three phase to phase or three phase to neutral voltages of each HV winding or bus

(b) Where HV voltages are not monitored

CCRA - Arlen MTS

(I) Low voltage active power (MW) and reactive power (MVAR) flows and directions for each transformer winding or for each LV bus
(II) Three phase to phase voltages of each low voltage bus

(c) Under load tap changer (ULTC) positions

(d) Off load tap changer (OLTC) positions do not have to be telemetered. However, the Customer must provide Hydro One with the in-service OLTC positions and notify Hydro One of any changes thereafter.

2.3 Device Statuses

(a) All HV circuit breakers/switchers and bus tie breakers
(b) All HV line-disconnect switches
(c) All HV bus/tie sectionalizing switches
(d) All LV transformer and bus tie breakers and switches
(e) All LV capacitor breakers or isolating switches

2.4 Stations Operated by Networks

For stations operated by Hydro One, the following are also required:

(a) Three phase feeders currents
(b) Status of all feeder breakers
(c) Status of all feeder-breaker reclosing (armed or not armed)
(d) Status of all feeder-tie switches
(e) Other site specific data

2.5 Alarms

An alarm signal shall be generated and transmitted whenever a Customer owned protection, which is designed to trip Hydro One's or Customer owned HV breakers, operates. A separate alarm must be provided for each circuit supplying the Customer. The alarms shall identify the name of the transformer station and the designation of the HV interrupted circuit.

2.6 115 kV line tap

Hydro One will:

- Provide 2 x 115 kV overhead line tap from circuits B5G and B6G to the new Arlen MTS.
- Provide single-way openers.
- Provide tapping structure to suit. Locate the structure to align with the New Facility termination entrance structure.
- Terminate the line conductors at the New Facility termination entrance structures.
- Terminate the skywire at the mast extensions at the New Facility termination entrance structures.
- Arrange outages.

In order for Hydro One to complete the work described in this Part 2, the Customer shall have completed the Customer Connection Work described in this Schedule "A".

Part 3: Network Customer Allocated Work

NONE

Part 4: Network Pool Work (Non-Recoverable from Customer)

NONE

Part 5: Work Chargeable to Customer

Hydro One will install transfer trip protection at Burlington TS to accommodate transfer trip protection between Arlen MTS and Burlington TS. The Customer will pay the actual cost of this work plus applicable taxes. The current estimate is $314,000 plus applicable taxes.

Part 6: Scope Change

For the purposes of this Part 6 of Schedule "A", the term "Non-Customer Initiated Scope Change(s)" means one or more changes that are required to be made to the Project Scope as detailed and documented in Parts 1 to 5 of this Schedule "A" such as a result of any one or more of the following:

- any environmental assessment(s);
- any IESO requirements identified in the System Impact Assessment or any revisions thereto.

Any change in the Project Scope as detailed and documented in Parts 1 to 5 of this Schedule "A" whether they are initiated by the Customer or are Non-Customer Initiated Scope Changes, may result in a change to the Project costs estimated in Schedule "B" of this Agreement and the Project schedule, including the Ready for Service Date.

All Customer initiated scope changes to this Project must be in writing to Hydro One.

Hydro One will advise the Customer of any cost and schedule impacts of any Customer initiated scope changes. Hydro One will advise the Customer of any Material cost and/or Material schedule impacts of any Non-Customer Initiated Scope Changes.

Hydro One will not implement any Customer initiated scope changes until written approval has been received from the Customer accepting the new pricing and schedule impact.

Hydro One will implement all Non-Customer Initiated Scope Changes until the estimate of the Engineering and Construction Cost of all of the Non-Customer Initiated Scope Changes made by Hydro One reaches 10% of the total sum of the estimates of the Engineering and Construction Cost of:

(i) the Line Connection Pool Work;
(ii) Network Pool Work
(iii) Network Customer Allocated Work; and
(iv) the Work Chargeable to Customer.

At that point, no further Non-Customer Initiated Scope Changes may be made by Hydro One without the written consent of the Customer accepting new pricing and schedule impact. If the Customer does not accept the new pricing and schedule impact, Hydro One will not be responsible for any delay in the Ready for Service Date as a consequence thereof.

CUSTOMER CONNECTION WORK

Part 1: General Project Requirements:

The Customer will:

(a) enter into an Connection Agreement with Hydro One at least 14 days prior to the connection of the New Facility to Hydro One's transmission system;

(b) ensure that project data is made available or provided to Hydro One as required by Hydro One;

(c) ensure that the work performed by the Customer and others required for successful installation, testing and commissioning of protective and metering equipment is completed as required to satisfy the Confirmation of Verification Evidence Report (COVER).

(d) install metering facilities in accordance with the IESO's Rules;

(e) obtain the IESO's approval of the connection design and satisfy any other requirements of the IESO, in order to connect to Hydro One's transmission system; and

(f) provide a dedicated communication circuit for remote access to the metering equipment in accordance with the IESO Rules.

Part 2: Line tap

The Customer will:

- Provide easement including the legal survey for the line tap and the skywires.
- Provide suitable steel termination entrance structures to accommodate the 115 kV overhead line tap.
- Provide suitable lightning masts to accommodate 1 overhead skywire equipped with insulated end.
- Provide connections from the NEMA pads on the line conductors to the New Facility bus/equipment.
- Provide connections from the skywires to the New Facility ground grid.
- Provide information on the phase rotation at the entrance structures.
- Provide environmental assessment report, geotechnical report, and engineering survey for the New Facility.

Part 3: Teleprotection at New Facility

The new "A" and "B" bi-directional transfer trip facility via main and alternate channels will be required between Burlington TS and Arlen MTS. The Customer will purchase and install all the necessary equipment at Arlen MTS required for the transfer trip protection to Burlington TS.

Part 4: Protection at New Facility

The Customer will:

- Ensure that any Customer protection that trips the 115kV transformer breaker must also independently and simultaneously open the 115kV breaker and motorized disconnect switch.

- Install dual line backup protections to cover both phase and ground faults on the line. This is consistent with the Transmission System Code.

Part 5: SCADA RTU

The Customer will:

- Comply with Market Rules for sending Real Time Data to the IESO.

CCRA - Arlen MTS

Part 6: Telecommunications

The Customer will:

- Provide SCADA quantities as required by the Transmission System Code to OGCC as per section 2.0

Part 7: Revenue Metering

The Customer will:

- Provide revenue metering system to IESO requirements including but not limited to Chapter 6 of the IESO rules.

Part 8: Interface Documentation

The Customer will:

- Submit the following Interface Documents for review per the Transmission System Code in complete packages of Group A, B, C; and
- Pay $3,700 for each additional review due to partial submission or incomplete information in the submission.

Group A:

- IESO application & approval-for information only.
- System 1-line showing ratings of all electrical equipment, such as disconnect switches, bushing potential devices, CVTs, power transformers, grounding transformers, grounding resistors, breakers, etc.
- GPR study and associated station ground design.
- Entrance structure (electrical & structural)
- General arrangement of the station

Group B:

- DC station service 1 line showing ratings of all electrical equipment such as batteries, chargers, etc.
- Information on switchgear fault ratings
- HV surge arrestor specification
- RTU configuration/communications protocol
- Line protection ac & dc EWD
- Transformer protection, ac & dc EWD
- Circuit switcher/HV disconnect switch/HV breaker ac & dc EWD
- LV breaker (transformer & bus tie breakers) ac & dc EWD
- Breaker failure (circuit switcher, transformer & bus tie breakers) ac & dc EWD
- HV equipment operating & protection philosophy & design descriptions of protections

Group C:

- Power transformer nameplate
- Relay settings including relay logic diagrams, coordination studies and fault calculations
- Commissioning procedure

The Customer shall submit the above noted documents in accordance with the following:

- Identify all submitted documents with revision numbers and/or dates in a transmittal.
- All submitted Connection Interface Documents are to be sent via courier from the Customer to the Hydro One contact,

- All submitted drawings are to be submitted in full size, folded & collated into packages for Hydro One internal distribution. For example, if there are 6 sets, then we should expect 6 packages in one courier package.
- Number of sets:
  - All 1 lines: 10 sets
  - General arrangement: 6 sets
  - All other drawings/documents: 4 sets

Part 8: Site Work

The Customer will:

- Provide bucket truck access to the Hydro One's Mid-Span-Openers located on the Customer's property

EXISTING LOAD:

The capacity allocated to the Customer is 321.7MW and is made up of the following contributions.

	A	B
Existing Load Facility	**Existing Load (MW)[1,]**	**Normal Capacity (MW)[2]**
Campbell TS	147.4	147.4
Cedar TS (T1 & T2)	96.4	96.4
Cedar TS (T7 & T8)	39.5	39.5
Hanlon TS	38.4	38.4

Notes:

1. Existing Load means the Customer's Assigned Capacity at the Existing Load Facility as of the date of this Agreement (Section 3.0.3 of the *Transmission System Code).*
2. Any station load above the Normal Capacity of the Existing Load Facility (Overload) will be determined in accordance with Section 6.7.9 of the *Transmission System Code* and Hydro One's Connection Procedures. If the Overload is transferred to the New or Modified Connection Facilities, the Overload will be credited to the Line Connection Revenue, Transformation Connection Revenue or Network Revenue requirement, whichever is applicable.

OTHER RELEVANT CONSIDERATIONS: There is an existing Connection and Cost Recovery Agreement (CCRA) in place between Guelph Hydro Electric Systems Inc. and Hydro One Networks Inc. for installation of a new metalclad to the two (2) idle windings at Cedar TS (T1 and T2). The metalclad consisted of 8 feeder positions. The existing CCRA ("Guelph Cedar TS Metalclad Project"; dated Mar 1, 2005) also includes an investment to add a feeder work at Campbell TS.
There is also another existing CCRA in place for feeder work at Hanlon TS ("Hanlon TS – Install Two 13.8kV Feeder Breaker Positions"; dated Jan 18, 2008).

EXCEPTIONAL CIRCUMSTANCES RE. NETWORK CONSTRUCTION OR MODIFICATIONS:

MISCELLANEOUS
Customer Connection Risk Classification: Low Risk

CCRA - Arlen MTS

True-Up Points:

(a) following the fifth and tenth anniversaries of the In Service Date; and

(b) following the fifteenth anniversary of the In Service Date if the Actual Load is 20% higher or lower than the Load Forecast at the end of the tenth anniversary of the In Service Date.

Customer's HST Registration Number: [redacted]

Documentation Required (after In Service Date):

Documentation describing the as-built electrical characteristics of the New Facility. This documentation shall include, but is not limited to the system 1 line, dc station 1 line, teleprotection ac and dc elementary wiring diagram (EWD), line protection ac and dc EWD, transformer protection ac and dc EWD, HV breaker and disconnect switch ac and dc EWD, LV transformer and bus tie breakers ac and dc EWD, breaker failure ac and dc EWD of the New Facility. Documentation required will be in the form of four (4) sets of full size drawings folded & collated, and electronic files in CD-ROM format that are compatible with AutoCAD 2006.

Ownership: Hydro One will own all equipment provided by Hydro One as part of the Hydro One Connection.

Approval Date (if Section 92 required to be obtained by Hydro One): Not required.

Security Requirements: Nil.

Security Date: Not applicable.

Easement Required from Customer: Yes

Easement Date: On or before July 15th, 2011

Easement Lands: Part of lands legally described as Pasrt of Lot 11, Concession 7, Part 1, 61R11333 City of Guelph being part of PIN 71199-0097

Easement Term: In perpetuity

Approval Date (for OEB leave to construct): Not required.

Revenue Metering: IESO compliant revenue metering to be provided by the Customer

Customer Notice Info:

Guelph Hydro Electric Systems Inc.
395 Southgate Drive, Guelph, ON,N1G 4Y1

Attention: Michael Wittemund, Manager of Distribution Engineering
Fax # 519 822 4963
Cell 519 820 9422
Office 519 837 4719

Schedule "B" (*Arlen MTS*)

TRANSFORMATION CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Transformation Connection Pool Work: None

Estimate of Transformation Connection Pool Work Capital Contribution: None.

Actual Engineering and Construction Cost of the Transformation Connection Pool Work: Not applicable.

Actual Transformation Connection Pool Work Capital Contribution: Not Applicable.

Capital Contribution Includes the Cost of Capacity Not Needed by the Customer: None.

LINE CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Line Connection Pool Work: $1,688,000

Estimate of Line Connection Pool Work Capital Contribution: None

Actual Engineering and Construction Cost of the Line Connection Pool Work: To be provided 180 days after the Ready for Service Date

Actual Line Connection Pool Work Capital Contribution: To be provided 180 days after Ready for Service Date

Capital Contribution Includes the Cost of Capacity Not Needed by the Customer:

WORK CHARGEABLE TO CUSTOMER

Estimate of the Engineering and Construction Cost of the Work Chargeable To Customer: $314,000.

Actual Engineering and Construction Cost of the Work Chargeable To Customer: To be provided 180 days after Ready for Service Date

CCRA - Arlen MTS

Schedule "B" (*Arlen MTS*)-CONT'D

MANNER OF PAYMENT OF THE ESTIMATE OF CAPITAL CONTRIBUTIONS AND WORK CHARGEABLE TO CUSTOMER

The Customer shall pay Hydro One the estimate of the Transformation Connection Pool Work Capital Contribution, the Estimate of Line Connection Pool Work Capital Contribution, the estimate of the Network Customer Allocated Work Capital Contribution and the estimate of the Engineering and Construction Cost of the Work Chargeable to Customer by making the progress payments specified below on or before the Payment Milestone Date specified below. Hydro One will invoice the Customer for each progress payment 30 days prior to the Payment Milestone Date.

Payment Milestone Date	Transformation Pool Work Capital Contribution	Line Pool Work Capital Contribution	Network Customer Allocated Work Capital Contribution	Work Chargeable To Customer	Total Payment Required
June 1, 2011		None		$314,000	$314,000

LINE CONNECTION REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Period: One year following the anniversary of the Ready for Service date and annually thereafter	New Load** - (MW)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [C]	Adjusted Load Forecast (MW) [D]	Line Connection Revenue (k$) for True-Up, Based on [C] or [D], whichever is applicable
1st Anniversary - 2012	0	0	0.0	0.0
2nd Anniversary -2013	0	0	0.0	0.0
3rd Anniversary -2014	0	0	0.0	0.0
4th Anniversary -2015	3.9	3.9	3.2	30.0
5th Anniversary -2016	8.1	8.1	6.6	62.5
6th Anniversary – 2017	12.3	12.3	10.0	94.3
7th Anniversary – 2018	16.8	16.8	13.6	128.7
8th Anniversary – 2019	21.2	21.2	17.2	162.6
9th Anniversary – 2020	25.7	25.7	20.8	197.3
10th Anniversary – 2021	29.3	29.3	23.7	224.4
11th Anniversary – 2022	32.5	32.5	26.3	249.2
12th Anniversary -2023	35.8	35.8	28.9	274.3
13th Anniversary – 2024	39.1	39.1	31.6	300.0
14th Anniversary – 2025	42.5	42.5	34.4	326.1
15th Anniversary - 2026	46.5	46.5	37.6	356.3
16th Anniversary -2027	48.0	48.0	38.8	368.2
17th Anniversary -2028	48.7	48.7	39.4	373.7
18th Anniversary -2029	49.5	49.5	40.0	379.2
19th Anniversary -2030	50.2	50.2	40.6	384.9

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20th Anniversary -2031	50.4	50.4	40.8	386.3
21st Anniversary -2032	50.4	50.4	40.8	386.3
22nd Anniversary -2033	50.4	50.4	40.8	386.3
23rd Anniversary -2034	50.4	50.4	40.8	386.3
24th Anniversary – 2035	50.4	50.4	40.8	386.3
25th Anniversary - 2036	50.4	50.4	40.8	386.3

Note: New Load is a weighted average of the annual peak loads for the two calendar years during each anniversary year multiplied by a Peak Load Index (PLI) of 0.87. PLI is defined as the average of the ratio of the average monthly peak load to the annual peak load.

** New Load based on Customer's Load Forecast which includes Part of New Load Exceeding Normal Capacity of Existing Load Facilities. "Overload" derived in accordance with Section 6.7.9 of the Transmission System Code and the OEB-Approved Connection Procedures. Any Customer load below the Normal Capacity of the Existing Load Facilities transferred to the New or Modified Facilities will not be credited towards the Transformation Connection Revenue Requirements, Line Connection Revenue Requirements or the Network Connection Revenue Requirements. The discounted cash flow calculation for Network Revenue requirements will be based on Incremental Network Load which is New Load less the amount of load, if any, that has been by-passed by the Customer at any of Hydro One's connection facilities.

CCRA - Arlen MTS

Standard Terms and Conditions for Load Customer Transmission Customer Connection Projects

1. Each party represents and warrants to the other that:

(a) it is duly incorporated, formed or registered (as applicable) under the laws of its jurisdiction of incorporation, formation or registration (as applicable);
(b) it has all the necessary corporate power, authority and capacity to enter into the Agreement and to perform its obligations hereunder;
(c) the execution, delivery and performance of the Agreement by it has been duly authorized by all necessary corporate and/or governmental and/or other organizational action and does not (or would not with the giving of notice, the lapse of time or the happening of any other event or condition) result in a violation, a breach or a default under or give rise to termination, greater rights or increased costs, amendment or cancellation or the acceleration of any obligation under (i) its charter or by-law instruments; (ii) any Material contracts or instruments to which it is bound; or (iii) any laws applicable to it;
(d) any individual executing this Agreement, and any document in connection herewith, on its behalf has been duly authorized by it to execute this Agreement and has the full power and authority to bind it;
(e) the Agreement constitutes a legal and binding obligation on it, enforceable against it in accordance with its terms;
(f) it is registered for purposes of Part IX of the *Excise Tax Act* (Canada). The GST registration number for Hydro One is 87086-5821 RT0001 and the GST registration number for the Customer is as specified in Schedule "A" of the Agreement; and
(g) no proceedings have been instituted by or against it with respect to bankruptcy, insolvency, liquidation or dissolution.

Part A: Hydro One Connection Work and Customer Connection Work

2. The Customer and Hydro One shall perform their respective obligations outlined in the Agreement in a manner consistent with Good Utility Practice and the Transmission System Code, in compliance with all Applicable Laws, and using duly qualified and experienced people.

3. The parties acknowledge and agree that:

(a) Hydro One is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Hydro One Connection Work and those required for the construction, Connection and operation of the New or Modified Connection Facilities;

(b) the Customer shall perform the Customer Connection Work, at its own expense;

(c) except as specifically provided in the Agreement, the Customer is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Customer Connection Work and those required for the construction, Connection and operation of the Customer's Facilities including, but not limited to, where applicable, leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998*;

(d) the Customer is responsible for installing equipment and facilities such as protection and control equipment to protect its own property, including, but not limited to the Customer's Facilities;

(e) the Customer shall provide Hydro One with Project data required by Hydro One, including, but not limited to (i) the same technical information that the Customer provided the IESO during any connection assessment and facility registration process associated with the Customer's Facilities in the form outlined in the applicable sections of the IESO's public website and (ii) technical specifications (including electrical drawings) for the Customer's Facilities;

(f) Hydro One may participate in the commissioning, inspection or testing of the Customer's Connection Facilities at a time that is mutually agreed by Hydro One and the Customer and the Customer shall ensure that the work performed by the Customer and others required for successful commissioning, inspection or testing of protective equipment is completed as required to enable Hydro One witnessing and testing to confirm satisfactory performance of such systems;

(g) unless otherwise provided herein, Hydro One's responsibilities under the Agreement with respect to the Connection of the New or Modified Connection Facilities to Hydro One's transmission system shall be limited to the performance of the Hydro One Connection Work;

(h) Hydro One is not permitted to Connect any new, modified or replacement Customer's Facilities unless any required Connection authorizations, certificate of inspection or other applicable approval have been issued or given by the Ontario Electrical Safety Authority in relation to such facilities;

(i) Hydro One may require that the Customer provide Hydro One with test certificates certifying that the Customer's Facilities have passed all relevant tests and comply with the *Transmission System Code*, the Market Rules, Good Utility Practice, the standards of all applicable reliability organizations and any Applicable

Laws, including, but not limited to any certificates of inspection that may be required by the Ontario Electrical Safety Authority;

(j) in addition to the Hydro One Connection Work described in Schedule "A", Hydro One shall: provide the Customer with such technical parameters as may be required to assist the Customer in ensuring that the design of the Customer's Facilities is consistent with the requirements applicable to Hydro One's transmission system and the basic general performance standards for facilities set out in the *Transmission System Code*, including Appendix 2 thereof; and

(k) if Hydro One requires access to the Customer's Facilities for the purposes of performing the Hydro One Connection Work or the Customer requires access to Hydro One's Facilities for the purposes of the Customer Connection Work, the parties agree that Section 27.13 of the Connection Agreement shall govern such access and is hereby incorporated in its entirety by reference into, and forms an integral part of the Agreement. All references to "this Agreement" in Section 27.13 shall be deemed to be a reference to the Agreement;

(l) the Customer shall enter into a Connection Agreement with Hydro One or amend its existing Connection Agreement with Hydro One at least 14 calendar days prior to the Connection;

(m) Hydro One shall use commercially reasonable efforts to ensure that any applications required to be filed to obtain any permits or approvals required under Applicable Laws for the Hydro One Connection Work are filed in a timely manner; and

(n) the Customer shall use commercially reasonable efforts to ensure that any applications required to be filed to obtain any permits or approvals required under Applicable Laws for the Customer Connection Work or for the construction, Connection and operation of the Customer's Facilities are filed in a timely manner.

4. The following aspects of the Hydro One Connection Work and Hydro One's rights and requirements hereunder are solely for the purpose of Hydro One ensuring that the Customer Facilities to be connected to Hydro One's transmission system do not materially reduce or adversely affect the reliability of Hydro One's transmission system and do not adversely affect other customers connected to Hydro One's transmission system, Hydro One's:

(i) specifications of the protection equipment on the Customer's side of the Connection Point;
(ii) acceptance of power system components on the Customer's side of the Connection Point;
(iii) acceptance of the technical specifications (including electrical drawings) for the Customer's Facilities and/or the Customer Connection Work; and
(iv) participation in the commissioning, inspection or testing of the Customer's Facilities,

The Customer is responsible for installing equipment and facilities such as protection and control equipment to protect its own property, including, but not limited to the Customer's Facilities.

5. Hydro One shall use commercially reasonable efforts to complete the Hydro One Connection Work by the Ready for Service Date specified in Schedule "A" provided that:

(a) the Customer is in compliance with its obligations under the Agreement;
(b) any work required to be performed by third parties has been performed in a timely manner and in a manner to the satisfaction of Hydro One, acting reasonably;
(c) there are no delays resulting from Hydro One not being able to obtain outages from the IESO required for any portion of the Hydro One Connection Work or from the IESO making changes to the Hydro One Connection Work or the scheduling of all or a portion of the Hydro One Connection Work ;
(d) Hydro One does not have to use its employees, agents and contractors performing the Hydro One Connection Work or the Network Pool Work elsewhere on its transmission system or distribution system due to an Emergency (as that term is defined in the *Transmission System Code*) or a Force Majeure Event;
(e) Hydro One is able to obtain the materials and labour required to perform the Hydro One Connection Work with the expenditure of Premium Costs where required;
(f) where Hydro One needs to obtain leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998,* such leave is obtained on or before the date specified as the Approval Date in Schedule "A" of the Agreement;
(g) where applicable, Hydro One received the easement described in Section 24 hereof by the Easement Date specified in Schedule "A" of the Agreement;
(h) Hydro One has received or obtained prior to the dates upon which Hydro One requires any or one or more of the following under Applicable Laws in order to perform all or any part of the Hydro One Connection Work:
  (i) environmental approvals, permits or certificates;
  (ii) land use permits from the Crown; and
  (iii) building permits and site plan approvals;
(j) Hydro One is able, using commercially reasonable efforts, to obtain all necessary land rights on terms substantially similar to the form of the easement that

is attached hereto as Appendix "B" of these Standard Terms and Conditions for the Project, prior to the dates upon which Hydro One needs to commence construction of the Hydro One Connection Work in order to meet the Ready for Service Date;

(k) there are no delays resulting from Hydro One being unable to obtain materials or equipment required from suppliers in time to meet the project schedule for any portion of the Hydro One Connection Work provided that such delays are beyond the reasonable control Hydro One; and

(l) the Customer executed the Agreement on or before the date specified as the Execution Date.

The Customer acknowledges and agrees that the Ready for Service Date may be materially affected by difficulties with obtaining or the inability to obtain all necessary land rights and/or environmental approvals, permits or certificates.

6. Upon completion of the Hydro One Connection Work:

(a) Hydro One shall own, operate and maintain all equipment specified in Schedule "A" of the Agreement under the heading "Ownership"; and

(b) other than equipment referred to in (a) above that shall be owned, operated and maintained by Hydro One, all other equipment provided by Hydro One as part of the Hydro One Connection Work or provided by the Customer as part of the Customer Connection Work shall be owned, operated and maintained by the Customer.

The Customer acknowledges that:

(i) ownership and title to the equipment referred to in (a) above shall throughout the Term and thereafter remain vested in Hydro One and the Customer shall have no right of property therein; and

(ii) any portion of the equipment referred to in (a) above that is located on the Customer's property shall be and remain the property of Hydro One and shall not be or become fixtures and/or part of the Customer's property.

7. The Customer acknowledges and agrees that Hydro One is not responsible for the provision of power system components on the Customer's Facilities, including, without limitation, all transformation, switching, metering and auxiliary equipment such as protection and control equipment.

All of the power system components on the Customer's side of the Connection Point including, without limitation, all transformation, switching and auxiliary equipment such as protection and control equipment shall be subject to the acceptance of Hydro One with regard to Hydro One's requirements to permit Connection of the New or Modified Connection Facilities to Hydro One's transmission system, and shall be installed, maintained and operated in accordance with all Applicable Laws, codes and standards, including, but not limited to, the *Transmission System Code*, at the expense of the Customer.

8. Where Hydro One has equipment for automatic reclosing of circuit breakers after an interruption for the purpose of improving the continuity of supply, it shall be the obligation of the Customer to provide adequate protective equipment for the Customer's facilities that might be adversely affected by the operation of such reclosing equipment. The Customer shall provide such equipment as may be required from time to time by Hydro One for the prompt disconnection of any of the Customer's apparatus that might affect the proper functioning of Hydro One's reclosing equipment.

9. The Customer shall provide Hydro One with copies of the documentation specified in Schedule "A" of the Agreement under the heading "Documentation Required", acceptable to Hydro One, within 120 calendar days after the Ready for Service Date. The Customer shall ensure that Hydro One may retain this documentation for Hydro One's ongoing planning, system design, and operating review. The Customer shall also maintain and revise such documentation to reflect changes to the Customer's Facilities and provide copies to Hydro One on demand and as specified in the Connection Agreement.

Part B: Transformation Connection Pool Work and/or Line Connection Pool Work and/or Network Customer Allocated Work

10.1 To the extent that the Pool Funded Cost of the Hydro One Connection Work is not recoverable by Transformation Connection Revenue for the Transformation Connection Pool Work and/or Line Connection Revenue for the Line Connection Pool Work and/or Network Revenue for the Network Customer Allocated Work during the Economic Evaluation Period, the Customer agrees to pay Hydro One a Capital Contribution towards the Pool Funded Cost of the Transformation Connection Pool Work and/or a Capital Contribution towards the Pool Funded Cost of the Line Connection Pool Work and/or a Capital Contribution towards the Pool Funded Cost of the Network Customer Allocated Work and any amounts payable to Hydro One under Subsection 12 (a) (i) hereof.

An estimate of the Engineering and Construction Cost (not including Taxes) of the Transformation Connection Pool Work and/or Line Connection Pool Work and/or Network Customer Allocated Work is provided in Schedule "B" of the Agreement.

An estimate of the Capital Contribution for each of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work is specified in Schedule "B" of the Agreement (plus Taxes). The Customer shall pay Hydro One the estimated Capital Contribution(s) in the manner specified in Schedule "B" of the Agreement.

Within 180 calendar days after the Ready for Service Date, Hydro One shall provide the Customer with a new Schedule "B" to replace Schedule "B" of the Agreement attached hereto which shall identify the following:

(i) the actual Engineering and Construction Cost of the Transformation Connection Pool Work;
(ii) the actual Engineering and Construction Cost of the Line Connection Pool Work;
(iii) the actual Engineering and Construction Cost of the Network Customer Allocated Work;
(iv) the actual Engineering and Construction Cost of the Work Chargeable to Customer;
(v) the actual Capital Contribution required to be paid by the Customer for each of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work; and
(vi) the revised Transformation Connection Revenue and/or Line Connection Revenue requirements and/or Network Revenue requirements based on the Load Forecast or the Adjusted Load Forecast, whichever is applicable.

The new Schedule "B" shall be made a part hereof as though it had been originally incorporated into the Agreement.

If an estimate of a Capital Contributions paid by the Customer exceeds the actual Capital Contribution required to be paid by the Customer for any or all of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work, Hydro One shall refund the difference to the Customer (plus Taxes) within 30 days following the issuing of the new Schedule "B". If the estimate of a Capital Contribution paid by the Customer is less than the actual Capital Contributions required to be paid by the Customer for any or all of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work, the Customer shall pay Hydro One the difference (plus Taxes) within 30 days following the issuing of the new Schedule "B".

10.2 Hydro One shall not include the following amounts in the Capital Contributions referenced in Section 10.1, any capital contribution for:

(a) a Connection Facility that was otherwise planned by Hydro One except for advancement costs;
(b) capacity added to a Connection Facility in anticipation of future load growth not attributable to the Customer; or
(c) the construction of or modifications to Hydro One's Network Facilities that may be required to accommodate the New or Modified Connection other than Network Customer Allocated Work unless Hydro One has indicated in Schedule "A" of the Agreement that exceptional circumstances exist so as to reasonably require the Customer to make a Capital Contribution.

10.3 Notwithstanding Sub-section 10.2(c) above, if Hydro One indicates in Schedule "A" of the Agreement that exceptional circumstances exist so as to reasonably require the Customer to make a Capital Contribution towards the Network Pool Work, Hydro One shall not, without the prior written consent of the Customer, refuse to commence or diligently perform the Network Pool Work pending direction from the OEB under section 6.3.5 of the *Transmission System Code* provided that the Customer provides Hydro One with a security deposit in accordance with Section 20 of these Standard Terms and Conditions.

Until such time as Hydro One has actually begun to perform the Network Pool Work, the Customer may request, in writing, that Hydro One not perform the Network Pool Work and Hydro One shall promptly return to the Customer any outstanding security deposit related to the Network Pool Work.

10.4 If the Customer has made a Capital Contribution under Section 10.1 hereof and where this Capital Contribution includes the cost of capacity on the Connection Facility not needed by the Customer as indicated in Schedule "B" of the Agreement, Hydro One shall provide the Customer with a refund, calculated in accordance with Section 6.2.25 of the *Transmission System Code* if that capacity is assigned to another Load Customer within five (5) years of the In Service Date.

11. Hydro One shall perform a True-Up, based on Actual Load:

(a) at the True-Up Points specified in Schedule "A" of the Agreement; and
(b) the time of disconnection where the Customer voluntarily and permanently disconnects the Customer's Facilities from Hydro One's transmission facilities and the prior to the final True-Up Point identified in (a) above.

For True-Up purposes, if the Customer does not pay a Capital Contribution, Hydro One shall provide the Customer with an Adjusted Load Forecast.

Hydro One shall perform True-Ups in a timely manner. Within 30 calendar days following completion of each of the True-Ups referred to in 11(a), Hydro One shall provide the Customer with the results of the True-Up.

12(a) If the result of a True-Up performed in accordance with Section 11 above is that the Actual Load and Updated Load Forecast is:

(i) less than the load in the Load Forecast or the Adjusted Load Forecast, whichever is applicable, and therefore does not generate the forecasted Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue required for the Economic Evaluation Period, the Customer shall pay Hydro One an amount equal to the shortfall adjusted to reflect the time value of money within 30 days after the date of Hydro One's invoice therefor; and

(ii) more than the load in the Load Forecast or the Adjusted Load Forecast, whichever is applicable, and therefore generates more than the forecasted Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue required for the Economic Evaluation Period, Hydro One shall post the excess Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue as a credit to the Customer in a notional account. Hydro One shall apply this credit against any shortfall in subsequent True-Up calculations. Where the Customer paid a Capital Contribution in accordance with Section 10.1 hereof, Hydro One shall rebate the Customer an amount that is the lesser of the credit balance in the notional account adjusted to reflect the time value of money, and the Capital Contribution adjusted to reflect the time value of money by no later than 30 days following the final True-Up calculation.

12(b) All adjustments to reflect the time value of money to be performed under Subsection 12(a) above shall be performed in accordance with the OEB-Approved Connection Procedures. As of the date of this Agreement, the time value of money is determined using Hydro One's after-tax cost of capital as used in the original economic evaluation performed in accordance with the requirements of the *Transmission System Code.*

13.1 With respect to the installation of embedded generation (as determined in accordance with Section 11.1 of the *Transmission System Code)* during the applicable True-Up period Hydro One shall comply with the requirements of Section 6.5.8 of the *Transmission System Code* when carrying out True-Up calculations if the Customer is a Distributor or the requirements of Section 6.5.9 of the Transmission System Code when carrying out True-Up calculations if the Customer is a Load Customer other than a Distributor.

13.2 With respect to energy conservation, energy efficiency, load management or renewable energy activities that occurred during the applicable True-Up period Hydro One shall comply with the requirements of Section 6.5.10 of the *Transmission System Code* when carrying out True-Up calculations provided that the Customer demonstrates to the reasonable satisfaction of Hydro One (such as by means of an energy study or audit) that the amount of any reduction in the Customer's load has resulted from energy conservation, energy efficiency, load management or renewable energy activities that occurred during the applicable True-Up period.

14. Hydro One shall provide the Customer with all information pertaining to the calculation of all Engineering and Construction Costs, Capital Contributions and True-Ups that the Customer is entitled to receive in accordance with the requirements of the *Transmission System Code.*

Part C: Work Chargeable to Customer, Network Pool Work and Premium Costs

15.1 The Customer shall pay Hydro One's Engineering and Construction Cost (plus Taxes) of the Hydro One Connection Work described asWork Chargeable to Customer in Schedule "A" of the Agreement which is estimated to be the amounts specified in Schedule "B" of the Agreement in the manner specified in Schedule "B" of the Agreement.

Hydro One shall identify the actual Engineering and Construction Cost of the Work Chargeable to Customer in the revised Schedule "B" provided to the Customer in accordance with Section 10.1 of this Agreement. Any difference between the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes) and the amount already paid by the Customer shall be paid within 30 days after the issuance of the revised Schedule "B" by:

(a) Hydro One to the Customer, if the amount already paid by the Customer exceeds the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes); or
(b) the Customer to Hydro One, if the amount already paid by the Customer is less than the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes).

15.2 Subject to Sections 10.3 and 18 hereof, Hydro One shall perform the Hydro One Connection Work described as Network Pool Work in Part 3 of Schedule "A" of the Agreement at Hydro One's sole expense.

16. As the Project is schedule-driven and as the estimated costs specified in Schedule "B" of the

Agreement are based upon normal timelines for delivery of material and performance of work, in addition to the amounts that the Customer is required to pay pursuant to Section 10.1 and 15.1 above, the Customer agrees to pay Hydro One's Premium Costs if the Customer causes or contributes to any delays, including, but not limited to, the Customer failing to execute the Agreement by the Execution Date specified in Schedule "A" of the Agreement.

Hydro One shall obtain the Customer's approval prior to Hydro One authorizing the purchase of materials or the performance of work that attracts Premium Costs. The Customer acknowledges that its failure to approve an expenditure of Premium Costs may result in further delays and Hydro One shall not be liable to the Customer as a result thereof. Hydro One shall invoice the Customer for expenditures of Premium Costs approved by the Customer within 180 calendar days after the Ready for Service Date.

Part D: Right of Customer to By-Pass Existing Load Facilities

17.1 **Obligation to Notify Hydro One of Customer's Intent to Bypass an Existing Load Facility:** If the Customer chooses to exercise its rights under the *Transmission System Code* and the Agreement to bypass the Existing Load Facility, the Customer shall notify Hydro One, in writing, at least 30 days prior to transferring load from the Existing Load Facility Hydro One will then proceed in accordance with Section 6.7 of the *Transmission System Code*.

17.2 **Hydro One has not received a Notice of Customer Intent to Bypass an Existing Load Facility and Customer has Transferred Existing Load:** Where Hydro One determines that the Customer has transferred load from the Existing Load Facility without notifying Hydro One or the OEB, Hydro One will notify the Customer, all other load customers served by the connection facility and the OEB of a potential by-pass situation in accordance with the OEB-Approved Connection Procedures. If the Customer does not intend to by-pass the Existing Load Facility, the Customer must in accordance with the OEB-Approved Connection Procedures:

i. notify Hydro One and the OEB within 30 days of receiving Hydro One's notification of potential by-pass, that it has no intention of by-passing Hydro One's Existing Load Facility;
ii. transfer the load back to the Existing Load Facility within an agreed time period; and
iii. compensate Hydro One for the lost revenues.

17.3 The Customer agrees that Sections 17.1 and 17.2 above shall also be a term of the Connection Agreement.

Part E: Cancellation or Termination of Project and Early Termination of Agreement for Breach

18. Notwithstanding any other term of the Agreement, if at any time prior to the In-Service Date, the Project is cancelled or the Agreement is terminated for any reason whatsoever other than breach of the Agreement by Hydro One, the Customer shall pay Hydro One's Engineering and Construction Cost (plus Taxes) of the Line Connection Pool Work, the Transformation Connection Pool Work, the Network Pool Work, the Network Customer Allocated Work and the Work Chargeable to Customer incurred on and prior to the date that the Project is cancelled or the Agreement is terminated, including the preliminary design costs and all costs associated with the winding up of the Project, including, but not limited to, storage costs, vendor cancellation costs, facility removal expenses and any environmental remediation costs.

If the Customer provides written notice to Hydro One that it is cancelling the Project, Hydro One shall have 10 Business Days to provide written notice to the Customer listing the individual items listed as materials which it agrees to purchase. Hydro One shall deduct the actual cost of those individual items of materials being purchased by Hydro One from the Engineering and Construction Costs referred to above.

If Hydro One does not require all or part of the materials, the Customer may exercise any of the following options or a combination thereof:

(i) where materials have been ordered but all or part of the materials have not been received by Hydro One, the Customer shall have the right to require Hydro One, at the Customer's sole expense, to continue with the purchase of the materials and transfer title to those materials on an "as is, where is basis" to the Customer upon the Customer paying Hydro One's Engineering and Construction Costs (plus Taxes) provided that the Customer exercises this option within 15 Business Days of the termination or cancellation; or
(ii) where all or part of the materials have been received by Hydro One but have not been installed, the Customer shall have the right to require Hydro One, at the Customer's sole expense, to transfer title to the materials on an "as is, where is basis" to the Customer upon the Customer paying Hydro One's Engineering and Construction Costs (plus Taxes) provided that the Customer exercises this option within 15 Business Days of the termination or cancellation. The Customer shall also be responsible for any warehousing costs associated with the storage of the materials to the date of transfer; or

(iii) where all or part of the materials have been received by Hydro One and have been installed, the Customer shall have the right to require Hydro One, at the Customer's sole expense, to: transfer title to the materials on an "as is, where is basis" to the Customer upon the later of (A) the Customer paying Hydro One's Engineering and Construction Costs (plus Taxes); and (B) the date that Hydro One removes the materials from its property at the risk of the Customer; provided that the Customer exercises this option within 15 Business Days of the termination or cancellation. The Customer shall also be responsible for any Engineering and Construction Costs (plus Taxes) associated with the removal of the materials that have been installed by Hydro One.

The Customer shall pay Hydro One's Engineering and Construction Costs (plus Taxes) which become payable under this Section 18 within 30 calendar days after the date of invoice.

Part F: Sale, Lease, Transfer or Other Disposition of Customer's Facilities

19. In the event that the Customer sells, leases or otherwise transfers or disposes of the Customer's Facilities to a third party during the Term of the Agreement, the Customer shall cause the purchaser, lessee or other third party to whom the Customer's Facilities are transferred or disposed to enter into an assumption agreement with Hydro One to assume all of the Customer's obligations in the Agreement; and notwithstanding such assumption agreement unless Hydro One agrees otherwise, in writing, the Customer shall remain obligated under Sections 10.1 12, 15.1 and 16 hereof. The Customer further acknowledges and agrees that in the event that all or a portion of the Customer's Facilities are shut down, abandoned or vacated for any period of time during the Term of the Agreement, the Customer shall remain obligated under Sections 10.1, 12, 15.1 and 16 for the said time period.

Part G: Security Requirements

20. If Hydro One requires that the Customer furnish security, which at the Customer's option may be in the form of cash, letter of credit or surety bond, the Customer shall furnish such security in the amount and by the dates specified in Schedule "A" of the Agreement. Hydro One shall return the security deposit to the Customer as follows:

(i) security deposits in the form of cash shall be returned to the Customer, together with Interest, less the amount of any Capital Contribution owed by the Customer once the Customer's Facilities are connected to Hydro One's New or Modified Connection Facilities; and

(ii) security deposits in any other form shall be returned to the Customer once the Customer's Facilities are connected to Hydro One's New or Modified Connection Facilities and any Capital Contribution has been paid.

Notwithstanding the foregoing, Hydro One may keep all or a part of the security deposit: (a) where and to the extent that the Customer fails to pay any amount due under the Agreement within the time stipulated for payment; or (b) in the circumstances described in the OEB-Approved Connection Procedures.

Part H: Disputes

21. Prior to the existence of OEB-Approved Connection Procedures either party may refer a Dispute to the OEB for a determination. Once there are OEB-Approved Connection Procedures, all disputes, including, but not limited to, disputes related to:

(a) the cost and the allocation of the costs under this Agreement;
(b) the cost and the allocation of costs of the Hydro One Connection Work and notwithstanding Hydro One's decision not to allocate or to allocate any part of the costs of this work to the Customer at this time; or
(c) any other costs and the allocation of any other costs associated with, related to, or arising out of the connection of the Project to Hydro One's transmission system or Hydro One's policies in respect of connections generally,

shall be dealt with in accordance with the dispute resolution procedure set out in the OEB-Approved Connection Procedures.

22. Before and after the existence of OEB-Approved Connection Procedures, if a dispute arises while Hydro One is constructing the New or Modified Connection Facilities, Hydro One shall not cease the work or slow the pace of the work without leave of the OEB.

23. Hydro One shall refund to the Customer or the Customer shall pay to Hydro One any portion of Capital Contributions, as the case may be, which the OEB subsequently determines should not have been allocated to the Customer or should have been allocated to the Customer by Hydro One but were not, as the case may be, or should have been allocated in a manner different from that allocated by Hydro One in this Agreement.

Part I: Easement

24. If specified in Schedule "A" that an easement(s) is required from the Customer, the Customer shall grant an easement to Hydro One substantially in the form of the easement attached hereto as Appendix "B" of these

Standard Terms and Conditions for the property(ies) described as the Easement Lands in Schedule "A" on or before the date specified as the Easement Date in Schedule "A" (hereinafter referred to as the "Easement") with good and marketable title thereto, free of all encumbrances, first in priority except as noted herein, and in registerable form, in consideration of the sum of $2.00.

Part J: Events of Default

25. Each of the following events shall constitute an "Event of Default" under the Agreement:

(a) failure by the Customer to pay any amount due under the Agreement, including any amount payable pursuant to Sections 10.1, 12, 15.1, 16 or 18 within the time stipulated for payment;
(b) breach by the Customer or Hydro One of any Material term, condition or covenant of the Agreement; or
(c) the making of an order or resolution for the winding up of the Customer or Hydro One or of their respective operations or the occurrence of any other dissolution, bankruptcy or reorganization or liquidation proceeding instituted by or against the Customer or Hydro One.

For greater certainty, a dispute shall not be considered an Event of Default under this Agreement. However, a Party's failure to comply, within a reasonable period of time, with the terms of a determination of such a dispute by the OEB or with a decision of a court of competent jurisdiction with respect to a determination made by the OEB shall be considered an Event of Default under the Agreement.

26. Upon the occurrence of an Event of Default by the Customer hereunder (other than those specified in Section 25(c) of the Agreement, for which no notice is required to be given by Hydro One), Hydro One shall give the Customer written notice of the Event of Default and allow the Customer 30 calendar days from the date of receipt of the notice to rectify the Event of Default, at the Customer's sole expense. If such Event of Default is not cured to Hydro One's reasonable satisfaction within the 30 calendar day period, Hydro One may, in its sole discretion, exercise the following remedy in addition to any remedies that may be available to Hydro One under the terms of the Agreement, at common law or in equity: deem the Agreement to be repudiated and, after giving the Customer at least 10 calendar days' prior written notice thereof, recover, as liquidated damages and not as a penalty, the following:

(i) the sum of the amounts payable by the Customer pursuant to Sections 10.1, 12, 15.1 and where applicable, Section 16 less any amounts already paid by the Customer in accordance with Section 10.1, 12, 15.1 and 16 if this clause is invoked after the In-Service Date; or

(ii) the amounts payable under Section 16 and 18 less any amounts already paid by the Customer in accordance with Sections 10.1, 15.1 and 16 if this clause is invoked prior to the In-Service Date.

27. Upon the occurrence of an Event of Default by Hydro One hereunder (other than those specified in Section 25(c), the Customer shall give Hydro One written notice of the Event of Default and shall allow Hydro One 30 calendar days from the date of receipt of the notice to rectify the Event of Default at Hydro One's sole expense. If such Event of Default is not cured to the Customer's reasonable satisfaction within the 30 calendar day period, the Customer may pursue any remedies available to it at law or in equity, including at its option the termination of the Agreement.

28. All rights and remedies of Hydro One and the Customer provided herein are not intended to be exclusive but rather are cumulative and are in addition to any other right or remedy otherwise available to Hydro One and the Customer respectively at law or in equity, and any one or more of Hydro One's and the Customer's rights and remedies may from time to time be exercised independently or in combination and without prejudice to any other right or remedy Hydro One or the Customer may have or may not have exercised. The parties further agree that where any of the remedies provided for and elected by the non-defaulting party are found to be unenforceable, the non-defaulting party shall not be precluded from exercising any other right or remedy available to it at law or in equity.

Part K: Changes to Transmission Rates

29. In the event that the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate is rescinded or the methodology of determination or components is materially changed, the Parties agree to negotiate a new mechanism for the purposes of the Agreement, provided that such new mechanism will not result in an increase in the amounts of Capital Contribution or Security Deposits payable by the Customer to Hydro One hereunder. The Parties shall have 90 calendar days from the effective date of rescission or fundamental change of the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate to agree to a new mechanism that is, to the extent possible, fair to the parties and constitutes a reasonably comparable replacement for the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate. If the Parties are unable to successfully negotiate a replacement within that 90 calendar day period, this shall be considered a dispute under the terms

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of this Agreement and the parties shall follow the dispute resolution procedure set out in the OEB-Approved Connection Procedures.

Any settlement on a new mechanism pursuant to this Section 29 shall apply retroactively from the date on which the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate was rescinded or fundamentally changed. Until such time as a new mechanism is determined hereunder, any amounts to be paid by the Customer under the Agreement shall be based on the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate in effect prior to the effective date of any such changes.

Part L: Incorporation of Liability and Force Majeure Provisions

30. PART III: LIABILITY AND FORCE MAJEURE (with the exception of Section 15.5 thereof) and Sections 1.1.12 and 1.1.17 of the Connection Agreement are hereby incorporated in their entirety by reference into, and form an integral part of the Agreement. Unless the context otherwise requires, all references in PART III: LIABILITY AND FORCE MAJEURE TO "this Agreement" shall be deemed to be a reference to the Agreement and all references to the "the Transmitter" shall be deemed to be a reference to Hydro One.

For the purposes of this Section 30, the Parties agree that the reference to:

(i) the Transmitter in lines 3 and 4 of Section 15.1 means the Transmitter or any party acting on behalf of the Transmitter such as contractors, subcontractors, suppliers, employees and agents; and
(ii) the Customer in lines 3 and 4 of Section 15.2 means the Customer or any party acting on behalf of the Customer such as contractors, subcontractors, suppliers, employees and agents.

Part M: General

31. This Agreement is subject to the *Transmission System Code* and the OEB-Approved Connection Procedures. If any provision of this Agreement is inconsistent with the:

(a) *Transmission System Code,* the said provision shall be deemed to be amended so as to comply with the *Transmission System Code;*
(b) OEB-Approved Connection Procedures the said provision shall be deemed to be amended so as to comply with the OEB-Approved Connection Procedures; and
(c) Connection Agreement made between the parties, associated with the new customer connection facilities, on the same subject matter, the Connection Agreement governs.

32. The failure of either party hereto to enforce at any time any of the provisions of the Agreement or to exercise any right or option which is herein provided shall in no way be construed to be a waiver of such provision or any other provision nor in any way affect the validity of the Agreement or any part hereof or the right of either party to enforce thereafter each and every provision and to exercise any right or option. The waiver of any breach of the Agreement shall not be held to be a waiver of any other or subsequent breach. Nothing shall be construed or have the effect of a waiver except an instrument in writing signed by a duly authorized officer of the party against whom such waiver is sought to be enforced which expressly waives a right or rights or an option or options under the Agreement.

33. Other than as specifically provided in the Agreement, no amendment, modification or supplement to the Agreement shall be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of the Agreement.

34. Any written notice required by the Agreement shall be deemed properly given only if either mailed or delivered to the Secretary, Hydro One Networks Inc., 483 Bay Street, North Tower, 15th Floor, Toronto, Ontario M5G 2P5, fax no: (416) 345-6240 on behalf of Hydro One, and to the person at the address specified in Schedule "A" of the Agreement on behalf of the Customer.

A faxed notice shall be deemed to be received on the date of the fax if received before 3 p.m. on a business day or on the next business day if received after 3 p.m. or a day that is not a business day. Notices sent by courier or registered mail shall be deemed to have been received on the date indicated on the delivery receipt. The designation of the person to be so notified or the address of such person may be changed at any time by either party by written notice.

35. The Agreement shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of the Province of Ontario and the laws of Canada applicable therein.

36. The Agreement may be executed in counterparts, including facsimile counterparts, each of which shall be deemed an original, but all of which shall together constitute one and the same agreement.

37. The Customer shall provide Hydro One with a copy of the Customer's final monthly bills associated

with the transmission of electricity from the Existing Load Facilities and/or the Customer's Facilities or authorize the IESO to provide Hydro One with same. Hydro One agrees to use this information solely for the purpose of the Agreement.

38. **Invoices and Interest:** Invoiced amounts are due 30 days after invoice issuance. All overdue amounts including, but not limited to amounts that are not invoiced but required under the terms of this Agreement to be paid in a specified time period, shall bear interest at 1.5% per month compounded monthly (19.56 percent per year) for the time they remain unpaid.

39. The obligation to pay any amount due hereunder, including, but not limited to, any amounts due under Sections 10.1, 12, 15.1, 16, 18 or 23 shall survive the termination of the Agreement.

Appendix "A": Definitions

In the Agreement, unless the context otherwise requires, terms which appear therein without definition, shall have the meanings respectively ascribed thereto in the *Transmission System Code* and unless there is something in the subject matter or context inconsistent therewith, the following words shall have the following meanings:

"Actual Load" means the actual load delivered by Hydro One to the Customer up to the True-Up Point in excess of the Normal Capacity of the Existing Load Facilities.

"Assigned Capacity" is calculated in accordance with Section 6.2.2 of the *Transmission System* Code.

"Adjusted Load Forecast" means a Load Forecast that has been adjusted to the point where the present value of the Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue equals the present value of the Pool Funded Cost of the Transformation Connection Pool Work and/or the Pool Funded Cost of the Line Connection Pool Work and/or the Pool Funded Cost of the Network Customer Allocated Work.

"Agreement" means the Connection Cost Recovery Agreement, Schedules "A" and "B" attached thereto and these Standard Terms and Conditions.

"Applicable Laws" means any and all applicable laws, including environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments or decrees or any requirement or decision or agreement with or by any government or governmental department, commission board, court authority or agency.

"Approval Date" means for the purpose of Subsection 5(f) of the Terms and Conditions, the date specified in Schedule "A" of the Agreement.

"Capital Contribution" means a capital contribution calculated using the economic evaluation methodology set out in the *Transmission System Code.*

"Connect and Connection" has the same meaning ascribed to the term "Connect" in the *Transmission System Code.*

"Connection Agreement" means the form of connection agreement appended to the *Transmission System Code* as Appendix 1, Version 1.

"Connection Facilities" has the meaning set forth in the *Transmission System Code.*

"Connection Point" has the meaning set forth in the *Transmission System Code* and for this project, is as specified in Schedule "A" of the Agreement.

"Customer Connection Work" means the work to be performed by the Customer, at its sole expense, which is described in Schedule "A" of the Agreement.

"Customer Connection Risk Classification" is as specified in Schedule "A" of the Agreement.

"Customer's Facilities" has the meaning set forth in the *Transmission System Code*, and includes, but is not limited to any new, modified or replaced Customer's Facilities.

"Customer's Property(ies)" means any lands owned by the Customer in fee simple or where the Customer has easement rights.

"Dispute" means a dispute between the Parties with respect to any of the matters listed in Section 6.1.4 of the *Transmission System Code* where either Party is alleging that the other is seeking to impose a term that is inconsistent or contrary to the *Ontario Energy Board Act*, the *Electricity Act, 1998*, Hydro One's transmission licence or the *Transmission System Code* or refusing to include a term or condition that is required to give effect to the Code.

"Distributor" has the meaning set forth in the *Transmission System Code.*

"Economic Evaluation Period" means the period of five (5) years for high risk connection, ten (10) years for a medium-high risk connection, fifteen (15) years for a medium-low risk connection and twenty-five years for a low risk connection commencing on the In Service Date whichever is applicable to the Customer as specified in Schedule "A" of the Agreement.

"Engineering and Construction Cost" means Hydro One's charge for equipment, labour and materials at Hydro One's standard rates plus Hydro One's standard overheads as well as interest during construction using Hydro One's capitalization rate in effect during the construction period.

"*Electricity Act,* 1998" means the *Electricity Act, 1998* being Schedule "A" of the *Energy Competition Act,* S.O. *1998*, c.15, as amended.

"Existing Load" in relation to the Customer and each of the Existing Load Facilities is equal to the Customer's Assigned Capacity at each of the Existing Load Facilities on the date of this Agreement.

"Existing Load Facility or Existing Load Facilities" means the connection facility(ies) owned by Hydro One

as specified in the Existing Load Table in Schedule "A" of the Agreement where the Customer has Existing Load.

"Force Majeure Event" has the meaning ascribed thereto in the Connection Agreement.

"**GST**" means the Goods and Services Tax.

"Hydro One Connection Work" means the work to be performed by Hydro One, which is described in Schedule "A" of the Agreement.

"Hydro One Facilities" means Hydro One's structures, lines, transformers, breakers, disconnect switches, buses, voltage/current transformers, protection systems, telecommunication systems, cables and any other auxiliary equipment used for the purpose of transmitting electricity.

"Hydro One's Property(ies)" means any lands owned by Hydro One in fee simple or where Hydro One now or hereafter has obtained easement rights.

"IESO" means the Independent Electricity System Operator continued under the *Electricity Act, 1998.*

"In Service Date" has the same meaning ascribed to the term "comes into service" in the *Transmission System Code.*

"Incremental Network Load" means the Customer's New Load less the amount of load, if any, that has been by-passed by the Customer at any of Hydro One's connection facilities.

"Interest" means the interest rates specified by the OEB to be applicable to security deposits in the form of cash as specified in Subsection 6.3.11(b) in the *Transmission System Code.*

"Line Connection Pool Work" means the Hydro One Connection Work specified in Schedule "A" of the Agreement under the heading "Line Connection Pool Work".

"Line Connection Revenue" means the amount of line connection revenue attributable to that part of the Customer's New Load to be received by Hydro One through the monthly collection of the Line Connection Service Rate during the Economic Evaluation Period.

"**Line Connection Service Rate"** means the line connection service rate approved by the OEB in Hydro One's Rate Order from time to time, or any mechanism instituted in accordance with Section 29.

"Load Customer" has the meaning set forth in the *Transmission System Code.*

"Load Forecast" means the initial load forecast of the New Load in excess of the Normal Capacity of the Existing Load Facilities used in the initial economic evaluation for the Economic Evaluation Period.

"Material" relates to the essence of the contract, more than a mere annoyance to a right, but an actual obstacle preventing the performance or exercise of a right.

"Network Customer Allocated Work" means the construction of or modifications to Network Facilities specified in Schedule "A" of the Agreement under the heading "Network Customer Allocated Work" that are minimum connection requirements.

"Network Facilities" has the meaning set forth in the *Transmission System Code.*

"Network Pool Work" means the Hydro One Connection Work specified in Schedule "A" of the Agreement under the heading "Network Pool Work".

"Network Revenue" means the amount of network revenue attributable to the Incremental Network Load to be received by Hydro One through the monthly collection of the Network Service Rate during the Economic Evaluation Period.

"Network Service Rate" " means the network service rate approved by the OEB in Hydro One's Rate Order from time to time, or any mechanism instituted in accordance with Section 29.

"New Load" means the load at the New or Modified Connection Facility that is in excess of, for each of the Existing Load Facilities, the lesser of the Existing Load or the Normal Capacity.

"New or Modified Connection Facilities" means the facilities owned by Hydro One as specified in Schedule "A" of the Agreement.

"Normal Capacity" means, where the Customer is:

(a) the only Load Customer supplied by an Existing Load Facility, the total normal supply capacity of the Existing Load Facility as determined in accordance with the OEB-Approved Connection Procedures; and

(b) one of two or more Load Customers served by an Existing Load Facility, the Customer's pro-rated share of the total normal supply capacity of the Existing Load Facility as determined in accordance with the OEB-Approved Connection Procedures.

"OEB" means the Ontario Energy Board.

"OEB-Approved Connection Procedures" means Hydro One's connection procedures as approved by the OEB from time to time.

"Ontario Energy Board Act" means the *Ontario Energy Board Act* being Schedule "B" of the *Energy Competition Act*, S.O. *1998*, c. 15, as amended.

"Pool-Funded Cost" means the present value of the Engineering and Construction Cost and projected on-going maintenance and other related incremental costs (including, but not limited to applicable taxes, and net of tax benefits), of each of the Transformation Connection Pool Work, the Line Connection Pool Work and/or the Network Customer Allocated Work calculated in accordance with the principles, criteria and methodology set out in Appendices 4 and 5 of the Transmission System Code.

"Premium Costs" means those costs incurred by Hydro One in order to maintain or advance the Ready for Service Date, including, but not limited to, additional amounts expended for materials or services due to short time-frame for delivery; and the difference between having Hydro One's employees, agents and contractors perform work on overtime as opposed to during normal business hours.

"Rate Order" has the meaning ascribed thereto in the *Transmission System Code.*

"Ready for Service Date" means the date upon which the Hydro One Connection Work is fully and completely constructed, installed, commissioned and energised to the Connection Point. The Customer's disconnect switches must be commissioned prior to this date in order to use them as isolation points.

"Standard Terms and Conditions" means these Standard Terms and Conditions for Low Risk Transmission Customer Connection Projects and Appendices "A" and "B" attached hereto.

"Taxes" means all property, municipal, sales, use, value added, goods and services, harmonized and any other non-recoverable taxes and other similar charges (other than taxes imposed upon income, payroll or capital).

"Transformation Connection Pool Work" means the Hydro One Connection Work specified in Schedule "A" of the Agreement under the heading "Transformation Connection Pool Work".

"Transformation Connection Revenue" means the amount of transformation connection revenue attributable to that part of the Customer's New Load to be received by Hydro One through the monthly collection of the Transformation Connection Service Rate during the Economic Evaluation Period.

"Transformation Connection Service Rate" means the line connection service rate approved by the OEB in Hydro One's Rate Order from time to time, or any mechanism instituted in accordance with Section 29.

"Transmission System Code" or "Code" means the code of standards and requirements issued by the OEB on July 25, 2005 that came into force on August 20, 2005 as published in the Ontario Gazette, as it may be amended, revised or replaced in whole or in part from time to time.

"Transmitter's Facilities" has the meaning ascribed thereto in the *Transmission System Code.*

"True-Up" means the calculation to be performed by Hydro One, as a transmitter, at each True-Up Point in accordance with the requirements of Subsection 6.5.4 of the *Transmission System Code.*

"True-Up Point" means the points of time based upon the Customer Connection Risk Classification when Hydro One is required to perform a True-Up as described in Section 11 of these Terms and Conditions.

"Updated Load Forecast" means the load forecast of the New Load in excess of the Normal Capacity of the Existing Load Facilities for the remainder of the Economic Evaluation Period.

"Work Chargeable to Customer" means the Hydro One Connection Work specified in Part 4 of Schedule "A" of the Agreement under the heading "Work Chargeable to Customer".

Appendix "B": Form of Easement

INTEREST / ESTATE TRANSFERRED

The Transferor is the owner in fee simple and in possession of _____
_____
_____ (the **"Lands"**).

The Transferee has erected, or is about to erect, certain Works (as more particularly described in paragraph 1(a) hereof) in, through, under, over, across, along and upon the Lands.

1 The Transferor hereby grants and conveys to Hydro One Networks Inc, its successors and assigns the rights and easement, free from all encumbrances and restrictions, the following unobstructed and exclusive rights, easements, rights-of-way, covenants, agreements and privileges in perpetuity (the **"Rights"**) in, through, under, over, across, along and upon that portion of the Lands of the Transferor described herein and shown highlighted on Schedule "A" hereto annexed (the **"Strip"**) for the following purposes:

(a) To enter and lay down, install, construct, erect, maintain, open, inspect, add to, enlarge, alter, repair and keep in good condition, move, remove, replace, reinstall, reconstruct, relocate, supplement and operate and maintain at all times in, through, under, over, across, along and upon the Strip an electrical transmission system and telecommunications system consisting in both instances of a pole structures, steel towers, anchors, guys and braces and all such aboveground or underground lines, wires, cables, telecommunications cables, grounding electrodes, conductors, apparatus, works, accessories, associated material and equipment, and appurtenances pertaining to or required by either such system (all or any of which are herein individually or collectively called the **"Works"**) as in the opinion of the Transferee are necessary or convenient thereto for use as required by Transferee in its undertaking from time to time, or a related business venture.

(b) To enter on and selectively cut or prune, and to clear and keep clear, and remove all trees (subject to compensation to Owners for merchantable wood values), branches, bush and shrubs and other obstructions and materials in, over or upon the Strip, and without limitation, to cut and remove all leaning or decayed trees located on the Lands whose proximity to the Works renders them liable to fall and come in contact with the Works or which may in any way interfere with the safe, efficient or serviceable operation of the Works or this easement by the Transferee.

(c) To conduct all engineering, legal surveys, and make soil tests, soil compaction and environmental studies and audits in, under, on and over the Strip as the Transferee in its discretion considers requisite.

(d) To erect, install, construct, maintain, repair and keep in good condition, move, remove, replace and use bridges and such gates in all fences which are now or may hereafter be on the Strip as the Transferee may from time to time consider necessary.

(e) Except for fences and permitted paragraph 2(a) installations, to clear the Strip and keep it clear of all buildings, structures, erections, installations, or other obstructions of any nature (hereinafter collectively called the **"obstruction"**) whether above or below ground, including removal of any materials and equipment or plants and natural growth, which in the opinion of the Transferee, endanger its Works or any person or property or which may be likely to become a hazard to any Works of the Transferee or to any persons or property or which do or may in any way interfere with the safe, efficient or serviceable operation of the Works or this easement by the Transferee.

(e) To enter on and exit by the Transferor's access routes and to pass and repass at all times in, over, along, upon and across the Strip and so much of the Lands as is reasonably required, for Transferee, its respective officers, employees, agents, servants, contractors, subcontractors, workmen and permittees with or without all plant machinery, material, supplies, vehicles and equipment for all purposes necessary or convenient to the exercise and enjoyment of this easement and

(f) To remove, relocate and reconstruct the line on or under the Strip.

2. The Transferor agrees that:

(a) It will not interfere with any Works established on or in the Strip and shall not, without the Transferee's consent in writing, erect or cause to be erected or permit in, under or upon the Strip any obstruction or plant or permit any trees, bush, shrubs, plants or natural growth which does or may interfere with the Rights granted herein. The Transferor agrees it shall not, without the Transferee's consent in writing, change or permit the existing configuration, grade or elevation of the Strip to be changed and the Transferor further agrees that no excavation or opening or work which may disturb or interfere with the existing surface of the Strip shall be done or made unless consent therefore in writing has been obtained from Transferee, provided however, that the Transferor shall not be required to obtain such permission in case of emergency. Notwithstanding the foregoing, in cases where in the reasonable discretion of the Transferee, there is no danger or likelihood of danger to the Works of the Transferee or to any persons or property and the safe or serviceable operation of this easement by the Transferee is not interfered with, the Transferor may at its expense and with the prior written approval of the Transferee, construct and maintain roads, lanes, walks, drains, sewers, water pipes, oil and gas pipelines, fences (not to exceed 2 metres in height) and service cables on or under the Strip (the **"Installation"**) or any portion thereof; provided that prior to commencing such Installation, the Transferor shall give to the Transferee thirty (30) days notice in writing thereof to enable the Transferee to have a representative present to inspect the proposed Installation during the performance of such work, and provided further that Transferor comply with all instructions given by such representative and that all such work shall be done to the reasonable satisfaction of such representative. In the event of any unauthorised interference aforesaid or contravention of this paragraph, or if any authorised interference, obstruction or Installation is not maintained in accordance with the Transferee's instructions or in the Transferee's reasonable opinion, may subsequently interfere with the Rights granted herein, the Transferee may at the Transferor's expense, forthwith remove, relocate, clear or correct the offending interference, obstruction, Installation or contravention complained of from the Strip, without being liable for any damages caused thereby.

(b) notwithstanding any rule of law or equity, the Works installed by the Transferee shall at all times remain the property of the Transferee, notwithstanding that such Works are or may become annexed or affixed to the Strip and shall at anytime and from time to time be removable in whole or in part by Transferee.

(c) no other easement or permission will be transferred or granted and no encumbrances will be created over or in respect to the Strip, prior to the registration of a Transfer of this grant of Rights.

(d) the Transferor will execute such further assurances of the Rights in respect of this grant of easement as may be requisite.

(e) the Rights hereby granted:

(i) shall be of the same force and effect to all intents and purposes as a covenant running with the Strip.

(ii) is declared hereby to be appurtenant to and for the benefit of the Works and undertaking of the Transferee described in paragraph 1(a).

3. The Transferee covenants and agrees to obtain at its sole cost and expense all necessary postponements and subordinations (in registrable form) from all current and future prior encumbrancers, postponing their respective rights, title and interests to the Transfer of Easement herein so as to place such Rights and easement in first priority on title to the Lands.

4. There are no representations, covenants, agreements, warranties and conditions in any way relating to the subject matter of this grant of Rights whether expressed or implied, collateral or otherwise except those set forth herein.

5. No waiver of a breach or any of the covenants of this grant of Rights shall be construed to be a waiver of any succeeding breach of the same or any other covenant.

6. The burden and benefit of this transfer of Rights shall run with the Strip and the Works and undertaking of the Transferee and shall extend to, be binding upon and enure to the benefit of the parties hereto and their respective heirs, executors, administrators, successors and assigns.

IN WITNESS WHEREOF the Transferor has hereunto set his hand and seal to this Agreement, this ___ day of _____ _____, 200__.

SIGNED, SEALED AND DELIVERED
In the presence of)
)
_____(seal)
Signature of Witness)
)
)
)
_____)
Signature of Witness

_____)
Transferor's Signature

_____(seal)
Transferor's Signature

)
SIGNED, SEALED AND DELIVERED)
In the presence of)
)
)
)
_____)
Signature of Witness

Consent Signature & Release of
Transferor's Spouse, if non-owner.

_____(seal)

CHARGEES

THE CHARGEE of land described in a Charge/Mortgage of Land dated _____

Between _____ and _____

and registered as Instrument Number _____ on _____ does

hereby consent to this Easement and releases and discharges the rights and easement herein from the said

Charge/Mortgage of Land.

Name	Signature(s)	Date of Signatures Y M D
	Per:	
	_____	
	_____	
	I/We have authority to bind the Corporation	

CCRA – Cedar TS

Schedule "B" Install Eight (8) feeders at Guelph Cedar T1-T2 TS (Project IP 11853)

TRANSFORMATION CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Transformation Connection Pool Work: $4,038,200.00

Actual Engineering and Construction Cost of the Transformation Connection Pool Work: $5,582,154.00

Estimate of Transformation Connection Pool Work Capital Contribution: NONE

Actual Transformation Connection Pool Work Capital Contribution: $0.00

LINE CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Line Connection Pool Work: N/A

Actual Engineering and Construction Cost of the Line Connection Pool Work: N/A

Estimate of Line Connection Pool Work Capital Contribution: N/A

Actual Line Connection Pool Work Capital Contribution: N/A

Manner of Payment of Estimate of Transformation Connection Pool Work Capital Contribution and /or Estimate of Line Connection Pool Work Capital Contribution:

N/A

NON-POOLABLE WORK

Estimate of the Engineering and Construction Cost of the Non-Poolable Work: $40,000.00

Actual Engineering and Construction Cost of the Non-Poolable Work: None

The scope of work for the Non-Poolable Work originally entailed Hydro One installing indoor voltage transformers and current transformers (collectively ITs) on each bus as part of the metalclad installation for the Customer's revenue metering. It was later decided to install outdoor ITs as opposed to indoor ITs in the Metalclad as a separate project for the Customer (Project IP 12838).

Manner of Payment of the Estimate of the Engineering and Construction Cost of the Non-Poolable Work: N/A

MISCELLANEOUS

Guaranteed Revenue Date: **Line Connection Pool Work –** N/A
Transformation Connection Pool Work – July 2017

Capacity Allocated to Customer (CATC): 252 MW

Base Load Trigger Point: 234 MW

READY FOR SERVICE DATE **June 30, 2006**

TRANSFORMATION CONNECTION REVENUE REQUIREMENTS AND LOAD FORECAST

Period: One year following the anniversary of the Ready for Service Date and annually thereafter	LOAD FORECAST: Incremental Load (Average Monthly Peak Load) MW	Transformation Connection Revenue (k$)
June 30, 2007	27.3	130.1
June 30, 2008	33.3	155.4
June 30, 2009	39.6	115.6
June 30, 2010	46.0	273.3
June 30, 2011	52.6	531.3
June 30, 2012	60.8	685.4
June 30, 2013	62.2	700.1
June 30, 2014	62.2	698.3
June 30, 2015	62.2	696.5
June 30, 2016	62.2	694.8
June 30, 2017	62.2	693.2
June 30, 2018	62.2	691.7
June 30, 2019	62.2	690.2
June 30, 2020	62.2	688.8
June 30, 2021	62.2	687.4
June 30, 2022	62.2	686.1
June 30, 2023	62.2	684.8
June 30, 2024	62.2	683.6
June 30, 2025	12.9	105.0

NOTES

The installation of two feeder positions at Guelph Campbell TS under the November 2001 CCRA in-service in July 2002 and the installation of eight (8) feeders at Guelph Cedar T1/T2 TS under the terms of this Agreement will be considered as two stages of the same Project for the purposes of the Transformation Connection Revenue Requirements specified in this Agreement.
Capacity Allocated to Customer: The capacity allocated to the customer for the Guelph Campbell stage (in-service July 2002) was 252 MW with a base load trigger point of 234 MW. These values will be used for the combined stage.

The capacity available to the Customer is supplied from all buses at the following Hydro One Facilities:
Guelph Campbell TS
Guelph Cedar TS (T1&T2 and T7&T8)
Guelph Hanlon TS

The new capacity allocated to The Customer when the eight (8) feeders are in-place at Guelph Cedar TS, will be 321.7 MW and is made up of the following contributions:

Guelph Campbell TS	147.4 MW
Guelph Cedar TS T1-T2	48.2 MW
Guelph Cedar TS T1-T2 (8-feeders)	48.2 MW
Guelph Cedar TS T7-T8	39.5 MW
Guelph Hanlon TS	38.4 MW

The Customer refers to these numbers as the “Practical Load Limit”. In the case of Guelph Campbell TS and Guelph Hanlon TS the “Practical Load Limit” is lower than the summer 10-day LTR. For Guelph Cedar TS T1-T2 and Guelph Cedar TS T7-T8 the practical load limit is the same as the summer 10-day LTR.

Connection and Cost Recovery Agreement

between

Guelph Hydro Electric Systems Inc.

and

Hydro One Networks Inc.

for

Guelph Cedar TS Metalclad Project

Guelph Cedar TS Metalclad Project

Guelph Hydro Electric Systems Inc. (the "Customer") has requested and Hydro One Networks Inc. ("Hydro One") has agreed to install a new metalclad to the 2 existing idle windings at Cedar TS with 8 new feeder positions (the "Project") on the terms and conditions set forth in this Agreement dated March 1, 2005 (the "Agreement") and the attached Standard Terms and Conditions for Transmission Customer Connection Project T&C V3 ESH LOW RISK CUSTOMERS 3-2005 (the "Standard Terms and Conditions"). Schedules "A" and "B" and the Standard Terms and Conditions are to be read with and form part of this Agreement.

Project Summary

- To install a new metalclad to the two (2) existing idle transformer windings at Cedar TS.
- The metalclad will consist of eight (8) new feeder positions.

Overview and purpose of the Project:

The purpose of the Project is for the Customer to utilize the existing available capacity of 45 MVA at Cedar TS.

Ready for Service Date: June 30, 2006

Financial Summary (Repayment schedule and Capital Contribution -Details in Schedule "B"):

Term: Notwithstanding any other term in this Agreement, the term of this Agreement commences on the date first written above and terminates on the earlier of the:
(a) Guaranteed Revenue Date for the Transformation Connection Pool Work; and
(b) July 1, 2017.

Special Circumstances

- Hydro One and the Customer are parties to a Connection and Cost Recovery Agreement dated November 21, 2001 (the "November 2001 CCRA") wherein in consideration of certain load guarantees provided by Customer, Hydro One supplied two additional breaker positions at Campbell TS. Hydro One and the Customer hereby agree that upon the Ready for Service Date of the Project described herein, Sections 12, 13, 14, 17, 18, 19, 20.1, 20.2, 20.3, 20.4, 20.5 and 20.6 of the November 2001 CCRA are hereby deleted and have no further force and effect.

- Notwithstanding any other term in this Agreement, Hydro One and the Customer acknowledge and agree that the Pool Funded Cost (including any reference to the Pool Funded Cost of the Hydro One Connection Work) and the Transformation Connection Revenue shall also include the Pool Funded Cost (as that term is defined in the Standard Terms and Conditions attached hereto) of the Networks Connection Work (as that term is defined in the November 2001 CCRA) and that the Incremental Load shall also include the Incremental Load from the November 2001 CCRA.

- If any provision of this Agreement is inconsistent with the *Transmission System Code* as that Code will be revised and issued as part of the Ontario Energy Board's Phase II Decision, the said provision shall be deemed to be amended so as to comply with the then-current Code.

- Customer shall execute a Feeder Egress Agreement with Hydro One by no later than the Ready for Service Date.

CCRA - Cedar TS

- **SCADA Access:** At the request of the Customer and subject to compliance with the *Transmission System Code*, operating data at the Project will be made available to the Customer. This work is excluded from the work being performed under this Agreement.

The Project schedule is subject to:

a) the Customer executing and delivering this Agreement to Hydro One by no later than March 22, 2005 (the "Execution Date"); and
b) all necessary approvals being obtained as described under Special Circumstances above or in Schedule "A".

This Agreement constitutes the entire agreement between the parties with respect to the subject matter of this Agreement and supersedes all prior oral or written representations and agreements concerning the subject matter of this Agreement.

Recommended to Hydro One Networks Inc. by

Arthur Fischer
Account Executive
Hydro One Networks Inc.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by the signatures of their proper authorized signatories, as of the day and year first written above.

HYDRO ONE NETWORKS INC.

Jim Patterson
Manager, Customer Business Relations
I have the authority to bind the Corporation.

GUELPH HYDRO ELECTRIC SYSTEMS INC.

Art Stokman
Vice President, Engineering & Operations
I have the authority to bind the Corporation.

Schedule "A" (*Guelph Cedar TS Metalclad Project*)

PROJECT SCOPE

New or Modified Facility: (Describe the equipment being constructed by Hydro One)

- Install a second set of 13.8 kV metalclad to the two idle transformer windings at Guelph Cedar T1-T2 TS.
- The new facilities will be designed, constructed, owned and operated by Hydro One.
- The metalclad will consist of eight (8) feeder positions and will be housed in a prefabricated building with a full basement.
- Protection, Control, Metering & Annunciation pertaining to Hydro One Facilities.
  Note: Does not include Revenue metering.
- Witness commissioning at Hydro One Facilities.
- Work required at Hydro One Facilities includes engineering, procurement of equipment; installation of equipment, commissioning.
- Witnessing of work required at interface of The Customer and Hydro One Facilities at "Guelph Cedar TS".

Connection Point:

Existing two idle LV-transformer windings at Guelph Cedar T1-T2 TS.

Ready for Service Date: June 25th, 2006

HYDRO ONE CONNECTION WORK

Part 1: Non-Poolable Work

Hydro One will install Voltage transformers and Current Transformers for revenue metering for each bus as part of the metalclad installation.

Part 2: Line Connection Pool Work

N/A

Part 3: Transformation Connection Pool Work

Hydro One will:

1. **General Requirements**

- Obtain Site Plan approval.
- Check zoning by laws on noise and landscaping requirements to conform to local municipal by laws.
- Obtain other necessary approvals/permits as required.
- Relocate existing wood poles to provide adequate clearance for the new metalclad.

2. **115 kV Switching & Connection**

N/A

CCRA - Cedar TS

3. Transformation Facilities

N/A

4. LV Switching Facilities

- Provide one (1) assembly of 15.0 kV (95 kV BIL) Class C arc-resistant metal-clad switchgear, suitable for 3 Phase-4 Wire system, equipped with:
  - Two (2) transformer breakers, minimum 2400 A continuous.
  - One (1) bus tie breaker, minimum 2400 A continuous.
  - Eight (8) feeder breakers and Eight (8) feeder tie switches incorporated in the metalclad switchgear, 1200 A continuous. (Note: All feeder breakers to supply the Customer)
  - Two (2) sets of 3 phase PTs for protection & control.

5. AC Station Service System

- No new station service transformers will be provided. The existing Guelph Cedar T1-T2 TS station service transformers have sufficient spare capacity to supply the new facilities. Provide ac distribution panels and auto-transfer scheme and station service metering and cabling.

6. DC Station Service System

- Provide a complete dc station service system complete with 125 Vdc sealed battery, charger, dc distribution panels, and cabling.

7. Grounding & lightning protection

- Provide new station and fence grounding. Extend station and fence grounding as required.
- Provide lightning protection as required for the locale.
- Install one neutral reactor for proper grounding of the neutral bus on idle winding.

8. Operating Plates

- Provide new operating nomenclature plates.

9. Protection & Control System

- Provide the following protections:
  - LV bus "A" & "B" differential protection (bus blocking scheme) for each bus.
  - Transformer breakers reclose, breaker failure & control for each breaker.
  - Bus tie breaker failure & control.
  - Feeder protection and feeder breaker reclose & control for 8 feeders using programmable electronic relays to current Hydro One standards.
- Provide SCADA telemetry quantities to Ontario Grid Control Centre (OGCC).
- Provide SCADA telemetry quantities to IESO.
- Requirements on 3% and 5% Voltage Reduction as required.
- Under Frequency Load Shedding relay as required.

10. Telecommunications

- Provide Ground Potential Rise study.

CCRA - Cedar TS

- Provide cable protection (Neutralizing Transformer or optical isolators).
- Arrange and order necessary telecomm circuits for: teleprotection, SCADA telemetry quantities to OGCC and IESO, supervisory control, voice, metering.
- Perform end to end checks.

11. Structural/foundation systems

- Provide new foundations/new steel structures to suit.
- Provide a pre-engineered building complete with building services.
- Building designed to accommodate LV switching equipment, ac station service (except for the station service transformers), dc station service, protection & control equipment, telecomm equipment and customer revenue metering equipment.

12. Mechanical/site system

- Provide grading, access road, and drainage.
- Obtain Certificate (s) of Approval.

13. Landscaping

- Provide landscaping per City, zoning and EA requirements.

CUSTOMER CONNECTION WORK:

The Customer will:

1 Feeder & feeder egress

- Provide feeders and feeder egress from the new station.
- Provide feeder impedances.

2 Revenue metering

- Provide revenue metering system in accordance with IESO Rules.
- Customer may engage Hydro One as MSP under separate agreements with Hydro One or act as own MSP.
- Cabling between instrument transformers and the metering cabinet.
- Hydro One will provide an allowance for such instrument transformers for station bus metering equipped as part of the metal-clad switchgear.

MISCELLANEOUS

Documentation Required: Feeder egress & feeder impedances

Easement Required (from customer): No
Name of Third Party for Easement: N/A
Easement Date: N/A
Easement Lands: N/A

Security Requirements: N/A

Security Date: N/A

Approval Date (for OEB leave to construct): N/A

Revenue Metering:

Revenue metering and associated equipment is the responsibility of the Customer and/or its designated Meter Service Provider ("MSP").

The Customer will reimburse Hydro One for any costs Hydro One incurs to purchase and install revenue metering and/or associated equipment. Revenue metering equipment installed by Hydro One will meet IESO metering standards. Revenue metering equipment installed by Hydro One will become the property of the Customer on the Ready for Service Date.

Hydro One will provide space inside the fence suitable for the Customer to accommodate revenue metering.

Hydro One Facilities - HV:

N/A

Hydro One Facilities - LV:

- Guelph Cedar T1-T2 TS
  Eight breaker positions (to be installed under this Project). All eight breaker positions are allocated to supply the Customer.

Ownership:

A. Hydro One will own all equipment and facilities installed by Hydro One as part of the Hydro One Connection Work in, under, on, over, along, upon, through and crossing Hydro One' Property(ies), as well as:

- NIL

A. Hydro One will own instrument transformers incorporated in the metaleiad (for revenue metering) at Guelph Cedar T1-T2 TS, installed by Hydro One as part of the Hydro One Connection Work.

Customer Notice Information:

Address: 104 Dawson Road
Guelph, Ontario N1H 1A7

Attention: Art Stokman

Fax No.: (519) 822-3633

Schedule "B" Install Eight (8) feeders at Guelph Cedar T1-T2 TS (Project IP 11853)

TRANSFORMATION CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Transformation Connection Pool Work: $4,038,200.00

Actual Engineering and Construction Cost of the Transformation Connection Pool Work: $5,582,154.00

Estimate of Transformation Connection Pool Work Capital Contribution: NONE

Actual Transformation Connection Pool Work Capital Contribution: $0.00

LINE CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Line Connection Pool Work: N/A

Actual Engineering and Construction Cost of the Line Connection Pool Work: N/A

Estimate of Line Connection Pool Work Capital Contribution: N/A

Actual Line Connection Pool Work Capital Contribution: N/A

Manner of Payment of Estimate of Transformation Connection Pool Work Capital Contribution and /or Estimate of Line Connection Pool Work Capital Contribution:

N/A

NON-POOLABLE WORK

Estimate of the Engineering and Construction Cost of the Non-Poolable Work: $40,000.00

Actual Engineering and Construction Cost of the Non-Poolable Work: None

The scope of work for the Non-Poolable Work originally entailed Hydro One installing indoor voltage transformers and current transformers (collectively ITs) on each bus as part of the metalclad installation for the Customer's revenue metering. It was later decided to install outdoor ITs as opposed to indoor ITs in the Metalclad as a separate project for the Customer (Project IP 12838).

Manner of Payment of the Estimate of the Engineering and Construction Cost of the Non-Poolable Work: N/A

MISCELLANEOUS

Guaranteed Revenue Date: **Line Connection Pool Work –** N/A
Transformation Connection Pool Work – July 2017

Capacity Allocated to Customer (CATC): 252 MW

Base Load Trigger Point: 234 MW

READY FOR SERVICE DATE **June 30, 2006**

TRANSFORMATION CONNECTION REVENUE REQUIREMENTS AND LOAD FORECAST

Period: One year following the anniversary of the Ready for Service Date and annually thereafter	LOAD FORECAST: Incremental Load (Average Monthly Peak Load) MW	Transformation Connection Revenue (k$)
June 30, 2007	27.3	130.1
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June 30, 2012	60.8	685.4
June 30, 2013	62.2	700.1
June 30, 2014	62.2	698.3
June 30, 2015	62.2	696.5
June 30, 2016	62.2	694.8
June 30, 2017	62.2	693.2
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June 30, 2019	62.2	690.2
June 30, 2020	62.2	688.8
June 30, 2021	62.2	687.4
June 30, 2022	62.2	686.1
June 30, 2023	62.2	684.8
June 30, 2024	62.2	683.6
June 30, 2025	12.9	105.0

NOTES

The installation of two feeder positions at Guelph Campbell TS under the November 2001 CCRA in-service in July 2002 and the installation of eight (8) feeders at Guelph Cedar T1/T2 TS under the terms of this Agreement will be considered as two stages of the same Project for the purposes of the Transformation Connection Revenue Requirements specified in this Agreement.
Capacity Allocated to Customer: The capacity allocated to the customer for the Guelph Campbell stage (in-service July 2002) was 252 MW with a base load trigger point of 234 MW. These values will be used for the combined stage.

The capacity available to the Customer is supplied from all buses at the following Hydro One Facilities:
Guelph Campbell TS
Guelph Cedar TS (T1&T2 and T7&T8)
Guelph Hanlon TS

The new capacity allocated to The Customer when the eight (8) feeders are in-place at Guelph Cedar TS, will be 321.7 MW and is made up of the following contributions:

Guelph Campbell TS	147.4 MW
Guelph Cedar TS T1-T2	48.2 MW
Guelph Cedar TS T1-T2 (8-feeders)	48.2 MW
Guelph Cedar TS T7-T8	39.5 MW
Guelph Hanlon TS	38.4 MW

The Customer refers to these numbers as the “Practical Load Limit”. In the case of Guelph Campbell TS and Guelph Hanlon TS the “Practical Load Limit” is lower than the summer 10-day LTR. For Guelph Cedar TS T1-T2 and Guelph Cedar TS T7-T8 the practical load limit is the same as the summer 10-day LTR.

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Standard Terms and Conditions for Transmission Customer Connection Projects

1. Intentionally Deleted

2. Subject to Section 23 and the termination rights herein, the Agreement shall be in full force and effect and binding on the parties as of the date of the Agreement (the "Effective Date") and shall expire on the earlier of the Guaranteed Revenue Date and the date that the amount to be paid by the Customer pursuant to Section 12 is reduced to zero (the "Term").

3. Each party represents and warrants to the other that:

(a) it has all the necessary corporate power, authority and capacity to enter into the Agreement and to perform its obligations hereunder; and

(b) the execution of the Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on its part.

Where the New or Modified Facility is owned by the Customer, the Customer represents and warrants to Hydro One that it has obtained all necessary approvals with respect to the construction of the New or Modified Facility (including, but not limited to, where applicable, leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998* (being Schedule "B" of the *Energy Competition Act, S.O. 1998,c. 15)*) and in order to proceed with the Customer Connection Work.

Part A: Hydro One Connection Work

4. The Customer and Hydro One shall perform their respective obligations outlined in the Agreement in a manner consistent with Good Utility Practice and the Transmission System Code, in compliance with all Applicable Laws, including, but not limited to the requirements of the Electrical Safety Code, and using duly qualified and experienced people.

5. The parties acknowledge and agree that:

(a) Hydro One is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Hydro One Connection Work and those required for the construction, connection and operation of the New or Modified Facility where the New or Modified Facility is owned by Hydro One;

(b) the Customer is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Customer Connection Work and those required for the construction, connection and operation of the New or Modified Facility where the New or Modified Facility is owned by the Customer, including those required under the Electrical Safety Code and the Customer shall ensure that it has received all such requisite permits, certificates, reviews and approvals prior to connection;

(c) the Customer will enter into a Connection Agreement with Hydro One at least 14 calendar days prior to the connection of the New or Modified Facility to Hydro One's transmission system;

(d) the Customer will ensure that Project data is made available or provided to Hydro One as required by Hydro One;

(e) the Customer will ensure that the work performed by the Customer and others required for successful installation, testing and commissioning of protective equipment is completed as required to enable Hydro One witnessing and testing to confirm satisfactory performance of such systems;

(f) the Customer will provide any hardware required to connect to Hydro One's transmission system;

(g) the Customer will provide coordination on protection;

(h) Hydro One's responsibilities under the Agreement with respect to the connection of the New or Modified Facility to Hydro One's transmission system shall be limited to the performance of the Hydro One Connection Work;

(i) the Customer shall perform the Customer Connection Work at its own expense;

(j) where the New or Modified Facility is owned by the Customer, the Customer shall provide technical specifications for the New or Modified Facility as required for Hydro One's reviews. Until Hydro One has accepted the technical specifications (including electrical drawings) for the New or Modified Facility and accepted the Customer's verification of those portions of the Customer's electrical facilities affecting Hydro One's transmission system, Hydro One shall not be bound to connect the New or Modified Facility to Hydro One's transmission system; and

(k) the Hydro One Connection Work and Hydro One's rights and requirements hereunder, including, but not limited to:

(i) Hydro One's specifications of the protection equipment on the Customer's side of the Connection Point;

(ii) Hydro One's acceptance of power system components on the Customer's side of the Connection Point; and

CCRA - Cedar TS

might affect the proper functioning of Hydro One's reclosing equipment.

10. The Customer shall provide Hydro One with copies of the documentation specified in Schedule "A" of the Agreement under the heading "Documentation Required", acceptable to Hydro One, by no later than 120 calendar days after the Ready for Service Date. The Customer shall ensure that Hydro One may retain this documentation for Hydro One's ongoing planning, system design, and operating review. Where the Customer owns the New or Modified Facility, the Customer shall also maintain and revise such documentation to reflect changes to the New or Modified Facility and provide copies to Hydro One on demand and as specified in the Connection Agreement.

11. Intentionally Deleted

Part B: Transformation Connection Pool Work and/or Line Connection Pool Work

12. To the extent that the Pool Funded Cost of the Hydro One Connection Work is not recoverable by Transformation Connection Revenue and/or Line Connection Revenue, the Customer agrees to pay Hydro One the capital contribution(s) towards the Pool Funded Cost of the Transformation Connection Pool Work and/or the Line Connection Pool Work and any amounts payable to Hydro One under Subsection 13.2 hereof.

An estimate of the Engineering and Construction Cost (not including applicable taxes) of the Transformation Connection Pool Work and/or Line Connection Pool Work is provided in Schedule "B" of the Agreement.

An estimate of the Capital Contribution for each of the Transformation Connection Pool Work and the Line Connection Pool Work is specified in Schedule "B" of the Agreement (plus applicable taxes). The Customer shall pay Hydro One the estimated Capital Contribution(s) in the manner specified in Schedule "B" of the Agreement.

By no later than 180 calendar days after the Ready for Service Date, Hydro One shall provide the Customer with a new Schedule "B" to replace Schedule "B" of the Agreement attached hereto which shall identify the following:

(i) the actual Engineering and Construction Cost of the Transformation Connection Pool Work;
(ii) the actual Engineering and Construction Cost of the Line Connection Pool Work;
(iii) the actual Engineering and Construction Cost of the Non-Poolable Work;
(iv) the actual Capital Contribution required to be paid by the Customer for each of the Transformation Connection Pool Work and the Line Connection Pool Work; and
(v) the revised Transformation Connection Revenue and/or Line Connection Revenue requirements.

The new Schedule "B" shall be made a part hereof as though it had been originally incorporated into the Agreement.

If the estimates of the Capital Contributions paid by the Customer exceeds the actual Capital Contributions required to be paid by the Customer for each of the Transformation Connection Pool Work and the Line Connection Pool Work, Hydro One shall refund the difference to the Customer (plus applicable taxes) by no later than 30 days following the rendering of the new Schedule "B". If the estimates of the Capital Contributions paid by the Customer are less than the actual Capital Contributions required to be paid by the Customer for each of the Transformation Connection Pool Work and the Line Connection Pool Work, the Customer shall pay Hydro One the difference (plus applicable taxes) by no later than 30 days following the rendering of the new Schedule "B".

13.1Hydro One shall perform a True-Up of the Transformation Connection Revenue and/or Line Connection Revenue at the following True-Up points:

(a) the end of the fifth and tenth anniversaries of the Ready for Service Date;
(b) the end of the fifteenth anniversary of the Ready for Service Date if the Actual Load is 20% higher or lower than the Load Forecast at the end of the tenth anniversary of the Ready for Service Date; and
(c) the time of disconnection where the Customer voluntarily and permanently disconnects the Customer's Facilities from the Hydro One Facilities prior to the final True-Up point identified in (a) or (b) above.

By no later than 30 calendar days following completion of each of the True-Ups referred to in 13.1(a) and (b), Hydro One shall provide the Customer with a new Schedule "B" to replace Schedule "B" of the Agreement attached hereto which shall identify the following:

(i) the Guaranteed Revenue Date if that date has changed as a result of the Updated Load Forecast; and
(ii) an updated Table showing the Transformation Connection Revenue and/or Line Connection Revenue requirements and the Updated Load Forecast for the remainder of the twenty-five year economic evaluation period where those amounts have changed as a result of the True-Up.

CCRA - Cedar TS

The Customer acknowledges that its failure to approve an expenditure of Premium Costs may result in further delays and Hydro One will not be liable to the Customer as a result thereof. The Customer shall pay any prior-approved Premium Costs within 30 calendar days after the date of Hydro One's final invoice therefor, billable at the end of the project. Interest shall be payable at the rate of 1.5 percent compounded monthly (19.56 percent per annum) on all overdue payments. The obligation to pay any amount hereunder shall survive the termination of the Agreement.

Part D: Cancellation or Deferral of Project and Early Termination of Agreement for Breach

16(a) If the Project is cancelled, the Agreement is terminated for any reason whatsoever other than breach of the Agreement by Hydro One, the Customer shall pay Hydro One's Engineering and Construction Costs (plus applicable taxes) incurred on and prior to the date that the Project is cancelled or the Agreement is terminated, including the preliminary design costs and all costs associated with the winding up of the Project, including, but not limited to, storage costs, vendor cancellation costs, facility removal expenses and any environmental remediation costs.

If the Customer provides written notice to Hydro One that it is cancelling or deferring the Project, Hydro One shall have 10 Business Days to provide written notice to the Customer listing the individual items listed as materials which it agrees to purchase. Hydro One shall deduct the actual costs of those individual items of materials being purchased by Hydro One from the Engineering and Construction Costs referred to above.

If Hydro One does not require all or part of the materials, the Customer may exercise any of the following options or a combination thereof:

(i) where materials have been ordered but all or part of the materials have not been received by Hydro One, the Customer shall have the right to require Hydro One, at the Customer's sole expense, to continue with the purchase of the materials and transfer title to those materials on an "as is, where is basis" to the Customer upon the Customer paying Hydro One's Engineering and Construction Costs (plus applicable taxes) provided that the Customer exercises this option within 15 Business Days of the termination, cancellation or deferral;

(ii) where all or part of the materials have been received by Hydro One but have not been installed, the Customer shall have the right to require Hydro One, at the Customer's sole expense, to transfer title to the materials on an "as is, where is basis" to the Customer upon the Customer paying Hydro One's Engineering and Construction Costs (plus applicable taxes) provided that the Customer exercises this option within 15 Business Days of the termination, cancellation or deferral. The Customer shall also be responsible for any warehousing costs associated with the storage of the materials to the date of transfer; or

(iii) where all or part of the materials have been received by Hydro One and have been installed, the Customer shall have the right to require Hydro One, at the Customer's sole expense, to: transfer title to the materials on an "as is, where is basis" to the Customer upon the later of (A) the Customer paying Hydro One's Engineering and Construction Costs (plus applicable taxes); and (B) the date that Hydro One removes the materials from its property at the risk of the Customer; provided that the Customer exercises this option within 15 Business Days of the termination, cancellation or deferral. The Customer shall also be responsible for any Engineering and Construction Costs (plus applicable taxes) associated with the removal of the materials that have been installed by Hydro One.

The Customer shall pay Hydro One's Engineering and Construction Costs (plus applicable taxes) which become payable under this Section 16 within 30 calendar days after the date of invoice.

16(b). If the Customer wishes to defer the Project, the Parties will negotiate the terms of such deferral.

Part E:Sale, Lease, Transfer or Other Disposition of Customer's Facilities

17. In the event that the Customer sells, leases or otherwise transfers or disposes of the Customer's Facilities to a third party during the Term of the Agreement, the Customer shall cause the purchaser, lessee or other third party to whom the Customer's Facilities are transferred or disposed to enter into an assumption agreement with Hydro One to assume all of the Customer's obligations in the Agreement; and notwithstanding such assumption agreement unless Hydro One agrees otherwise, in writing, the Customer shall remain obligated under Sections 12, 13.2, 14, 15 and 16 by the purchaser, lessee or other third party in the case of a transfer or disposition. The Customer further acknowledges and agrees that in the event that all or a portion of the Customer's Facilities are shut down, abandoned or vacated for any period of time during the Term of the Agreement, the Customer shall remain obligated under Sections 12, 13.2, 14 and 15 for the said time period.

Part F: Security Requirements

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remedies that may be available to Hydro One under the terms of the Agreement, at common law or in equity: deem the Agreement to be repudiated and, after giving the Customer at least 10 calendar days' prior written notice thereof, recover, as liquidated damages and not as a penalty, the balance of the amounts payable by the Customer pursuant to Sections 12, 13.2, 14, 15 and 16.

24. Upon the occurrence of an Event of Default by Hydro One hereunder, the Customer shall give Hydro One written notice of the Event of Default and shall allow Hydro One 30 calendar days from the date of receipt of the notice to rectify the Event of Default at Hydro One's sole expense. If such Event of Default is not cured to the Customer's reasonable satisfaction within the 30 calendar day period, the Customer may pursue any remedies available to it at law or in equity, including at its option the termination of the Agreement.

25. All rights and remedies of Hydro One and the Customer provided herein are not intended to be exclusive but rather are cumulative and are in addition to any other right or remedy otherwise available to Hydro One and the Customer respectively at law or in equity, and any one or more of Hydro One's and the Customer's rights and remedies may from time to time be exercised independently or in combination and without prejudice to any other right or remedy Hydro One or the Customer may have or may have exercised. The parties further agree that where any of the remedies provided for and elected by the non-defaulting party are found to be unenforceable, the non-defaulting party shall not be precluded from exercising any other right or remedy available to it at law or in equity.

In addition to any other remedy provided hereunder, all overdue amounts that are outstanding for longer than 30 days shall bear interest at 1.5 percent compounded monthly (19.56 percent per annum).

Part J: Capital Contributions and Changes to Transmission Rates

26.1 Until Hydro One has published and the Ontario Energy Board has accepted Hydro One's procedure and methodology for determining the requirement for a capital contribution in accordance with Section 4.1 of the *Transmission System Code*, any Capital Contributions paid by the Customer under the terms of the Agreement are subject to adjustment with such adjustment to be solely based on the procedure and methodology accepted by the OEB.

26.2 In the event that the Transformation Connection Service Rate or the Line Connection Service Rate is rescinded or the methodology of determination or components is materially changed, the Parties agree to negotiate a new mechanism for the purposes of the Agreement. The Parties shall have 90 calendar days from the effective date of rescission or fundamental change of the Transformation Connection Service Rate or the Line Connection Service Rate to agree to a new mechanism. If the Parties are unable to successfully negotiate a replacement within that 90 calendar day period, they shall submit to arbitration, in accordance with the requirements of the Transmission System Code (or the Connection Agreement attached thereto); or if there is no arbitration provision in the Transmission System Code (or the Connection Agreement attached thereto), to the requirements of the *Arbitration Act* (Ontario), as amended, to settle on a new mechanism. The decision of the arbitrator shall be binding on each party with no right of appeal.

The terms of reference of the arbitration shall be to identify a new mechanism that is, to the extent possible, fair to the parties and constitutes a reasonably comparable replacement for the Transformation Connection Service Rate or the Line Connection Service Rate.

Any settlement on a new mechanism pursuant to this Section 19 shall apply retroactively from the date on which the Transformation Connection Service Rate or the Line Connection Service Rate was rescinded or fundamentally changed. Until such time as a new mechanism is determined hereunder, any amounts to be paid by the Customer under the Agreement shall be based on the Transformation Connection Service Rate or the Line Connection Service Rate in effect prior to the effective date of any such changes.

Part K: Liability and Force Majeure

27. Other than for sums payable under the Agreement, the Customer shall only be liable to Hydro One and Hydro One shall only be liable to the Customer for any damages that arise directly out of the willful misconduct or negligence in meeting their respective obligations under the Agreement.

Despite the foregoing, neither Party shall be liable under any circumstances whatsoever for any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential, incidental or special damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in statute, contract, tort or otherwise.

This provision shall survive the termination of the Agreement.

28. Neither party shall be considered to be in default in the performance of its obligations under the Agreement, except obligations to make payments with

CCRA - Cedar TS

Appendix "A": Definitions

Throughout the Agreement, unless there is something in the subject matter or context inconsistent therewith, the following words shall have the following meanings:

"Actual Load" means the actual load delivered by Hydro One to the Customer up to the True-Up point.

"Agreement" means the Connection Cost Recovery Agreement, Schedules "A" and "B" attached thereto and these Standard Terms and Conditions.

"Applicable Laws", means any and all applicable laws, including environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments or decrees or any requirement or decision or agreement with or by any governmental or governmental department, commission board, court authority or agency.

"Approval Date" means for the purpose of Subsection 6(f) of the Terms and Conditions, the date specified in Schedule "A" of the Agreement.

"Base Load Trigger Point" is as specified in Schedule "B" of the Agreement and was determined using the following formula:

Base Load Trigger Point = 3 yr. Avg. PLI * CATC

With:

PLI = |(sum of Twelve Monthly Peaks)/Annual Peak*12|

"Business Day" means a day other than Saturday, Sunday, statutory holiday in Ontario or any other day on which the principal chartered banks located in the City of Toronto, are not open for business during normal banking hours.

"Capital Contribution" means a capital contribution calculated using the economic evaluation methodology set out in the *Transmission System Code*.

"Capacity Allocated to Customer " or **"CATC"** is that portion of the existing capacity on the Hydro One Facilities that can effectively and economically serve the Customer's peak load and is as specified in Schedule "B" of the Agreement.

"Connection Agreement" has the meaning set forth in the Transmission System Code.

"Connection Point" means the point where the Customer's Facilities are connected to Hydro One's transmission system.

"Customer Connection Work" means the work to be performed by the Customer, at its sole expense, which is described in Schedule "A" of the Agreement.

"Customer's Facilities" has the meaning set forth in the Transmission System Code, and includes, but is not limited to the New or Modified Facility where the Customer owns the New or Modified Facility. In addition to the foregoing, Customer's Facilities may include any other assets specified in Schedule "A" of the Agreement.

"Customer's Property(ies)" means any lands owned by the Customer in fee simple or where the Customer has easement rights.

"Distribute" has the meaning ascribed thereto in the *Electricity Act, 1998*.

"Embedded Generation" shall have the meaning ascribed thereto in the *Transmission System Code* that will be revised and issued as part of the Phase II Decision.

"Emergency" has the meaning set forth in the Transmission System Code.

"Engineering and Construction Cost" means Hydro One's charge for equipment, labour and materials at Hydro One's standard rates plus Hydro One's project specific overheads as filed with the OEB as well as interest during construction.

"Good Utility Practice" has the meaning set forth in the Transmission System Code.

"Guaranteed Revenue Date" means, for the purposes of Section 2 of the Terms and Conditions, the date specified in Schedule "B" of the Agreement.

"Hydro One Connection Work" means the work to be performed by Hydro One, which is described in Schedule "A" of the Agreement.

"Hydro One Facilities" means collectively the Hydro One Facilities – LV and the Hydro One Facilities – HV.

"Hydro One Facilities – HV" means the facilities owned by Hydro One specified in Schedule "A" of the Agreement that convey electricity at voltages of more than 50 kilovolts.

"Hydro One Facilities – LV" means the facilities owned by Hydro One specified in Schedule "A" of the

CCRA - Cedar TS

"Transformation Connection Service Rate" means Hydro One's transformation connection service rate approved by the Ontario Energy Board ("OEB") from time to time, or any mechanism instituted in accordance with Section 19).

"Transmission Rate" has the meaning set forth in the form of Connection Agreement attached to the Transmission System Code.

"Transmission System Code" means the code of standards and requirements issued by the OEB on July 14, 2000, as it may be amended, revised or replaced in whole or in part from time to time.

"Transmit" has the meaning ascribed thereto in the *Electricity Act, 1998*.

"True Up" means the process whereby Hydro One revises the Line Connection Revenue and the Transformation Connection Revenue, based on the Actual Load and the Updated Load Forecast, using the same methodology used to carry out the initial economic evaluation and the same inputs except for load.

"Updated Load Forecast" means the load forecast for the remainder of the twenty-five year economic evaluation period when the Load Forecast is adjusted to the point where the present value of the Transformation Connection Revenue and/or Line Connection Revenue equals the present value of the Pool Funded Cost.

CCRA – Winona TS

Winona TS

Hamilton Hydro Inc (the "Customer") has requested and Hydro One Networks Inc. ("Networks") has agreed to build a new 115-27.6 kV 50/83 MVA transformer station "Winona TS" (the "Project") on the terms and conditions set forth in this Agreement (the "Agreement") dated March 22, 2002, the attached Standard Terms and Conditions (reference # T&C V1 ESH 15-25 01-2002) and the attached Amendment to the Standard Terms and Conditions (reference # T&C V1 ESH 15-25 01-2002), dated March 22, 2002.

Project Summary

Overview and purpose of the project

Hamilton Hydro Inc. has advised Networks that it would need new capacity to supply 27.6 kV loads in the Stoney Creek area. The loads in the Stoney Creek area have already exceeded the available capacity.

The Customer has requested that Networks build a new 115-27.6 kV 50/83 MVA transformer station "Winona TS" near Fruitland Rd. and South Service Rd in Stoney Creek.

Ready for Service date **June 30, 2003**

Financial Summary (Repayment schedule and Capital Contribution)

Term: **25 years**

Special Circumstances

(eg ordering long lead material, concurrent processes)

The Project schedule is subject to:

a) the Customer executing and returning this Agreement to Networks by no later than the Execution Date specified in Schedule "B"; and
b) all necessary approvals being obtained as outlined under Special Circumstances.

This Agreement constitutes the entire agreement between the parties with respect to the subject matter of this Agreement and supersedes all prior oral or written representations and agreements concerning the subject matter of this Agreement. Schedules "A" and "B" and the Standard Terms and Conditions (reference version # T&C V1 ESH 15-25 01-2002) attached hereto are to be read with and form part of this Agreement.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by the signatures of their proper officers, as of the day and year first written above.

HYDRO ONE NETWORKS INC.

Anthony Horton
Director – Networks Customer Relations
I have the authority to bind the Corporation.

HAMILTON HYDRO INC.

Don Marsales
Chief Operating Officer
I have the authority to bind the Corporation.

Schedule "A"

Networks Connection Work

Project Scope:

The scope of project by Networks to build a new transformer station "Winona TS" is described below.

- A new transformer station ("Winona TS") to be designed constructed, owned and operated by Networks, and to be located in Stoney Creek in the City of Hamilton, Ontario, proposed to be located near Fruitland Rd. and South Service Rd. for supply to Hamilton Hydro Inc.
- Connection to the 115 kV circuits Q2AH (Beach TS x Beamsville TS section).
- Protection, Control, Metering & Annunciation pertaining to "Networks" facilities.
  Note: Does not include Revenue metering.
- Purchase property for "Winona TS"
- Environmental Assessment.
- Witness commissioning at Network's facilities.
- Work required at Networks facilities includes engineering, procurement of equipment; installation of equipment, commissioning.
- Witnessing of work required at interface of Hamilton Hydro and Network's facilities at "Winona TS".

Non-Poolable Work:

Protection Changes

- Review/revise Q2AH protections at Hamilton Beach TS, Beamsville TS, Vineland DS and Allanburg TS as required.
- Revise existing Q2AH protections to include cascading of Transfer Trip signals to new Winona TS.
- Provide new operating plates.
- Conduct review of Interface Documents and review compliance with the Transmission System Code (TSC).
- Perform witness verification tests, on potential checks and on load checks per Witness of Verification Evidence Report.

Teleprotection

- Provide teleprotection for Q2AH based on the following considerations:
  - Assume terminal station at Beach TS.
  - Tone equipment
  - Dual channel transfer trip.
  - Leased circuits.

SCADA Modifications & Telemetry Quantities

- Modify the master SCADA at Territory Operating Centre (TOC) and Transmission Operation Management Centre (TOMC) to suit.
- Provide new modem at TOC.
- Provide telemetry quantities (device status, measured quantities and alarms) to be "collected" from a port and modem from the local RTU to TOC/TOMC.

Line Connection Pool Work

Networks will:

1 115 kV Line Tap

- Provide 115 kV line tap based on the use of wood pole structures from overhead circuit Q2AH.
- Provide two (2) load break bus switch structures.

CCRA - Winona TS

- Provide line conductors, 2 skywires equipped with insulator end, dead-end insulators and line hardware including standard NEMA pads on the line conductors.
- Provide openers (maintenance loops) at the transmission tower.
- Terminate the line conductors at the load break switch structures and at the termination entrance structure (s).
- Terminate the skywires at the entrance structures.
- Arrange & coordinate all outages.
- Conduct archaeological survey.
- Amend existing easement for the line tap if required.
- Obtain all necessary permits and approvals.
- Provide new operating plates.
- It is assumed that the line tap will be exempt from Environmental Assessment.

2 In-line Switching

- Provide two (2) 115 kV load break switches.

Transformation Connection Pool Work:

Networks will:

New Substation

1. General Requirements

- Obtain Environmental Assessment approval.
- Obtain Site Plan approval.
- Check zoning by laws on noise and landscaping requirements to conform with local municipal by laws.
- Obtain other necessary approvals/permits as required.

2. 115 kV Switching & Connection

- Provide entrance structure (s) to accommodate the overhead line tap and skywires. The entrance structure (s) are to be designed to accommodate the HV disconnect switches and the HV surge arrestors.
- Provide two (2) 115 kV 600 A 550 kV LIL motorised disconnect switches to meet the requirements of the line tap and to interrupt the maximum transformer magnetizing current.
- Provide connections from the NEMA pads on the line conductors to the station bus/equipment.
- Provide connections from the skywires to the station ground grid.

3. Transformation Facilities

- Provide two (2) 50/66.6/83.3 MVA 110-28.4 transformers (CSA/ANSI Standard) with ULTC, HV wye un-grounded, LV zig-zag grounded through reactors, with attached radiators and conservator tank.
- Provide heat activated detectors and a Fire Panel.
- Provide neutral reactors (1.5 ohm air core, 1000 A continuous, 6000 A at 15 seconds).
- Provide six (6) 108 kV station class surge arrestors and six (6) 27.6 kV station class surge arrestors.
- The transformer "pocket", the transformer foundation and spill containment pit, will be designed for the specified transformer only.

4. LV Switching Facilities

- Provide one (1) assembly of 27.6 kV (150 kV LIL) Class C arc-resistant metal-clad switchgear, suitable for 3 Phase-4 Wire system, equipped with:
  - Two (2) transformer breakers, 2000 A continuous.
  - One (1) bus tie breaker, 2000 A continuous.
  - Four (4) feeder breakers, 1200 A continuous.
  - Space provision in building for two (2) future feeder positions.
  - Two (2) sets of 3 phase PTs for protection & control

CCRA - Winona TS

- One lot 28 kV 2000 A bus duct between the transformers and the switchgear complete with supports, enclosure and entrance bushings.
- 1000 A neutral arrangement.

5. AC Station Service System

- Provide an ac station service system complete with two (2) suitably rated station service transformers, ac distribution panels, auto-transfer scheme, station service metering, and cabling.

6 DC Station Service System

- Provide a dc station service system complete with 125 Vdc sealed battery, charger, dc distribution panels, and cabling.

7 Grounding & lightning protection

- Provide new station and fence grounding to current HON standard.
- Provide lightning protection as required for the locale.

8 Operating Plates

- Provide new operating plates.

9 Protection & Control System

- Provide the following protections in factory assembled, tested & commissioned panels based on the use of SEL relays unless stated otherwise:
  - Teleprotection (transfer trip), dual channel, using suitable tone equipment
  - Line backup protections for each HV line.
  - Transformer "A" & "B" differential protection for each power transformer.
  - HV disconnect switch control.
  - RTU to provide SCADA, SER/A complete with local control computer.
  - Tap changer control from RTU for each power transformer.
  - HV load break switch control.

- Provide the following protections:
  - LV bus "A" & "B" differential protection (bus blocking scheme) for each bus.
  - Transformer breakers reclose, breaker failure & control for each breaker.
  - Bus tie breaker breaker failure & control.
  - Feeder protection and feeder breaker reclose & control for 6 feeders.

- Provide SCADA telemetry quantities to TOC and TOMC (Richview TS).
- Provide SCADA telemetry quantities to IMO.
- Requirements on 3% and 5% Voltage Reduction as required.
- Under Frequency Load Shedding relay as required.

10 Telecommunications

- Provide Ground Potential Rise study.
- Provide cable protection (Neutralizing Transformer or optical isolators).
- Arrange and order necessary telecomm circuits for: teleprotection, SCADA telemetry quantities to TOC/TOMC and IMO, supervisory control, voice, metering.
- Perform end to end checks.

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11 Structural/foundation systems

- Provide new foundations/new steel structures to suit.
- Provide transformer foundations for the specified transformer rating
- Provide a pre-engineered building complete with building services.
- Building designed to accommodate: LV switching equipment , ac station service except for the SSTs, dc station service, protection & control equipment, telecomm equipment, customer revenue metering equipment.
- Provide new 2.4 m chain link fence. The final fence material will be dependent on the City and zoning requirements.

12 Mechanical/site system

- Provide grading, access road, and drainage.
- Provide a spill containment system.
- Obtain Certificate (s) of Approval.

13 Landscaping

- Provide landscaping per City, zoning and EA requirements.

14 Property

- Acquire property with a 60 m frontage at the SE or SW corner of Fruitland Road and South Service Road. This site is tentatively identified by Hamilton Hydro as the preferred site. Approximately 2.3 Acres are required for the station and the cost of the Transformation Connection Pool Work ($9,177,000) includes an estimate of $502,000 for the cost of this size property. (For further details, refer to Miscellaneous Section)

15 Environmental Assessment

- Obtain environmental assessment & approval. The project is subject to the Class EA requirement.
- Provide archaeological assessment.

16 Interface Milestones

Customer Connection Work:

The Customer will:

1 Feeder & feeder egress

- Provide feeders and feeder egress from the new station.
- Provide feeder impedances.

2 Revenue metering

- Provide revenue metering system in accordance with IMO Rules.
- Customer may engage Hydro One Networks Services as MSP or act as own MSP.
- Cabling between instrument transformers and the metering cabinet.
- Hydro One will provide an allowance for such instrument transformers for station total metering equipped as part of the metal-clad switchgear.

Miscellaneous

Documentation Required:

Feeder egress & feeder impedances

Easement Required (from customer): No

Name of Third Party for Easement: N/A

Easement Date: N/A

Easement Lands: N/A

New or Modified Facility: New facility "Winona TS" currently proposed to be built near Fruitland Rd. and South Service Rd in Stoney Creek.

Connection Point: The Connection Point is the customer's four feeders to be connected to the four 27.6 kV breakers at Networks "Winona TS"

Ready for Service Date: June 30, 2003

Execution Date: March 22, 2002

Security Requirements: N/A

Approval Date: N/A

Environmental Assessment:

Completion of the Project on the Customer's Ready for Service date is subject to Network's obtaining environmental assessment approval by August 30, 2002

Feeder Egress Agreement Required: Yes

A Feeder Egress Agreement signed by the Customer and Networks is required by the Ready for Service Date.

Property Purchase Date: September 16 2002

Completion of the Project on the Customer's Ready for Service date is subject to Network's purchase of property by September 16, 2002

Approximately 2.3 Acres are required for the station and the cost of the Transformation Connection Pool Work ($9,177,000) includes an estimate of $502,000 for the cost of this size property. Any variation in the actual cost of the property required for the station will be reflected in the Customer's capital contribution and will be recovered by direct billing as described in the Agreement's Standard Terms and Conditions, Section 12 (Amendment).

Network agrees to purchase the property required for the Project provided that the Customer agrees to re-purchase, within two years of the property purchase date and on a pro-rata basis based on the original purchase price, that portion of the property not required for the Project (the remaining property).

During this two year period Networks will make reasonable efforts to sell the property to third parties. Any third party offer to purchase which is below the Customer pro-rata purchase price will be subject to the prior approval of the Customer. Should the property be sold above the purchase price within the two-year period, the Customer will receive the benefit of the increase in value over the purchase price of the property.

The Customer agrees to reimburse Networks for all costs incurred to purchase, support and resell the remaining property including carrying costs.

The customer agrees that if the remaining property cannot be severed the full original purchase price will be included in the Transformation Connection Pool Work Estimate (Sch B)

Revenue Metering:

Revenue metering and associated equipment is the responsibility of the Customer and/or its designated Meter Service Provider.

The Customer will reimburse Networks for any costs Networks incurs to purchase and install revenue metering and/or associated equipment. Revenue metering equipment installed by Networks will meet IMO metering standards. Revenue metering equipment installed by Networks will become the property of the Customer on the Ready for Service date.

Networks will provide space inside the fence suitable for the Customer to accommodate revenue metering.

SCADA Access:

At the request of the Customer and subject to compliance with the Transmission System Code, operating data at the Project will be made available to the Customer. This work is excluded from the work being performed under this Agreement.

Networks' Facilities – HV:

- Networks facilities that currently supply Hamilton Hydro's Stoney Creek Area:
  Hamilton Lake TS (Lake TS T1/T2 transformers)
  Hamilton Nebo TS (Nebo TS T1/T2 transformers)

- Networks HV facilities currently supplying Hamilton Hydro's Dundas, Village of Ancaster, Flamborough, and Waterdown Area:
  Dundas TS (T3/T4 transformers) - Supply to Dundas, Village of Ancaster, and Flamborough Area
  Burlington TS (T15/T16 transformers) - Supply to Waterdown Area

- "Winona TS" (to be installed under this Project)

Networks' Facilities – LV:

- Networks LV (27.6 kV) facilities currently supplying the customer's Stoney Creek Area:
  Lake TS "B" and "Y" buses: Breaker positions 29M1, 29M2, 29M3, 29M4, 29M5, and 29M6
  Nebo TS "B" and "Y" buses: Breaker positions 157M3, and 157M4

- Networks LV(27.6 kV) facilities currently supplying the customer's Dundas, Village of Ancaster, Flamborough, and Waterdown Area
  Dundas TS "B" and "Y" buses: Breaker positions 2M2, and 2M7. Also supplied from 2M1, and 2M6 breaker positions via Hydro One Networks Distribution feeders.
  Burlington TS "J" bus: Breaker positions 39M31 via Burlington Hydro feeder

- "Winona TS" 27.6 kV
  Four breaker positions (to be installed under this Project)

Note: Breaker positions that supply other customers are excluded from above.

Ownership:

A. Networks will own all equipment and facilities installed by Networks as part of the Networks Connection Work in, under, on, over, along, upon, through and crossing Networks' Property(ies), as well as:

- NIL

B. Hamilton Hydro will own instrument transformers (for revenue metering) at "Winona TS" installed by Networks as part of the Networks Connection Work.

Customer Notice Information:

Address: Hamilton Hydro Inc.
P.O. Box 2249 LCD 1,
55 John Street North
Hamilton
ONT., L8N 3E4

Attention: Don Marsales
Chief Operating Officer

Fax No: (905) 523-5764

Schedule "B"

Transformation Connection Pool Work Estimate: $9,177,000

Line Connection Pool Work Estimate: $445,000

Non-Poolable Work Estimate (recoverable): $160,000 (plus applicable taxes)

Manner of Payment of Non-Poolable Work:

Customer shall pay Networks for Non-Poolable work using the following payment schedule:

January 2, 2003	– 50%
July 30, 2003	– 50%

Capital Contribution: $2,085,000 (plus applicable taxes) for Pool Work

Manner of Payment of Capital Contribution:

Customer shall pay Networks the Capital Contribution using the following payment schedule:

April 23, 2002	– 20%
January 2, 2003	– 40%
March 1, 2003	– 20%
July 30, 2003	– 20%

Available Capacity:

27.6 kV available capacity for Stoney Creek Area:

Lake TS	106.0 MVA
Nebo TS	33.5 MVA (allocated to Hamilton Hydro)

27.6 kV available capacity for Dundas, Ancaster, Flamborough, Waterdown Area:

Dundas TS	42.9 MVA (allocated to Hamilton Hydro)
Burlington TS	11.0 MVA (allocated to Hamilton Hydro)

Capacity to be installed under this project:

"Winona TS"	83.3 MVA

Base Load Trigger Point:

98.7 MW (Based on January 1999 to December 2001 loads and existing available capacity)

Guaranteed Revenue Date:

Line Connection Pool Work: Prior to June 30, 2008

Transformation Connection Pool Work: June 30, 2028

GUARANTEED INCREMENTAL TRANSFORMATION CONNECTION REVENUE AND/OR LINE CONNECTION REVENUE[1]

Period: Each twelve month period commencing on the Ready for Service Date	Guaranteed Incremental Line Connection Revenue (k$)	Guaranteed Incremental Transformation Connection Revenue (k$)
2003		
2004	155.5	281.0
2005	193.1	348.9
2006	231.9	419.2
2007	272.1	491.8
2008		573.0
2009		666.1
2010		765.6
2011		868.4
2012		974.8
2013		1,084.8
2014		1,198.5
2015		1,316.1
2016		1,437.6
2017		1,499.4
2018		1,499.4
2019		1,499.4
2020		1,499.4
2021		1,499.4
2022		1,499.4
2023		1,499.4
2024		1,499.4
2025		1,499.4
2026		1,499.4
2027		1,499.4
2028		1,499.4

Standard Terms and Conditions for Transmission Customer Connection Projects

1. The Customer agrees to guarantee a minimum amount of revenue to be derived from Incremental Load in accordance with the terms and conditions of the Agreement to hold the Pool harmless as a result of the Project.

2. Subject to Section 23 and the termination rights herein, the Agreement shall be in full force and effect and binding on the parties as of the date of the Agreement (the "Effective Date") and shall expire on the earlier of the Guaranteed Revenue Date and the date that the debt owed by the Customer pursuant to Section 12 is reduced to zero (the "Term").

3. Each party represents and warrants to the other that:

(a) it has all the necessary corporate power, authority and capacity to enter into the Agreement and to perform its obligations hereunder; and
(b) the execution of the Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on its part.

Where the New or Modified Facility is owned by the Customer, the Customer represents and warrants to Hydro One Networks Inc. ("Networks") that it has obtained all necessary approvals with respect to the construction of the New or Modified Facility (including, but not limited to, where applicable, leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998* (being Schedule "B" of the *Energy Competition Act, S.O. 1998,c. 15)*) and in order to proceed with the Customer Connection Work.

Part A: Networks Connection Work

4. The Customer and Networks shall perform their respective obligations outlined in the Agreement in a manner consistent with Good Utility Practice and the Transmission System Code, in compliance with all Applicable Laws, including, but not limited to the requirements of the Electrical Safety Code, and using duly qualified and experienced people.

5. The parties acknowledge and agree that:

(a) Networks is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Networks Connection Work and those required for the construction, connection and operation of the New or Modified Facility where the New or Modified Facility is owned by Networks;

(b) the Customer is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Customer Connection Work and those required for the construction, connection and operation of the New or Modified Facility where the New or Modified Facility is owned by the Customer, including those required under the Electrical Safety Code and the Customer shall ensure that it has received all such requisite permits, certificates, reviews and approvals prior to connection;

(c) the Customer will enter into a Connection Agreement with Networks at least 14 calendar days prior to the connection of the New or Modified Facility to Networks' transmission system;

(d) the Customer will ensure that Project data is made available or provided to Networks as required by Networks;

(e) the Customer will ensure that the work performed by the Customer and others required for successful installation, testing and commissioning of protective equipment is completed as required to enable Networks witnessing and testing to confirm satisfactory performance of such systems;

(f) the Customer will provide any hardware required to connect to Networks' transmission system;

(g) the Customer will provide coordination on protection;

(h) Networks' responsibilities under the Agreement with respect to the connection of the New or Modified Facility to Networks' transmission system shall be limited to the performance of the Networks Connection Work;

(i) the Customer shall perform the Customer Connection Work at its own expense;

(j) where the New or Modified Facility is owned by the Customer, the Customer shall provide technical specifications for the New or Modified Facility as required for Networks' reviews. Until Networks has accepted the technical specifications (including electrical drawings) for the New or Modified Facility and accepted the Customer's verification of those portions of the Customer's electrical facilities affecting Networks' transmission system, Networks shall not be bound to connect the New or Modified Facility to Networks' transmission system; and

(k) the Networks Connection Work and Networks' rights and requirements hereunder, including, but not limited to:

(i) Networks' specifications of the protection equipment on the Customer's side of the Connection Point;
(ii) Networks' acceptance of power system components on the Customer's side of the Connection Point; and
(iii) Networks' acceptance of the technical specifications (including electrical drawings) for the New or Modified Facility where the New or Modified Facility is owned by the Customer and/or the Customer Connection Work;

are solely for the protection of Networks' transmission system and that the Customer is responsible for installing equipment and facilities such as protection and control equipment to protect its own property, including, but not limited to the New or Modified Facility where the New or Modified Facility is owned by the Customer.

6. Networks shall use reasonable efforts to complete the Networks Connection Work by the Ready for Service Date specified in Schedule "A" provided that:

(a) the Customer is in compliance with its obligations under the Agreement;
(b) any work required to be performed by third parties has been performed in a timely manner and in a manner to the satisfaction of Networks, acting reasonably;
(c) there are no delays resulting from Networks not being able to obtain outages from the Independent Electricity Market Operator required for the Networks Connection Work or from the IMO making changes to the Networks Connection Work or the scheduling of all or a portion thereof;
(d) Networks does not have to use its employees, agents and contractors performing the Networks Connection Work elsewhere on its transmission system or distribution system due to an Emergency (as that term is defined in the Transmission System Code) or an event of force majeure;
(e) Networks is able to obtain the materials and labour required to perform the Networks Connection Work with the expenditure of Premium Costs where required;
(f) where Networks needs to obtain leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998* (being Schedule "B" of the *Energy Competition Act, S.O. 1998, c.*

15), such leave is obtained by no later than the date specified as the Approval Date in Schedule "A" of the Agreement;

(g) where applicable, Networks received the easement described in Section 21 hereof by the Easement Date specified in Schedule "A";

(h) the Customer executed this Agreement by no later than the date specified as the Execution Date in Schedule "A"; and

(i) Networks obtains internal approval to commit the funds for the Project.

7. Upon completion of the Networks Connection Work:

(a) Networks shall own, operate and maintain all equipment referred to in Schedule "A" of the Agreement; and

(b) other than equipment referred to in (a) above that will be owned, operated and maintained by Networks, all other equipment provided by Networks as part of the Networks Connection Work or provided by the Customer as part of the Customer Connection Work will be owned, operated and maintained by the Customer.

The Customer acknowledges that:

(i) ownership and title to the equipment referred to in (a) above shall throughout the Term and thereafter remain vested in Networks and the Customer shall have no right of property therein;

(ii) that any portion of the equipment referred to in (a) above that is located on the Customer's property shall be and remain the property of Networks and shall not be or become fixtures and/or part of the Customer's property; and

(iii) the right to the benefit of any capital cost allowance determined for capital contribution(s) by the Customer for the equipment referred to in (a) above shall be the Customer's.

8. The Customer acknowledges and agrees that Networks is not responsible for the provision of power system components on the Customer's Facilities, including, without limitation, all transformation, switching, metering and auxiliary equipment such as protection and control equipment.

All of the power system components on the Customer's side of the Connection Point including, without limitation, all transformation, switching and auxiliary equipment such as protection and control equipment shall be subject to the acceptance of Networks with regard to Networks' requirements to permit connection of the New or Modified Facility to Networks' transmission system, and shall be installed, maintained and operated in accordance with all applicable laws, codes and standards, including, but not limited to, the Transmission System Code, at the expense of the Customer. Networks acceptance is solely for the protection of Networks' Facilities.

9. Where Networks has equipment for automatic reclosing of circuit breakers after an interruption for the purpose of improving the continuity of feeder connection, it shall be the obligation of the Customer to provide adequate protective equipment for the Customer's facilities that might be adversely affected by the operation of such reclosing equipment. The Customer shall provide such equipment as may be required from time to time by Networks for the prompt disconnection of any of the Customer's apparatus that might affect the proper functioning of Networks' reclosing equipment.

10. The Customer shall provide Networks with copies of the documentation specified in Schedule "A" of the Agreement under the heading "Documentation Required", acceptable to Networks, by no later than 120 calendar days after the Ready for Service Date. The Customer shall ensure that Networks may retain this documentation for Networks' ongoing planning, system design, and operating review. Where the New or Modified Facility is owned by the Customer, the Customer shall also maintain and revise such documentation to reflect changes to the New or Modified Facility and provide copies to Networks on demand and as specified in the Connection Agreement.

11. Nothing contained within the Agreement, including, subsection 13 below shall preclude, prevent, prohibit or operate as a waiver of any of the parties rights to make application to the OEB, participate in any hearings before the OEB or to make any appeals to a Court of competent jurisdiction regarding any decision by the OEB with respect to any costs and the allocation of any costs associated with, related to, or arising out of the connection of the Project to Networks' transmission system or Networks' policies in respect of connections generally.

Part B: Transformation Connection Pool Work and/or Line Connection Pool Work and Non-Poolable Work

12. The Customer shall pay Networks the Actual Cost of the Networks Connection Work described as the Transformation Connection Pool Work and/or Line Connection Pool Work in Schedule "A" of the Agreement which is estimated to be the amount specified in Schedule "B" of the Agreement (plus applicable taxes) (the "Transformation Connection Pool Work Estimate" and/or the "Line Connection Pool Work Estimate").

The Customer shall pay Networks a capital contribution in the amount specified in Schedule "B" of the Agreement (plus applicable taxes) (the "Capital Contribution") in the manner specified in Schedule "B" of the Agreement for that part of the Transformation Connection Pool Work and/or the Line Connection Pool Work that cannot be supported by revenue guarantees.

The Actual Cost of the Transformation Connection Pool Work and/or Line Connection Pool Work shall be particularly identified by Networks by no later than 180 calendar days after the Ready for Service Date and Networks shall also provide the Customer with a new Schedule "B" to replace Schedule "B" of the Agreement attached hereto and that new Schedule "B"shall be made a part hereof as though it had been originally incorporated into the Agreement.

If the Actual Cost of the Transformation Connection Pool Work and/or Line Connection Pool Work exceeds the Transformation Connection Pool Work Estimate and/or the Line Connection Pool Work Estimate, the Customer shall pay an additional capital contribution proportionate to the difference between the Actual Cost and the Transformation Connection Pool Work Estimate and/or the Line Connection Pool Work Estimate (plus applicable taxes) within 30 days after the date of Networks' invoice therefor.

The Actual Cost of the Transformation Connection Pool Work and/or Line Connection Pool Work less any Capital Contribution paid by the Customer is a debt owed to Networks by the Customer and subject to Sections 13 and 14 below, that debt shall be paid by the Customer to Networks on the earlier of the following dates:

(i) the Guaranteed Revenue Date; and

(ii) the date of termination of the Agreement.

13(a). Notwithstanding Section 12, the parties further agree that, provided that the Actual Incremental Transformation Connection Revenue and/or the Actual Incremental Line Connection Revenue received by Networks is equal to or exceeds the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue for a specified period, Networks will forgive an amount of the foregoing debt equal to the amount of the Guaranteed Incremental Transformation

Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the period in question PROVIDED THAT the Customer's peak load met or exceeded the Available Capacity during at least one month of the twelve month period in question.

13(b). Commencing on the first anniversary of the Ready for Service Date and every year thereafter during the Term, if the Customer's peak load fails to meet or exceed the Available Capacity during at least one month of the a period, the Customer will not receive a credit for that period and the Customer shall pay Networks the Guaranteed Incremental Transformation Connection Revenue specified for the period in question by no later than 30 days after the date of Networks' invoice therefor.

13(c). Commencing on the fifth anniversary of the Ready for Service Date and every fifth year thereafter during the Term, if the Actual Incremental Transformation Connection Revenue and/or Actual Incremental Line Connection Revenue received by Networks is less than the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the previous five periods in question, the Customer shall pay Networks the difference by no later than 30 days after the date of Networks' invoice therefor.

13(d). For every period during the term, with the exception of every fifth period commencing on the fifth anniversary of the Ready for Service Date and every fifth year thereafter, if the Actual Incremental Transformation Connection Revenue and/or Actual Incremental Line Connection Revenue received by Networks is less than the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the period in question and such difference is less than 20% of the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the period in question, the Customer shall be entitled to carry forward that amount (the "Carry Forward Amount"), which shall be added to the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue for the following period to result in a Revised Guaranteed Incremental Transformation Connection Revenue and/or Revised Guaranteed Incremental Line Connection Revenue for the next following period.

Thereafter any reference to:

(I) Guaranteed Incremental Transformation Connection Revenue in the Agreement shall mean the greater of Guaranteed Incremental Transformation Connection Revenue for the period in question and the Revised Guaranteed Incremental Transformation Connection Revenue; AND

(II) Guaranteed Incremental Line Connection Revenue in the Agreement shall mean the greater of Guaranteed Incremental Line Connection Revenue for the period in question and the Revised Guaranteed Incremental Line Connection Revenue.

13(e). Notwithstanding Section 13(c) above, if in any period during the Term, the Actual Incremental Transformation Connection Revenue and/or Actual Incremental Line Connection Revenue received by Networks is less than the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the period in question and such difference is greater than 20% of the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the period in question, the Customer shall pay Networks the difference by no later than 30 days after the date of Networks' invoice therefor.

13(f) Commencing on the fifth anniversary of the Ready for Service Date and every fifth year thereafter, if the Actual Incremental Transformation Connection Revenue and/or Actual Incremental Line Connection Revenue received by Networks is more than the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the five periods in question, Networks will reduce the amount of debt owing by the Customer by reducing the amount of Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue that must be received by Networks during the next five periods shown in Schedule B of the Agreement such that the total reduction over the next five periods is equal to the excess amount received by Networks. This may have the effect of shortening the Term of the Agreement.

13(g). The Customer acknowledges and. agrees that:

(a) the Incremental Transformation Connection Revenue is distinct revenue that does not include Transformation Connection revenue derived from Base Load Trigger Point or any network revenue; and

(b) the Incremental Line Connection Revenue is distinct revenue that does not include Line Connection revenue derived from Base Load Trigger Point or any network revenue.

14. The Customer shall pay Networks Actual Cost of the Networks Connection Work described as Non-Poolable Work in Schedule "A" of the Agreement which is estimated to be the amount specified in Schedule "B" of the Agreement (plus applicable taxes) in the manner specified in Schedule "B" of the Agreement.

Within 60 days after the Ready for Service Date, Networks shall provide the Customer with a final invoice or credit memorandum which shall indicate whether the amounts already paid by the Customer exceeds or is less than the Actual Cost of the Non-Poolable Work. Any difference between the Actual Cost of the Non-Poolable Work (plus applicable taxes) and the amount already paid by the Customer shall be paid within 30 days after the rendering of the said final invoice or credit memorandum, by Networks to the Customer, if the amount already paid by the Customer exceeds the Actual Cost of the Non-Poolable Work (plus applicable taxes), or by the Customer to Networks, if the amount already paid by the Customer is less than the Actual Cost of the Non-Poolable Work (plus applicable taxes).

15. As the Project is schedule-driven and as the estimated costs specified in Schedule "B" of the Agreement are based upon normal timelines for delivery of material and performance of work, in addition to the amounts that the Customer is required to pay pursuant to Section 12 and 14 above, the Customer agrees to pay Networks' Premium Costs if the Customer causes or contributes to any delays, including, but not limited to, the Customer failing to execute the Agreement by the Execution Date specified in Schedule "A" of the Agreement.

Networks will obtain the Customer's approval prior to Networks' authorizing the purchase of materials or the performance of work that will attract Premium Costs. The Customer acknowledges that its failure to approve an expenditure of Premium Costs may result in further delays and Networks will not be liable to the Customer as a result thereof. The Customer shall pay any prior-approved Premium Costs within 30 calendar days after the date of Networks' final invoice therefor, billable at the end of the project. Interest shall be payable at the rate of 18 per cent per year on all overdue payments. The obligation to pay any amount hereunder shall survive the termination of the Agreement.

16(a) If the Project is cancelled, the Agreement is terminated for any reason whatsoever other than breach of the Agreement by Networks, the Customer shall pay Networks' Actual Costs incurred on and prior to the date that the Project is cancelled or the Agreement is terminated, including the preliminary design costs and all costs associated with the winding up of the Project, including, but not limited to, storage costs, facility removal expenses and any environmental remediation costs.

If the Customer provides written notice to Networks that it is cancelling or deferring the Project, Networks shall have 10 Business Days to provide written notice to the Customer listing the individual items listed as materials which it agrees to purchase. Networks shall deduct the actual costs of those individual items of materials being purchased by Networks from the Actual Costs referred to above.

If Networks does not require all or part of the materials, the Customer may exercise any of the following options or a combination thereof:

(i) where materials have been ordered but all or part of the materials have not been received by Networks, the Customer shall have the right to require Networks, at the Customer's sole expense, to continue with the purchase of the materials and transfer title to those materials on an "as is, where is basis" to the Customer upon the Customer paying Networks's Actual Costs provided that the Customer exercises this option within 15 Business Days of the termination, cancellation or deferral;

(ii) where all or part of the materials have been received by Networks but have not been installed, the Customer shall have the right to require Networks, at the Customer's sole expense, to transfer title to the materials on an "as is, where is basis" to the Customer upon the Customer paying Networks's Actual Costs provided that the Customer exercises this option within 15 Business Days of the termination, cancellation or deferral. The Customer shall also be responsible for any warehousing costs associated with the storage of the materials to the date of transfer; or

(iv) where all or part of the materials have been received by Networks and have been installed, the Customer shall have the right to require Networks, at the Customer's sole expense, to: transfer title to the materials on an "as is, where is basis" to the Customer upon the later of (A) the Customer paying Networks's Actual Costs; and (B) the date that Networks removes the materials from its property at the risk of the Customer; provided that the Customer exercises this option within 15 Business Days of the termination, cancellation or deferral. The Customer shall also be responsible for any costs associated with the installation and the removal of the materials that have been installed by Networks.

The Customer shall pay Networks' Actual Costs which become payable under this Section within 30 calendar days after the date of invoice.

16(b). If the Customer wishes to defer the Project, the Parties will negotiate the terms of such deferral.

17. In the event that the Customer sells, leases or otherwise transfers or disposes of the Customer's Facilities to a third party during the Term of the Agreement, the Customer shall cause the purchaser, lessee or other third party to whom the Customer's Facilities are transferred or disposed to enter into an assumption agreement with Networks to assume all of the Customer's obligations in the Agreement; and notwithstanding such assumption agreement, the Customer shall remain obligated to pay the amounts thereafter payable pursuant to Sections 12, 13, 14, 15 and 16 by the purchaser, lessee or other third party in the case of a transfer or disposition. The Customer further acknowledges and agrees that in the event that all or a portion of the Customer's Facilities are shut down, abandoned or vacated for any period of time during the Term of the Agreement, the Customer shall remain obligated to pay the amounts payable pursuant to Sections 12, 13, 14 and 15 for the said time period.

18. The Customer, whenever required by Networks to do so, shall furnish security satisfactory to Networks for the performance by the Customer of its obligations for pooled and non-pooled costs under the Agreement, and shall maintain the security in full force and effect during the continuance of the Agreement. The security must be in a form acceptable to Networks and may be an irrevocable letter of credit given by a bank chartered in Canada, a surety bond given by a surety company acceptable to Networks, negotiable bonds satisfactory to Networks or a cash deposit. The security provided shall not exceed the remaining amounts owing in respect of the Non–Pool Work and Transformation Connection Pool Work and/or Line Connection Pool Work less any capital contributions.

The Customer, if not in default under the Agreement shall be entitled to the interest payable on negotiable bonds held as security or the interest on cash deposits at the prevailing rate paid by Networks on cash deposits. Where the Customer has furnished any of the forms of security hereinbefore specified, the Customer if not in default as aforesaid shall have the right at any time to substitute for the security any other of the forms of security acceptable to Networks. If at any time the security furnished to Networks becomes unsatisfactory to Networks, the Customer upon request of Networks shall promptly furnish security, within fifteen (15) Business Days of receipt of notice, that is satisfactory to Networks. Security held in regards to the Agreement shall be returned to the Customer once obligations are fulfilled.

Upon or any time after the occurrence or deemed occurrence of an Event of Default and the expiry of the rectification period set forth in Section 23, Networks may do any one or more of the following: (i) exercise its rights and remedies as a secured party with respect to all security, including any such rights and remedies under Applicable Laws then in effect; (ii) exercise its rights of set-off against any and all property of the Customer in the possession of Networks or its agent; (iii) draw on any outstanding letter of credit issued for its benefit; and (iv) liquidate all security then held by or for the benefit of Networks free from any claim or right of any nature whatsoever of the Customer, including any equity or right of purchase or redemption by the Customer. Networks shall apply the proceeds of the collateral realised upon the exercise of any such rights or remedies to reduce the Customer's obligations under the Agreement (the Customer remaining liable for amounts owing to Networks after such application), subject to Networks' obligation to return any surplus proceeds remaining after such obligations are satisfied in full.

Part C:

19. In the event that the Transformation Connection Service Rate or the Line Connection Service Rate is rescinded or the methodology of determination or components is materially changed, the Parties agree to negotiate a new mechanism for the purposes of the Agreement. The Parties shall have 90 calendar days from the effective date of rescission or fundamental change of the Transformation Connection Service Rate or the Line Connection Service Rate to agree to a new mechanism. If the Parties are unable to successfully negotiate a replacement within that 90 calendar day period, they shall submit to arbitration, in accordance with the requirements of the Transmission System Code (or the Connection Agreement attached thereto); or if there is no arbitration provision in the Transmission System Code (or the Connection Agreement attached thereto), to the requirements of the *Arbitration Act* (Ontario), as amended, to settle on a new

mechanism. The decision of the arbitrator shall be binding on each party with no right of appeal.

The terms of reference of the arbitration shall be to identify a new mechanism that is, to the extent possible, fair to the parties and constitutes a reasonably comparable replacement for the Transformation Connection Service Rate or the Line Connection Service Rate.

Any settlement on a new mechanism pursuant to this Section 19 shall apply retroactively from the date on which the Transformation Connection Service Rate or the Line Connection Service Rate was rescinded or fundamentally changed. Until such time as a new mechanism is determined hereunder, any amounts to be paid by the Customer under the Agreement shall be based on the Transformation Connection Service Rate or the Line Connection Service Rate in effect prior to the effective date of any such changes.

20.1 The Customer:

(a) shall not Transmit or Distribute electricity using the Customer's Facilities to any load now or hereafter supplied from Networks' Facilities or Third Party Facilities and if the Customer does so, the Customer shall pay Networks an amount equal to the avoided applicable Transmission Rates as if the load remained on Networks' Facilities or the Third Party Facilities, as the case may be, until the date that:

(i) Networks' Facilities or the Third Party Facilities are removed from service at end-of-useful-life and are not replaced by new transmission facilities; or
(ii) Networks requires Networks' Facilities to provide transmission services to other Customers or the affected third party requires the Third Party Facilities to supply its customers.

(b) shall not permit any third party to transmit or distribute electricity using or by connecting to the Customer's Facilities or in any other manner, to any load now or hereafter supplied from Networks' Facilities or the Third Party Facilities and if the Customer does so, the Customer shall pay Networks an amount equal to the avoided applicable Transmission Rates as if the load remained on Networks' Facilities or the Third Party Facilities until the date that:

(i) Networks' Facilities or the Third Party Facilities are removed from service at end-of-useful-life and are not replaced by new transmission facilities; or
(ii) Networks requires Networks' Facilities to provide transmission services to other customers or the affected third party requires the Third Party Facilities to supply its customers.

(c) shall not supply new load growth using the Customer's Facilities or the Third Party Facilities when Networks has spare capacity available at Networks' Facilities to supply such load; and if it does so, the Customer shall pay Networks an amount equal to the avoided applicable Transmission Rates by paying as if the new load were supplied from the Networks Facilities. Notwithstanding the foregoing, the Customer will not owe any amounts to the Networks, if the Customer can demonstrate to the satisfaction of the Networks, acting reasonably, that it would have been uneconomic or inefficient for the Customer to supply the load growth in question using Networks' Facilities.

(d) shall cause the purchaser, lessee or other third party to whom the Customer sells, leases, or otherwise transfers or disposes of the Customer's Facilities to enter into an assumption agreement with Networks to assume all of the Customer's obligations under this Section 20.1.

20.2 Nothing contained within this Agreement, including, without limiting the generality of the foregoing, Section 20.2, shall preclude, prevent, prohibit or operate as a waiver of any of the Parties' rights to:

(i) make application to the OEB;
(ii) participate in any hearings before the OEB; or
(iii) make any appeals to a Court of competent jurisdiction regarding any decision by the OEB,

with respect to any matter, issue, thing, interpretation, consideration or consequence whatsoever that is related to:

A. the Transmission or Distribution of electricity to any load now or hereafter supplied from Networks' Facilities or the facilities of any licensed electricity distributor by the Customer or by a third party using the Customer's Facilities to supply said load;
B. the interpretation or application of Section 20.1 above; and
C. the Transmission and Distribution of electricity to any load now or hereafter supplied from Networks facilities other than Networks' Facilities or from facilities of any licensed electricity distributor by any other Customer or by a third party.

20.3 Section 20.1 shall be subject to and applied in accordance with any Order or decision made by the OEB or any court with respect to any matter, issue, thing, interpretation, consideration or consequence that relates to:

(i) the Transmission and Distribution of electricity to any load now or hereafter supplied from Networks' Facilities or the facilities of any licensed distributor by the Customer or by a third party using the Customer's Facilities to supply said load; and
(ii) the terms and conditions of Section 20.1.

20.4 With respect to any Order or decision of the OEB or a court relating to the Transmission or Distribution of electricity to any load now or hereafter supplied from facilities other than Networks' Facilities or from the facilities of any licensed distributor by any Customer other than by the Customer or by a third party, the parties acting reasonably shall agree in writing as to application of said Order or decision to Section 20.1 and to any amendments thereto.

20.5 Sections 20.1 to 20.4 inclusive shall survive the termination of this Agreement and will be terms of any Connection Agreement or such other agreement as required by the Transmission System Code that is applicable to the owner and/or operator of the Customer's Facilities.

Part D: Easement

21. If specified in Schedule "A" that an easement is required, the Customer shall or the Customer shall cause the third party specified in Schedule "A" to grant an easement to Hydro One substantially in the form of the easement that will be attached hereto as Appendix "C", if required, for the property described as the Easement Lands in Schedule "A" by no later than the date specified as the Easement Date in Schedule "A" (hereinafter referred to as the "Easement") with good and marketable title thereto, free of all encumbrances, first in priority except as noted herein, and in registerable form, in consideration of the sum of $2.00.

The above Easement shall be for a term of 80 years commencing on the In-Service Date provided that in the event that Networks removes the asset that is the subject of the Easement during the 80-year period, Networks shall surrender the Easement at that time. With respect to the Easement, after the expiry of the 80-year period, the parties agree to enter into good faith negotiations for an extension of the Easement term, if one or the other, or both, of the parties so request. Subject to the foregoing, the Easement shall survive the termination of the Agreement.

Part E: Events of Default

22. Each of the following events shall constitute an "Event of Default" under the Agreement:

(a) failure by the Customer to pay any amount due under the Agreement, including any amount payable pursuant to Sections 12, 13, 14, 15 or 16 within the time stipulated for payment;
(b) breach by the Customer or Networks of any Material term, condition or covenant of the Agreement; or
(c) the making of an order or resolution for the winding up of the Customer or of its operations or the occurrence of any other dissolution, bankruptcy or reorganization or liquidation proceeding instituted by or against the Customer.

23. Upon the occurrence of an Event of Default by the Customer hereunder (other than those specified in section 22(c) of the Agreement, for which no notice is required to be given by Networks), Networks shall give the Customer written notice of the Event of Default and allow the Customer 30 calendar days from the date of receipt of the notice to rectify the Event of Default, at the Customer's sole expense. If such Event of Default is not cured to Networks' reasonable satisfaction within the 30 calendar day period, Networks may, in its sole discretion, exercise the following remedy in addition to any remedies that may be available to Networks under the terms of the Agreement, at common law or in equity: deem the Agreement to be repudiated and, after giving the Customer at least 10 calendar days' prior written notice thereof, recover, as liquidated damages and not as a penalty, the balance of the amounts payable by the Customer pursuant to Sections 12, 13, 14, 15 and 16.

24. Upon the occurrence of an Event of Default by Networks hereunder, the Customer shall give Networks written notice of the Event of Default and shall allow Networks 30 calendar days from the date of receipt of the notice to rectify the Event of Default at Networks' sole expense. If such Event of Default is not cured to the Customer's reasonable satisfaction within the 30 calendar day period, the Customer may pursue any remedies available to it at law or in equity, including at its option the termination of the Agreement.

25. All rights and remedies of Networks and the Customer provided herein are not intended to be exclusive but rather are cumulative and are in addition to any other right or remedy otherwise available to Networks and the Customer respectively at law or in equity, and any one or more of Networks' and the Customer's rights and remedies may from time to time be exercised independently or in combination and without prejudice to any other right or remedy Networks or the Customer may have or may have exercised. The parties further agree that where any of the remedies provided for and elected by the non-defaulting party are found to be unenforceable, the non-defaulting party shall not be precluded from exercising any other right or remedy available to it at law or in equity.

In addition to any other remedy provided hereunder, all overdue amounts that are outstanding for longer than 30 days shall bear interest at 18% per annum.

Part F: Capital Contributions and Transmission System Code

26. Until Networks' has published and the Ontario Energy Board has accepted Networks' procedure and methodology for determining the requirement for a capital contribution in accordance with Section 4.1 of the *Transmission System Code*, any Capital Contributions paid by the Customer under the terms of this Agreement are subject to adjustment with such adjustment to be solely based on the procedure and methodology accepted by the OEB.

Part G: Liability and Force Majeure

27. Other than for sums payable under the Agreement, the Customer shall only be liable to Networks and Networks shall only be liable to the Customer for any damages that arise directly out of the willful misconduct or negligence in meeting their respective obligations under the Agreement.

Despite the foregoing, neither Party shall be liable under any circumstances whatsoever for any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential, incidental or special damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in statute, contract, tort or otherwise.

This provision shall survive the termination of the Agreement.

28. Neither party shall be considered to be in default in the performance of its obligations under the Agreement, except obligations to make payments with respect to amounts already accrued, to the extent that performance of any such obligation is prevented or delayed by any cause, existing or future, which is beyond the reasonable control of, and not a result of the fault or negligence of, the affected party ("Force Majeure") and includes, but is not limited to, system operating conditions mandated by the IMO, strikes, lockouts and any other labour disturbances and manufacturer's delays for equipment or materials required for the Networks Connection Work. The non-affected party shall be relieved of any obligation hereunder during the continuation of the event of Force Majeure.

If a party is prevented or delayed in the performance of any such obligation by Force Majeure, such party shall immediately provide notice to the other party of the circumstances preventing or delaying performance and the expected duration thereof. Such notice shall be confirmed in writing as soon as reasonably possible. The party so affected by the Force Majeure shall endeavour to remove the obstacles which prevent performance and shall resume performance of its obligations as soon as reasonably practicable, except that there shall be no obligation on the party so affected by the Force Majeure where the event of Force Majeure is a strike, lockout or other labour disturbance.

Part H: General

29. No amendment, modification or supplement to the Agreement shall be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of the Agreement.

30. The failure of any party hereto to enforce at any time any of the provisions of the Agreement or to exercise any right or option which is herein provided shall in no way be construed to be a waiver of such provision or any other provision nor in any way affect the validity of the Agreement or any part hereof or the right of any party to enforce thereafter each and every provision and to exercise any right or option. The waiver of any breach of the Agreement shall not

be held to be a waiver of any other or subsequent breach. Nothing shall be construed or have the effect of a waiver except an instrument in writing signed by a duly authorized officer of the party against whom such waiver is sought to be enforced which expressly waives a right or rights or an option or options under the Agreement.

31. Each party acknowledges and agrees that it has participated in the drafting of the Agreement and that no portion of the Agreement shall be interpreted less favourably to either party because that party or its counsel was primarily responsible for the drafting of that portion.

32. Any written notice required by the Agreement shall be deemed properly given only if either mailed or delivered to the Secretary, Hydro One Networks Inc., 483 Bay Street, South Tower, 10th Floor, Toronto, Ontario M5G 2P5, fax no: (416) 345-6240 on behalf of Networks, and to the person at the address specified in Schedule "A" of the Agreement on behalf of the Customer.

A faxed notice will be deemed to be received on the date of the fax if received before 3 p.m. or on the next business day if received after 3 p.m. Notices sent by courier or registered mail shall be deemed to have been received on the date indicated on the delivery receipt. The designation of the person to be so notified or the address of such person may be changed at any time by either party by written notice.

33. The Agreement shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of the Province of Ontario and the laws of Canada applicable therein, and, subject to Section 19, the courts of Ontario shall have exclusive jurisdiction to determine all disputes arising out of the Agreement.

34. The Agreement may be executed in counterparts, including facsimile counterparts, each of which shall be deemed an original, but all of which shall together constitute one and the same agreement.

35. The Customer shall provide Networks with a copy of the Customer's final monthly bills associated with Networks' Facilities and/or the Customer's Facilities or authorize the IMO to provide Networks with same. Networks agrees to use this information solely for the purpose of the Agreement.

36. The obligation to pay any amount due and payable hereunder, including, but not limited to, any amounts due under Sections 12, 13, 14, 15 or 16 shall survive the termination of the Agreement.

Appendix "A": Definitions

Throughout the Agreement, unless there is something in the subject matter or context inconsistent therewith, the following words shall have the following meanings:

"Actual Cost" means Networks' charge for equipment, labour and materials at Networks' standard rates plus Networks' standard overheads and interest thereon.

"Actual Incremental Transformation Connection Revenue" means the actual amount of transformation connection revenue attributable to the Incremental Load received by Networks through the monthly collection of the Transformation Connection Service Rate for the period specified in Schedule "B" of the Agreement.

"Actual Incremental Line Connection Revenue" means the actual amount of line connection revenue attributable to the Incremental Load received by Networks through the monthly collection of the Line Connection Service Rate for the period specified in Schedule "B" of the Agreement.

"Agreement" means the Connection Cost Recovery Agreement, Schedules "A" and "B" attached thereto and these Standard Terms and Conditions.

"Applicable Laws", means any and all applicable laws, including environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments or decrees or any requirement or decision or agreement with or by any governmental or governmental department, commission board, court authority or agency.

"Approval Date" means for the purpose of Subsection 6(f) of the Terms and Conditions, the date specified in Schedule "A" of the Agreement.

"Available Capacity" is that portion of the existing capacity on Networks' Facilities that can effectively and economically serve the Customer's peak load and is as specified in Schedule "B" of the Agreement.

"Base Load Trigger Point" is as specified in Schedule "B" of the Agreement and was determined using the following formula:

Base Load Trigger Point = 3 yr. Avg. PLI * Available Capacity
With:
PLI = [(sum of Twelve Monthly Peaks)/Annual Peak*12]

"Business Day" means a day other than Saturday, Sunday, statutory holiday in Ontario or any other day on which the principal chartered banks located in the City of Toronto, are not open for business during normal banking hours.

"Connection Agreement" has the meaning set forth in the Transmission System Code.

"Connection Point" means the point where the New or Modified Facility is connected to Networks' transmission system.

"Customer Connection Work" means the work to be performed by the Customer, at its sole expense, which is described in Schedule "A" of the Agreement.

"Customer's Facilities" has the meaning set forth in the Transmission System Code, and includes, but is not limited to the New or Modified Facility where the New or Modified Facility is owned by the Customer. In addition to the foregoing, Customer's Facilities may include any other assets specified in Schedule "A" of the Agreement.

"Customer's Property(ies)" means any lands owned by the Customer in fee simple or where the Customer has easement rights.

"Distribute" has the meaning ascribed thereto in the *Electricity Act, 1998.*

"Emergency" has the meaning set forth in the Transmission System Code.

"Good Utility Practice" has the meaning set forth in the Transmission System Code.

"Guaranteed Transformation Connection Revenue" means the minimum amount of transformation connection revenue specified in Schedule "B" attributable to the Load to be received by Networks through the monthly collection of the Transformation Connection Service Rate for the period specified in Schedule "B".

"Guaranteed Line Connection Revenue" means the minimum amount of line connection revenue specified in Schedule "B" of the Agreement attributable to the Load to be received by Networks through the monthly collection of the Line Connection Service Rate for the period specified in Schedule "B" of the Agreement.

"Guaranteed Revenue Date" means, for the purposes of Section 2 of the Terms and Conditions, the date specified in Schedule "B" of the Agreement.

"IMO Rules" means the Independent Market Operator (IMO) administered Market Rules, including, but not limited to Chapter 6 thereof.

"In Service Date" means the date that the IMO has approved the final connection of the New or Modified Facility.

"Incremental Load" is determined using the following formula:

[(sum of Twelve Monthly Peaks) – (Base Load Trigger Point *12]

"Line Connection Pool" is as defined or referenced in Networks' transmission rate schedules approved by the OEB on Open Access (being the date that Section 26(1) of the *Electricity Act, 1998* (being Schedule "A" of the *Energy Competition Act, S.O. 1998, c. 15)* comes into force.

"**Line Connection Service Rate"** means Networks' line connection service rate approved by the Ontario Energy Board ("OEB") from time to time, or any mechanism instituted in accordance with Section 19).

"Material" relates to the essence of the contract, more than a mere annoyance to a right, but an actual obstacle preventing the performance or exercise of a right.

"Networks Connection Work" means the work to be performed by Networks which is described in Schedule "A" of the Agreement.

"Networks' Facilities" means collectively the Networks' Facilities – LV and the Networks' Facilities – HV.

"Networks' Facilities – HV" means the facilities owned by Networks specified in Schedule "A" of the Agreement that convey electricity at voltages of more than 50 kilovolts.

"Networks' Facilities – LV" means the facilities owned by Networks specified in Schedule "A" of the Agreement that convey electricity at voltages of 50 kilovolts or less.

"Networks' Property(ies)" means any lands owned by Networks in fee simple or where Networks now or hereafter has obtained easement rights.

"New or Modified Facility" means the facilities specified in Schedule "A" of the Agreement.

"Premium Costs" means those costs incurred by Networks in order to maintain or advance the Ready for Service Date, including, but not limited to, additional amounts expended for materials or services due to short time-frame for delivery; and the difference between having Networks' employees, agents and contractors perform work on overtime as opposed to during normal business hours.

"Ready for Service Date" means the date upon which the Networks Connection Work is fully and completely constructed, installed, commissioned and energised to the Connection Point. The Customer's disconnect switches must be commissioned prior to this date in order to use them as isolation points.

"Third Party Facilities" means any and all equipment, elements, and facilities of any kind whatsoever owned by someone other than the parties to this connection agreement and that are connected to Networks' transmission system.

"Transformation Connection Pool" is as defined or referenced in Networks' transmission rate schedules approved by the OEB on Open Access (being the date that Section 26(1) of the *Electricity Act, 1998* (being Schedule "A" of the *Energy Competition Act, S.O. 1998, c. 15)* comes into force.

"**Transformation Connection Service Rate"** means Networks' transformation connection service rate approved by the Ontario Energy Board ("OEB") from time to time, or any mechanism instituted in accordance with Section 19).

"**Transmission Rate"** has the meaning set forth in the form of Connection Agreement attached to the Transmission System Code.

"Transmission System Code" means the code of standards and requirements issued by the OEB on July 14, 2000, as it may be amended from time to time, setting forth mandatory terms, conditions and obligations regarding connections between the facilities of distributors and the facilities of transmitters in accordance with the requirements of the *Ontario Energy Board Act, 1998*, including mandatory required terms and conditions for Connection Agreements.

"Transmit" has the meaning ascribed thereto in the *Electricity Act, 1998*.

Appendix "B": Access Provisions

1. When the Customer's staff, its contractors, or agents work at Networks' Facilities or site, Networks' safety and environmental requirements shall be observed by such staff, contractors and agents. As a minimum, all Applicable Laws shall govern such work.

2. The Customer's staff, its contractors, or agents working at Networks' Facilities or site shall be qualified to work around electrical hazards.

3. The Customer's staff, its contractors, or agents shall be entitled to access Networks' Facilities or site, and Networks will grant such access, to carry out work at all reasonable times on reasonable prior notice to Networks, subject to Networks' policies and procedures.

4. If the Customer wishes to have access to Networks' Facilities, the Customer shall notify Networks of the particular work to be undertaken and of the date and time when it proposes to access the relevant Facilities, subject to Networks' policies and procedures. Networks shall not unreasonably withhold access to its Facilities.

5. At any time when the Customer or its representatives are on or in Networks' site, the Customer and its representatives shall:

(a) use all reasonable precautions not to damage or interfere with Networks' site and Facilities;
(b) observe Networks' requirements for reporting occupational health and safety, electrical safety, environmental requirements, technical requirements, and matters of industrial relations; and
(c) neither ask questions, nor give any direction, instruction or advice to any person involved in operating or maintaining Networks' site or Facilities, other than the person whom Networks has designated for that purpose.

6. If the Customer or its representatives cause any loss or damage when given access to Networks', the Customer or its representative shall promptly advise Networks' controlling authority of the loss or damage.

7. The Customer shall not, and shall ensure that its representatives do not, intentionally interfere with any of Networks' Facilities in or on its sites. The Customer shall use reasonable efforts not to cause loss or damage to Networks' Facilities. If the Customer interferes with any of Networks' Facilities, it shall indemnify Networks for reasonable costs and expenses incurred from any resulting loss or damage.

8. In an emergency, Networks may, as far as reasonably necessary in the circumstances, have access to and interfere with the Customers' Facilities. Networks shall use reasonable efforts not to cause loss or damage to the Customer's Facilities. If Networks interferes with any of the Customer's Facilities, it shall indemnify the Customer for reasonable costs and expenses incurred from any resulting loss or damage.

9. Where the Customer requests assistance from Network beyond routine OM&A activities, the Customer shall pay Networks its Actual Costs related to the Customer's staff, contractors or agents accessing Network's Facilities or sites, including, but not limited to, the cost of having a Networks representative accompany the Customer's staff, contractors, or agents accessing Network's Facilities or sites in accordance with the invoices rendered by Networks.

10. The Customer shall indemnify and save harmless Networks from and against all liabilities, damages, suits, claims, demands, costs, actions, proceedings, causes of action, losses, expenses and injury (including death) of any kind or nature whatsoever (the "causes of action") resulting from, caused by or in any manner connected with installed Customer equipment on Networks' Facilities or sites or Customer's staff, its contractors, or agents accessing Network's Facilities or sites including, but not limited to:

(a) causes of actions arising out of health and safety violations or environmental spills;
(b) costs incurred by Networks having to pay other customers due to interruptions caused by the Customer;
(c) damage to Networks equipment;
(d) incremental costs and expenses incurred by Networks related to the Customer's equipment installations, removals, relocations, upgrades, or any other Customer work.

except to the extent that the "causes of action" are caused by the negligence or willful misconduct of Networks.

11. Where Networks staff, contractors, or agents require access to the Customer's Facilities or site, clauses 1 to 10 will apply reciprocally.

Amendment to the Standard Terms and Conditions **March 22, 2002**
(Reference # T&C V1 ESH 15-25 01-2002)

Hamilton Hydro Inc & Hydro One Networks Inc.

Section 12:

Section 12 is amended to read as follows:

12. The Customer shall pay Networks the Fixed Cost (plus applicable taxes) of the Networks Connection Pool Work described as Transformation Connection Pool Work and Line Connection Pool Work in Schedule "A" of the Agreement which are the costs specified in Schedule "B" as Cost of Transformation Connection Pool Work and Cost of Line Connection Pool Work.

Any Additional Networks Connection Pool Work and/or Costs identified after the Agreement Execution Date and not included in the Networks Connection Pool Work described in Schedule "A" of the Agreement and/or the Cost of Transformation Connection Pool Work and Cost of Line Connection Pool Work specified in Schedule "B" of the Agreement, shall be particularly identified by Networks and shall require the Customer's approval prior to Networks doing the additional work and/or incurring the additional cost. Additional Networks Connection Pool Work and/or Costs can include but are not limited to changes in the scope of the Networks Connection Pool Work, Premium Costs, etc. Such additional Networks Connection Pool Work and/or Costs shall be recovered from the Customer via direct billing by no later than 180 calendar days after the Ready for Service Date.

The Customer shall pay Networks a capital contribution in the amount specified in Schedule "B" of the Agreement (plus applicable taxes) in the manner specified in Schedule "B" of the Agreement for that part of the Transformation Connection Pool Work and/or the Line Connection Pool Work that cannot be supported by revenue guarantees.

The Fixed Cost of the Transformation Connection Pool Work and/or Line Connection Pool Work less any Capital Contribution paid by the Customer is a debt owed to Networks by the Customer and subject to Sections 13 and 14 below, that debt shall be paid by the Customer to Networks on the earlier of the following dates:

(i) the Guaranteed Revenue Date; and
(ii) the date of termination of the Agreement.

Section 13(c):

Section 13 (c) is amended to read as follows:

13 (c) The parties will jointly track the actual incremental transformation connection revenue and/or the incremental line connection revenue on an annual basis in order to determine if there are any trends that would suggest a significant shortfall or surplus of Actual Incremental Line Connection Revenue and/or Actual Incremental Transformation Connection Revenue. This will be done in order to facilitate planning and tracking between Networks and the Customer as it pertains to the load associated with these line connection and transformation connection facilities as compared to the revenue guarantee. However, there will be no requirements for credits, payments or other adjustments as between Networks and the Customer arising out of this process.

Section 13(d):

Section 13 (d) is amended to read as follows:

13(d) Commencing on the fifth anniversary of the Ready for Service Date and every fifth year thereafter during the Term, an exercise will be undertaken by Networks and the Customer in order to assess the variations with respect to the Actual Incremental Line Connection Revenue and the Actual Incremental Transformation Connection Revenue as compared to the Guaranteed Incremental Line Connection Revenue and the Guaranteed Incremental Transformation Connection Revenue for the previous five twelve month periods. If the Actual Incremental Transformation Connection Revenue and/or Actual Incremental Line Connection Revenue received by Networks is less than the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the five twelve-month periods in question and such difference is less than 20% of the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the five twelve-month periods in question the variation shall be reflected in the Guaranteed Incremental Line Connection Revenue and the Guaranteed Incremental Transformation Connection Revenue for the next five periods and no further analysis or discussion will be required.
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Section 13(e):

Section 13 (e) is amended to read as follows:

13(e) Upon the undertaking of the exercise referred to in Section 13(d) above, if the Actual Incremental Transformation Connection Revenue and/or Actual Incremental Line Connection Revenue received by Networks is less than the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the five twelve-month periods in question and such difference is greater than 20% of the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the five twelve-month periods in question, Networks and the Customer, acting reasonably will determine the most equitable methodology for compensation for the variation. The method of compensation can include but is not limited to a credit for the next 5-year period, invoicing, etc.

Section 13(f):

Section 13 (f) remains the same with the following adder:

13 (f) Addendum Where the actual incremental transformation connection revenue and/or the incremental line connection revenue results in shortening the term of the agreement to a period equal to or less than 25 years, Networks will take this into due consideration and will rebate the Customer all or a portion of the initial capital contribution specified in Schedule “B” of the Agreement in actual dollars paid and not the Net Present Value (NPV) of the dollars paid. Rebate of Capital Contribution will take into account any prior compensation to the Customer which may have been determined by Section 13 (e) above. The total of all rebates from Networks to the Customer during the term of the Agreement shall not exceed the Customer's initial capital contribution.

Section 13 (h):

Section 13 (h) is added to the Agreement to read as follows:

13(h) The Base Load Trigger Point will be revised in the future to reflect any permanent reduction in the Available Capacity.

Section 14

Section 14 is amended to read as follows:

14. The Customer shall pay Networks Fixed Cost (plus applicable taxes) of the Networks Connection Work described as Non-Poolable Work in Schedule "A" of the Agreement which is the cost specified as Cost of Non-Poolable Work in Schedule "B" of the Agreement.

Any Additional Networks Non-Poolable Work and/or Costs identified after the Areement Execution Date and not included in the Networks Non-Poolable Work described in Schedule "A" of the Agreement and/or the Cost of Non-Poolable Work specified in Schedule "B" of the Agreement, shall be particularly identified by Networks and shall require the Customer's approval prior to Networks doing the additional work and/or incurring the additional cost. Additional Networks Non-Poolable Work and/or Costs can include but are not limited to increase in the scope of the Networks Non-Poolable Work , Premium Costs, etc. Such additional Networks Non-Poolable Work and/or Costs shall be recovered from the Customer via direct billing by no later than 180 calendar days after the Ready for Service Date.

Section 20.1 (e):

Section 20.1 (e) is added to the Agreement to read as follows:

20.1 (e) When Section 20.1 is applied to a new generator connection the Customer shall pay Networks an amount equal to the avoided applicable Line Connection Charges and Transformation Connection charges, as if the load remained on Networks Facilities or the Third Party Facilities.

Standard Terms and Conditions for Transmission Customer Connection Projects

1. The Customer agrees to guarantee a minimum amount of revenue to be derived from Incremental Load in accordance with the terms and conditions of the Agreement to hold the Pool harmless as a result of the Project.

2. Subject to Section 23 and the termination rights herein, the Agreement shall be in full force and effect and binding on the parties as of the date of the Agreement (the "Effective Date") and shall expire on the earlier of the Guaranteed Revenue Date and the date that the debt owed by the Customer pursuant to Section 12 is reduced to zero (the "Term").

3. Each party represents and warrants to the other that:

(a) it has all the necessary corporate power, authority and capacity to enter into the Agreement and to perform its obligations hereunder; and
(b) the execution of the Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on its part.

Where the New or Modified Facility is owned by the Customer, the Customer represents and warrants to Hydro One Networks Inc. ("Networks") that it has obtained all necessary approvals with respect to the construction of the New or Modified Facility (including, but not limited to, where applicable, leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998* (being Schedule "B" of the *Energy Competition Act, S.O. 1998,c. 15)*) and in order to proceed with the Customer Connection Work.

Part A: Networks Connection Work

4. The Customer and Networks shall perform their respective obligations outlined in the Agreement in a manner consistent with Good Utility Practice and the Transmission System Code, in compliance with all Applicable Laws, including, but not limited to the requirements of the Electrical Safety Code, and using duly qualified and experienced people.

5. The parties acknowledge and agree that:

(a) Networks is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Networks Connection Work and those required for the construction, connection and operation of the New or Modified Facility where the New or Modified Facility is owned by Networks;

(b) the Customer is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Customer Connection Work and those required for the construction, connection and operation of the New or Modified Facility where the New or Modified Facility is owned by the Customer, including those required under the Electrical Safety Code and the Customer shall ensure that it has received all such requisite permits, certificates, reviews and approvals prior to connection;

(c) the Customer will enter into a Connection Agreement with Networks at least 14 calendar days prior to the connection of the New or Modified Facility to Networks' transmission system;

(d) the Customer will ensure that Project data is made available or provided to Networks as required by Networks;

(e) the Customer will ensure that the work performed by the Customer and others required for successful installation, testing and commissioning of protective equipment is completed as required to enable Networks witnessing and testing to confirm satisfactory performance of such systems;

(f) the Customer will provide any hardware required to connect to Networks' transmission system;

(g) the Customer will provide coordination on protection;

(h) Networks' responsibilities under the Agreement with respect to the connection of the New or Modified Facility to Networks' transmission system shall be limited to the performance of the Networks Connection Work;

(i) the Customer shall perform the Customer Connection Work at its own expense;

(j) where the New or Modified Facility is owned by the Customer, the Customer shall provide technical specifications for the New or Modified Facility as required for Networks' reviews. Until Networks has accepted the technical specifications (including electrical drawings) for the New or Modified Facility and accepted the Customer's verification of those portions of the Customer's electrical facilities affecting Networks' transmission system, Networks shall not be bound to connect the New or Modified Facility to Networks' transmission system; and

(k) the Networks Connection Work and Networks' rights and requirements hereunder, including, but not limited to:

(i) Networks' specifications of the protection equipment on the Customer's side of the Connection Point;
(ii) Networks' acceptance of power system components on the Customer's side of the Connection Point; and
(iii) Networks' acceptance of the technical specifications (including electrical drawings) for the New or Modified Facility where the New or Modified Facility is owned by the Customer and/or the Customer Connection Work;

are solely for the protection of Networks' transmission system and that the Customer is responsible for installing equipment and facilities such as protection and control equipment to protect its own property, including, but not limited to the New or Modified Facility where the New or Modified Facility is owned by the Customer.

6. Networks shall use reasonable efforts to complete the Networks Connection Work by the Ready for Service Date specified in Schedule "A" provided that:

(a) the Customer is in compliance with its obligations under the Agreement;
(b) any work required to be performed by third parties has been performed in a timely manner and in a manner to the satisfaction of Networks, acting reasonably;
(c) there are no delays resulting from Networks not being able to obtain outages from the Independent Electricity Market Operator required for the Networks Connection Work;
(d) Networks does not have to use its employees, agents and contractors performing the Networks Connection Work elsewhere on its transmission system or distribution system due to an Emergency (as that term is defined in the Transmission System Code) or an event of force majeure;
(e) Networks is able to obtain the materials and labour required to perform the Networks Connection Work with the expenditure of Premium Costs where required;
(f) where Networks needs to obtain leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998* (being Schedule "B" of the *Energy Competition Act, S.O. 1998, c. 15)*, such leave is obtained by no later than the date specified as the Approval Date in Schedule "A" of the Agreement;

(g) the Customer executed this Agreement by no later than the date specified as the Execution Date in Schedule "A"; and
(h) Networks obtains internal approval to commit the funds for the Project.

7. Upon completion of the Networks Connection Work:

(a) Networks shall own, operate and maintain all equipment referred to in Schedule "A" of the Agreement; and
(b) other than equipment referred to in (a) above that will be owned, operated and maintained by Networks, all other equipment provided by Networks as part of the Networks Connection Work or provided by the Customer as part of the Customer Connection Work will be owned, operated and maintained by the Customer.

The Customer acknowledges that:

(i) ownership and title to the equipment referred to in (a) above shall throughout the Term and thereafter remain vested in Networks and the Customer shall have no right of property therein;
(ii) that any portion of the equipment referred to in (a) above that is located on the Customer's property shall be and remain the property of Networks and shall not be or become fixtures and/or part of the Customer's property; and
(iii) the right to the benefit of any capital cost allowance determined for capital contribution(s) by the Customer for the equipment referred to in (a) above shall be the Customer's.

8. The Customer acknowledges and agrees that Networks is not responsible for the provision of power system components on the Customer's Facilities, including, without limitation, all transformation, switching, metering and auxiliary equipment such as protection and control equipment.

All of the power system components on the Customer's side of the Connection Point including, without limitation, all transformation, switching and auxiliary equipment such as protection and control equipment shall be subject to the acceptance of Networks with regard to Networks' requirements to permit connection of the New or Modified Facility to Networks' transmission system, and shall be installed, maintained and operated in accordance with all applicable laws, codes and standards, including, but not limited to, the Transmission System Code, at the expense of the Customer. Networks acceptance is solely for the protection of Networks' Facilities.

9. Where Networks has equipment for automatic reclosing of circuit breakers after an interruption for the purpose of improving the continuity of feeder connection, it shall be the obligation of the Customer to provide adequate protective equipment for the Customer's facilities that might be adversely affected by the operation of such reclosing equipment. The Customer shall provide such equipment as may be required from time to time by Networks for the prompt disconnection of any of the Customer's apparatus that might affect the proper functioning of Networks' reclosing equipment.

10. The Customer shall provide Networks with copies of the documentation specified in Schedule "A" of the Agreement under the heading "Documentation Required", acceptable to Networks, by no later than 120 calendar days after the Ready for Service Date. The Customer shall ensure that Networks may retain this documentation for Networks' ongoing planning, system design, and operating review. Where the New or Modified Facility is owned by the Customer, the Customer shall also maintain and revise such documentation to reflect changes to the New or Modified Facility and provide copies to Networks on demand and as specified in the Connection Agreement.

11. Nothing contained within the Agreement, including, subsection 13 below shall preclude, prevent, prohibit or operate as a waiver of any of the parties rights to make application to the OEB, participate in any hearings before the OEB or to make any appeals to a Court of competent jurisdiction regarding any decision by the OEB with respect to any costs and the allocation of any costs associated with, related to, or arising out of the connection of the Project to Networks' transmission system or Networks' policies in respect of connections generally.

Part B: Transformation Connection Pool Work and/or Line Connection Pool Work and Non-Poolable Work

12. The Customer shall pay Networks the Actual Cost of the Networks Connection Work described as the Transformation Connection Pool Work and/or Line Connection Pool Work in Schedule "A" of the Agreement which is estimated to be the amount specified in Schedule "B" of the Agreement (plus applicable taxes) (the "Transformation Connection Pool Work Estimate" and/or the "Line Connection Pool Work Estimate").

The Customer shall pay Networks a capital contribution in the amount specified in Schedule "B" of the Agreement (plus applicable taxes) (the "Capital Contribution") in the manner specified in Schedule "B" of the Agreement for that part of the Transformation Connection Pool Work and/or the Line Connection Pool Work that cannot be supported by revenue guarantees.

The Actual Cost of the Transformation Connection Pool Work and/or Line Connection Pool Work shall be particularly identified by Networks by no later than 180 calendar days after the Ready for Service Date and Networks shall also provide the Customer with a new Schedule "B" to replace Schedule "B" of the Agreement attached hereto and that new Schedule "B"shall be made a part hereof as though it had been originally incorporated into the Agreement.

If the Actual Cost of the Transformation Connection Pool Work and/or Line Connection Pool Work exceeds the Transformation Connection Pool Work Estimate and/or the Line Connection Pool Work Estimate, the Customer shall pay an additional capital contribution proportionate to the difference between the Actual Cost and the Transformation Connection Pool Work Estimate and/or the Line Connection Pool Work Estimate (plus applicable taxes) within 30 days after the date of Networks' invoice therefor.

The Actual Cost of the Transformation Connection Pool Work and/or Line Connection Pool Work less any Capital Contribution paid by the Customer is a debt owed to Networks by the Customer and subject to Sections 13 and 14 below, that debt shall be paid by the Customer to Networks on the earlier of the following dates:

(i) the Guaranteed Revenue Date; and
(ii) the date of termination of the Agreement.

13(a). Notwithstanding Section 12, the parties further agree that, provided that the Actual Incremental Transformation Connection Revenue and/or the Actual Incremental Line Connection Revenue received by Networks is equal to or exceeds the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue for a specified period, Networks will forgive an amount of the foregoing debt equal to the amount of the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the period in question PROVIDED THAT the Customer's peak load met or exceeded the

Available Capacity during at least one month of the twelve month period in question.

13(b). Commencing on the first anniversary of the Ready for Service Date and every year thereafter during the Term, if the Customer's peak load fails to meet or exceed the Available Capacity during at least one month of the a period, the Customer will not receive a credit for that period and the Customer shall pay Networks the Guaranteed Incremental Transformation Connection Revenue specified for the period in question by no later than 30 days after the date of Networks' invoice therefor.

13(c). Commencing on the fifth anniversary of the Ready for Service Date and every fifth year thereafter during the Term, if the Actual Incremental Transformation Connection Revenue and/or Actual Incremental Line Connection Revenue received by Networks is less than the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the previous five periods in question, the Customer shall pay Networks the difference by no later than 30 days after the date of Networks' invoice therefor.

13(d). For every period during the term, with the exception of every fifth period commencing on the fifth anniversary of the Ready for Service Date and every fifth year thereafter, if the Actual Incremental Transformation Connection Revenue and/or Actual Incremental Line Connection Revenue received by Networks is less than the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the period in question and such difference is less than 20% of the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the period in question, the Customer shall be entitled to carry forward that amount (the "Carry Forward Amount"), which shall be added to the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue for the following period to result in a Revised Guaranteed Incremental Transformation Connection Revenue and/or Revised Guaranteed Incremental Line Connection Revenue for the next following period.

Thereafter any reference to:

(I) Guaranteed Incremental Transformation Connection Revenue in the Agreement shall mean the greater of Guaranteed Incremental Transformation Connection Revenue for the period in question and the Revised Guaranteed Incremental Transformation Connection Revenue; AND

(II) Guaranteed Incremental Line Connection Revenue in the Agreement shall mean the greater of Guaranteed Incremental Line Connection Revenue for the period in question and the Revised Guaranteed Incremental Line Connection Revenue.

13(e). Notwithstanding Section 13(c) above, if in any period during the Term, the Actual Incremental Transformation Connection Revenue and/or Actual Incremental Line Connection Revenue received by Networks is less than the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the period in question and such difference is greater than 20% of the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the period in question, the Customer shall pay Networks the difference by no later than 30 days after the date of Networks' invoice therefor.

13(f) Commencing on the fifth anniversary of the Ready for Service Date and every fifth year thereafter, if the Actual Incremental Transformation Connection Revenue and/or Actual Incremental Line Connection Revenue received by Networks is more than the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the five periods in question, Networks will reduce the amount of debt owing by the Customer by reducing the amount of Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue that must be received by Networks during the next five periods shown in Schedule B of the Agreement such that the total reduction over the next five periods is equal to the excess amount received by Networks. This may have the effect of shortening the Term of the Agreement.

13(g). The Customer acknowledges and. agrees that:

(a) the Incremental Transformation Connection Revenue is distinct revenue that does not include Transformation Connection revenue derived from Base Load Trigger Point or any network revenue; and

(b) the Incremental Line Connection Revenue is distinct revenue that does not include Line Connection revenue derived from Base Load Trigger Point or any network revenue.

14. The Customer shall pay Networks Actual Cost of the Networks Connection Work described as Non-Poolable Work in Schedule "A" of the Agreement which is estimated to be the amount specified in Schedule "B" of the Agreement (plus applicable taxes) in the manner specified in Schedule "B" of the Agreement.

Within 60 days after the Ready for Service Date, Networks shall provide the Customer with a final invoice or credit memorandum which shall indicate whether the amounts already paid by the Customer exceeds or is less than the Actual Cost of the Non-Poolable Work. Any difference between the Actual Cost of the Non-Poolable Work (plus applicable taxes) and the amount already paid by the Customer shall be paid within 30 days after the rendering of the said final invoice or credit memorandum, by Networks to the Customer, if the amount already paid by the Customer exceeds the Actual Cost of the Non-Poolable Work (plus applicable taxes), or by the Customer to Networks, if the amount already paid by the Customer is less than the Actual Cost of the Non-Poolable Work (plus applicable taxes).

15. As the Project is schedule-driven and as the estimated costs specified in Schedule "B" of the Agreement are based upon normal timelines for delivery of material and performance of work, in addition to the amounts that the Customer is required to pay pursuant to Section 12 and 14 above, the Customer agrees to pay Networks' Premium Costs if the Customer causes or contributes to any delays, including, but not limited to, the Customer failing to execute the Agreement by the Execution Date specified in Schedule "A" of the Agreement.

Networks will obtain the Customer's approval prior to Networks' authorizing the purchase of materials or the performance of work that will attract Premium Costs. The Customer acknowledges that its failure to approve an expenditure of Premium Costs may result in further delays and Networks will not be liable to the Customer as a result thereof. The Customer shall pay any prior-approved Premium Costs within 30 calendar days after the date of Networks' final invoice therefor, billable at the end of the project. Interest shall be payable at the rate of 18 per cent per year on all overdue payments. The obligation to pay any amount hereunder shall survive the termination of the Agreement.

16(a) If the Project is cancelled, the Agreement is terminated for any reason whatsoever other than breach of the Agreement by Networks, the Customer shall pay Networks' Actual Costs incurred on and prior to the date that the Project is cancelled or the

Agreement is terminated, including the preliminary design costs and all costs associated with the winding up of the Project, including, but not limited to, storage costs, facility removal expenses and any environmental remediation costs.

If the Customer provides written notice to Networks that it is cancelling or deferring the Project, Networks shall have 10 Business Days to provide written notice to the Customer listing the individual items listed as materials which it agrees to purchase. Networks shall deduct the actual costs of those individual items of materials being purchased by Networks from the Actual Costs referred to above.

If Networks does not require all or part of the materials, the Customer may exercise any of the following options or a combination thereof:

(i) where materials have been ordered but all or part of the materials have not been received by Networks, the Customer shall have the right to require Networks, at the Customer's sole expense, to continue with the purchase of the materials and transfer title to those materials on an "as is, where is basis" to the Customer upon the Customer paying Networks's Actual Costs provided that the Customer exercises this option within 15 Business Days of the termination, cancellation or deferral;

(ii) where all or part of the materials have been received by Networks but have not been installed, the Customer shall have the right to require Networks, at the Customer's sole expense, to transfer title to the materials on an "as is, where is basis" to the Customer upon the Customer paying Networks's Actual Costs provided that the Customer exercises this option within 15 Business Days of the termination, cancellation or deferral. The Customer shall also be responsible for any warehousing costs associated with the storage of the materials to the date of transfer; or

(iv) where all or part of the materials have been received by Networks and have been installed, the Customer shall have the right to require Networks, at the Customer's sole expense, to: transfer title to the materials on an "as is, where is basis" to the Customer upon the later of (A) the Customer paying Networks's Actual Costs; and (B) the date that Networks removes the materials from its property at the risk of the Customer; provided that the Customer exercises this option within 15 Business Days of the termination, cancellation or deferral. The Customer shall also be responsible for any costs associated with the installation and the removal of the materials that have been installed by Networks.

The Customer shall pay Networks' Actual Costs which become payable under this Section within 30 calendar days after the date of invoice.

16(b). If the Customer wishes to defer the Project, the Parties will negotiate the terms of such deferral.

17. In the event that the Customer sells, leases or otherwise transfers or disposes of the Customer's Facilities to a third party during the Term of the Agreement, the Customer shall cause the purchaser, lessee or other third party to whom the Customer's Facilities are transferred or disposed to enter into an assumption agreement with Networks to assume all of the Customer's obligations in the Agreement; and notwithstanding such assumption agreement, the Customer shall remain obligated to pay the amounts thereafter payable pursuant to Sections 12, 13, 14, 15 and 16 by the purchaser, lessee or other third party in the case of a transfer or disposition. The Customer further acknowledges and agrees that in the event that all or a portion of the Customer's Facilities are shut down, abandoned or vacated for any period of time during the Term of the Agreement, the Customer shall remain obligated to pay the amounts payable pursuant to Sections 12, 13, 14 and 15 for the said time period.

18. The Customer, whenever required by Networks to do so, shall furnish security satisfactory to Networks for the performance by the Customer of its obligations for pooled and non-pooled costs under the Agreement, and shall maintain the security in full force and effect during the continuance of the Agreement. The security must be in a form acceptable to Networks and may be an irrevocable letter of credit given by a bank chartered in Canada, a surety bond given by a surety company acceptable to Networks, negotiable bonds satisfactory to Networks or a cash deposit. The security provided shall not exceed the remaining amounts owing in respect of the Non–Pool Work and Transformation Connection Pool Work and/or Line Connection Pool Work less any capital contributions.

The Customer, if not in default under the Agreement shall be entitled to the interest payable on negotiable bonds held as security or the interest on cash deposits at the prevailing rate paid by Networks on cash deposits. Where the Customer has furnished any of the forms of security hereinbefore specified, the Customer if not in default as aforesaid shall have the right at any time to substitute for the security any other of the forms of security acceptable to Networks. If at any time the security furnished to Networks becomes unsatisfactory to Networks, the Customer upon request of Networks shall promptly furnish security, within fifteen (15) Business Days of receipt of notice, that is satisfactory to Networks. Security held in regards to the Agreement shall be returned to the Customer once obligations are fulfilled.

Upon or any time after the occurrence or deemed occurrence of an Event of Default and the expiry of the rectification period set forth in Section 23, Networks may do any one or more of the following: (i) exercise its rights and remedies as a secured party with respect to all security, including any such rights and remedies under Applicable Laws then in effect; (ii) exercise its rights of set-off against any and all property of the Customer in the possession of Networks or its agent; (iii) draw on any outstanding letter of credit issued for its benefit; and (iv) liquidate all security then held by or for the benefit of Networks free from any claim or right of any nature whatsoever of the Customer, including any equity or right of purchase or redemption by the Customer. Networks shall apply the proceeds of the collateral realised upon the exercise of any such rights or remedies to reduce the Customer's obligations under the Agreement (the Customer remaining liable for amounts owing to Networks after such application), subject to Networks' obligation to return any surplus proceeds remaining after such obligations are satisfied in full.

Part C:

19. In the event that the Transformation Connection Service Rate or the Line Connection Service Rate is rescinded or the methodology of determination or components is materially changed, the Parties agree to negotiate a new mechanism for the purposes of the Agreement. The Parties shall have 90 calendar days from the effective date of rescission or fundamental change of the Transformation Connection Service Rate or the Line Connection Service Rate to agree to a new mechanism. If the Parties are unable to successfully negotiate a replacement within that 90 calendar day period, they shall submit to arbitration, in accordance with the requirements of the Transmission System Code (or the Connection Agreement attached thereto); or if there is no arbitration provision in the Transmission System Code (or the Connection Agreement attached thereto), to the requirements of the *Arbitration Act* (Ontario), as amended, to settle on a new mechanism. The decision of the arbitrator shall be binding on each party with no right of appeal.

The terms of reference of the arbitration shall be to identify a new mechanism that is, to the extent possible, fair to the parties and constitutes a reasonably comparable replacement for the Transformation Connection Service Rate or the Line Connection Service Rate.

Any settlement on a new mechanism pursuant to this Section 19 shall apply retroactively from the date on which the Transformation Connection Service Rate or the Line Connection Service Rate was rescinded or fundamentally changed. Until such time as a new mechanism is determined hereunder, any amounts to be paid by the Customer under the Agreement shall be based on the Transformation Connection Service Rate or the Line Connection Service Rate in effect prior to the effective date of any such changes.

20.1 The Customer:

(a) shall not Transmit or Distribute electricity using the Customer's Facilities to any load now or hereafter supplied from Networks' Facilities or Third Party Facilities and if the Customer does so, the Customer shall pay Networks an amount equal to the avoided applicable Transmission Rates as if the load remained on Networks' Facilities or the Third Party Facilities, as the case may be, until the date that:

(i) Networks' Facilities or the Third Party Facilities are removed from service at end-of-useful-life and are not replaced by new transmission facilities; or
(ii) Networks requires Networks' Facilities to provide transmission services to other Customers or the affected third party requires the Third Party Facilities to supply its customers.

(b) shall not permit any third party to transmit or distribute electricity using or by connecting to the Customer's Facilities or in any other manner, to any load now or hereafter supplied from Networks' Facilities or the Third Party Facilities and if the Customer does so, the Customer shall pay Networks an amount equal to the avoided applicable Transmission Rates as if the load remained on Networks' Facilities or the Third Party Facilities until the date that:

(i) Networks' Facilities or the Third Party Facilities are removed from service at end-of-useful-life and are not replaced by new transmission facilities; or
(ii) Networks requires Networks' Facilities to provide transmission services to other customers or the affected third party requires the Third Party Facilities to supply its customers.

(c) shall not supply new load growth using the Customer's Facilities or the Third Party Facilities when Networks has spare capacity available at Networks' Facilities to supply such load; and if it does so, the Customer shall pay Networks an amount equal to the avoided applicable Transmission Rates by paying as if the new load were supplied from the Networks Facilities. Notwithstanding the foregoing, the Customer will not owe any amounts to the Networks, if the Customer can demonstrate to the satisfaction of the Networks, acting reasonably, that it would have been uneconomic or inefficient for the Customer to supply the load growth in question using Networks' Facilities.

(d) shall cause the purchaser, lessee or other third party to whom the Customer sells, leases, or otherwise transfers or disposes of the Customer's Facilities to enter into an assumption agreement with Networks to assume all of the Customer's obligations under this Section 20.1.

20.2 Nothing contained within this Agreement, including, without limiting the generality of the foregoing, Section 20.2, shall preclude, prevent, prohibit or operate as a waiver of any of the Parties' rights to:

(i) make application to the OEB;
(ii) participate in any hearings before the OEB; or
(iii) make any appeals to a Court of competent jurisdiction regarding any decision by the OEB,

with respect to any matter, issue, thing, interpretation, consideration or consequence whatsoever that is related to:

A. the Transmission or Distribution of electricity to any load now or hereafter supplied from Networks' Facilities or the facilities of any licensed electricity distributor by the Customer or by a third party using the Customer's Facilities to supply said load;
B. the interpretation or application of Section 20.1 above; and
C. the Transmission and Distribution of electricity to any load now or hereafter supplied from Networks facilities other than Networks' Facilities or from facilities of any licensed electricity distributor by any other Customer or by a third party.

20.3 Section 20.1 shall be subject to and applied in accordance with any Order or decision made by the OEB or any court with respect to any matter, issue, thing, interpretation, consideration or consequence that relates to:

(i) the Transmission and Distribution of electricity to any load now or hereafter supplied from Networks' Facilities or the facilities of any licensed distributor by the Customer or by a third party using the Customer's Facilities to supply said load; and
(ii) the terms and conditions of Section 20.1.

20.4 With respect to any Order or decision of the OEB or a court relating to the Transmission or Distribution of electricity to any load now or hereafter supplied from facilities other than Networks' Facilities or from the facilities of any licensed distributor by any Customer other than by the Customer or by a third party, the parties acting reasonably shall agree in writing as to application of said Order or decision to Section 20.1 and to any amendments thereto.

20.5 Sections 20.1 to 20.4 inclusive shall survive the termination of this Agreement and will be terms of any Connection Agreement or such other agreement as required by the Transmission System Code that is applicable to the owner and/or operator of the Customer's Facilities.

Part D: Easement

21. If specified in Schedule "A" that an easement is required, the Customer shall or the Customer shall cause the third party specified in Schedule "A" to grant an easement to Hydro One substantially in the form of the easement that will be attached hereto as Appendix "C", if required, for the property described as the Easement Lands in Schedule "A" by no later than the date specified as the Easement Date in Schedule "A" (hereinafter referred to as the "Easement") with good and marketable title thereto, free of all encumbrances, first in priority except as noted herein, and in registerable form, in consideration of the sum of $2.00.

The above Easement shall be for a term of 80 years commencing on the In-Service Date provided that in the event that Networks removes the asset that is the subject of the Easement during the 80-year period, Networks shall surrender the Easement at that time. With respect to the Easement, after the expiry of the 80-year

period, the parties agree to enter into good faith negotiations for an extension of the Easement term, if one or the other, or both, of the parties so request. Subject to the foregoing, the Easement shall survive the termination of the Agreement.

Part E: Events of Default

22. Each of the following events shall constitute an "Event of Default" under the Agreement:

(a) failure by the Customer to pay any amount due under the Agreement, including any amount payable pursuant to Sections 12, 13, 14, 15 or 16 within the time stipulated for payment;
(b) breach by the Customer or Networks of any Material term, condition or covenant of the Agreement;
(c) the making of an order or resolution for the winding up of the Customer or of its operations or the occurrence of any other dissolution or liquidation proceeding instituted by or against the Customer; and

23. Upon the occurrence of an Event of Default by the Customer hereunder (other than those specified in section 22(c) of the Agreement, for which no notice is required to be given by Networks), Networks shall give the Customer written notice of the Event of Default and allow the Customer 30 calendar days from the date of receipt of the notice to rectify the Event of Default, at the Customer's sole expense. If such Event of Default is not cured to Networks' reasonable satisfaction within the 30 calendar day period, Networks may, in its sole discretion, exercise the following remedy in addition to any remedies that may be available to Networks under the terms of the Agreement, at common law or in equity: deem the Agreement to be repudiated and, after giving the Customer at least 10 calendar days' prior written notice thereof, recover, as liquidated damages and not as a penalty, the balance of the amounts payable by the Customer pursuant to Sections 12, 13, 14, 15 and 16.

24. Upon the occurrence of an Event of Default by Networks hereunder, the Customer shall give Networks written notice of the Event of Default and shall allow Networks 30 calendar days from the date of receipt of the notice to rectify the Event of Default at Networks' sole expense. If such Event of Default is not cured to the Customer's reasonable satisfaction within the 30 calendar day period, the Customer may pursue any remedies available to it at law or in equity, including at its option the termination of the Agreement.

25. All rights and remedies of Networks and the Customer provided herein are not intended to be exclusive but rather are cumulative and are in addition to any other right or remedy otherwise available to Networks and the Customer respectively at law or in equity, and any one or more of Networks' and the Customer's rights and remedies may from time to time be exercised independently or in combination and without prejudice to any other right or remedy Networks or the Customer may have or may have exercised. The parties further agree that where any of the remedies provided for and elected by the non-defaulting party are found to be unenforceable, the non-defaulting party shall not be precluded from exercising any other right or remedy available to it at law or in equity.

In addition to any other remedy provided hereunder, all overdue amounts that are outstanding for longer than 30 days shall bear interest at 18% per annum.

Part F: Connection Agreement and Transmission System Code

26. In the event that the Connection Agreement referred to in Section 5(c) is entered into prior to the effective date of the Transmission System Code, the Parties shall make such amendments to the Connection Agreement as may be necessary to ensure compliance with the mandatory requirements of the Transmission System Code in effect on the date that Section 26(1) of the *Electricity Act, 1998* (being Schedule "A" of the *Energy Competition Act*, S.O. 1998, c. 15) is proclaimed.

27. Until Networks' has published and the Ontario Energy Board has accepted Networks' procedure and methodology for determining the requirement for a capital contribution in accordance with Section 4.1 of the *Transmission System Code*, any Capital Contributions paid by the Customer under the terms of this Agreement are subject to adjustment with such adjustment to be solely based on the procedure and methodology accepted by the OEB.

Part G: Liability and Force Majeure

28(a) Other than for sums payable under the Agreement, the Customer shall only be liable to Networks and Networks shall only be liable to the Customer for any damages that arise directly out of the willful misconduct or negligence in meeting their respective obligations under the Agreement.

Despite the foregoing, neither Party shall be liable under any circumstances whatsoever for any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential or incidental damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in statute, contract, tort or otherwise.

For any damage suffered by the Customer prior to the Transmission System Code coming into effect, the total liability of Networks to the Customer for any and all claims for damages under the Agreement whether it arises by statute, contract, tort or otherwise, will not exceed the Actual Cost of the Networks' Connection Work. Once the Transmission System Code comes into effect, Appendix 1, Article 8 of the Transmission System Code shall apply.

This provision shall survive the termination of the Agreement.

28(b). Neither party shall be considered to be in default in the performance of its obligations under the Agreement, except obligations to make payments with respect to amounts already accrued, to the extent that performance of any such obligation is prevented or delayed by any cause, existing or future, which is beyond the reasonable control of, and not a result of the fault or negligence of, the affected party ("Force Majeure") and includes, but is not limited to, system operating conditions mandated by the IMO, strikes, lockouts and any other labour disturbances and manufacturer's delays for equipment or materials required for the Networks Connection Work. The non-affected party shall be relieved of any obligation hereunder during the continuation of the event of Force Majeure.

If a party is prevented or delayed in the performance of any such obligation by Force Majeure, such party shall immediately provide notice to the other party of the circumstances preventing or delaying performance and the expected duration thereof. Such notice shall be confirmed in writing as soon as reasonably possible. The party so affected by the Force Majeure shall endeavour to remove the obstacles which prevent performance and shall resume performance of its obligations as soon as reasonably practicable, except that there shall be no obligation on the party so affected by the Force Majeure where the event of Force Majeure is a strike, lockout or other labour disturbance.

Part H: General

29. No amendment, modification or supplement to the Agreement shall be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of the Agreement.

30. The failure of any party hereto to enforce at any time any of the provisions of the Agreement or to exercise any right or option which is herein provided shall in no way be construed to be a waiver of such provision or any other provision nor in any way affect the validity of the Agreement or any part hereof or the right of any party to enforce thereafter each and every provision and to exercise any right or option. The waiver of any breach of the Agreement shall not be held to be a waiver of any other or subsequent breach. Nothing shall be construed or have the effect of a waiver except an instrument in writing signed by a duly authorized officer of the party against whom such waiver is sought to be enforced which expressly waives a right or rights or an option or options under the Agreement.

31. Each party acknowledges and agrees that it has participated in the drafting of the Agreement and that no portion of the Agreement shall be interpreted less favourably to either party because that party or its counsel was primarily responsible for the drafting of that portion.

32. Any written notice required by the Agreement shall be deemed properly given only if either mailed or delivered to the Secretary, Hydro One Networks Inc., 483 Bay Street, South Tower, 10th Floor, Toronto, Ontario M5G 2P5, fax no: (416) 345-6240 on behalf of Networks, and to the person at the address specified in Schedule "A" of the Agreement on behalf of the Customer.

A faxed notice will be deemed to be received on the date of the fax if received before 3 p.m. or on the next business day if received after 3 p.m. Notices sent by courier or registered mail shall be deemed to have been received on the date indicated on the delivery receipt. The designation of the person to be so notified or the address of such person may be changed at any time by either party by written notice.

33. The Agreement shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of the Province of Ontario and the laws of Canada applicable therein, and, subject to Section 19, the courts of Ontario shall have exclusive jurisdiction to determine all disputes arising out of the Agreement.

34. The Agreement may be executed in counterparts, including facsimile counterparts, each of which shall be deemed an original, but all of which shall together constitute one and the same agreement.

35. The Customer shall provide Networks with a copy of the Customer's final monthly bills associated with Networks' Facilities and/or the Customer's Facilities or authorize the IMO to provide Networks with same. Networks agrees to use this information solely for the purpose of the Agreement.

36. The obligation to pay any amount due and payable hereunder, including, but not limited to, any amounts due under Sections 12, 13, 14, 15 or 16 shall survive the termination of the Agreement.

Appendix "A": Definitions

Throughout the Agreement, unless there is something in the subject matter or context inconsistent therewith, the following words shall have the following meanings:

"Actual Cost" means Networks' charge for equipment, labour and materials at Networks' standard rates plus Networks' standard overheads and interest thereon.

"Actual Incremental Transformation Connection Revenue" means the actual amount of transformation connection revenue attributable to the Incremental Load received by Networks through the monthly collection of the Transformation Connection Service Rate for the period specified in Schedule "B" of the Agreement.

"Actual Incremental Line Connection Revenue" means the actual amount of line connection revenue attributable to the Incremental Load received by Networks through the monthly collection of the Line Connection Service Rate for the period specified in Schedule "B" of the Agreement.

"Agreement" means the Connection Cost Recovery Agreement, Schedules "A" and "B" attached thereto and these Standard Terms and Conditions.

"Applicable Laws", means any and all applicable laws, including environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments or decrees or any requirement or decision or agreement with or by any governmental or governmental department, commission board, court authority or agency.

"Approval Date" means for the purpose of Subsection 6(f) of the Terms and Conditions, the date specified in Schedule "A" of the Agreement.

"Available Capacity" is that portion of the existing capacity on Networks' Facilities that can effectively and economically serve the Customer's peak load and is as specified in Schedule "B" of the Agreement.

"Base Load Trigger Point" is as specified in Schedule "B" of the Agreement and was determined using the following formula:

Base Load Trigger Point = 3 yr. Avg. PLI * Available Capacity
With:
PLI = [(sum of Twelve Monthly Peaks)/Annual Peak*12]

"Business Day" means a day other than Saturday, Sunday, statutory holiday in Ontario or any other day on which the principal chartered banks located in the City of Toronto, are not open for business during normal banking hours.

"Connection Agreement" has the meaning set forth in the Transmission System Code.

"Connection Point" means the point where the New or Modified Facility is connected to Networks' transmission system.

"Customer Connection Work" means the work to be performed by the Customer, at its sole expense, which is described in Schedule "A" of the Agreement.

"Customer's Facilities" has the meaning set forth in the Transmission System Code, and includes, but is not limited to the New or Modified Facility where the New or Modified Facility is owned by the Customer. In addition to the foregoing, Customer's Facilities may include any other assets specified in Schedule "A" of the Agreement.

"Customer's Property(ies)" means any lands owned by the Customer in fee simple or where the Customer has easement rights.

"Distribute" has the meaning ascribed thereto in the *Electricity Act, 1998*.

"Emergency" has the meaning set forth in the Transmission System Code.

"Good Utility Practice" has the meaning set forth in the Transmission System Code.

"Guaranteed Transformation Connection Revenue" means the minimum amount of transformation connection revenue specified in Schedule "B" attributable to the Load to be received by Networks through the monthly collection of the Transformation Connection Service Rate for the period specified in Schedule "B".

"Guaranteed Line Connection Revenue" means the minimum amount of line connection revenue specified in Schedule "B" of the Agreement attributable to the Load to be received by Networks through the monthly collection of the Line Connection Service Rate for the period specified in Schedule "B" of the Agreement.

"Guaranteed Revenue Date" means, for the purposes of Section 2 of the Terms and Conditions, the date specified in Schedule "B" of the Agreement.

"IMO Rules" means the Independent Market Operator (IMO) administered Market Rules, including, but not limited to Chapter 6 thereof.

"In Service Date" means the date that the IMO has approved the final connection of the New or Modified Facility.

"Incremental Load" is determined using the following formula:

[(sum of Twelve Monthly Peaks) – (Base Load Trigger Point *12]

"Line Connection Pool" is as defined or referenced in Networks' transmission rate schedules approved by the OEB on Open Access (being the date that Section 26(1) of the *Electricity Act, 1998* (being Schedule "A" of the *Energy Competition Act, S.O. 1998, c. 15)* comes into force.

"**Line Connection Service Rate"** means Networks' line connection service rate approved by the Ontario Energy Board ("OEB") from time to time, or any mechanism instituted in accordance with Section 19).

"Material" relates to the essence of the contract, more than a mere annoyance to a right, but an actual obstacle preventing the performance or exercise of a right.

"Networks Connection Work" means the work to be performed by Networks which is described in Schedule "A" of the Agreement.

"Networks' Facilities" means collectively the Networks' Facilities – LV and the Networks' Facilities – HV.

"Networks' Facilities – HV" means the facilities owned by Networks specified in Schedule "A" of the Agreement that convey electricity at voltages of more than 50 kilovolts.

"Networks' Facilities – LV" means the facilities owned by Networks specified in Schedule "A" of the Agreement that convey electricity at voltages of 50 kilovolts or less.

"Networks' Property(ies)" means any lands owned by Networks in fee simple or where Networks now or hereafter has obtained easement rights.

"New or Modified Facility" means the facilities specified in Schedule "A" of the Agreement.

"Premium Costs" means those costs incurred by Networks in order to maintain or advance the Ready for Service Date, including, but not limited to, additional amounts expended for materials or services due to short time-frame for delivery; and the difference between having Networks' employees, agents and contractors perform work on overtime as opposed to during normal business hours.

"Ready for Service Date" means the date upon which the Networks Connection Work is fully and completely constructed, installed, commissioned and energised to the Connection Point. The Customer's disconnect switches must be commissioned prior to this date in order to use them as isolation points.

"Third Party Facilities" means any and all equipment, elements, and facilities of any kind whatsoever owned by someone other than the parties to this connection agreement and that are connected to Networks' transmission system.

"Transformation Connection Pool" is as defined or referenced in Networks' transmission rate schedules approved by the OEB on Open Access (being the date that Section 26(1) of the *Electricity Act, 1998* (being Schedule "A" of the *Energy Competition Act, S.O. 1998, c. 15)* comes into force.

"**Transformation Connection Service Rate"** means Networks' transformation connection service rate approved by the Ontario Energy Board ("OEB") from time to time, or any mechanism instituted in accordance with Section 19).

"**Transmission Rate"** has the meaning set forth in the form of Connection Agreement attached to the Transmission System Code.

"Transmission System Code" means the code of standards and requirements issued by the OEB on July 14, 2000, as it may be amended from time to time, setting forth mandatory terms, conditions and obligations regarding connections between the facilities of distributors and the facilities of transmitters in accordance with the requirements of the *Ontario Energy Board Act*, *1998,* including mandatory required terms and conditions for Connection Agreements.

"Transmit" has the meaning ascribed thereto in the *Electricity Act, 1998*.

Appendix "B": Access Provisions

1. When the Customer's staff, its contractors, or agents work at Networks' Facilities or site, Networks' safety and environmental requirements shall be observed by such staff, contractors and agents. As a minimum, all Applicable Laws shall govern such work.

2. The Customer's staff, its contractors, or agents working at Networks' Facilities or site shall be qualified to work around electrical hazards.

3. The Customer's staff, its contractors, or agents shall be entitled to access Networks' Facilities or site, and Networks will grant such access, to carry out work at all reasonable times on reasonable prior notice to Networks, subject to Networks' policies and procedures.

4. If the Customer wishes to have access to Networks' Facilities, the Customer shall notify Networks of the particular work to be undertaken and of the date and time when it proposes to access the relevant Facilities, subject to Networks' policies and procedures. Networks shall not unreasonably withhold access to its Facilities.

5. At any time when the Customer or its representatives are on or in Networks' site, the Customer and its representatives shall:

(a) use all reasonable precautions not to damage or interfere with Networks' site and Facilities;
(b) observe Networks' requirements for reporting occupational health and safety, electrical safety, environmental requirements, technical requirements, and matters of industrial relations; and
(c) neither ask questions, nor give any direction, instruction or advice to any person involved in operating or maintaining Networks' site or Facilities, other than the person whom Networks has designated for that purpose.

6. If the Customer or its representatives cause any loss or damage when given access to Networks', the Customer or its representative shall promptly advise Networks' controlling authority of the loss or damage.

7. The Customer shall not, and shall ensure that its representatives do not, intentionally interfere with any of Networks' Facilities in or on its sites. The Customer shall use reasonable efforts not to cause loss or damage to Networks' Facilities. If the Customer interferes with any of Networks' Facilities, it shall indemnify Networks for reasonable costs and expenses incurred from any resulting loss or damage.

8. In an emergency, Networks may, as far as reasonably necessary in the circumstances, have access to and interfere with the Customers' Facilities. Networks shall use reasonable efforts not to cause loss or damage to the Customer's Facilities. If Networks interferes with any of the Customer's Facilities, it shall indemnify the Customer for reasonable costs and expenses incurred from any resulting loss or damage.

9. Where the Customer requests assistance from Network beyond routine OM&A activities, the Customer shall pay Networks its Actual Costs related to the Customer's staff, contractors or agents accessing Network's Facilities or sites, including, but not limited to, the cost of having a Networks representative accompany the Customer's staff, contractors, or agents accessing Network's Facilities or sites in accordance with the invoices rendered by Networks.

10. The Customer shall indemnify and save harmless Networks from and against all liabilities, damages, suits, claims, demands, costs, actions, proceedings, causes of action, losses, expenses and injury (including death) of any kind or nature whatsoever (the "causes of action") resulting from, caused by or in any manner connected with installed Customer equipment on Networks' Facilities or sites or Customer's staff, its contractors, or agents accessing Network's Facilities or sites including, but not limited to:

(a) causes of actions arising out of health and safety violations or environmental spills;
(b) costs incurred by Networks having to pay other customers due to interruptions caused by the Customer;
(c) damage to Networks equipment;
(d) incremental costs and expenses incurred by Networks related to the Customer's equipment installations, removals, relocations, upgrades, or any other Customer work.

except to the extent that the "causes of action" are caused by the negligence or willful misconduct of Networks.

11. Where Networks staff, contractors, or agents require access to the Customer's Facilities or site, clauses 1 to 10 will apply reciprocally.

CCRA – Midhurst TS

MWH

Hydro One Networks Inc.
Michael Lesychyn
Customer Contracts & Business Relations
483 Bay Street
15th Floor
Toronto, Ontario
M5G 2P5
Telephone: (416) 345-5954

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hydro one

September 30, 2003

Mr. George Todd
President & CEO
Barrie Hydro Distribution Inc.
55 Patterson Road
P.O. Box 7000
Barrie, Ontario
L4M 4V8

Dear Mr. Todd:

Please find enclosed your copy of the Midhurst TS Expansion CCRA. If you have any questions concerning this CCRA, please don't hesitate to contact me @ (416) 345-5954.

Sincerely,

Michael Lesychyn
Customer Contracts & Business Relations
Hydro One Networks Inc.

Connection and Cost Recovery Agreement

between

Barrie Hydro Distribution Inc.

BarrieHydro Distribution Inc.

and

HYDRO ONE NETWORKS INC.

hydro one

For the

Midhurst TS Expansion

Project Title

Barrie Hydro Distribution Inc. (the "Customer") has requested and Hydro One Networks Inc. ("Networks") has agreed to the Midhurst Transformer Station Expansion (the "Project") on the terms and conditions set forth in this Agreement (the "Agreement") dated September 22, 2003 and the attached Standard Terms and Conditions T&C V4 ESH 15-25 02-2003.

Project Summary

The Project scope is to expand Network's existing transformer station known as the Midhurst Transformer Station ("Midhurst TS") as described below:

- A second DESN transformer pair at Midhurst TS is to be designed constructed, owned and operated by Networks, and to be located on existing Midhurst TS property (the "New Midhurst TS").
- Two circuits (rigid aluminium bus work installed on station post insulators) from the drops from M6E and M7E to the 75/100/125 MVA transformers.
- Protection, Control, Metering & Annunciation pertaining to Networks' facilities. Note: this does not include revenue metering.
- Witness commissioning at Networks' facilities.
- Work required at Networks' facilities includes engineering, procurement of equipment; installation of equipment, commissioning.
- Witnessing of work required at interface of the Customer's and Networks' facilities at New Midhurst TS.

Overview and purpose of the project

To meet projected load increases in the City of Barrie and reduce Barrie Transformer Station loading below 10-day LTR

Ready for Service date

No later than April 15th 2005.

Financial Summary (Repayment schedule and Capital Contribution)

The total project cost is $13,610,000.00. Due to the level of projected load increases no capital contribution is required for the pooled work. Revenue streams are guaranteed for 24 years. Non pooled work costs are $260,000.00 and will be supported by a contribution from the Customer

Term: 24 years

Special Circumstances

None

The Project schedule is subject to:

a) the Customer executing and returning this Agreement to Networks by no later than Oct 01 2003, and
b) all necessary approvals being obtained as outlined under Special Circumstances above.

This Agreement constitutes the entire agreement between the parties with respect to the subject matter of this Agreement and supersedes all prior oral or written representations and agreements concerning the subject matter of this Agreement. Schedules "A" and "B" and the Standard Terms and Conditions T&C V4 ESH 15-25 02-2003 attached hereto are to be read with and form part of this Agreement.

Recommended by

Marty Longlade
Account Executive

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by the signatures of their proper officers, as of the day and year first written above.

HYDRO ONE NETWORKS INC.

Jim Patterson
Manager – Customer Contracts & Business Relations

I have the authority to bind the Corporation.

BARRIE HYDRO DISTRIBUTION INC.

George Todd
President & CEO

I have the authority to bind the Corporation.

Schedule "A"

Midhurst TS Networks Connection Work

Project Scope:

The Project scope is to expand the existing Midhurst transformer station ("Midhurst TS") as described below.

- A new transformer station (the "New Midhurst TS") to be designed constructed, owned and operated by Networks, and to be located on the Midhurst TS property as a second DESN.
- Two circuits (rigid aluminium bus work installed on station post insulators) from the drops from M6E and M7E to the 75/100/125 MVA transformers.
- Protection, Control, Metering & Annunciation pertaining to Networks' facilities.
  Note: Does not include Revenue metering.
- Witness commissioning at Networks' facilities.
- Work required at Networks facilities includes engineering, procurement of equipment, installation of equipment, commissioning etc.
- Witnessing of work required at interface of the Customer's and Networks' facilities at the New Midhurst TS.

NETWORKS CONNECTION WORK:

Part 1 - Non-Poolable Work:

Networks will:

Protection Changes

- Review/revise M6E/M7E protections at Networks' Essa Transformer Station ("Essa TS"), Orillia Transformer Station, Muskoka Transformer Station, Bracebridge Transformer Station and Minden Transformer Station ("Minden TS") as required.
- Revise existing M6E/M7E line backup protections, M6E/M7E blocking protection, M6E/M7E remote trip send and receive, and existing T1, T2 transformer protection and transformer breaker failure protections.
- Provide new operating plates.
- Conduct review of Interface Documents and review compliance with the Transmission System Code.
- Perform witness verification tests, on potential checks and on load checks per Witness of Verification Evidence Report.

Teleprotection

- Replace four existing 230 kV line traps at Essa TS and Minden TS (two at Essa and two at Minden) on lines M6E and M7E with higher current rating units.

SCADA Modifications & Telemetry Quantities

- Modify the master SCADA at Territory Operating Centre (TOC) and Transmission Operation Management Centre (TOMC) to suit.
- Provide new modem at TOC.
- Provide telemetry quantities (device status, measured quantities and alarms) to be "collected" from a port and modem from the local RTU to TOC/TOMC.

Part 2 - Line Connection Pool Work:

Networks will:

1 **230 kV Line Tap**

- Connect to the existing strain conductors of the 230 kV lines M6E and M7E.

- Provide two circuits (rigid aluminium buswork installed on station post insulators) from the drops of M6E and M7E to the 75/100/125 MVA transformers.
- Provide 230 kV line traps
- Arrange & co-ordinate all outages.
- Amend existing easement for the line tap if required.
- Provide new operating plates.

Part 3 - Transformation Connection Pool Work:

Networks will:

1. **230 kV Switching & Connection**

- Provide two (2) 230 kV 1200 A 900 kV BIL, vertical break, gang operated motorised disconnect switches to interrupt the maximum transformer magnetising current.
- Provide connections from the NEMA pads on the line conductors to the station bus/equipment.
- Provide connections from the skywires to the station ground grid.

2. **Transformation Facilities**

- Provide two (2) 75/100/125 MVA, 215.5-44 kV transformers with ULTC, HV wye un-grounded, LV wye grounded through reactors, with attached radiators and conservator tank.
- Provide six (6) single phase bushing potential devices, 133 kV/115-66 V, 80 W, 60 Hz.
- Provide heat-activated detectors and a Fire Panel.
- Provide 44 kV neutral reactors (5 ohm air core, 4000 A at 10 seconds).
- Provide eight (8) 192 kV station class surge arrestors and six (6) 39 kV station class surge arrestors.
- The transformer "pocket", the transformer foundation and spill containment pit, will be designed for the specified transformer only.

3. **LV Switching Facilities**

- Provide two (2) circuit breakers, 48 kV, SF6, 3000 A, 1500 MVA as transformer breakers.
- Provide one (1) circuit breaker, 48 kV, SF6, 2000 A, 1500 MVA as a bus tie breaker.
- Provide eight (8) circuit breakers, 48 kV, SF6, 1200 A, 1500 MVA as feeder breakers
- Provide four (4) disconnect switches, 44 kV, manual gang operated, 3000 A, 25 kA, C/W 44 kV insulators as transformer breaker and bus tie breaker isolating switches.
- Provide forty-eight (48) disconnect switches, 44 kV, hook stick operated, 1200 A C/W 44 kV insulators as feeder breaker isolating switches.
- Provide four (4) disconnect switches, 46 kV, 250 kV BIL, 600 A, vertical break, manual gang operated, upright mounting, C/W station post insulators as feeder tie switches.
- Provide one (1) disconnect switch, 44 kV, manual gang operated, 1200 A, 25 kA, C/W 44 kV insulators as isolating switch for AC station service transformer.

4. **AC Station Service System**

- Provide an ac station service transformer, pad mounted with air bushings, 44 kV/208-120 V, 200 kVA, delta-star, C/W fuses on the 120/208 V side.

6 **DC Station Service System**

- Provide a dc station service system complete with 125 V dc sealed battery, charger, dc distribution panels, and cabling.

7 **Grounding & lightning protection**

- Extend existing station grounding to the 2nd DESN area.
- Provide lightning protection to the new area..

8 Operating Plates

- Provide new operating plates.

9 Protection & Control System

- Provide the following protections and control in factory assembled, tested & commissioned panels based on the use of SEL relays unless stated otherwise:
  - Line backup protections for each HV line.
  - Transformer "A" & "B" differential protection for each power transformer.
  - LV bus "A" & "B" differential protection (bus blocking scheme) for each bus.
  - Transformer breaker failure, reclose and control for 2 transformer breakers
  - Bus tie breaker failure and control
  - Feeder protection and feeder breaker reclose & control for 8 feeders.
  - HV load break switch control.
- Provide Remote and Local Control System for remote and local control of New Midhurst TS for: Telemetry quantities (device status, measured quantities and alarms)
  - Breaker, switch, and tap-changer control.
- Requirements on 3% and 5% Voltage Reduction as required.
- Provide under Frequency Load Shedding protection.
- Provide fire protection and security system in the P&C building.

10 Telecommunications

- Supply telecommunication facilities in the P&C House at New Midhurst TS
- Wall mount back board
  - Provide 25 pair (50 connector) sliding link terminal bar.
  - Provide wall mounted touch-tone phone.

11 Structural/foundation systems

- Provide new foundations/new steel structures to suit.
- Provide transformer foundations for the specified transformer rating
- Provide a pre-engineered building complete with building services.
- Provide foundation for the installation of pre-fabricated P&C building.

12 Mechanical/site system

- Provide grading, access road, and drainage.
- Provide a spill containment system.
- Obtain Certificate (s) of Approval.

CUSTOMER CONNECTION WORK:

The Customer will:

1 Feeder & feeder egress

- Provide all 44 KV feeders and feeder egress from the new DESN.

2 Revenue Metering

- Provide a revenue-metering installation in accordance with IMO Rules.
- All cabling between instrument transformers and the metering cabinet is the customer's responsibility

- Revenue metering located inside the Midhurst TS fence must receive Hydro One's approval for design and location

Miscellaneous

Documentation Required:

- Technical and Construction Details related to Feeder egress
- Feeder impedance and Feeder Single line drawings
- Provide operational and technical data as agreed to from time to time

Easement required (from customer): No

Name of Third Party for Easement: N/A

Easement Date: N/A

Easement Lands: N/A

New or Modified Facility: New DESN at Networks' existing Midhurst Transformer Station site.

Connection Point: Where Networks' secondary 44KV bus drops meet the outgoing cable for each of the Customer's feeders for underground feeders or at Networks' NEMA pad (i.e. the interface between the switchyard bus work and the feeder line) for overhead feeders.

Ready for Service Date: April 15, 2005

Execution Date: September 22, 2003

Security Requirements: N/A

Approval Date: N/A

Environmental Assessment: N/A

Feeder Egress Agreement Required: Yes - a Feeder Egress Agreement signed by the Customer and Networks is required by the Ready for Service Date.
License Agreement Required : Yes- a License Agreement between the Customer and Networks must be signed to accommodate any customer equipment located within Midhurst TS boundaries by the Ready for Service Date.

Access Agreement Required. Yes - an Access Agreement between the Customer and Networks must be signed to address location of Customer owned equipment inside the station fence by the Ready for Service Date.

Property Purchase Date: N/A

Revenue Metering:

Revenue metering and associated equipment is the responsibility of the Customer and/or its designated meter service provider.

The Customer will reimburse Networks for any costs incurred by Networks as a result of purchasing and installing revenue metering and/or associated equipment. Revenue metering equipment installed by Networks will meet the independent Market Operator ("IMO") metering standards and such equipmentwill become the property of the Customer on the Ready for Service date.

Networks will provide space inside Midhurst TS boundary fence suitable for the Customer to accommodate revenue metering.

Hydro One Networks will allow access to the revenue metering equipment so that maintenance and/or repair can be completed by the Customer pursuant to IMO requirements.

SCADA Access:

At the request of the Customer and subject to compliance with the Transmission System Code, operating data at the Project will be made available to the Customer. This work is excluded from the work being performed under this Agreement.

All real time operating information provided to Networks' customers shall be sent only from the network management system as defined by Hydro One. Transmission of data to customers shall be via ICCP communication data links between Networks and the customers.

Networks' Facilities – HV:

- The following Networks facilities that currently supply Barrie Hydro's Supply Area:
  Barrie Transformer Station ("Barrie TS"), 115-44 kV (T1/T2 transformers 50/66/83 MVA)
  Midhurst Transformer Station ("Midhurst TS"), 230-44 kV (T1/T2 transformers 75/100/125 MVA)

- "New Midhurst TS, 2nd DESN" 230-44 kV (T3/T4 transformers 75/100/125 MVA) to be installed under this Project)

Networks' Facilities – LV:
The following Networks LV (44 kV) facilities currently supplying the customer's area:
- Barrie TS (44 kV) Breaker positions M1, M2, M4, M5, M6 and M7
- New Midhurst TS (existing 44 kV) Breaker positions M5, M6, M7 and M8
- "New Midhurst TS 2nd DESN" 44 KV
- Eight breaker positions (to be installed under this Project)

Note: Breaker positions that supply other Networks' customers are excluded from above.

Ownership:

A. Networks will own all equipment and facilities installed by Networks as part of the Networks Connection Work in, under, on, over, along, upon, through and crossing Networks' Property(ies), as well as:
- NIL

B. Barrie Hydro will own instrument transformers (for revenue metering) at Midhurst TS installed by Networks as part of the Networks Connection Work. Barrie Hydro will also own all equipment inside New Midhurst TS boundary on their side of the defined Connection Point.

Customer Notice Information:

Address: Barrie Hydro Distribution Inc.
P.O. Box 7000,
55 Patterson Road
Barrie
ONT, L4M 4V8

Attention: Doug Switzer
Manager of System Policy and Planning

Fax No: (705) 722-4887

Schedule "B" **DATE July 27, 2003**

Transformation Connection Pool Work Estimate: $13,350,000

Line Connection Pool Work Estimate: $0

Non-Poolable Work Estimate (recoverable): $260,000 (plus applicable taxes)

Manner of Payment of Non-Poolable Work:

Customer shall pay Networks for Non-Poolable work using the following payment schedule:

July 2, 2004 – 50%
April 15, 2005 or earlier in-service date of Midhurst TS – 50%

Capital Contribution: None required for Pool Work

Manner of Payment of Capital Contribution: None

Available Capacity:

44 kV available capacity for Barrie Area:
Barrie TS: 94.6 MVA
Midhurst TS (existing DESN) 96 MVA (allocated to Barrie Hydro)
Total Load = 190.6 MVA

Capacity to be installed under this project:
"Midhurst TS 2nd DESN" 156.9 MVA (Summer Limited Time Rating)

Base Load Trigger Point (BLTP):

BLTP = Available Capacity X Peak Load Index (PLI)
PLI = 0.886
BLTP = 190.6 X 0.886
BLTP = 168.87

Guaranteed Revenue Date:

Line Connection Pool Work: N/A

Transformation Connection Pool Work: April 15, 2030

GUARANTEED INCREMENTAL TRANSFORMATION CONNECTION REVENUE AND/OR LINE CONNECTION REVENUE[1]

Period: Each twelve month period commencing on the Ready for Service Date	Guaranteed Incremental Line Connection Revenue (k$)	Guaranteed Incremental Transformation Connection Revenue (k$)
2006	0	641.38
2007	0	783.03
2008	0	925.42
2009	0	1066.88
2010	0	1208.35
2011	0	1349.81
2012	0	1491.28
2013	0	1627.74
2014	0	1739.77
2015	0	1855.16
2016	0	1974.01
2017	0	2096.43
2018	0	2209.48
2019	0	2252.02
2020	0	2252.02
2021	0	2252.02
2022	0	2252.02
2023	0	2252.02
2024	0	2252.02
2025	0	2252.02
2026	0	2252.02
2027	0	2252.02
2028	0	2252.02
2029	0	2252.02
2030	0	2252.02

Standard Terms and Conditions for Transmission Customer Connection Projects

1. The Customer agrees to guarantee a minimum amount of revenue to be derived from Incremental Load in accordance with the terms and conditions of the Agreement to hold the Pool harmless as a result of the Project.

2. Subject to Section 22 and the termination rights herein, the Agreement shall be in full force and in effect and binding on the parties as of the date of the Agreement (the "Effective Date") and shall expire on the earlier of the Guaranteed Revenue Date and the date that the debt owed by the Customer pursuant to Section 12 is reduced to zero (the "Term").

3. Each party represents and warrants to the other that:

(a) it has all the necessary corporate power, authority and capacity to enter into the Agreement and to perform its obligations hereunder; and

(b) the execution of the Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on its part.

Hydro One Networks Inc. ("Networks") represents and warrants to the Customer that it has obtained all necessary approvals with respect to the construction of the New or Modified Facility (including, but not limited to, where applicable, leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998* (being Schedule "B" of the *Energy Competition Act, S.O. 1998,c. 15)*) .

Part A: Networks Connection Work

4. The Customer and Networks shall perform their respective obligations outlined in the Agreement in a manner consistent with Good Utility Practice and the Transmission System Code, in compliance with all Applicable Laws, including, but not limited to the requirements of the Electrical Safety Code, and using duly qualified and experienced people.

5. The parties acknowledge and agree that:

(a) Networks is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Networks Connection Work and those required for the construction, connection and operation of the New or Modified Facility where the New or Modified Facility is owned by Networks;

(b) the Customer is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Customer Connection Work and those required for the construction, connection and operation of the New or Modified Facility where the New or Modified Facility is owned by the Customer, including those required under the Electrical Safety Code and the Customer shall ensure that it has received all such requisite permits, certificates, reviews and approvals prior to connection;

(c) the Customer will enter into a Connection Agreement with Networks at least 14 calendar days prior to the connection of the New or Modified Facility to Networks' transmission system;

(d) the Customer will ensure that Project data is made available or provided to Networks as required by Networks;

(e) the Customer will ensure that the work performed by the Customer and others required for successful installation, testing and commissioning of protective equipment is completed as required to enable Networks witnessing and testing to confirm satisfactory performance of such systems;

(f) the Customer will provide any hardware required to connect to Networks' transmission system;

(g) the Customer will provide coordination on protection;

(h) Networks' responsibilities under the Agreement with respect to the connection of the New or Modified Facility to Networks' transmission system shall be limited to the performance of the Networks Connection Work;

(i) the Customer shall perform the Customer Connection Work at its own expense;

(j) the Networks Connection Work and Networks' rights and requirements hereunder, including, but not limited to:

(i) Networks' specifications of the protection equipment on the Customer's side of the Connection Point;
(ii) Networks' acceptance of power system components on the Customer's side of the Connection Point; and
(iii) Networks' acceptance of the technical specifications (including electrical drawings) for the Customer Connection Work;

are solely for the protection of Networks' transmission system and that the Customer is responsible for installing equipment and facilities such as protection and control equipment to protect its own property.

6. Networks shall use reasonable efforts to complete the Networks Connection Work by the Ready for Service Date specified in Schedule "A" provided that:

(a) the Customer is in compliance with its obligations under the Agreement;
(b) any work required to be performed by third parties has been performed in a timely manner and in a manner to the satisfaction of Networks, acting reasonably;
(c) there are no delays resulting from Networks not being able to obtain outages from the Independent Electricity Market Operator (the "IMO") required for the Networks Connection Work or from the IMO making changes to the Networks Connection Work or the scheduling of all or a portion thereof;
(d) Networks does not have to use its employees, agents and contractors performing the Networks Connection Work elsewhere on its transmission system or distribution system due to an Emergency (as that term is defined in the Transmission System Code) or an event of force majeure;
(e) Networks is able to obtain the materials and labour required to perform the Networks Connection Work with the expenditure of Premium Costs where required;
(f) where Networks needs to obtain leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998* (being Schedule "B" of the *Energy Competition Act, S.O. 1998, c. 15)*, such leave is obtained by no later than the date specified as the Approval Date in Schedule "A" of the Agreement;

(g) the Customer executed this Agreement by no later than the date specified as the Execution Date in Schedule "A"; and
(h) Networks obtains internal approval to commit the funds for the Project.

7. Upon completion of the Networks Connection Work:

(a) Networks shall own, operate and maintain all equipment referred to in Schedule "A" of the Agreement; and
(b) other than equipment referred to in (a) above that will be owned, operated and maintained by Networks, all other

equipment provided by Networks as part of the Networks Connection Work or provided by the Customer as part of the Customer Connection Work will be owned, operated and maintained by the Customer.

The Customer acknowledges that:

(i) ownership and title to the equipment referred to in (a) above shall throughout the Term and thereafter remain vested in Networks and the Customer shall have no right of property therein;
(ii) that any portion of the equipment referred to in (a) above that is located on the Customer's property shall be and remain the property of Networks and shall not be or become fixtures and/or part of the Customer's property; and
(iii) the right to the benefit of any capital cost allowance determined for capital contribution(s) by the Customer for the equipment referred to in (a) above shall be the Customer's.

8. The Customer acknowledges and agrees that Networks is not responsible for the provision of power system components on the Customer's Facilities, including, without limitation, all transformation, switching, metering and auxiliary equipment such as protection and control equipment.

All of the power system components on the Customer's side of the Connection Point including, without limitation, all transformation, switching and auxiliary equipment such as protection and control equipment shall be subject to the acceptance of Networks with regard to Networks' requirements to permit connection of the New or Modified Facility to Networks' transmission system, and shall be installed, maintained and operated in accordance with all applicable laws, codes and standards, including, but not limited to, the Transmission System Code, at the expense of the Customer. Networks acceptance is solely for the protection of Networks' Facilities.

9. Where Networks has equipment for automatic reclosing of circuit breakers after an interruption for the purpose of improving the continuity of feeder connection, it shall be the obligation of the Customer to provide adequate protective equipment for the Customer's facilities that might be adversely affected by the operation of such reclosing equipment. The Customer shall provide such equipment as may be required from time to time by Networks for the prompt disconnection of any of the Customer's apparatus that might affect the proper functioning of Networks' reclosing equipment.

10. The Customer shall provide Networks with copies of the documentation specified in Schedule "A" of the Agreement under the heading "Documentation Required", acceptable to Networks, by no later than 120 calendar days after the Ready for Service Date. The Customer shall ensure that Networks may retain this documentation for Networks' ongoing planning, system design, and operating review. Where the New or Modified Facility is owned by the Customer, the Customer shall also maintain and revise such documentation to reflect changes to the New or Modified Facility and provide copies to Networks on demand and as specified in the Connection Agreement.

11. Nothing contained within the Agreement, including, subsection 13 below shall preclude, prevent, prohibit or operate as a waiver of any of the parties rights to make application to the OEB, participate in any hearings before the OEB or to make any appeals to a Court of competent jurisdiction regarding any decision by the OEB with respect to any costs and the allocation of any costs associated with, related to, or arising out of the connection of the Project to Networks' transmission system or Networks' policies in respect of connections generally.

Part B: Transformation Connection Pool Work and/or Line Connection Pool Work and Non-Poolable Work

12. The Customer shall pay Networks the Cost of the Networks Connection Work described as the Transformation Connection Pool Work and/or Line Connection Pool Work in Schedule "A" of the Agreement which is the amount specified in Schedule "B" of the Agreement (plus applicable taxes) being the amount shown as the "Transformation Connection Pool Work Cost" and/or the "Line Connection Pool Work Cost".

The Customer shall pay Networks the Capital Contribution (plus applicable taxes) in the manner specified in Schedule "B" of the Agreement for that part of the Transformation Connection Pool Work and/or the Line Connection Pool Work that cannot be supported by revenue guarantees.

The Cost of the Transformation Connection Pool Work and/or Line Connection Pool Work less any Capital Contribution paid by the Customer is a debt owed to Networks by the Customer and subject to Sections 13 and 14 below, that debt shall be paid by the Customer to Networks on the earlier of the following dates:

(i) the Guaranteed Revenue Date; and
(ii) the date of termination of the Agreement.

13(a). Notwithstanding Section 12, the parties further agree that, provided that the Actual Incremental Transformation Connection Revenue and/or the Actual Incremental Line Connection Revenue received by Networks is equal to or exceeds the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue for a specified period, Networks will forgive an amount of the foregoing debt equal to the amount of the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the period in question provided that the Customer's peak load met or exceeded the Available Capacity during at least one month of the twelve month period in question.

13(b). Commencing on the first anniversary of the Ready for Service Date and every year thereafter during the Term, if the Customer's peak load fails to meet or exceed the Available Capacity during at least one month of the period, the Customer will not receive a credit for that period and the Customer shall pay Networks the Guaranteed Incremental Transformation Connection Revenue specified for the period in question by no later than 30 days after the date of Networks' invoice therefor.

13(c). Commencing on the fifth anniversary of the Ready for Service Date and every fifth year thereafter during the Term, if the Actual Incremental Transformation Connection Revenue and/or Actual Incremental Line Connection Revenue received by Networks is less than the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the previous five periods in question, the Customer shall pay Networks the difference by no later than 30 days after the date of Networks' invoice therefor.

13(d). For every period during the Term, with the exception of every fifth period commencing on the fifth anniversary of the Ready for Service Date and every fifth year thereafter, if the Actual Incremental Transformation Connection Revenue and/or Actual Incremental Line Connection Revenue received by Networks is less than the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the period in question and such difference is less than 20% of the Guaranteed Incremental Transformation Connection

Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the period in question, the Customer shall be entitled to carry forward that amount (the "Carry Forward Amount"), which shall be added to the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue for the following period to result in a Revised Guaranteed Incremental Transformation Connection Revenue and/or Revised Guaranteed Incremental Line Connection Revenue for the next following period.

Thereafter any reference to:

(I) Guaranteed Incremental Transformation Connection Revenue in the Agreement shall mean the greater of Guaranteed Incremental Transformation Connection Revenue for the period in question and the Revised Guaranteed Incremental Transformation Connection Revenue; AND

(II) Guaranteed Incremental Line Connection Revenue in the Agreement shall mean the greater of Guaranteed Incremental Line Connection Revenue for the period in question and the Revised Guaranteed Incremental Line Connection Revenue.

13(e). Notwithstanding Section 13(c) above, if in any period during the Term, the Actual Incremental Transformation Connection Revenue and/or Actual Incremental Line Connection Revenue received by Networks is less than the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the period in question and such difference is greater than 20% of the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the period in question, the Customer shall pay Networks the difference by no later than 30 days after the date of Networks' invoice therefor.

13(f) Commencing on the fifth anniversary of the Ready for Service Date and every fifth year thereafter, if the Actual Incremental Transformation Connection Revenue and/or Actual Incremental Line Connection Revenue received by Networks is more than the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the five periods in question, Networks will reduce the amount of debt owing by the Customer by reducing the amount of Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue that must be received by Networks during the next five periods shown in Schedule B of the Agreement such that the total reduction over the next five periods is equal to the excess amount received by Networks. This may have the effect of shortening the Term of the Agreement.

13(g). The Customer acknowledges and agrees that:

(a) the Actual Incremental Transformation Connection Revenue is distinct revenue that does not include Transformation Connection revenue derived from Base Load Trigger Point or any network revenue; and

(b) the Actual Incremental Line Connection Revenue is distinct revenue that does not include Line Connection revenue derived from Base Load Trigger Point or any network revenue.

13(h) For every period during the Term, Networks shall provide the Customer with an annual reconciliation report which shows the Actual Incremental Transformation Connection Revenue and/or Actual Incremental Line Connection Revenue received by Networks and any adjustment to the debt, if any, owed by the Customer to Networks.

14. The Customer shall pay the amount shown for the cost of the Networks Connection Work described as Non-Pool Work in Schedule "A" of the Agreement which is the amount specified in Schedule "B" of the Agreement (plus applicable taxes) in the manner specified in Schedule "B" of the Agreement.

15. As the Project is schedule-driven and as the monetary amounts specified in Schedule "B" of the Agreement are based upon normal timelines for delivery of material and performance of work, in addition to the amounts that the Customer is required to pay pursuant to Section 12 and 14 above, the Customer agrees to pay Networks' Premium Costs if the Customer causes or contributes to any delays, including, but not limited to, the Customer failing to execute the Agreement by the Execution Date specified in Schedule "A" of the Agreement.

Networks will obtain the Customer's approval prior to Networks authorizing the purchase of materials or the performance of work that will attract Premium Costs. The Customer acknowledges that its failure to approve an expenditure of Premium Costs may result in further delays and Networks will not be liable to the Customer as a result thereof. The Customer shall pay any prior-approved Premium Costs within 30 calendar days after the date of Networks' final invoice therefor, billable at the end of the project. Interest shall be payable at the rate of 18 per cent per year on all overdue payments. The obligation to pay any amount hereunder shall survive the termination of the Agreement.

16(a) If the Project is cancelled or the Agreement is terminated for any reason whatsoever other than breach of the Agreement by Networks, the Customer shall pay Networks' Actual Costs incurred on and prior to the date that the Project is cancelled or the Agreement is terminated, including the preliminary design costs and all costs associated with the winding up of the Project, including, but not limited to, storage costs, facility removal expenses and any environmental remediation costs.

If the Customer provides written notice to Networks that it is cancelling or deferring the Project, Networks shall have 10 Business Days to provide written notice to the Customer listing the individual items listed as materials which it agrees to purchase. Networks shall deduct the actual costs of those individual items of materials being purchased by Networks from the Actual Costs referred to above.

If Networks does not require all or part of the materials, the Customer may exercise any of the following options or a combination thereof:

(ii) where materials have been ordered but all or part of the materials have not been received by Networks, the Customer shall have the right to require Networks, at the Customer's sole expense, to continue with the purchase of the materials and transfer title to those materials on an "as is, where is basis" to the Customer upon the Customer paying Networks' Actual Costs for such materials, provided that the Customer exercises this option within 15 Business Days of the termination, cancellation or deferral;

(ii) where all or part of the materials have been received by Networks but have not been installed, the Customer shall have the right to require Networks, at the Customer's sole expense, to transfer title to the materials on an "as is, where is basis" to the Customer upon the Customer paying Networks' Actual Costs for such materials, provided that the Customer exercises this option within 15 Business Days of the termination, cancellation or deferral. The Customer shall

also be responsible for any warehousing costs associated with the storage of the materials to the date of transfer; or

(iii) where all or part of the materials have been received by Networks and have been installed, the Customer shall have the right to require Networks, at the Customer's sole expense, to: transfer title to the materials on an "as is, where is basis" to the Customer upon the later of (A) the Customer paying Networks' Actual Costs for such materials; and (B) the date that Networks removes the materials from its property at the risk of the Customer; provided that the Customer exercises this option within 15 Business Days of the termination, cancellation or deferral. The Customer shall also be responsible for any costs associated with the installation and the removal of the materials that have been installed by Networks.

The Customer shall pay all amounts which become payable under this Section within 30 calendar days after the date of invoice.

16(b). If the Customer wishes to defer the Project, the Parties will negotiate the terms of such deferral.

17. In the event that the Customer sells, leases or otherwise transfers or disposes of the Customer's Facilities to a third party during the Term of the Agreement, the Customer shall cause the purchaser, lessee or other third party to whom the Customer's Facilities are transferred or disposed to enter into an assumption agreement with Networks to assume all of the Customer's obligations in the Agreement; and notwithstanding such assumption agreement, the Customer shall remain obligated to pay the amounts thereafter payable pursuant to Sections 12, 13, 14, 15 and 16 by the purchaser, lessee or other third party in the case of a transfer or disposition. The Customer further acknowledges and agrees that in the event that all or a portion of the Customer's Facilities are shut down, abandoned or vacated for any period of time during the Term of the Agreement, the Customer shall remain obligated to pay the amounts payable pursuant to Sections 12, 13, 14 and 15 for the said time period.

Part C:

18. In the event that the Transformation Connection Service Rate or the Line Connection Service Rate is rescinded or the components, or the methodology of determination of such rates is materially changed, the Parties agree to negotiate a new mechanism for the purposes of the Agreement. The Parties shall have 90 calendar days or longer if mutually agreed to by the parties in writing from the effective date of rescission or fundamental change of the Transformation Connection Service Rate or the Line Connection Service Rate to agree to a new mechanism. If the Parties are unable to successfully negotiate a replacement within that 90 calendar day period, they shall submit to arbitration, in accordance with the requirements of the Transmission System Code (or the Connection Agreement attached thereto); or if there is no arbitration provision in the Transmission System Code (or the Connection Agreement attached thereto), to the requirements of the *Arbitration Act, 1991* (Ontario), as amended, to settle on a new mechanism. The decision of the arbitrator shall be binding on each party with no right of appeal.

The terms of reference of the arbitration shall be to identify a new mechanism that is, to the extent possible, fair to the parties and constitutes a reasonably comparable replacement for the Transformation Connection Service Rate or the Line Connection Service Rate.

Any settlement on a new mechanism pursuant to this Section 18 shall apply retroactively from the date on which the Transformation Connection Service Rate or the Line Connection Service Rate was rescinded or fundamentally changed. Until such time as a new mechanism is determined hereunder, any amounts to be paid by the Customer under the Agreement shall be based on the Transformation Connection Service Rate or the Line Connection Service Rate in effect prior to the effective date of any such changes.

19.1 The Customer:

(a) shall not Transmit or Distribute electricity using the Customer's Facilities to any load now or hereafter supplied from Networks' Facilities or Third Party Facilities and if the Customer does so, the Customer shall pay Networks an amount equal to the avoided applicable Transmission Rates as if the load remained on Networks' Facilities or the Third Party Facilities, as the case may be, until the date that:

(i) Networks' Facilities or the Third Party Facilities are removed from service at end-of-useful-life and are not replaced by new transmission facilities; or
(ii) Networks requires Networks' Facilities to provide transmission services to other Customers or the affected third party requires the Third Party Facilities to supply its customers.

(b) shall not permit any third party to transmit or distribute electricity using or by connecting to the Customer's Facilities or in any other manner, to any load now or hereafter supplied from Networks' Facilities or the Third Party Facilities and if the Customer does so, the Customer shall pay Networks an amount equal to the avoided applicable Transmission Rates as if the load remained on Networks' Facilities or the Third Party Facilities until the date that:

(i) Networks' Facilities or the Third Party Facilities are removed from service at end-of-useful-life and are not replaced by new transmission facilities; or
(ii) Networks requires Networks' Facilities to provide transmission services to other customers or the affected third party requires the Third Party Facilities to supply its customers.

(c) shall not supply new load growth using the Customer's Facilities or the Third Party Facilities when Networks has spare capacity available at Networks' Facilities to supply such load; and if it does so, the Customer shall pay Networks an amount equal to the avoided applicable Transmission Rates by paying as if the new load were supplied from the Networks Facilities. Notwithstanding the foregoing, the Customer will not owe any amounts to the Networks, if the Customer can demonstrate to the satisfaction of the Networks, acting reasonably, that it would have been uneconomic or inefficient for the Customer to supply the load growth in question using Networks' Facilities.

(d) shall cause the purchaser, lessee or other third party to whom the Customer sells, leases, or otherwise transfers or disposes of the Customer's Facilities to enter into an assumption agreement with Networks to assume all of the Customer's obligations under this Section 19.1.

19.2 Nothing contained within this Agreement, including, without limiting the generality of the foregoing, Section 19.1, shall preclude, prevent, prohibit or operate as a waiver of any of the Parties' rights to:

(i) make application to the OEB;
(ii) participate in any hearings before the OEB; or
(iii) make any appeals to a Court of competent jurisdiction regarding any decision by the OEB,

with respect to any matter, issue, thing, interpretation, consideration or consequence whatsoever that is related to:

A. the Transmission or Distribution of electricity to any load now or hereafter supplied from Networks' Facilities or the facilities of any licensed electricity distributor by the Customer or by a third party using the Customer's Facilities to supply said load;
B. the interpretation or application of Section 19.1 above; and
C. the Transmission and Distribution of electricity to any load now or hereafter supplied from Networks facilities other than Networks' Facilities or from facilities of any licensed electricity distributor by any other Customer or by a third party.

19.3 Section 19.1 shall be subject to and applied in accordance with any Order or decision made by the OEB or any court with respect to any matter, issue, thing, interpretation, consideration or consequence that relates to:

(i) the Transmission and Distribution of electricity to any load now or hereafter supplied from Networks' Facilities or the facilities of any licensed distributor by the Customer or by a third party using the Customer's Facilities to supply said load; and
(ii) the terms and conditions of Section 19.1.

19.4 With respect to any Order or decision of the OEB or a court relating to the Transmission or Distribution of electricity to any load now or hereafter supplied from facilities other than Networks' Facilities or from the facilities of any licensed distributor by any Customer other than by the Customer or by a third party, the parties acting reasonably shall agree in writing as to application of said Order or decision to Section 19.1 and to any amendments thereto.

19.5 Sections 19.1 to 19.4 inclusive shall survive the termination of this Agreement and will be terms of any Connection Agreement or such other agreement as required by the Transmission System Code that is applicable to the owner and/or operator of the Customer's Facilities.

Part D: Easement

20. If specified in Schedule "A" that an easement is required, the Customer shall or the Customer shall cause the third party specified in Schedule "A" to grant an easement to Networks substantially in the form of the easement that will be attached hereto as Appendix "C", if required, for the property described as the Easement Lands in Schedule "A" by no later than the date specified as the Easement Date in Schedule "A" (hereinafter referred to as the "Easement") with good and marketable title thereto, free of all encumbrances, first in priority except as noted herein, and in registerable form, in consideration of the sum of $2.00.

The above Easement shall be for perpetuity (the "Term") commencing on the In-Service Date provided that in the event that Networks removes the asset that is the subject of the Easement during the term, Networks shall surrender the Easement at that time. Subject to the foregoing, the Easement shall survive the termination of the Agreement.

Part E: Events of Default

21. Each of the following events shall constitute an "Event of Default" under the Agreement:

(a) failure by the Customer to pay any amount due under the Agreement, including any amount payable pursuant to Sections 12, 13, 14, 15 or 16 within the time stipulated for payment;
(b) breach by the Customer or Networks of any Material term, condition or covenant of the Agreement; or
(c) the making of an order or resolution for the winding up of the Customer or of its operations or the occurrence of any other dissolution, bankruptcy or reorganization or liquidation proceeding instituted by or against the Customer.

22. Upon the occurrence of an Event of Default by the Customer hereunder (other than those specified in section 21(c) of the Agreement, for which no notice is required to be given by Networks), Networks shall give the Customer written notice of the Event of Default and allow the Customer 30 calendar days from the date of receipt of the notice to rectify the Event of Default, at the Customer's sole expense. If such Event of Default is not cured to Networks' reasonable satisfaction within the 30 calendar day period, Networks may, in its sole discretion, exercise the following remedy in addition to any remedies that may be available to Networks under the terms of the Agreement, at common law or in equity: deem the Agreement to be repudiated and, after giving the Customer at least 10 calendar days' prior written notice thereof, recover, as liquidated damages and not as a penalty, the balance of the amounts payable by the Customer pursuant to Sections 12, 13, 14, 15 and 16.

23 Upon the occurrence of an Event of Default by Networks hereunder, the Customer shall give Networks written notice of the Event of Default and shall allow Networks 30 calendar days from the date of receipt of the notice to rectify the Event of Default at Networks' sole expense. If such Event of Default is not cured to the Customer's reasonable satisfaction within the 30 calendar day period, the Customer may pursue any remedies available to it at law or in equity, including at its option the termination of the Agreement.

24. All rights and remedies of Networks and the Customer provided herein are not intended to be exclusive but rather are cumulative and are in addition to any other right or remedy otherwise available to Networks and the Customer respectively at law or in equity, and any one or more of Networks' and the Customer's rights and remedies may from time to time be exercised independently or in combination and without prejudice to any other right or remedy Networks or the Customer may have or may have exercised. The parties further agree that where any of the remedies provided for and elected by the non-defaulting party are found to be unenforceable, the non-defaulting party shall not be precluded from exercising any other right or remedy available to it at law or in equity.

In addition to any other remedy provided hereunder, all overdue amounts that are outstanding for longer than 30 days shall bear interest at 18% per annum.

Part F: Capital Contributions and Transmission System Code

25. Until Networks has published and the Ontario Energy Board has accepted Networks' procedure and methodology for determining the requirement for a capital contribution in accordance with Section 4.1 of the *Transmission System Code*, any Capital Contributions paid by the Customer under the terms of this Agreement are subject to adjustment with such adjustment to be solely based on the procedure and methodology accepted by the OEB.

Part G: Liability and Force Majeure

26. Other than for sums payable under the Agreement, the Customer shall only be liable to Networks and Networks shall only be liable to the Customer for any damages that arise directly out of the willful misconduct or negligence in meeting their respective obligations under the Agreement.

Despite the foregoing, neither Party shall be liable under any circumstances whatsoever for any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential, incidental or special damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in statute, contract, tort or otherwise.

This provision shall survive the termination of the Agreement.

27. Neither party shall be considered to be in default in the performance of its obligations under the Agreement, except obligations to make payments with respect to amounts already accrued, to the extent that performance of any such obligation is prevented or delayed by any cause, existing or future, which is beyond the reasonable control of, and not a result of the fault or negligence of, the affected party ("Force Majeure") and includes, but is not limited to, system operating conditions mandated by the IMO, strikes, lockouts and any other labour disturbances and manufacturer's delays for equipment or materials required for the Networks Connection Work. The non-affected party shall be relieved of any obligation hereunder during the continuation of the event of Force Majeure.

If a party is prevented or delayed in the performance of any such obligation by Force Majeure, such party shall immediately provide notice to the other party of the circumstances preventing or delaying performance and the expected duration thereof. Such notice shall be confirmed in writing as soon as reasonably possible. The party so affected by the Force Majeure shall endeavour to remove the obstacles which prevent performance and shall resume performance of its obligations as soon as reasonably practicable, except that there shall be no obligation on the party so affected by the Force Majeure where the event of Force Majeure is a strike, lockout or other labour disturbance.

Part H: General

28. No amendment, modification or supplement to the Agreement shall be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of the Agreement.

29. The failure of any party hereto to enforce at any time any of the provisions of the Agreement or to exercise any right or option which is herein provided shall in no way be construed to be a waiver of such provision or any other provision nor in any way affect the validity of the Agreement or any part hereof or the right of any party to enforce thereafter each and every provision and to exercise any right or option. The waiver of any breach of the Agreement shall not be held to be a waiver of any other or subsequent breach. Nothing shall be construed or have the effect of a waiver except an instrument in writing signed by a duly authorized officer of the party against whom such waiver is sought to be enforced which expressly waives a right or rights or an option or options under the Agreement.

30. Each party acknowledges and agrees that it has participated in the drafting of the Agreement and that no portion of the Agreement shall be interpreted less favourably to either party because that party or its counsel was primarily responsible for the drafting of that portion.

31. Any written notice required by the Agreement shall be deemed properly given only if either mailed or delivered to the Secretary, Hydro One Networks Inc., 483 Bay Street, South Tower, 10th Floor, Toronto, Ontario M5G 2P5, fax no: (416) 345-6240 on behalf of Hydro One, and to the person at the address specified in Schedule "A" of the Agreement on behalf of the Customer.

A faxed notice will be deemed to be received on the date of the fax if received before 3 p.m. or on the next business day if received after 3 p.m. Notices sent by courier or registered mail shall be deemed to have been received on the date indicated on the delivery receipt. The designation of the person to be so notified or the address of such person may be changed at any time by either party by written notice.

32. The Agreement shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of the Province of Ontario and the laws of Canada applicable therein, and, subject to Section 18, the courts of Ontario shall have exclusive jurisdiction to determine all disputes arising out of the Agreement.

33. The Agreement may be executed in counterparts, including facsimile counterparts, each of which shall be deemed an original, but all of which shall together constitute one and the same agreement.

34. The Customer shall provide Networks with a copy of the Customer's final monthly bills associated with Networks' Facilities and/or the Customer's Facilities or authorize the IMO to provide Networks with same. Networks agrees to use this information solely for the purpose of the Agreement.

35. The obligation to pay any amount due and payable hereunder, including, but not limited to, any amounts due under Sections 12, 13, 14, 15 or 16 shall survive the termination of the Agreement.

36. Each of the Parties hereto agrees to be bound by the terms of Appendix "D" attached hereto.

Appendix "A": Definitions

Throughout the Agreement, unless there is something in the subject matter or context inconsistent therewith, the following words shall have the following meanings:

"Actual Cost" means Networks' charge for equipment, labour and materials at Networks' standard rates plus Networks' standard overheads and interest thereon.

"Actual Incremental Transformation Connection Revenue" means the actual amount of transformation connection revenue attributable to the Incremental Load received by Networks through the monthly collection of the Transformation Connection Service Rate for the period specified in Schedule "B" of the Agreement.

"Actual Incremental Line Connection Revenue" means the actual amount of line connection revenue attributable to the Incremental Load received by Networks through the monthly collection of the Line Connection Service Rate for the period specified in Schedule "B" of the Agreement.

"Agreement" means the Connection Cost Recovery Agreement, Schedules "A" and "B" attached thereto and these Standard Terms and Conditions together with all appendices attached thereto.

"Applicable Laws", means any and all applicable laws, including environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments or decrees or any requirement or decision or agreement with or by any governmental or governmental department, commission board, court authority or agency.

"Approval Date" means for the purpose of Subsection 6(f) of the Terms and Conditions, the date specified in Schedule "A" of the Agreement.

"Available Capacity" is that portion of the existing capacity on Networks' Facilities that can effectively and economically serve the Customer's peak load and is as specified in Schedule "B" of the Agreement.

"Base Load Trigger Point" is as specified in Schedule "B" of the Agreement and was determined using the following formula:

Base Load Trigger Point = 3 yr. Avg. PLI * Available Capacity
With:
PLI = [(sum of Twelve Monthly Peaks)/Annual Peak*12]

"Business Day" means a day other than Saturday, Sunday, statutory holiday in Ontario or any other day on which the principal chartered banks located in the City of Toronto, are not open for business during normal banking hours.

"Capital Contribution" means the capital contribution amount or amounts specified in Schedule "B" of the Agreement.

"Confidential Information" means:

(i) the terms of this Agreement and the operations and dealings under this Agreement;
(ii) all information disclosed by a Party to the other Party under this Agreement or in negotiating this Agreement which by its nature is confidential to the Party disclosing the information; and
(iii) all interpretative reports or other data generated by a Party that are based in whole or in part on information that is made Confidential Information by clauses (i) and (ii).

"Connection Agreement" has the meaning set forth in the Transmission System Code.

"Connection Point" means the point where the New or Modified Facility is connected to Networks' transmission system.

"Cost" means Networks' charge for the Transformation Connection Pool Work Cost and/or the Line Connection Pool Work Cost as set out in Schedule "B" of the Agreement.

"Customer Connection Work" means the work to be performed by the Customer, at its sole expense, which is described in Schedule "A" of the Agreement.

"Customer's Facilities" has the meaning set forth in the Transmission System Code, and includes, but is not limited to the New or Modified Facility where the New or Modified Facility is owned by the Customer. In addition to the foregoing, Customer's Facilities may include any other assets specified in Schedule "A" of the Agreement.

"Customer's Property(ies)" means any lands owned by the Customer in fee simple or where the Customer has easement rights.

"Distribute" has the meaning ascribed thereto in the *Electricity Act, 1998*.

"Emergency" has the meaning set forth in the Transmission System Code.

"Good Utility Practice" has the meaning set forth in the Transmission System Code.

"Guaranteed Incremental Transformation Connection Revenue" means the minimum amount of transformation connection revenue specified in Schedule "B" attributable to the Load to be received by Networks through the monthly collection of the Transformation Connection Service Rate for the period specified in Schedule "B".

"Guaranteed Incremental Line Connection Revenue" means the minimum amount of line connection revenue specified in Schedule "B" of the Agreement attributable to the Load to be received by Networks through the monthly collection of the Line Connection Service Rate for the period specified in Schedule "B" of the Agreement.

"Guaranteed Revenue Date" means, for the purposes of Section 2 of the Terms and Conditions, the date specified in Schedule "B" of the Agreement.

"IMO Rules" means the Independent Market Operator (IMO) administered Market Rules, including, but not limited to Chapter 6 thereof.

"In Service Date" means the date that the IMO has approved the final connection of the New or Modified Facility.

"Incremental Load" is determined using the following formula:

[(sum of Twelve Monthly Peaks) – (Base Load Trigger Point *12]

"Line Connection Pool" is as defined or referenced in Networks' transmission rate schedules approved by the OEB on May 1, 2002.

"Line Connection Service Rate" means Networks' line connection service rate approved by the OEB from time to time, or any mechanism instituted in accordance with Section 18.

"Material" relates to the essence of the contract, more than a mere annoyance to a right, but an actual obstacle preventing the performance or exercise of a right.

"Networks Connection Work" means the work to be performed by Networks which is described in Schedule "A" of the Agreement.

"Networks' Facilities" means collectively the Networks' Facilities – LV and the Networks' Facilities – HV.

"Networks' Facilities – HV" means the facilities owned by Networks specified in Schedule "A" of the Agreement that convey electricity at voltages of more than 50 kilovolts.

"Networks' Facilities – LV" means the facilities owned by Networks specified in Schedule "A" of the Agreement that convey electricity at voltages of 50 kilovolts or less.

"Networks' Property(ies)" means any lands owned by Networks in fee simple or where Networks now or hereafter has obtained easement rights.

"New or Modified Facility" means the facilities specified in Schedule "A" of the Agreement.

"OEB" means the Ontario Energy Board.

"Pool" means the Transformation Connection Pool or the Line Connection Pool.

"Premium Costs" means those costs incurred by Networks in order to maintain or advance the Ready for Service Date, including, but not limited to, additional amounts expended for materials or services due to short time-frame for delivery; and the difference between having Networks' employees, agents and contractors perform work on overtime as opposed to during normal business hours.

"Ready for Service Date" means the date upon which the Networks Connection Work is fully and completely constructed, installed, commissioned and energised to the Connection Point. The Customer's disconnect switches must be commissioned prior to this date in order to use them as isolation points.

"Third Party Facilities" means any and all equipment, elements, and facilities of any kind whatsoever owned by someone other than the parties to this connection agreement and that are connected to Networks' transmission system.

"Transformation Connection Pool" is as defined or referenced in Networks' transmission rate schedules approved by the OEB on May 1, 2002.

"Transformation Connection Service Rate" means Networks' transformation connection service rate approved by OEB from time to time, or any mechanism instituted in accordance with Section 18.

"Transmission Rate" has the meaning set forth in the form of Connection Agreement attached to the Transmission System Code.

"Transmission System Code" means the code of standards and requirements issued by the OEB on July 14, 2000, as it may be amended from time to time, setting forth mandatory terms, conditions and obligations regarding connections between the facilities of distributors and the facilities of transmitters in accordance with the requirements of the *Ontario Energy Board Act, 1998,* including mandatory required terms and conditions for Connection Agreements.

"Transmit" has the meaning ascribed thereto in the *Electricity Act, 1998.*

Appendix "B": Access Provisions

1. When the Customer's staff, its contractors, or agents work at Networks' Facilities or site, Networks' safety and environmental requirements shall be observed by such staff, contractors and agents. As a minimum, all Applicable Laws shall govern such work.

2. The Customer's staff, its contractors, or agents working at Networks' Facilities or site shall be qualified to work around electrical hazards.

3. The Customer's staff, its contractors, or agents shall be entitled to access Networks' Facilities or site, and Networks will grant such access, to carry out work at all reasonable times on reasonable prior notice to Networks, subject to Networks' policies and procedures.

4. If the Customer wishes to have access to Networks' Facilities, the Customer shall notify Networks of the particular work to be undertaken and of the date and time when it proposes to access the relevant Facilities, subject to Networks' policies and procedures. Networks shall not unreasonably withhold access to its Facilities.

5. At any time when the Customer or its representatives are on or in Networks' site, the Customer and its representatives shall:

(a) use all reasonable precautions not to damage or interfere with Networks' site and Facilities;
(b) observe Networks' requirements for reporting occupational health and safety, electrical safety, environmental requirements, technical requirements, and matters of industrial relations; and
(c) neither ask questions, nor give any direction, instruction or advice to any person involved in operating or maintaining Networks' site or Facilities, other than the person whom Networks has designated for that purpose.

6. If the Customer or its representatives cause any loss or damage when given access to Networks', the Customer or its representative shall promptly advise Networks' controlling authority of the loss or damage.

7. The Customer shall not, and shall ensure that its representatives do not, intentionally interfere with any of Networks' Facilities in or on its sites. The Customer shall use reasonable efforts not to cause loss or damage to Networks' Facilities. If the Customer interferes with any of Networks' Facilities, it shall indemnify Networks for reasonable costs and expenses incurred from any resulting loss or damage.

8. In an emergency, Networks may, as far as reasonably necessary in the circumstances, have access to and interfere with the Customers' Facilities. Networks shall use reasonable efforts not to cause loss or damage to the Customer's Facilities. If Networks interferes with any of the Customer's Facilities, it shall indemnify the Customer for reasonable costs and expenses incurred from any resulting loss or damage.

9. Where the Customer requests assistance from Network beyond routine OM&A activities, the Customer shall pay Networks its Actual Costs related to the Customer's staff, contractors or agents accessing Network's Facilities or sites, including, but not limited to, the cost of having a Networks representative accompany the Customer's staff, contractors, or agents accessing Network's Facilities or sites in accordance with the invoices rendered by Networks.

10. The Customer shall indemnify and save harmless Networks from and against all liabilities, damages, suits, claims, demands, costs, actions, proceedings, causes of action, losses, expenses and injury (including death) of any kind or nature whatsoever (the "causes of action") resulting from, caused by or in any manner connected with installed Customer equipment on Networks' Facilities or sites or Customer's staff, its contractors, or agents accessing Network' Facilities or sites including, but not limited to:

(a) causes of actions arising out of health and safety violations or environmental spills;
(b) costs incurred by Networks having to pay other customers due to interruptions caused by the Customer;
(c) damage to Networks equipment;
(d) incremental costs and expenses incurred by Networks related to the Customer's equipment installations, removals, relocations, upgrades, or any other Customer work.

except to the extent that the "causes of action" are caused by the negligence or willful misconduct of Networks.

11. Where Networks staff, contractors, or agents require access to the Customer's Facilities or site, clauses 1 to 10 will apply reciprocally.

Appendix "C" : Form of Easement

INTEREST / ESTATE TRANSFERRED

The Transferor is the owner in fee simple and in possession of _____
_____
_____
_____
_____
_____ (the **"Lands"**).

The Transferee has erected, or is about to erect, certain Works (as more particularly described in paragraph 1(a) hereof) in, through, under, over, across, along and upon the Lands.

1 The Transferor hereby grants and conveys to Hydro One Networks Inc, its successors and assigns the rights and easement, free from all encumbrances and restrictions, the following unobstructed and exclusive rights, easements, rights-of-way, covenants, agreements and privileges in perpetuity (the **"Rights"**) in, through, under, over, across, along and upon that portion of the Lands of the Transferor described herein and shown highlighted on Schedule "A" hereto annexed (the **"Strip"**) for the following purposes:

(a) To enter and lay down, install, construct, erect, maintain, open, inspect, add to, enlarge, alter, repair and keep in good condition, move, remove, replace, reinstall, reconstruct, relocate, supplement and operate and maintain at all times in, through, under, over, across, along and upon the Strip an electrical transmission system and telecommunications system consisting in both instances of a pole structures, steel towers, anchors, guys and braces and all such aboveground or underground lines, wires, cables, telecommunications cables, grounding electrodes, conductors, apparatus, works, accessories, associated material and equipment, and appurtenances pertaining to or required by either such system (all or any of which are herein individually or collectively called the **"Works"**) as in the opinion of the Transferee are necessary or convenient thereto for use as required by Transferee in its undertaking from time to time, or a related business venture.

(b) To enter on and selectively cut or prune, and to clear and keep clear, and remove all trees (subject to compensation to Owners for merchantable wood values), branches, bush and shrubs and other obstructions and materials in, over or upon the Strip, and without limitation, to cut and remove all leaning or decayed trees located on the Lands whose proximity to the Works renders them liable to fall and come in contact with the Works or which may in any way interfere with the safe, efficient or serviceable operation of the Works or this easement by the Transferee.

(c) To conduct all engineering, legal surveys, and make soil tests, soil compaction and environmental studies and audits in, under, on and over the Strip as the Transferee in its discretion considers requisite.

(d) To erect, install, construct, maintain, repair and keep in good condition, move, remove, replace and use bridges and such gates in all fences which are now or may hereafter be on the Strip as the Transferee may from time to time consider necessary.

(e) Except for fences and permitted paragraph 2(a) installations, to clear the Strip and keep it clear of all buildings, structures, erections, installations, or other obstructions of any nature (hereinafter collectively called the **"obstruction"**) whether above or below ground, including removal of any materials and equipment or plants and natural growth, which in the opinion of the Transferee, endanger its Works or any person or property or which may be likely to become a hazard to any Works of the Transferee or to any persons or property or which do or may in any way interfere with the safe, efficient or serviceable operation of the Works or this easement by the Transferee.

(e) To enter on and exit by the Transferor's access routes and to pass and repass at all times in, over, along, upon and across the Strip and so much of the Lands as is reasonably required, for Transferee, its respective officers, employees, agents, servants, contractors, subcontractors, workmen and permittees with or without all plant machinery, material, supplies, vehicles and equipment for all purposes necessary or convenient to the exercise and enjoyment of this easement and

(f) To remove, relocate and reconstruct the line on or under the Strip.

2. The Transferor agrees that:

(a) It will not interfere with any Works established on or in the Strip and shall not, without the Transferee's consent in writing, erect or cause to be erected or permit in, under or upon the Strip any obstruction or plant or permit any trees, bush, shrubs, plants or natural growth which does or may interfere with the Rights granted herein. The Transferor agrees it shall not, without the Transferee's consent in writing, change or permit the existing configuration, grade or elevation of the Strip to be changed and the Transferor further agrees that no excavation or opening or work which may disturb or interfere with the existing surface of the Strip shall be done or made unless consent therefore in writing has been obtained from Transferee, provided however, that the Transferor shall not be required to obtain such permission in case of emergency. Notwithstanding the foregoing, in cases where in the reasonable discretion of the Transferee, there is no danger or likelihood of danger to the Works of the Transferee or to any persons or property and the safe or serviceable operation of this easement by the Transferee is not interfered with, the

Transferor may at its expense and with the prior written approval of the Transferee, construct and maintain roads, lanes, walks, drains, sewers, water pipes, oil and gas pipelines, fences (not to exceed 2 metres in height) and service cables on or under the Strip (the **"Installation"**) or any portion thereof; provided that prior to commencing such Installation, the Transferor shall give to the Transferee thirty (30) days notice in writing thereof to enable the Transferee to have a representative present to inspect the proposed Installation during the performance of such work, and provided further that Transferor comply with all instructions given by such representative and that all such work shall be done to the reasonable satisfaction of such representative. In the event of any unauthorised interference aforesaid or contravention of this paragraph, or if any authorised interference, obstruction or Installation is not maintained in accordance with the Transferee's instructions or in the Transferee's reasonable opinion, may subsequently interfere with the Rights granted herein, the Transferee may at the Transferor's expense, forthwith remove, relocate, clear or correct the offending interference, obstruction, Installation or contravention complained of from the Strip, without being liable for any damages caused thereby.

(b) notwithstanding any rule of law or equity, the Works installed by the Transferee shall at all times remain the property of the Transferee, notwithstanding that such Works are or may become annexed or affixed to the Strip and shall at anytime and from time to time be removable in whole or in part by Transferee.

(c) no other easement or permission will be transferred or granted and no encumbrances will be created over or in respect to the Strip, prior to the registration of a Transfer of this grant of Rights.

(d) the Transferor will execute such further assurances of the Rights in respect of this grant of easement as may be requisite.

(e) the Rights hereby granted:

(i) shall be of the same force and effect to all intents and purposes as a covenant running with the Strip.

(ii) is declared hereby to be appurtenant to and for the benefit of the Works and undertaking of the Transferee described in paragraph 1(a).

3. The Transferee covenants and agrees to obtain at its sole cost and expense all necessary postponements and subordinations (in registrable form) from all current and future prior encumbrancers, postponing their respective rights, title and interests to the Transfer of Easement herein so as to place such Rights and easement in first priority on title to the Lands.

4. There are no representations, covenants, agreements, warranties and conditions in any way relating to the subject matter of this grant of Rights whether expressed or implied, collateral or otherwise except those set forth herein.

5. No waiver of a breach or any of the covenants of this grant of Rights shall be construed to be a waiver of any succeeding breach of the same or any other covenant.

6. The burden and benefit of this transfer of Rights shall run with the Strip and the Works and undertaking of the Transferee and shall extend to, be binding upon and enure to the benefit of the parties hereto and their respective heirs, executors, administrators, successors and assigns.

CHARGEES

THE CHARGEE of land described in a Charge/Mortgage of Land dated _____

Between _____
and _____
_____

and registered as Instrument Number _____
on _____ does

hereby consent to this Easement and releases and discharges the rights and easement herein from the said

Charge/Mortgage of Land.

Name

Signature(s)
Date of Signatures

Y M
D

Per:

_____

_____

I/We have authority to bind the Corporation

Appendix "D": Confidentiality

1. Confidential Information shall at all times be treated as confidential, and shall be prepared, given, and used in good faith. The Parties shall use the Confidential Information only for the requirements of the work being performed including, but not limited to, planning or operating the Parties' Connection Facilities or Transmission Systems, and not for any other purpose, and shall not disclose it to any third party, directly or indirectly, without the prior written consent of the Party that provided the Confidential Information, and in such events the third party shall agree to use the Confidential Information solely for the requirements of the work as specified. Confidential Information shall not be used for any commercial purpose of any kind whatsoever other than contemplated herein.

2. "Confidential Information" does not include:

(a) information that is in the public domain, provided that specific items of information shall not be considered to be in the public domain merely because more general information is in the public domain and provided that the information is not in the public domain as a result of a breach of confidence by the Party seeking to disclose the information or a person to whom it has disclosed the information;
(b) information that is, at the time of the disclosure, in the possession of the recipient, provided that it was lawfully obtained either from the other Party or from sources, who did not acquire it directly or indirectly from the other Party under an obligation of confidence; and
(c) information that must be disclosed in compliance with a judicial or governmental order or other legal process.

3. Each Party shall keep Confidential Information confidential except:

(a) as may be necessary in an Emergency;
(b) to the extent required by applicable law;
(c) if required in connection with legal proceedings, arbitration or any expert determination relating to the subject matter of this Agreement, or for the purpose of advising a Party in relation thereto;
(d) to the extent required by the Party's licence; or
(e) to the extent required by the Market Rules or as may be required to enable a Party to fulfill its obligation to any reliability organization.

4. The Parties shall make any information required to be provided or communicated under the terms of this Agreement available to each other in a timely and co-operative manner.

5. The confidentiality provisions of this Schedule "D" will continue and survive for a period of 6 years after the termination of this Agreement.

6. Except as provided in this Agreement, each party acknowledges and agrees that it cannot disclose any Confidential Information of the other party (the "Disclosing Party") to anyone, including the OEB, without the consent of the Disclosing Party, which shall not be unreasonably withheld.

Notwithstanding the foregoing, each Party acknowledges and agrees that it can disclose the any confidential information with respect to the costs identified herein to the OEB as part of and for the purpose of making an application to the OEB, participating in any OEB hearings or making an appeal to a Court of competent jurisdiction regarding any decision of the OEB, provided that the Customer:

(i) requests that the OEB hold the Confidential Information in confidence in accordance with Section 3 of the OEB's "Guidelines for the Treatment of Filings made in Confidence – Phase 1" (effective March 19, 2001) (the "Guidelines"). Notwithstanding the generality of the foregoing, it is understood that:

(aa) the Customer will provide Networks with 10 business days prior written notice of its intention to file an application to the OEB which will include Confidential Information. The aforementioned notice will list the Confidential Information being filed by the Customer and Networks shall provide the Customer with:

1) a letter signed by a duly authorized signing officer of Networks providing a full explanation of the need for considering the Confidential Information confidential; and

2) the documentation required to be filed by the Customer under c) and d) of Section 3.2.1 of the Guidelines, where possible, with respect to the Confidential Information. Where it is not possible for Networks to provide an abridged version of one or more of the documents comprising the Confidential Information, Networks will provide an explanation in the letter described in Subsection 6(aa)1) as to why it is not possible to provide the abridged version(s).

(bb) the Customer will file any documentation provided by Networks under Subsection 6(c)(aa) with its application provided that Networks provides same to the Customer by no later than 10 business days following Networks' receipt of the notice of intention to file an application to the OEB.

(cc) the Customer's cover letter to the Board referenced in Subsection 3.2.1(b) of the Guidelines will include the following wording:

[the Customer] and Hydro One Networks Inc. are parties to an agreement that contains obligations of confidence with respect to information that Hydro One Networks Inc. considers confidential. The documentation that [the Customer] is requesting that the Ontario Energy Board hold in confidence is information that is protected by the aforementioned agreement. As such, [the Customer] is contractually bound to seek such protection. Attached to this letter is a letter signed by a duly authorized signing officer of Hydro One Networks Inc. providing a full explanation of the need for considering the documentation confidential.

(dd) if a panel hears or chooses to have a Panel of Board Members (a "Panel") make a determination on the issue of confidentiality, the Customer shall request that the Board permit Networks to be a party so as to be able to make submissions with respect to the Confidential Information.

(ee) the Customer shall not make submissions to the OEB or any panel of the OEB requesting or supporting any request that the Confidential Information be made public.

(ff) if a Panel determines that any of the documents comprising Confidential Information should be made public, Networks will have the right to appeal, or to request a rehearing or a judicial review of the determination in accordance with Section 3.7.1 of the Guidelines.

CCRA – Kenilworth TS

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CONNECTION AND COST RECOVERY AGREEMENT (CCRA) – Simplified – Kenilworth TS New Cap Bank

THIS CONNECTION AND COST RECOVERY AGREEMENT made between Hydro One Networks Inc. (**"Hydro One"**) and Alectra Utilities Corporation (the **"Customer"**) dated September 10, 2024 **.**

WHEREAS:

(a) The Customer is requesting Hydro One to purchase, install and connect a new capacitor bank for power factor correction, (to be in compliance with IESO's market rules), on Hydro One's transmission system within Kenilworth TS (the "**Proposed Project**").

(b) Hydro One is agreeable to performing the work required for the Project on the following terms and conditions, including but not limited to the Project cost and the Project schedule being subject to the Customer executing and delivering this Agreement to Hydro One by no later than September 27, 2024 (the **"Execution Date"**).

NOW THEREFORE in consideration of the mutual covenants, agreements, terms and conditions herein and other good and valuable consideration, the receipt and sufficiency of which is hereby irrevocably acknowledged, the parties agree as follows:

1. Each of the parties hereto confirms the truth and accuracy of the recitals and agrees that the recitals form part of this Agreement.

2. Subject to Section 13 and the termination rights herein, the Agreement shall be in full force and effect and binding on the parties as of the date that the parties execute the Agreement (the **"Effective Date**") and shall expire on the date that the Customer pays Hydro One the final invoice in full for Work Chargeable to Customer or Hydro One issues a refund to the Customer in accordance with Section 10 hereof (the "**Term**").

3. Each party represents and warrants to the other that:

(a) it is duly incorporated, formed or registered (as applicable) under the laws of its jurisdiction of incorporation, formation or registration (as applicable);

(b) it has all the necessary corporate power, authority and capacity to enter into the Agreement and to perform its obligations hereunder;

(c) the execution, delivery and performance of the Agreement by it has been duly authorized by all necessary corporate and/or governmental and/or other organizational action and does not (or would not with the giving of notice, the lapse of time or the happening of any other event or condition) result in a violation, a breach or a default under or give rise to termination, greater rights or increased costs, amendment or cancellation or the acceleration of any obligation under (i) its charter or by-law instruments; (ii) any Material contracts or instruments to which it is bound; or (iii) any Applicable Laws;

(d) any individual executing this Agreement, and any document in connection herewith, on its behalf has been duly authorized by it to execute this Agreement and has the full power and authority to bind it;

(e) the Agreement constitutes a legal and binding obligation on it, enforceable against it in accordance with its terms;

(f) it is registered for purposes of Part IX of the Excise Tax Act (Canada). The HST registration number for Hydro One is [redacted] and the HST registration number for the Customer is as specified in Schedule "C" of the Agreement; and

(g) no proceedings have been instituted by or against it with respect to bankruptcy, insolvency, liquidation or dissolution.

Part A: Work Chargeable to Customer and Customer Work

4. The Customer and Hydro One shall perform their respective obligations outlined in the Agreement in a manner consistent with Good Utility Practice and the Transmission System Code, in compliance with all Applicable Laws, including, but not limited to the requirements of the Electrical Safety Authority, and using duly qualified and experienced people.

5. The parties acknowledge and agree that:

(a) Hydro One is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Work Chargeable to Customer;

(b) the Customer is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Customer Work;

(c) the Customer shall perform the Customer Work at its own expense;

(d) the Customer is responsible for installing equipment and facilities such as protection and control equipment to protect its own property, including, but not limited to the Customer's Facilities;

(e) the Customer shall provide Hydro One with Project data required by Hydro One, including, but not limited to: (i) the same technical information that the Customer provided the IESO during any connection assessment and facility registration process associated with the Customer's Facilities in the form outlined in the applicable sections of the IESO's public website and (ii) technical specifications (including electrical drawings) for the Customer's Facilities;

(f) Hydro One may participate in the commissioning, inspection or testing of the Customer Work at a time that is mutually agreed by Hydro One and the Customer and the Customer shall ensure that the work performed by the Customer and others required for successful commissioning, inspection or testing of protective equipment is completed as required to enable Hydro One witnessing and testing to confirm satisfactory performance of such systems;

(f) unless otherwise provided herein, Hydro One's responsibilities under the Agreement with respect to the connection of the New or Modified Connection Facilities to Hydro One's transmission system shall be limited to the performance of the Work Chargeable to Customer;

(g) Hydro One is not permitted to connect any new, modified or replacement Customer's Facilities unless any required connection authorizations, certificate of inspection or other applicable approval have been issued or given by the Ontario Electrical Safety Authority in relation to such facilities;

(h) Hydro One may require that the Customer provide Hydro One with test certificates certifying that the Customer's Facilities have passed all relevant tests and comply with the Transmission System Code, the Market Rules, Good Utility Practice, the standards of all applicable reliability organizations and any Applicable Laws, including, but not limited to any certificates of inspection that may be required by the Ontario Electrical Safety Authority;

(i) in addition to the Work Chargeable to Customer described in Schedule "A", Hydro One shall provide the Customer with such technical parameters as may be required to assist the Customer in ensuring that the design of the Customer's Facilities is consistent with the requirements applicable to Hydro One's transmission system and the basic general performance standards for facilities set out in the Transmission System Code, including Appendix 2 thereof;

(j) if Hydro One requires access to the Customer's Facilities for the purposes of performing the Work Chargeable to Customer or the Customer requires access to Hydro One's facilities for the purposes of the Customer's Work, the parties agree that Section 27.13 of the Connection Agreement shall govern such access and is hereby incorporated in its entirety by reference into and forms an integral part of the Agreement. All references to "this Agreement" in Section 27.13 of the Connection Agreement shall be deemed to be a reference to this Agreement;

(k) the Customer shall enter into a Connection Agreement or a Connection Agreement Amending Agreement as required with Hydro One at least 14 calendar days prior to the connection;

(m) the Customer shall provide Hydro One with copies of the documentation specified in Schedule "C" of the Agreement under the heading "Documentation Required", acceptable to Hydro One, within 120 calendar days after the Ready for Service Date. The Customer shall ensure that Hydro One may retain this documentation for Hydro One's ongoing planning, system design, and operating review. The Customer shall also maintain and revise such documentation to reflect changes to the Customer's Facilities and provide copies to Hydro One on demand and as specified in the Connection Agreement; and

(n) owing to the duration of outages approved by the IESO, the portions of the Work Chargeable to Customer that must be performed by Hydro One during such outages will be subject to Premium Costs and Hydro One will not be required to obtain the Customer's permission for same.

6. The Work Chargeable to Customer and Hydro One's rights and requirements hereunder, including, but not limited to Hydro One's:

(i) specifications of the protection equipment on the Customer's side of the Connection Point;

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(ii) review and acceptance of power system components on the Customer's side of the Connection Point;
(iii) acceptance of the technical specifications (including electrical drawings) for the Customer's Facilities; and
(iv) participation in the commissioning, inspection and testing of the Customer's Facilities;

are solely for the purpose of Hydro One ensuring that the Customer's Facilities will not materially reduce or adversely affect the reliability of Hydro One's transmission system and do not adversely affect other customers connected to Hydro One's transmission system.

7. Hydro One shall use reasonable efforts to complete the Work Chargeable to Customer by January 30, 2026 (the "**Ready for Service Date**") provided that:

(a) the Customer is in compliance with its obligations in this Agreement;

(b) any work required to be performed by third parties has been performed in a timely manner and in a manner to the satisfaction of Hydro One, acting reasonably;

(c) there are no delays resulting from Hydro One not being able to obtain outages from the IESO required for the Work Chargeable to Customer or from the IESO making changes to the Work Chargeable to Customer or the scheduling of all or a portion thereof;

(d) Hydro One does not have to use its employees, agents and contractors performing the Work Chargeable to Customer elsewhere on its transmission system or distribution system due to an Emergency (as that term is defined in the Transmission System Code) or a Force Majeure Event (as that term is defined in the Connection Agreement);

(e) Hydro One is able to obtain the materials and labour required to perform the Work Chargeable to Customer with the expenditure of Premium Costs where required;

(f) there are no delays resulting from Hydro One being unable to obtain materials or equipment required from suppliers in time to meet the project schedule for any portion of the Work Chargeable to Customer provided that such delays are beyond the reasonable control of Hydro One; and

(g) the Customer executed the Agreement on or before the date specified as the Execution Date in the recitals.

8. Upon completion of the Work Chargeable to Customer, Hydro One shall own, operate and maintain all equipment and facilities installed by Hydro One as part of the Work Chargeable to the Customer in, under, on, over, along, upon, through and crossing Hydro One's Property(ies).

The Customer acknowledges that:

(i) ownership and title to the equipment referred to above shall throughout the Term and thereafter remain vested in Hydro One and the Customer shall have no right of property therein; and

(ii) that any portion of the equipment referred to above that is located on the Customer's Property(ies) shall be and remain the property of Hydro One and shall not be or become fixtures and/or part of the Customer's Property(ies).

9. The Customer acknowledges and agrees that Hydro One is not responsible for the provision of power system components on the Customer's Facilities, including, without limitation, all transformation, switching, metering and auxiliary equipment such as protection and control equipment.

All of the power system components on the Customer's side of the Connection Point including, without limitation, all transformation, switching and auxiliary equipment such as protection and control equipment shall be subject to the acceptance of Hydro One with regard to Hydro One's requirements to permit connection of the New or Modified Connection Facilities to Hydro One's transmission system and shall be installed, maintained and operated in accordance with all Applicable Laws, codes and standards, including, but not limited to, the Transmission System Code, at the expense of the Customer.

Where Hydro One has equipment for automatic reclosing of circuit breakers after an interruption for the purpose of improving the continuity of feeder connection, it shall be the obligation of the Customer to provide adequate protective equipment for the Customer's Facilities that might be adversely affected by the operation of such reclosing equipment. The Customer shall provide such equipment as may be required from time to time by Hydro One for the prompt disconnection of any of the Customer's apparatus that might affect the proper functioning of Hydro One's reclosing equipment.

Part B: Work Chargeable to Customer

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10. The Customer shall pay Hydro One's Engineering and Construction Cost (plus applicable Taxes) of the Work Chargeable to Customer which is estimated to be the amount specified in Schedule "C" of the Agreement in the manner specified in Schedule "C" of the Agreement.

Within 180 days after the Ready for Service Date, Hydro One shall provide the Customer with an invoice or a credit memorandum specifying the actual Engineering and Construction Cost of the Work Chargeable to Customer (plus applicable Taxes).

Any difference between the Engineering and Construction Cost of the Work Chargeable to Customer (plus applicable Taxes) and the amount already paid by the Customer shall be paid within 30 days after the issuance of the invoice or credit memorandum by:

(a) Hydro One to the Customer, if the amount already paid by the Customer exceeds the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes); or
(b) the Customer to Hydro One, if the amount already paid by the Customer is less than the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes).

Part C: Events of Default

11. Each of the following events shall constitute an "Event of Default" under the Agreement:

(a) failure by the Customer to pay any amount due under this Agreement, including any amount payable pursuant to Section 10 within the time stipulated for payment;
(b) breach by the Customer or Hydro One of any Material term, condition or covenant of the Agreement; or
(c) the making of an order or resolution for the winding up of the Customer or of its operations or the occurrence of any other dissolution, bankruptcy or reorganization or liquidation proceeding instituted by or against the Customer.

For greater certainty, a dispute will not be considered an Event of Default under the Agreement. However, a party's failure to comply with the terms of a settlement or resolution of a dispute by the OEB will be considered an Event of Default under the Agreement.

12. Upon the occurrence of an Event of Default by the Customer hereunder (other than those specified in Section 11(c) of this Agreement, for which no notice is required to be given by Hydro One), Hydro One shall give the Customer written notice of the Event of Default and allow the Customer 30 calendar days from the date of receipt of the notice to rectify the Event of Default, at the Customer's sole expense. If such Event of Default is not cured to Hydro One's reasonable satisfaction within the 30 calendar day period, Hydro One may, in its sole discretion, exercise the following remedy in addition to any remedies that may be available to Hydro One under the terms of the Agreement, at common law or in equity: deem the Agreement to be repudiated and, after giving the Customer at least 10 calendar days' prior written notice thereof, recover, as liquidated damages and not as a penalty, the balance of the amounts payable by the Customer pursuant to Section 10.

13. Upon the occurrence of an Event of Default by Hydro One hereunder, the Customer shall give Hydro One written notice of the Event of Default and shall allow Hydro One 30 calendar days from the date of receipt of the notice to rectify the Event of Default at Hydro One's sole expense. If such Event of Default is not cured to the Customer's reasonable satisfaction within the 30 calendar day period, the Customer may pursue any remedies available to it at law or in equity, including at its option the termination of the Agreement.

14. All rights and remedies of Hydro One and the Customer provided herein are not intended to be exclusive but rather are cumulative and are in addition to any other right or remedy otherwise available to Hydro One and the Customer respectively at law or in equity, and any one or more of Hydro One's and the Customer's rights and remedies may from time to time be exercised independently or in combination and without prejudice to any other right or remedy Hydro One or the Customer may have or may have exercised. The parties further agree that where any of the remedies provided for and elected by the non-defaulting party are found to be unenforceable, the non-defaulting party shall not be precluded from exercising any other right or remedy available to it at law or in equity.

Part D: Disputes

15. All disputes, including, but not limited to, disputes related to:

(a) the cost and the allocation of the costs under this Agreement;
(b) the cost and the allocation of costs of the Work Chargeable To Customer and notwithstanding Hydro One's decision not to allocate or to allocate any part of the costs of this work to the Customer at this time; or
(c) any other costs and the allocation of any other costs associated with, related to, or arising out of the connection of the Project to Hydro One's transmission system or Hydro One's policies in respect of connections generally,

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shall be dealt with in accordance with the dispute resolution procedure set out in the OEB-Approved Connection Procedures.

16. Before and after the existence of OEB-Approved Connection Procedures, if a dispute arises while Hydro One is performing the Work Chargeable to Customer, Hydro One shall not cease the work or slow the pace of the work without leave of the OEB.

17. Hydro One shall refund to the Customer or the Customer shall pay to Hydro One any portion of the Work Chargeable to Customer or the Work Not Chargeable to Customer, as the case may be, which the OEB subsequently determines should not have been allocated to the Customer or should have been allocated to the Customer by Hydro One but was not, as the case may be, or should have been allocated in a manner different from that all allocated by Hydro One in this Agreement. This obligation shall survive the termination of this Agreement.

Part E: Incorporation of Liability and Force Majeure Provisions

18. PART III: LIABILITY AND FORCE MAJEURE (with the exception of Section 15.5 thereof) of the Connection Agreement ("**Part III**") and Sections 1.1.12 and 1.1.17 of the Connection Agreement are hereby incorporated in their entirety by reference into and form an integral part of the Agreement. Unless the context otherwise requires, all references in Part III to "this Agreement" shall be deemed to be a reference to the Agreement and all references to the "the Transmitter" shall be deemed to be a reference to Hydro One.

For the purposes of this Section 18, the parties agree that the references to:

(i) the Transmitter in lines 3 and 4 of Section 15.1 of Part III means the Transmitter or any party acting on behalf of the Transmitter such as contractors, subcontractors, suppliers, employees and agents; and

(ii) the Customer in lines 3 and 4 of Section 15.2 of Part III means the Customer or any party acting on behalf of the Customer such as contractors, subcontractors, suppliers, employees and agents.

Part F: General

19. This Agreement is subject to the Transmission System Code and the OEB-Approved Connection Procedures. If any provision of this Agreement is inconsistent with the:

(a) Transmission System Code, the said provision shall be deemed to be amended so as to comply with the Transmission System Code;
(b) OEB-Approved Connection Procedures, the said provision shall be deemed to be amended so as to comply with the OEB-Approved Connection Procedures; or
(c) Connection Agreement made between the parties, associated with the new customer connection facilities, the Connection Agreement governs.

20. The failure of any party hereto to enforce at any time any of the provisions of the Agreement or to exercise any right or option which is herein provided shall in no way be construed to be a waiver of such provision or any other provision nor in any way affect the validity of the Agreement or any part hereof or the right of any party to enforce thereafter each and every provision and to exercise any right or option. The waiver of any breach of the Agreement shall not be held to be a waiver of any other or subsequent breach. Nothing shall be construed or have the effect of a waiver except an instrument in writing signed by a duly authorized officer of the party against whom such waiver is sought to be enforced which expressly waives a right or rights or an option or options under the Agreement.

21. Other than as provided in this Agreement, no amendment, modification or supplement to the Agreement shall be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of the Agreement.

22. Any written notice required by the Agreement shall be deemed properly given only if either mailed or delivered to Robert Reinmuller, P.Eng., Vice President, Transmission System Planning & Large Customer, Hydro One Networks Inc., 483 Bay Street, Toronto, Ontario, M5G 2P5, or by electronic mail to Robert.Reinmuller@HydroOne.com on behalf of Hydro One and at the address specified in the customer notice section of Schedule "C" on behalf of the Customer.

Notices sent by courier or registered mail shall be deemed to have been received on the date indicated on the delivery receipt. The designation of the person to be so notified or the address of such person may be changed at any time by either party by written notice.

23. The Agreement shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of the Province of Ontario and the laws of Canada applicable therein, and, subject to Section 15, the courts of Ontario shall

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have exclusive jurisdiction to determine all disputes arising out of the Agreement.

24. This Agreement may be executed in any number of counterparts and by different parties in separate counterparts, each of which when so signed shall be deemed to be an original and all of which taken together shall constitute one and the same Agreement. Any signature or acknowledgement required to be provided hereunder may be done so electronically or digitally, and each such electronic signature or acknowledgment will have the same legal effect, validity and enforceability as a handwritten signature or paper document.

25. The obligation to pay any amount due and payable hereunder, including, but not limited to, any amount due under Section 10 shall survive the termination of the Agreement.

26. Invoiced amounts are due 30 days after invoice issuance. All overdue amounts including, but not limited to amounts that are not invoiced but required under the terms of this Agreement to be paid in a specified time period, shall bear interest at 1.5% per month compounded monthly (19.56 percent per year) for the time they remain unpaid.

27. This Agreement will supersede the terms of any purchase orders issued by the Customer to Hydro One in respect of the Project irrespective of whether same have been issued by Customer and/or accepted by Hydro One on or after the execution of this Agreement by the Customer.

28. PART SEVEN: EXCHANGE AND CONFIDENTIALITY OF INFORMATION ("**Part 7**") and Sections 1.1.3 and 1.1.17 of the Connection Agreement are hereby incorporated in their entirety by reference into and form an integral part of this Agreement. Unless the context otherwise requires, all references in Part 7 to "this Agreement" shall be deemed to be a reference to this Agreement.

29. If the Project involves the installation of a Generation Facility by the Customer at the site of a load facility that is connected to or is connecting to the transmission system, the Customer acknowledges that Hydro One has informed the Customer that:

(a) other than in the circumstances described in Section 11.2.3A of the Code, Hydro One is required to collect bypass compensation (calculated in accordance with Section 11.2.6 of the Code) from the Customer under Section 11.2.1(b) of the Code if the Customer, while retaining its connection to Hydro One's transmission system, also connects its load facility to a Generation Facility such that the Customer reduces its load served directly by Hydro One's transmission system, and the line connection or transformation connection rates in relation to that facility will be reduced; and

(b) if the Generation Facility has an installed capacity of 2 MW or more for renewable generation and 1 MW or higher for non-renewable generation and is being installed to displace all or any portion of the load demand at the load facility, the amounts invoiced by the IESO for line and transformation connection services applicable to the load facility will be calculated such that the customer demand in any hour will be the sum of: (a) the load-adjusted demand supplied from the transmission system plus (b) the demand that is supplied by a Generation Facility in accordance with Note 3 of the Provincial Transmission Rates set out in the OEB-approved Uniform Transmission Rates (OEB-2021-0276)).

30. This Agreement constitutes the entire agreement between the parties with respect to the subject matter of this Agreement and supersedes all prior oral or written representations and agreements concerning the subject matter of this Agreement. Appendix A attached hereto and Schedules "A", "B" and "C" are to be read with and form part of this Agreement.

IN WITNESS WHEREOF, the parties hereto have caused this Connection and Cost Recovery Agreement to be executed by the signatures of their proper authorized signatories, as of the date written below.

HYDRO ONE NETWORKS INC.

Signed by:
Robert Reinmuller
24DC60989B73411...
Robert Reinmuller P.Eng.
VP, Transmission System Planning & Large Customer
Date: October 7, 2024
I have the authority to bind the Corporation

ALECTRA UTILITIES CORPORATION

Name: Mike Matthews
Title: EVP, Asset Strategy & Operations
Date: October 2, 2024
I have the authority to bind the Corporation

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Appendix "A": Definitions

In the Agreement, unless the context otherwise requires, terms which appear therein without definition, shall have the meanings respectively ascribed thereto in the Transmission System Code and unless there is something in the subject matter or context inconsistent therewith, the following words shall have the following meanings:

"Agreement" means the Simplified Connection and Cost Recovery Agreement, Appendix "A" and Schedules "A", "B" and "C" attached hereto.

"Applicable Laws" means any and all applicable laws, including environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments or decrees or any requirement or decision or agreement with or by any government or government department, commission board, court authority or agency.

"Business Day" means a day other than Saturday, Sunday, statutory holiday in Ontario or any other day on which the principal chartered banks located in the City of Toronto, are not open for business during normal banking hours.

"Confidential Information" has the meaning ascribed thereto in the Connection Agreement.

"Connection Agreement" means the form of connection agreement appended to the Transmission System Code as Appendix 1, Version A where the Customer is a load customer and Version B where the Customer is a generator (as that term is defined in the Transmission System Code). Notwithstanding the foregoing, if the Customer has a transmission connection agreement that has been modified in the manner described in Section 2 of Schedule 2 of Hydro One's OEB-issued transmission licence ET-2003-0035 (the "**Hydro One Licence**") to reflect the amendments described in Schedule 3 [for legacy system configurations as well as operating concerns for Bruce Power and OPG generation facilities] and/or Schedule 4 [to facilitate compliance with Power Reactor Operating Licences, issued by the Canadian Nuclear Safety Commission] of Hydro One's transmission licence ET-2003-0035; or has entered in the transmission connection agreement described in Section 3 of Schedule 2 of Hydro One's licence, any reference to Connection Agreement in this Agreement shall mean the Customer's executed transmission connection agreement with Hydro One.

"Connection Point" means the point where the Customer's Facilities are connected to Hydro One's transmission system or are connected to third party facilities connected to Hydro One's transmission system, as the case may be.

"Customer Work" means the work to be performed by the Customer, at its sole expense, which is described in Schedule "B" of this Agreement.

"Customer's Facilities" has the meaning set forth in the Transmission System Code.

"Customer's Property(ies)" means any lands owned by the Customer in fee simple or where the Customer has easement rights.

"Electricity Act, 1998" means the *Electricity Act, 1998* being Schedule "A" of *the Energy Competition Act*, S.O. 1998, c.15, as amended.

"Engineering and Construction Cost" means Hydro One's charge for equipment, labour and materials at Hydro One's standard rates plus Hydro One's standard overheads as well as interest during construction using Hydro One's capitalization rate in effect during the construction period.

"Force Majeure Event" has the meaning ascribed thereto in the Connection Agreement.

"Generation Facility" means a facility for generating electricity or providing ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system, and includes any structures, equipment or other things used for that purpose.

"Good Utility Practice" has the meaning set forth in the Transmission System Code.

"Hydro One's Property(ies)" means any lands owned by Hydro One in fee simple or where Hydro One now or hereafter has obtained easement rights.

"IESO" means the Independent Electricity System Operator continued under the Electricity Act, 1998.

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"In Service Date" has the same meaning ascribed to the term "come into service" in the Transmission System Code.

"Market Rules" rules made under section 32 of the *Electricity Act, 1998* (Ontario), including, but not limited to Chapter 6 thereof.

"Material" relates to the essence of the contract, more than a mere annoyance to a right, but an actual obstacle preventing the performance or exercise of a right.

"New or Modified Connection Facilities" means the facilities owned by Hydro One as specified in Schedule "C" of the Agreement.

"OEB" means the Ontario Energy Board.

"OEB-Approved Connection Procedures" means Hydro One's connection procedures as approved by the OEB from time to time.

"Ontario Energy Board Act" means the *Ontario Energy Board Act* being Schedule "B" of the *Energy Competition Act*, S.O. *1998*, c. 15, as amended.

"Premium Costs" means those costs incurred by Hydro One in order to maintain or advance the Ready for Service Date, including, but not limited to, additional amounts expended for materials or services due to short time-frame for delivery; and the difference between having Hydro One's employees, agents and contractors perform work on overtime as opposed to during normal business hours.

"Ready for Service Date" means the date upon which the Work Chargeable to Customer is fully and completely constructed, installed, commissioned and energised to the Connection Point. The Customer's disconnect switches must be commissioned prior to this date in order to use them as isolation points.

"Taxes" means all property, municipal, sales, use, value added, goods and services, harmonized and any other non-recoverable taxes and other similar charges (other than taxes imposed upon income, payroll or capital).

"Transmission System Code" means the code of standards and requirements issued by the OEB, as it may be amended, revised or replaced in whole or in part from time to time in accordance with the Section 70.2 and 70.3 of the *Ontario Energy Board Act*.

"Work Chargeable to Customer" means the work to be performed by Hydro One described in Schedule "A" of this Agreement.

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Schedule "A" (Kenilworth TS – cap bank)

PROJECT SCOPE - WORK CHARGEABLE TO CUSTOMER

Hydro One will perform the following work:

- Procure and install a 12 MVar capacitor bank;
- Installation of concrete foundation to support capacitor bank;
- Connect new capacitor bank to SC1Q breaker;
- Install new capacitor protections and modify station protections as required;
- Commissioning of breaker, protections and capacitor bank; and
- Installation of concrete encased duct and cable between SC1Q breaker on Q bus to the new capacitor bank.

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Schedule "B"

CUSTOMER WORK

The Customer will:

- Provide any coordination as required by Hydro One to accommodate installation of new capacitor bank.

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Schedule "C" (Project Title):

Part 1: Estimate of Engineering and Construction Cost:

Hydro One has estimated that the Engineering and Construction Cost of the Work Chargeable to Customer is $ **2,694,000** (excluding HST) (the "**Cost Estimate**") and is summarized as follows:

Project Description	**Estimated Engineering and Construction Cost**
Project Management	$172,000
Engineering	$514,000
Equipment & Materials	$852,000
Construction	$665,000
Stations &Operations	$124,000
Sub-Total	$2,327,000
Contractor's Contingency	$366,000
AFUDC* & Overheads	
Total Price ($)	$2,694,000

(*) AFUDC = Allowance for Funds Used During Construction and is the term used in the OEB accounting procedures meaning interest during construction if applicable.

Notes:
1. Price for preliminary engineering is not included in any of the prices above.
2. Contingency of 16% is included in the total.
3. Capital overheads are included in the total price.
4. Capital interest is included in the total price.
5. The Cost Estimate is a result of the following type of estimate performed by Hydro One:

√	Type of Estimate	Description	Typical Range of Estimate
	AACE* Class 3	**Detailed Estimate:** Prepared based on the completion of preliminary design activities which may include drawings, technical studies, and surveys. This estimate may represent 20% design definition and can include cost for materials/Procurement, Engineering and Project Management, Construction and Commissioning, Risk/Contingencies, Interest and Overheads.	+30% /-20%**
√	AACE Class 4	**Budgetary Estimate:** Prepared based on the completion of conceptual estimate which may include sketches, review of existing drawings, and a site assessment at the connecting customer's expense and upon completion of the CCEA. This estimate may represent 10% design definition and can be summarized into cost of Materials/Procurement, Engineering, Project management cost and Construction and Commissioning cost.	+50/-30%**
	AACE Class 5	**Conceptual Estimate:** Prepared based on the Customer's conceptual scope of work and is summarized into the following two basic groupings: ▪ Historical cost of Materials/Procurement ▪ Engineering, Project management, Construction and Commissioning.	+100/-50**
	Planner's Estimate	**High-level Ballpark Estimate for Preliminary Planning Purposes:** Provided when the Customer wants to bypass the estimating stage of the Transmission Connection Process and go straight to project execution using the unit costs from a somewhat comparable project (which may not be recent if the work to be performed by Hydro One is rarely performed or rarely performed in certain areas of the province).	None but substantially less accurate than AACE Class 5 Range

* Association for the Advancement of Cost Engineering
** AACE cost estimation system No. 18R-97.

Notwithstanding the type of estimate performed by Hydro One for the Project, the Customer shall pay Hydro One the Engineering and Construction Cost of the Work Chargeable to Customer. The Range of Estimate provided in the table above for estimates is indicative and not guaranteed by Hydro One. What the Range of Estimate does do is highlight the risk to the Customer that as the Range of Estimate for the type of estimate performed for the Project is less refined, the scope of the Work Chargeable to Customer contains a greater number of assumptions on the part of Hydro One which if they are incorrect may

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materially change the scope of the Work Chargeable to Customer from what is identified in Schedule "A", delay the Ready for Service Date identified herein and/or increase the Engineering and Construction Cost of the Work Chargeable to Customer and may also materially change the scope of the Customer Work to be performed by the Customer from what is identified in Schedule "B".

Part 2: Manner of Payment

The Customer shall pay Hydro One the Cost Estimate (plus HST) by making the progress payments specified below on or before the Payment Milestone Date specified below:

Payment Milestone Date	Work Chargeable to Customer	HST	Total Payment (incl. HST)
CCRA Execution	$598,610	$77,819.30	$676,429.30
January 17, 2025	$1,901,605	$247,208.65	$2,148,813.65
January 16, 2026	$193,785	$25,192.05	$218,977.05

2.2 Scope Change

For the purposes of this Section 2.2, the term "Non-Customer Initiated Scope Change(s)" means one or more changes that are required to be made to the Work Chargeable to Customer as detailed and documented in Schedule "A" such as a result of any one or more of the following:

- any environmental assessment(s);
- requirement for Hydro One to obtain approval under Section 92 (leave to construct) of the Ontario Energy Board Act if the transmission line route selected by Hydro One is greater than 2 km in length;
- Hydro One having to expropriate property under the Ontario Energy Board Act;
- conditions included by the OEB in any approval issued by the OEB under Section 92 of the *Ontario Energy Board Act* or any approval issued by the OEB to expropriate under the *Ontario Energy Board Act*; and
- any IESO requirements identified in the System Impact Assessment or any revisions thereto.

Any change in the Work Chargeable to Customer as detailed and documented in Schedule "A" whether they are initiated by the Customer or are Non-Customer Initiated Scope Changes, may result in a change to the Cost Estimate in Part 1 above and the Project schedule, including the Ready for Service Date.

All Customer initiated scope changes must be made in writing to Hydro One. Hydro One will advise the Customer of any cost and schedule impacts of any Customer initiated scope changes. Hydro One will advise the Customer of any Material cost and/or Material schedule impacts of any Non-Customer Initiated Scope Changes. Hydro One will not implement any Customer initiated scope changes until written approval has been received from the Customer accepting the new pricing and schedule impact.

Hydro One will implement all Non-Customer initiated scope changes until the estimate of the Engineering and Construction Cost of all of the Non-Customer initiated scope changes made by Hydro One reaches 10% of the total sum of the Cost Estimate in Part 1 above.

Part 3: Miscellaneous

New or Modified Connection Facilities: 12Mvar capacitor bank.

Customer's HST Registration Number: HST# [redacted].

Documentation Required (after In Service Date): N/A

Revenue Metering: N/A

Customer Notice Info: Alectra Utilities, 161 Cityview Blvd, Vaughan, Ontario, L4H 0A9
Attention: Bob Braletic, Station Design Manager.

2-Staff-124

Attachment 2
Load True Up Goreway–Nebo-Cedar-Arlen–Winona–Midhurst

Date:	19-Nov-21
Project #	

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - 2nd true-up

Facility Name: Goreway TS new (2nd) 230/28-28 kV DESN
Description: 10 Year True Up Transformation Pool Capital Contribution
Customer: Hydro One Brampton

			In-Service Date	<------- Project year ended - annualized from In-Service Date ------->																						
		Month	May-23	May-23	May-23	May-23	May-23	May-23	May-23	May-23	May-23	May-23	May-23	May-23	May-23	May-23	May-23	May-23	May-23	May-23	May-23	May-23	May-23	May-23	May-23	May-23
		Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
								1st true-up					2nd true-up					3rd true-up									
			0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast																												
Load Forecast (MW)				13.4	22.3	17.6	18.9	21.1	18.3	20.2	25.3	35.1	20.6	48.5	55.9	60.6	65.5	72.5	79.8	85.1	88.7	92.3	94.5	95.6	96.9	98.0	99.3	100.5
Load adjustments (MW)				8.0	10.2	11.4	14.2	16.5	18.7	20.7	22.4	24.0	24.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				21.5	32.5	29.0	33.1	37.7	37.0	40.9	47.8	59.1	44.8	48.5	55.9	60.6	65.5	72.5	79.8	85.1	88.7	92.3	94.5	95.6	96.9	98.0	99.3	100.5
Tariff Applied ($/kW/Month)				1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61
Incremental Revenue - $k				414.9	627.5	560.3	639.3	727.6	714.7	790.7	923.3	1,141.4	865.5	936.6	1,080.6	1,170.6	1,265.5	1,401.4	1,542.0	1,644.6	1,712.8	1,782.9	1,825.3	1,847.7	1,872.5	1,894.2	1,918.7	1,942.4
Removal Costs - $k			0.0																									
On-going OM&A Costs - $k			0.0	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)
Ontario Capital Tax and Municipal Tax - $k				(200.8)	(196.7)	(192.9)	(189.4)	(186.2)	(183.2)	(180.5)	(178.0)	(175.7)	(173.6)	(171.6)	(169.8)	(168.2)	(166.7)	(165.3)	(164.0)	(162.8)	(161.7)	(160.7)	(159.8)	(159.0)	(158.2)	(157.5)	(156.8)	(156.2)
Net Revenue/(Costs) before taxes - $k			0.0	172.1	388.9	325.4	407.9	499.4	489.5	568.2	703.3	923.7	649.9	722.9	868.8	960.4	1,056.9	1,194.1	1,313.0	1,416.8	1,486.1	1,557.1	1,600.5	1,623.7	1,649.3	1,671.7	1,696.9	1,721.2
Income Taxes - $k			0.0	262.2	483.9	456.0	383.2	310.9	276.0	214.4	136.8	33.2	97.5	47.8	(24.3)	(76.3)	(128.2)	(192.3)	(248.7)	(298.8)	(336.1)	(372.8)	(399.3)	(418.0)	(436.6)	(453.4)	(470.4)	(486.4)
Operating Cash Flow (after taxes) - $k			0.0	434.3	872.7	781.4	791.1	810.3	765.5	782.6	840.1	956.8	747.4	770.7	844.5	884.1	928.6	1,001.8	1,064.3	1,118.0	1,150.0	1,184.3	1,201.3	1,205.7	1,212.7	1,218.3	1,226.5	1,234.9
		Cumulative PV @ 5.68%																										
PV Operating Cash Flow (after taxes) - $k	**(A)**	**12,045.4**	**0.0**	**422.5**	**803.3**	**680.6**	**652.0**	**631.9**	**564.9**	**546.5**	**555.0**	**598.2**	**442.1**	**431.4**	**447.3**	**443.1**	**440.4**	**449.6**	**451.9**	**449.2**	**437.3**	**426.1**	**408.9**	**388.4**	**369.6**	**351.4**	**334.7**	**318.9**
Capital Expenditures - $k																												
Capital cost before overheads & AFUDC - $k			(23,871.0)																									
- Overheads - $k			0.0																									
- AFUDC - $k			0.0																									
Total upfront capital expenditures - $k			**(23,871.0)**																									
On-going capital expenditures - $k				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $k			0.0																									
Total capital expenditures - $k			**(23,871.0)**																									
Capital Contributions - $k																												
Previous capital contribution/(credit)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0																
Current capital contribution/(credit)													0.0															
PV of annual capital contribution			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0															
Total PV			**0.0**																									
PV Proceeds on disposal of assets - $k			**0.0**																									
PV CCA Residual Tax Shield - $k			**152.4**																									
PV Working Capital - $k			**(1.6)**																									
PV Capital (after taxes) - $k	**(B)**	**(23,720.2)**	**(23,720.2)**																									
Cumulative PV Cash Flow (after taxes) - $k	**(A) + (B)**	**(11,674.8)**	**(23,720.2)**	**(23,297.7)**	**(22,494.4)**	**(21,813.8)**	**(21,161.9)**	**(20,529.9)**	**(19,965.0)**	**(19,418.6)**	**(18,863.6)**	**(18,265.3)**	**(17,823.2)**	**(17,391.8)**	**(16,944.4)**	**(16,501.3)**	**(16,060.9)**	**(15,611.3)**	**(15,159.4)**	**(14,710.2)**	**(14,272.9)**	**(13,846.8)**	**(13,437.9)**	**(13,049.5)**	**(12,679.8)**	**(12,328.4)**	**(11,993.7)**	**(11,674.8)**

Discounted Cash Flow Summary

Economic Study Horizon - Years:		**25**			
Discount Rate - %		**5.68%**			
		Before Cont		**After Cont**	**Impact**
		$k		$k	$k
PV Incremental Revenue		14,358.2		14,358.2	
PV OM&A Costs		(646.2)		(646.2)	
PV Ontario Capital Tax and Municipal Tax		(2,397.3)		(1,091.8)	1,305.6
PV Income Taxes		(3,790.4)		(4,227.8)	(437.4)
PV CCA Tax Shield		4,673.5		1,994.0	(2,679.5)
PV Capital - Upfront	(23,871.0)		(23,871.0)		
Add: PV Capital Contribution	**0.0**	(23,871.0)	**13,486.1**	(10,384.9)	13,486.1
PV Capital - On-going		0.0		0.0	
PV Proceeds on disposal of assets		0.0		0.0	
PV Working Capital		(1.6)		(1.6)	
PV Surplus / (Shortfall)		**(11,674.8)**		**(0.0)**	**11,674.8**
Profitability Index*		**0.5**		**1.0**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Capital Contributions

	Date	PV of Cont $k	Previous Cont Payments $k	Current Cont / (Credit) $k
Initial economic evaluatior	2010	9,823.7	9,823.7	
1st true-up	2015	469.4	618.8	
2nd true-up	2020	3,193.0		5,548.5
Total		**13,486.1**	**10,442.5**	**5,548.5**
Contribution Required (before HST)				**5,548.5**

Notes:
1) Payment from customer must include HST/GST.

Other Assumptions		**Notes:**
In-Service Date:	23-May-10	
Municipal Tax	0.63%	Transmission system average
Federal Income Tax	19.50%	Federal corporate income tax
Ontario Corporation Income Tax	14.00%	Provincial corporate income tax
Working cash net lag days	17.75	As per Lead Lag study
CCA Rate for Class 47 Assets	8%	100% Class 47 assets

Calculation Time Stamp 19-Nov-21, 3:08 PM

Date:	29-Nov-22
Project #	20968

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - 1st true-up

Facility Name	Nebo TS Upgrade - Transformation
Description:	Horizon Allocation
Customer:	Horizon Utilities

			In-Service Date	<------- Project year ended - annualized from In-Service Date ------->																							
		Month	Dec-13	Dec-13	Dec-13	Dec-13	Dec-13	Dec-13	Dec-13	Dec-13	Dec-13	Dec-13	Dec-13	Dec-13	Dec-13	Dec-13	Dec-13	Dec-13	Dec-13	Dec-13	Dec-13	Dec-13	Dec-13	Dec-13	Dec-13	Dec-13	Dec-13
		Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
								1st true-up					2nd true-up					3rd true-up									
			0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast																												
Load Forecast (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.8	19.3	19.1	18.9	18.7	18.5	18.3	18.1	17.9	17.7	17.5
Load adjustments (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.8	19.3	19.1	18.9	18.7	18.5	18.3	18.1	17.9	17.7	17.5
Tariff Applied ($/kW/Month)				1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86
Incremental Revenue - $k				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	218.1	431.8	427.3	422.8	418.4	413.9	409.4	405.0	400.5	396.0	391.6
Removal Costs - $k			(108.2)																									
On-going OM&A Costs - $k			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ontario Capital Tax and Municipal Tax - $k				(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)
Net Revenue/(Costs) before taxes - $k			(108.2)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	(25.9)	192.2	405.8	401.4	396.9	392.4	388.0	383.5	379.0	374.6	370.1	365.7
Income Taxes - $k			28.4	57.8	104.6	96.8	89.6	83.0	76.9	71.3	66.1	61.4	57.0	53.0	49.3	45.9	42.8	(17.4)	(76.1)	(77.4)	(78.4)	(79.3)	(80.0)	(80.6)	(81.0)	(81.3)	(81.5)	(81.6)
Operating Cash Flow (after taxes) - $k			(79.8)	31.8	78.7	70.9	63.7	57.0	51.0	45.3	40.2	35.4	31.1	27.1	23.4	20.0	16.8	174.8	329.7	324.0	318.5	313.1	307.9	302.9	298.0	293.2	288.6	284.0
		Cumulative PV @ 6.05%																										
PV Operating Cash Flow (after taxes) - $k	**(A**	1,398.2	(79.8)	30.9	72.1	61.2	51.8	43.8	36.9	31.0	25.9	21.5	17.8	14.6	11.9	9.6	7.6	74.6	132.7	123.0	114.0	105.7	98.0	90.9	84.3	78.3	72.6	67.4
Capital Expenditures - $k																												
Capital cost before overheads & AFUDC - $k			(4,103.4)																									
- Overheads - $k			(642.5)																									
- AFUDC - $k			(106.5)																									
Total upfront capital expenditures - $			**(4,852.3)**																									
On-going capital expenditures - $k				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $			0.0																									
Total capital expenditures - $k			**(4,852.3)**																									
Capital Contributions - $k																												
Previous capital contribution/(credit			0.0	0.0	0.0	0.0	0.0																					
Current capital contribution/(credit								0.0																				
PV of annual capital contributior			0.0	0.0	0.0	0.0	0.0	0.0																				
Total PV			**0.0**																									
PV Proceeds on disposal of assets - $k			**0.0**																									
PV CCA Residual Tax Shield - $k			**21.7**																									
PV Working Capital - $k			**0.0**																									
PV Capital (after taxes) - $k	**(E**	(4,830.6)	**(4,830.6)**																									
Cumulative PV Cash Flow (after taxes) - $k	**(A) + (B**	(3,432.4)	**(4,910.5)**	**(4,879.6)**	**(4,807.5)**	**(4,746.3)**	**(4,694.4)**	**(4,650.6)**	**(4,613.8)**	**(4,582.8)**	**(4,556.9)**	**(4,535.4)**	**(4,517.6)**	**(4,503.0)**	**(4,491.1)**	**(4,481.5)**	**(4,473.9)**	**(4,399.3)**	**(4,266.6)**	**(4,143.6)**	**(4,029.6)**	**(3,923.9)**	**(3,825.9)**	**(3,735.0)**	**(3,650.7)**	**(3,572.4)**	**(3,499.8)**	**(3,432.4)**

Discounted Cash Flow Summary

Economic Study Horizon - Years:	**25**
Discount Rate - %	**6.05%**

		Before Cont $k		After Cont $k	Impact $k
PV Incremental Revenue		1,390.2		1,390.2	
PV OM&A Costs		(108.2)		(108.2)	
PV Ontario Capital Tax and Municipal Ta		(339.9)		(73.8)	266.0
PV Income Taxes		(247.3)		(317.2)	(69.8)
PV CCA Tax Shield		725.1		151.4	(573.7)
PV Capital - Upfron	(4,852.3)		(4,852.3)		
Add: PV Capital Contribution	**0.0**	(4,852.3)	**3,809.9**	(1,042.5)	3,809.9
PV Capital - On-going		0.0		0.0	
PV Proceeds on disposal of asset		0.0		0.0	
PV Working Capita		0.0		0.0	
PV Surplus / (Shortfall)		(3,432.4)		**0.0**	**3,432.4**
Profitability Index*		**0.3**		**1.0**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Capital Contributions

	Date	PV of Cont $k	Previous Cont Payments $k	Current Cont / (Credit) $k
Initial economic evaluatio	2013	3,321.9	3,321.9	
1st true-up	2018	488.0		654.5
Total		**3,809.9**	**3,321.9**	**654.5**
Contribution Required (before HST)				**654.5**
HST @ 13%				85.1
Contribution Required (including HST)[1]				**739.6**

Notes:
1) Payment from customer must include HST.

Other Assumptions		**Notes:**
In-Service Date:	13-Dec-13	
Municipal Tax	0.53%	Transmission system average
Federal Income Tax	15.00%	Federal corporate income ta
Ontario Corporation Income Tax:	11.25%	Provincial corporate income tax
Working cash net lag days	14.67	As per Lead Lag study
CCA Rate for Class 47 Assets	8%	100% Class 47 assets

Calculation Time Stamp: 29-Nov-22, 11:20 PM

Date:	14-Mar-24
Project #	

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - 3rd true-up

Facility Name:	Guelph Cedar TS MetalClad - Converted Model
Description:	15 Year TrueUp
Customer:	Guelph (LDC)

			In-Service Date	<------- Project year ended - annualized from In-Service Date ------->																							
		Month	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30
		Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
								1st true-up					2nd true-up					3rd true-up									
			0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast																											
Load Forecast (MW)				19.9	13.7	2.2	6.5	21.2	21.7	15.0	21.5	18.6	14.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	94.9	101.5	108.2	115.0	122.0	129.1	136.4	143.8
Load adjustments (MW)				2.3	7.1	10.8	12.1	14.0	16.5	19.2	24.4	33.0	38.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				22.3	20.8	13.0	18.6	35.2	38.1	34.2	45.9	51.6	52.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	94.9	101.5	108.2	115.0	122.0	129.1	136.4	143.8
Tariff Applied ($/kW/Month)				1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
Incremental Revenue - $k				400.8	373.8	234.0	335.5	633.2	686.3	616.1	826.8	928.6	937.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,708.5	1,826.9	1,947.7	2,070.9	2,196.5	2,324.7	2,455.4	2,588.8
Removal Costs - $k			0.0																									
On-going OM&A Costs - $k			0.0	(55.8)	(55.8)	(55.8)	(55.8)	(55.8)	(55.8)	(55.8)	(55.8)	(55.8)	(55.8)	(55.8)	(55.8)	(55.8)	(55.8)	(55.8)	(55.8)	(55.8)	(55.8)	(55.8)	(55.8)	(55.8)	(55.8)	(55.8)	(55.8)	(55.8)
Ontario Capital Tax and Municipal Tax - $K				(73.3)	(72.7)	(72.1)	(71.5)	(70.9)	(70.3)	(69.8)	(69.3)	(68.8)	(68.3)	(67.8)	(67.4)	(67.0)	(66.6)	(66.2)	(65.8)	(65.5)	(65.1)	(64.8)	(64.5)	(64.2)	(63.9)	(63.6)	(63.4)	(63.1)
Net Revenue/(Costs) before taxes - $k			0.0	271.6	245.3	106.1	208.3	506.6	560.2	490.5	701.8	804.0	813.4	(123.6)	(123.2)	(122.8)	(122.4)	(122.0)	(121.6)	(121.3)	1,587.5	1,706.3	1,827.4	1,950.9	2,076.8	2,205.3	2,336.3	2,469.9
Income Taxes - $k			0.0	(66.9)	(19.8)	26.3	(12.0)	(118.8)	(139.9)	(117.8)	(193.9)	(231.7)	(237.0)	89.0	87.1	85.2	83.3	81.6	79.9	78.3	(521.3)	(564.2)	(607.9)	(652.4)	(697.7)	(743.8)	(790.8)	(838.6)
Operating Cash Flow (after taxes) - $k			0.0	204.7	225.5	132.4	196.3	387.7	420.2	372.7	507.9	572.2	576.4	(34.6)	(36.2)	(37.6)	(39.1)	(40.4)	(41.7)	(43.0)	1,066.3	1,142.1	1,219.5	1,298.5	1,379.1	1,461.5	1,545.5	1,631.3
		Cumulative PV @ 6.29%																										
PV Operating Cash Flow (after taxes) - $k	**(A)**	**5,342.0**	**0.0**	**198.5**	**205.8**	**113.7**	**158.5**	**294.6**	**300.4**	**250.7**	**321.4**	**340.7**	**322.8**	**(18.2)**	**(17.9)**	**(17.6)**	**(17.1)**	**(16.7)**	**(16.2)**	**(15.7)**	**366.5**	**369.3**	**371.0**	**371.7**	**371.4**	**370.3**	**368.4**	**365.8**
Capital Expenditures - $k																												
Capital cost before overheads & AFUDC - $k			(5,582.2)																									
- Overheads - $k			0.0																									
- AFUDC - $k			0.0																									
Total upfront capital expenditures - $k			**(5,582.2)**																									
On-going capital expenditures - $k				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $k			0.0																									
Total capital expenditures - $k			**(5,582.2)**																									
Capital Contributions - $k																												
Previous capital contribution/(credit)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0											
Current capital contribution/(credit)																		0.0										
PV of annual capital contribution			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0										
Total PV			**0.0**																									
PV Proceeds on disposal of assets - $k			**0.0**																									
PV CCA Residual Tax Shield - $k			**60.8**																									
PV Working Capital - $k			**(1.3)**																									
PV Capital (after taxes) - $k	**(B)**	**(5,522.7)**	**(5,522.7)**																									
Cumulative PV Cash Flow (after taxes) - $k	**(A) + (B)**	**(180.7)**	**(5,522.7)**	**(5,324.1)**	**(5,118.3)**	**(5,004.6)**	**(4,846.1)**	**(4,551.5)**	**(4,251.0)**	**(4,000.4)**	**(3,679.0)**	**(3,338.3)**	**(3,015.6)**	**(3,033.8)**	**(3,051.7)**	**(3,069.3)**	**(3,086.4)**	**(3,103.1)**	**(3,119.3)**	**(3,135.0)**	**(2,768.5)**	**(2,399.2)**	**(2,028.2)**	**(1,656.5)**	**(1,285.1)**	**(914.9)**	**(546.5)**	**(180.7)**

Discounted Cash Flow Summary

Economic Study Horizon - Years: 25

Discount Rate - % 6.29%

		Before Cont $k	After Cont $k	Impact $k
PV Incremental Revenue		8,898.4	8,898.4	
PV OM&A Costs		(715.4)	(715.4)	
PV Ontario Capital Tax and Municipal Tax		(881.5)	(877.2)	4.3
PV Income Taxes		(2,656.5)	(2,655.1)	1.4
PV CCA Tax Shield		757.8	728.5	(29.2)
PV Capital - Upfront	(5,582.2)		(5,582.2)	
Add: PV **Capital Contribution**	**0.0**	(5,582.2)	**204.3**	(5,377.9)	204.3
PV Capital - On-going		0.0	0.0	
PV Proceeds on disposal of assets		0.0	0.0	
PV Working Capital		(1.3)	(1.3)	
PV Surplus / (Shortfall)		**(180.7)**	**(0.0)**	**180.7**
Profitability Index*		**1.0**	**1.0**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Capital Contributions

	Date	PV of Cont $k	Previous Cont Payments $k	Current Cont / (Credit) $k
Initial economic evaluation	2006	0.0	0.0	
1st true-up	2011	0.0	0.0	
2nd true-up	2016	0.0	0.0	
3rd true-up	2021	204.3		510.2
Total		**204.3**	**0.0**	**510.2**
Contribution Required (before HST)				**510.2**

Notes:
1) Payment from customer must include HST/GST.

Other Assumptions		**Notes:**
In-Service Date:	30-Jun-06	
Municipal Tax	1.02%	Transmission system average
Federal Income Tax	21.00%	Federal corporate income tax
Ontario Corporation Income Tax	14.00%	Provincial corporate income tax
Working cash net lag days	11.38	As per Lead Lag study
CCA Rate for Class 1 Assets	4%	100% Class 1 assets

Calculation Time Stamp: 13-Feb-26, 10:11 AM

Date:	14-Mar-24
Project #	

SUMMARY OF CONTRIBUTION CALCULATIONS
Line Pool - 2nd true-up

Facility Name: Guelph Arlen MTS Line Connection - Customer Model
Description: Second True Up
Customer:

		In-Service Date	<------- Project year ended - annualized from In-Service Date ------->																							
	Month	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30
	Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
							1st true-up					2nd true-up					3rd true-up										
		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast																											
Load Forecast (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32.0	36.4	39.7	43.1	47.2	48.1	48.9	49.6	50.3	50.4	50.4	50.4	50.4	50.4	50.4
Load adjustments (MW)			0.0	0.0	0.4	14.6	10.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			0.0	0.0	0.4	14.6	10.7	0.0	0.0	0.0	0.0	0.0	32.0	36.4	39.7	43.1	47.2	48.1	48.9	49.6	50.3	50.4	50.4	50.4	50.4	50.4	50.4
Tariff Applied ($/kW/Month)			0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79
Incremental Revenue - $k			0.0	0.0	3.9	137.9	101.7	0.0	0.0	0.0	0.0	0.0	303.4	345.1	376.4	408.6	447.5	456.0	463.6	470.2	476.8	477.8	477.8	477.8	477.8	477.8	477.8
Removal Costs - $k		0.0																									
On-going OM&A Costs - $k		0.0	(15.6)	(15.6)	(15.6)	(15.6)	(15.6)	(15.6)	(15.6)	(15.6)	(15.6)	(15.6)	(15.6)	(15.6)	(15.6)	(15.6)	(15.6)	(15.6)	(15.6)	(15.6)	(15.6)	(15.6)	(15.6)	(15.6)	(15.6)	(15.6)	(15.6)
Ontario Capital Tax and Municipal Tax - $K			(11.4)	(11.4)	(11.4)	(11.4)	(11.4)	(11.4)	(11.4)	(11.4)	(11.4)	(11.4)	(11.4)	(11.4)	(11.4)	(11.4)	(11.4)	(11.4)	(11.4)	(11.4)	(11.4)	(11.4)	(11.4)	(11.4)	(11.4)	(11.4)	(11.4)
Net Revenue/(Costs) before taxes - $k		0.0	(27.0)	(27.0)	(23.0)	111.0	74.7	(27.0)	(27.0)	(27.0)	(27.0)	(27.0)	276.4	318.1	349.4	381.6	420.5	429.0	436.6	443.2	449.9	450.8	450.8	450.8	450.8	450.8	450.8
Income Taxes - $k		0.0	29.9	50.5	45.9	4.9	12.3	38.3	35.9	33.6	31.5	29.6	(57.9)	(71.3)	(81.6)	(92.1)	(104.3)	(107.9)	(111.1)	(113.9)	(116.7)	(117.8)	(118.6)	(119.3)	(119.9)	(120.5)	(121.1)
Operating Cash Flow (after taxes) - $k		0.0	3.0	23.5	22.9	115.9	86.9	11.3	8.9	6.6	4.5	2.6	218.5	246.8	267.8	289.6	316.2	321.2	325.5	329.3	333.2	333.0	332.3	331.5	330.9	330.3	329.8
	Cumulative PV @ 6.17%																										
PV Operating Cash Flow (after taxes) - $k (A)	1,866.4	0.0	2.9	21.5	19.7	94.0	66.4	8.2	6.0	4.2	2.7	1.5	116.6	124.0	126.8	129.1	132.8	127.0	121.3	115.6	110.1	103.7	97.4	91.6	86.1	81.0	76.1
Capital Expenditures - $k																											
Capital cost before overheads & AFUDC - $k		(1,838.7)																									
- Overheads - $k		(125.0)																									
- AFUDC - $k		(10.7)																									
Total upfront capital expenditures - $k		(1,974.4)																									
On-going capital expenditures - $k			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $k		0.0																									
Total capital expenditures - $k		(1,974.4)																									
Capital Contributions - $k																											
Previous capital contribution/(credit)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0																
Current capital contribution/(credit)												0.0															
PV of annual capital contribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0															
Total PV		0.0																									
PV Proceeds on disposal of assets - $k		0.0																									
PV CCA Residual Tax Shield - $k		9.2																									
PV Working Capital - $k		(0.5)																									
PV Capital (after taxes) - $k (B)	(1,965.7)	(1,965.7)																									
Cumulative PV Cash Flow (after taxes) - $k (A) + (B)	(99.4)	(1,965.7)	(1,962.9)	(1,941.4)	(1,921.7)	(1,827.7)	(1,761.3)	(1,753.1)	(1,747.1)	(1,742.9)	(1,740.1)	(1,738.6)	(1,622.0)	(1,498.0)	(1,371.2)	(1,242.1)	(1,109.3)	(982.3)	(861.0)	(745.4)	(635.3)	(531.6)	(434.2)	(342.6)	(256.5)	(175.5)	(99.4)

Discounted Cash Flow Summary

Economic Study Horizon - Years: 25

Discount Rate - % 6.17%

		Before Cont $k	After Cont $k	Impact $k
PV Incremental Revenue		2,524.8	2,524.8	
PV OM&A Costs		(202.3)	(202.3)	
PV Ontario Capital Tax and Municipal Tax		(147.4)	(147.4)	
PV Income Taxes		(614.5)	(614.5)	0.0
PV CCA Tax Shield		314.9	294.7	(20.2)
PV Capital - Upfront	(1,974.4)	(1,974.4)	(1,974.4)	
Add: PV **Capital Contribution**	0.0	(1,974.4)	119.6	(1,854.9)	119.6
PV Capital - On-going		0.0	0.0	
PV Proceeds on disposal of assets		0.0	0.0	
PV Working Capital		(0.5)	(0.5)	
PV Surplus / (Shortfall)		(99.4)	(0.0)	99.4
Profitability Index*		0.9	1.0	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Capital Contributions

	Date	PV of Cont $k	Previous Cont Payments $k	Current Cont / (Credit) $k
Initial economic evaluation	2011	0.0	0.0	
1st true-up	2016	0.0	0.0	
2nd true-up	2021	119.6		217.5
Total		119.6	0.0	217.5
Contribution Required (before HST)				217.5

Notes:
1) Payment from customer must include HST/GST.

Other Assumptions		**Notes:**
In-Service Date:	30-Nov-11	
Municipal Tax	0.58%	Transmission system average
Federal Income Tax	16.50%	Federal corporate income tax
Ontario Corporation Income Tax	11.75%	Provincial corporate income tax
Working cash net lag days	14.67	As per Lead Lag study
CCA Rate for Class 47 Assets	8%	100% Class 47 assets

Calculation Time Stamp: 13-Feb-26, 9:23 AM

Date:	6-Dec-22
Project #	

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - 3rd true-up

Facility Name: Winona TS
Description: 5 Year True Up
Customer: Horizon Utilities

		In-Service Date	<------- Project year ended - annualized from In-Service Date ------->																							
	Month	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30	Jun-30
	Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
							1st true-up					2nd true-up					3rd true-up										
		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast																											
Load Forecast (MW)			2.4	4.5	7.0	12.3	5.3	0.0	0.0	0.0	0.0	4.4	10.7	4.1	7.2	5.1	8.0	30.1	28.9	31.8	40.6	48.5	49.8	50.6	50.3	50.0	49.7
Load adjustments (MW)			0.0	0.0	0.3	1.9	3.5	3.6	0.3	5.6	5.8	7.4	9.5	11.1	13.0	14.8	16.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			2.4	4.5	7.2	14.2	8.8	3.6	0.3	5.6	5.8	11.8	20.3	15.2	20.2	19.9	24.3	30.1	28.9	31.8	40.6	48.5	49.8	50.6	50.3	50.0	49.7
Tariff Applied ($/kW/Month)			1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
Incremental Revenue - $k			42.5	80.4	130.2	254.8	158.5	65.4	5.9	101.3	103.5	211.6	364.9	272.9	363.0	358.9	436.9	541.8	520.2	572.4	730.8	873.2	896.4	910.7	906.0	900.5	893.8
Removal Costs - $k		0.0																									
On-going OM&A Costs - $k		0.0	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)
Ontario Capital Tax and Municipal Tax - $k			(144.4)	(143.4)	(142.3)	(141.3)	(140.4)	(139.5)	(138.6)	(137.7)	(136.9)	(136.1)	(135.4)	(134.7)	(134.0)	(133.3)	(132.7)	(132.1)	(131.5)	(130.9)	(130.4)	(129.9)	(129.4)	(128.9)	(128.5)	(128.0)	(127.6)
Net Revenue/(Costs) before taxes - $k		0.0	(127.9)	(88.9)	(38.1)	87.5	(7.9)	(100.1)	(158.7)	(62.5)	(59.4)	49.4	203.5	112.2	203.0	199.5	278.2	344.7	323.7	376.5	535.4	678.3	702.0	716.8	712.5	707.5	701.3
Income Taxes - $k		0.0	111.0	169.5	142.9	84.9	120.2	154.4	174.6	129.7	124.3	74.5	5.8	40.6	(1.2)	(3.1)	(38.7)	(69.0)	(63.3)	(87.7)	(155.5)	(216.7)	(228.9)	(237.3)	(237.8)	(237.9)	(237.4)
Operating Cash Flow (after taxes) - $k		0.0	(17.0)	80.6	104.7	172.4	112.3	54.3	15.8	67.2	64.9	123.9	209.3	152.8	201.8	196.4	239.4	275.7	260.4	288.8	379.9	461.6	473.2	479.5	474.7	469.6	463.8
	Cumulative PV @ 6.21%																										
PV Operating Cash Flow (after taxes) - $k (A	2,226.5	0.0	(16.5)	73.7	90.1	139.6	85.6	38.9	10.7	42.8	38.9	69.9	111.1	76.4	95.0	87.1	99.9	108.3	96.3	100.6	124.6	142.5	137.5	131.2	122.3	113.9	105.9
Capital Expenditures - $k																											
Capital cost before overheads & AFUDC - $k		(8,852.0)																									
- Overheads - $k		(50.0)																									
- AFUDC - $k		(274.8)																									
Total upfront capital expenditures - $k		(9,176.8)																									
On-going capital expenditures - $k			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $		0.0																									
Total capital expenditures - $k		(9,176.8)																									
Capital Contributions - $k																											
Previous capital contribution/(credit		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0											
Current capital contribution/(credit																	0.0										
PV of annual capital contributio		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0										
Total PV		**0.0**																									
PV Proceeds on disposal of assets - $k		**0.0**																									
PV CCA Residual Tax Shield - $k		**123.4**																									
PV Working Capital - $k		(36.7)																									
PV Capital (after taxes) - $k (E	(9,090.1)	(9,090.1)																									
Cumulative PV Cash Flow (after taxes) - $k (A) + (B	(6,863.6)	(9,090.1)	(9,106.5)	(9,032.9)	(8,942.8)	(8,803.2)	(8,717.6)	(8,678.6)	(8,667.9)	(8,625.1)	(8,586.3)	(8,516.4)	(8,405.2)	(8,328.9)	(8,233.8)	(8,146.8)	(8,046.9)	(7,938.5)	(7,842.2)	(7,741.6)	(7,617.1)	(7,474.5)	(7,337.0)	(7,205.8)	(7,083.4)	(6,969.5)	(6,863.6)

Discounted Cash Flow Summary

Economic Study Horizon - Years: 25

Discount Rate - % 6.21%

		Before Cont $k		After Cont $k		Impact $k
PV Incremental Revenue		3,972.9		3,972.9		
PV OM&A Costs		(454.3)		(454.3)		
PV Ontario Capital Tax and Municipal Ta		(1,767.3)		(345.1)		1,422.2
PV Income Taxes		(912.2)		(1,966.0)		(1,053.7)
PV CCA Tax Shield		1,510.9		421.8		(1,089.1)
PV Capital - Upfron	(9,176.8)		(9,176.8)			
Add: PV Capital Contribution	**0.0**	(9,176.8)	**7,543.5**	(1,633.3)		7,543.5
PV Capital - On-going		0.0		0.0		
PV Proceeds on disposal of asset		0.0		40.6		40.6
PV Working Capita		(36.7)		(36.7)		
PV Surplus / (Shortfall)		(6,863.6)		**0.0**		**6,863.6**
Profitability Index*		**0.3**		**1.0**		

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Capital Contributions

	Date	PV of Cont $k	Previous Cont Payments $k	Current Cont / (Credit) $k
Initial economic evaluation	2003	2,085.0	2,085.0	
1st true-up	2008	5,877.8	7,944.9	
2nd true-up	2013	0.0	0.0	
3rd true-up	2018	(419.3)		(1,035.5)
Total		**7,543.5**	**10,029.9**	**(1,035.5)**

Contribution Required (before HST) N/A

Notes:
1) Payment from customer must include HST/GST.

Other Assumptions		**Notes:**
In-Service Date:	30-Jun-03	
Municipal Tax	1.28%	Transmission system average
Federal Income Tax	27.00%	Federal corporate income tax
Ontario Corporation Income Tax	14.00%	Provincial corporate income tax
Working cash net lag days	22.22	As per Lead Lag study
CCA Rate for Class 1 Assets	4%	100% Class 1 assets

Calculation Time Stamp: 06-Dec-22; 5:23 PM

Date:	9-Nov-15
Project #	

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - 2nd true-up

Facility Name: Barrie Hydro New DESN at Midhurst TS
Description:
Customer: Powerstream (formerly Barrie Hydro)

			In-Service Date	<------- Project year ended - annualized from In-Service Date ------->																							
	Month		Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31
	Year		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
								1st true-up					2nd true-up					3rd true-up									
			0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast																												
Load Forecast (MW)				30.7	38.6	56.5	37.2	38.2	47.5	42.8	44.1	57.6	45.8	71.6	83.2	93.8	105.4	117.0	126.0	136.0	146.0	156.0	166.0	173.3	180.8	188.4	196.3	204.4
Load adjustments (MW)				0.0	1.2	1.8	3.6	5.1	5.7	5.6	5.8	7.2	8.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				30.7	39.7	58.3	40.9	43.4	53.2	48.4	49.9	64.8	54.5	71.6	83.2	93.8	105.4	117.0	126.0	136.0	146.0	156.0	166.0	173.3	180.8	188.4	196.3	204.4
Tariff Applied ($/kW/Month)				1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
Incremental Revenue - $k				552.8	715.3	1,050.3	735.5	781.1	957.2	871.1	898.2	1,166.1	981.1	1,289.1	1,497.9	1,688.7	1,897.5	2,106.3	2,268.3	2,448.3	2,628.3	2,808.3	2,988.3	3,119.3	3,253.8	3,391.7	3,533.3	3,678.5
Removal Costs - $k			0.0																									
On-going OM&A Costs - $k			0.0	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)
Ontario Capital Tax and Municipal Tax - $K				(210.1)	(208.6)	(207.1)	(205.6)	(204.2)	(202.9)	(201.6)	(200.4)	(199.2)	(198.1)	(197.0)	(195.9)	(194.9)	(194.0)	(193.0)	(192.2)	(191.3)	(190.5)	(189.7)	(189.0)	(188.2)	(187.5)	(186.9)	(186.2)	(185.6)
Net Revenue/(Costs) before taxes - $k			0.0	316.7	480.7	817.2	503.9	550.9	728.3	643.5	671.8	940.9	757.1	1,066.1	1,276.0	1,467.8	1,677.5	1,887.3	2,011.1	2,192.0	2,372.8	2,553.6	2,734.4	2,866.1	3,001.3	3,139.9	3,282.0	3,427.9
Income Taxes - $k			0.0	(51.1)	(9.3)	(164.1)	(35.4)	(63.2)	(147.5)	(117.3)	(136.2)	(259.5)	(185.5)	(325.7)	(422.5)	(511.2)	(607.6)	(704.7)	(765.5)	(851.5)	(937.2)	(1,022.8)	(1,108.1)	(1,171.4)	(1,236.0)	(1,301.9)	(1,369.3)	(1,438.2)
Operating Cash Flow (after taxes) - $k			0.0	265.6	471.5	653.1	468.4	487.7	580.9	526.1	535.7	681.5	571.6	740.4	853.5	956.5	1,070.0	1,182.5	1,245.6	1,340.5	1,435.6	1,530.8	1,626.3	1,694.8	1,765.3	1,837.9	1,912.7	1,989.7
	Cumulative PV @ 6.50%																											
PV Operating Cash Flow (after taxes) - $k **(A)**	**10,563.8**		**0.0**	**257.4**	**429.0**	**558.0**	**375.8**	**367.4**	**410.9**	**349.5**	**334.1**	**399.1**	**314.3**	**382.3**	**413.8**	**435.5**	**457.4**	**474.7**	**469.5**	**474.4**	**477.1**	**477.7**	**476.5**	**466.3**	**456.1**	**445.9**	**435.7**	**425.6**
Capital Expenditures - $k																												
Capital cost before overheads & AFUDC - $k			(13,350.0)																									
- Overheads - $k			0.0																									
- AFUDC - $k			0.0																									
Total upfront capital expenditures - $k			**(13,350.0)**																									
On-going capital expenditures - $k				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $k			0.0																									
Total capital expenditures - $k			**(13,350.0)**																									
Capital Contributions - $k																												
Previous capital contribution/(credit)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0																
Current capital contribution/(credit)													0.0															
PV of annual capital contribution			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0															
Total PV			**0.0**																									
PV Proceeds on disposal of assets - $k			**0.0**																									
PV CCA Residual Tax Shield - $k			**173.1**																									
PV Working Capital - $k			**(165.8)**																									
PV Capital (after taxes) - $k **(B)**	**(13,342.7)**		**(13,342.7)**																									
Cumulative PV Cash Flow (after taxes) - $k (A) + (B)	**(2,778.9)**		**(13,342.7)**	**(13,085.3)**	**(12,656.3)**	**(12,098.2)**	**(11,722.4)**	**(11,355.1)**	**(10,944.2)**	**(10,594.7)**	**(10,260.7)**	**(9,861.6)**	**(9,547.3)**	**(9,165.0)**	**(8,751.2)**	**(8,315.7)**	**(7,858.3)**	**(7,383.6)**	**(6,914.1)**	**(6,439.7)**	**(5,962.6)**	**(5,484.9)**	**(5,008.4)**	**(4,542.1)**	**(4,086.0)**	**(3,640.2)**	**(3,204.5)**	**(2,778.9)**

Discounted Cash Flow Summary

Economic Study Horizon - Years:		**25**			
Discount Rate - %		**6.50%**			
		Before Cont		**After Cont**	**Impact**
		$k		$k	$k
PV Incremental Revenue		18,578.1		18,578.1	
PV OM&A Costs		(439.9)		(439.9)	
PV Ontario Capital Tax and Municipal Tax		(2,508.6)		(1,916.2)	592.3
PV Income Taxes		(7,158.1)		(7,346.9)	(188.8)
PV CCA Tax Shield		2,265.4		1,766.7	(498.7)
PV Capital - Upfront	(13,350.0)		(13,350.0)		
Add: PV **Capital Contribution**	**0.0**	(13,350.0)	**2,874.0**	(10,476.0)	2,874.0
PV Capital - On-going		0.0		0.0	
PV Proceeds on disposal of assets		0.0		0.0	
PV Working Capital		(165.8)		(165.8)	
PV Surplus / (Shortfall)		**(2,778.9)**		**(0.0)**	**2,778.9**
Profitability Index*		**0.8**		**1.0**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Capital Contributions

	Date	PV of Cont $k	Previous Cont Payments $k	Current Cont / (Credit) $k
Initial economic evaluation	2004	1,954.4	1,954.4	
1st true-up	2009	3,194.5	4,376.2	
2nd true-up	2014	(2,274.9)		(4,269.3)
Total		**2,874.0**	**6,330.6**	**(4,269.3)**
Contribution Required (before HST)				**N/A**

Notes:
1) Payment from customer must include HST/GST.

Other Assumptions		**Notes:**
In-Service Date:	31-Dec-04	
Municipal Tax	1.28%	Transmission system average
Federal Income Tax	28.00%	Federal corporate income tax
Ontario Corporation Income Tax	15.50%	Provincial corporate income tax
Working cash net lag days	22.22	As per Lead Lag study
CCA Rate for Class 1 Assets	4%	100% Class 1 assets

Calculation Time Stamp: 09-Nov-15, 11:46 AM

2-Staff-124

Attachment 3
Capital Contribution Calculations Markham 5– Newton–Line to Heritage-H29 H30 TX Line Reconductoring to Pleasant TS

Date:	12-Mar-24
Project #	

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - Estimated cost

Facility Name:	Markham MTS#5 T
Description:	Build new 230/27.6kV Transformer Station
Customer:	ALECTRA UTILITIES CORPORATION

			In-Service Date	<------- Project year ended - annualized from In-Service Date -------->																							
			Month	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1
			Year	2027	2028	2029	2030	2031	2032 (1st true-up)	2033	2034	2035	2036	2037 (2nd true-up)	2038	2039	2040	2041	2042 (3rd true-up)	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052
				0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast																												
Load Forecast (MW)					51.9	86.7	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1
Load adjustments (MW)					0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					51.9	86.7	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1
Tariff Applied ($/kW/Month)					2.98	2.98	2.98	2.98	2.98	2.98	2.98	2.98	2.98	2.98	2.98	2.98	2.98	2.98	2.98	2.98	2.98	2.98	2.98	2.98	2.98	2.98	2.98	2.98
Incremental Revenue - $k					1,854.2	3,100.4	4,650.6	4,650.6	4,650.6	4,650.6	4,650.6	4,650.6	4,650.6	4,650.6	4,650.6	4,650.6	4,650.6	4,650.6	4,650.6	4,650.6	4,650.6	4,650.6	4,650.6	4,650.6	4,650.6	4,650.6	4,650.6	4,650.6
Removal Costs - $k				0.0																								
On-going OM&A Costs - $k				0.0	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)	(50.0)
Ontario Capital Tax and Municipal Tax - $K					(538.4)	(527.3)	(517.1)	(507.8)	(499.2)	(491.2)	(483.9)	(477.2)	(471.1)	(465.4)	(460.2)	(455.4)	(450.9)	(446.9)	(443.1)	(439.7)	(436.5)	(433.6)	(430.9)	(428.5)	(426.2)	(424.1)	(422.2)	(420.4)	(418.8)
Net Revenue/(Costs) before taxes - $k				0.0	1,265.8	2,523.1	4,083.5	4,092.8	4,101.4	4,109.4	4,116.6	4,123.4	4,129.5	4,135.2	4,140.4	4,145.2	4,149.6	4,153.7	4,157.5	4,160.9	4,164.1	4,167.0	4,169.7	4,172.1	4,174.4	4,176.5	4,178.4	4,180.2	4,181.8
Income Taxes - $k				0.0	433.6	801.4	146.9	22.6	(91.8)	(197.0)	(293.8)	(382.9)	(464.8)	(540.2)	(609.6)	(673.4)	(732.1)	(786.1)	(835.8)	(881.5)	(923.5)	(962.2)	(997.8)	(1,030.6)	(1,060.7)	(1,088.4)	(1,113.9)	(1,137.4)	(1,159.0)
Operating Cash Flow (after taxes) - $k				0.0	1,699.4	3,324.4	4,230.4	4,115.4	4,009.6	3,912.3	3,822.8	3,740.4	3,664.7	3,595.0	3,530.8	3,471.8	3,417.6	3,367.6	3,321.7	3,279.4	3,240.5	3,204.7	3,171.8	3,141.5	3,113.7	3,088.1	3,064.5	3,042.8	3,022.8
		Cumulative PV @ 5.68%																										
PV Operating Cash Flow (after taxes) - $k	**(A)**	**46,541.0**		**0.0**	**1,653.0**	**3,060.0**	**3,684.5**	**3,391.7**	**3,126.9**	**2,887.0**	**2,669.3**	**2,471.4**	**2,291.1**	**2,126.7**	**1,976.5**	**1,839.0**	**1,712.9**	**1,597.1**	**1,490.7**	**1,392.6**	**1,302.1**	**1,218.5**	**1,141.1**	**1,069.5**	**1,003.0**	**941.3**	**883.9**	**830.4**	**780.6**
Capital Expenditures - $k																												
Capital cost before overheads & AFUDC - $k				(64,000.0)																								
- Overheads - $k				0.0																								
- AFUDC - $k				0.0																								
Total upfront capital expenditures - $k				**(64,000.0)**																								
On-going capital expenditures - $k					0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $k				0.0																								
Total capital expenditures - $k				**(64,000.0)**																								
Capital Contributions - $k																												
Previous capital contribution/(credit)				0.0																								
Current capital contribution/(credit)				0.0																								
PV of annual capital contribution				0.0																								
Total PV				**0.0**																								
PV Proceeds on disposal of assets - $k				**0.0**																								
PV CCA Residual Tax Shield - $k				**408.7**																								
PV Working Capital - $k				**(1.7)**																								
PV Capital (after taxes) - $k	**(B)**	**(63,593.0)**		**(63,593.0)**																								
Cumulative PV Cash Flow (after taxes) - $k	**(A) + (B)**	**(17,052.0)**		**(63,593.0)**	**(61,939.9)**	**(58,879.9)**	**(55,195.4)**	**(51,803.7)**	**(48,676.8)**	**(45,789.8)**	**(43,120.5)**	**(40,649.2)**	**(38,358.0)**	**(36,231.3)**	**(34,254.8)**	**(32,415.8)**	**(30,702.9)**	**(29,105.8)**	**(27,615.1)**	**(26,222.5)**	**(24,920.4)**	**(23,701.9)**	**(22,560.8)**	**(21,491.3)**	**(20,488.3)**	**(19,547.0)**	**(18,663.1)**	**(17,832.6)**	**(17,052.0)**

Discounted Cash Flow Summary

Economic Study Horizon - Years:		**25**			
Discount Rate - %		**5.68%**			
		Before Cont $k		**After Cont** $k	**Impact** $k
PV Incremental Revenue		58,863.7		58,863.7	
PV OM&A Costs		(677.4)		(677.4)	
PV Ontario Capital Tax and Municipal Tax		(6,427.5)		(4,461.3)	1,966.1
PV Income Taxes		(17,339.2)		(17,997.8)	(658.7)
PV CCA Tax Shield		12,530.1		8,697.2	(3,832.9)
PV Capital - Upfront	(64,000.0)		(64,000.0)		
Add: PV **Capital Contribution**	**0.0**	(64,000.0)	**19,577.4**	(44,422.6)	19,577.4
PV Capital - On-going		0.0		0.0	
PV Proceeds on disposal of assets		0.0		0.0	
PV Working Capital		(1.7)		(1.7)	
PV Surplus / (Shortfall)		**(17,052.0)**		**(0.0)**	**17,052.0**
Profitability Index*		**0.7**		**1.0**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Capital Contributions

	Date	PV of Cont $k	Previous Cont Payments $k	Current Cont / (Credit) $k
Initial economic evaluation	2027	19,577.4		19,577.4
Total		**19,577.4**	**0.0**	**19,577.4**
Contribution Required (before HST)				**19,577.4**

Notes:
1) Payment from customer must include HST/GST.

Other Assumptions		**Notes:**
In-Service Date:	1-May-27	
Municipal Tax	0.63%	Transmission system average
Federal Income Tax	19.50%	Federal corporate income tax
Ontario Corporation Income Tax	14.00%	Provincial corporate income tax
Working cash net lag days	17.75	As per Lead Lag study
CCA Rate for Class 47 Assets	8%	100% Class 47 assets

Calculation Time Stamp: 02-Feb-26, 3:20 PM

Date:	31-Jan-26
Project #	

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - Estimated cost

Facility Name: Newton TS Transformer Expansion
Description:
Customer: Alectra

			In-Service Date	<------- Project year ended - annualized from In-Service Date ------->																						
		Month	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1
		Year	2031	2032	2033	2034	2035	2036 (1st true-up)	2037	2038	2039	2040	2041 (2nd true-up)	2042	2043	2044	2045	2046 (3rd true-up)	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056
			0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast																												
Load Forecast (MW)				15.0	18.0	21.0	24.0	27.0	30.0	33.0	37.0	40.0	43.0	46.0	50.0	53.0	57.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
Load adjustments (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				15.0	18.0	21.0	24.0	27.0	30.0	33.0	37.0	40.0	43.0	46.0	50.0	53.0	57.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
Tariff Applied ($/kW/Month)				1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61
Incremental Revenue - $k				289.8	347.8	405.7	463.7	521.6	579.6	637.6	714.8	772.8	830.8	888.7	966.0	1,024.0	1,101.2	1,159.2	1,159.2	1,159.2	1,159.2	1,159.2	1,159.2	1,159.2	1,159.2	1,159.2	1,159.2	1,159.2
Removal Costs - $k			0.0																									
On-going OM&A Costs - $k			0.0	(47.0)	(47.0)	(47.0)	(47.0)	(47.0)	(47.0)	(47.0)	(47.0)	(47.0)	(47.0)	(47.0)	(47.0)	(47.0)	(47.0)	(47.0)	(47.0)	(47.0)	(47.0)	(47.0)	(47.0)	(47.0)	(47.0)	(47.0)	(47.0)	(47.0)
Ontario Capital Tax and Municipal Tax - $K				(277.6)	(271.9)	(266.6)	(261.8)	(257.4)	(253.3)	(249.5)	(246.1)	(242.9)	(240.0)	(237.3)	(234.8)	(232.5)	(230.4)	(228.5)	(226.7)	(225.1)	(223.6)	(222.2)	(220.9)	(219.8)	(218.7)	(217.7)	(216.8)	(215.9)
Net Revenue/(Costs) before taxes - $k			0.0	(34.8)	28.9	92.1	154.9	217.3	279.3	341.0	421.8	482.9	543.8	604.4	684.2	744.4	823.8	883.7	885.5	887.1	888.6	890.0	891.3	892.4	893.5	894.5	895.4	896.3
Income Taxes - $k			0.0	453.9	839.4	750.3	666.7	588.3	514.7	445.3	373.5	311.9	253.6	198.4	139.6	89.9	36.2	(8.9)	(32.4)	(54.1)	(74.1)	(92.4)	(109.3)	(124.8)	(139.1)	(152.3)	(164.4)	(175.5)
Operating Cash Flow (after taxes) - $k			0.0	419.1	868.2	842.3	821.6	805.6	794.0	786.4	795.3	794.8	797.4	802.8	823.8	834.4	860.0	874.9	853.1	833.0	814.6	797.6	782.0	767.6	754.4	742.2	731.0	720.8
		Cumulative PV @ 5.68%																										
PV Operating Cash Flow (after taxes) - $k	**(A)**	10,616.1	**0.0**	**407.6**	**799.2**	**733.6**	**677.1**	**628.2**	**585.9**	**549.1**	**525.5**	**496.9**	**471.7**	**449.4**	**436.4**	**418.2**	**407.9**	**392.6**	**362.2**	**334.7**	**309.7**	**287.0**	**266.2**	**247.3**	**230.0**	**214.1**	**199.5**	**186.1**
Capital Expenditures - $k																												
Capital cost before overheads & AFUDC - $k			(33,000.0)																									
- Overheads - $k			0.0																									
- AFUDC - $k			0.0																									
Total upfront capital expenditures - $k			**(33,000.0)**																									
On-going capital expenditures - $k				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $k			0.0																									
Total capital expenditures - $k			**(33,000.0)**																									
Capital Contributions - $k																												
Previous capital contribution/(credit)			0.0																									
Current capital contribution/(credit)			0.0																									
PV of annual capital contribution			0.0																									
Total PV			**0.0**																									
PV Proceeds on disposal of assets - $k			**0.0**																									
PV CCA Residual Tax Shield - $k			**210.7**																									
PV Working Capital - $k			**(1.6)**																									
PV Capital (after taxes) - $k	**(B)**	(32,790.9)	**(32,790.9)**																									
Cumulative PV Cash Flow (after taxes) - $k	**(A) + (B)**	(22,174.8)	**(32,790.9)**	**(32,383.2)**	**(31,584.0)**	**(30,850.4)**	**(30,173.3)**	**(29,545.0)**	**(28,959.1)**	**(28,410.1)**	**(27,884.6)**	**(27,387.7)**	**(26,916.0)**	**(26,466.6)**	**(26,030.3)**	**(25,612.1)**	**(25,204.2)**	**(24,811.6)**	**(24,449.3)**	**(24,114.6)**	**(23,804.9)**	**(23,518.0)**	**(23,251.8)**	**(23,004.5)**	**(22,774.5)**	**(22,560.5)**	**(22,360.9)**	**(22,174.8)**

Discounted Cash Flow Summary

Economic Study Horizon - Years: 25

Discount Rate - % 5.68%

		Before Cont $k		After Cont $k	Impact $k
PV Incremental Revenue		10,516.3		10,516.3	
PV OM&A Costs		(636.8)		(636.8)	
PV Ontario Capital Tax and Municipal Tax		(3,314.2)		(757.3)	2,556.8
PV Income Taxes		(2,199.4)		(3,055.9)	(856.5)
PV CCA Tax Shield		6,460.8		1,476.4	(4,984.4)
PV Capital - Upfront	(33,000.0)		(33,000.0)		
Add: PV **Capital Contribution**	**0.0**	(33,000.0)	**25,458.9**	(7,541.1)	25,458.9
PV Capital - On-going		0.0		0.0	
PV Proceeds on disposal of assets		0.0		0.0	
PV Working Capital		(1.6)		(1.6)	
PV Surplus / (Shortfall)		**(22,174.8)**		**0.0**	**22,174.8**
Profitability Index*		**0.3**		**1.0**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Capital Contributions

	Date	PV of Cont $k	Previous Cont Payments $k	Current Cont / (Credit) $k
Initial economic evaluation	2031	25,458.9		25,458.9
Total		**25,458.9**	**0.0**	**25,458.9**
Contribution Required (before HST)				**25,458.9**

Notes:
1) Payment from customer must include HST/GST.

Other Assumptions		**Notes:**
In-Service Date:	1-May-31	
Municipal Tax	0.63%	Transmission system average
Federal Income Tax	19.50%	Federal corporate income tax
Ontario Corporation Income Tax	14.00%	Provincial corporate income tax
Working cash net lag days	17.75	As per Lead Lag study
CCA Rate for Class 47 Assets	8%	100% Class 47 assets

Calculation Time Stamp: 31-Jan-26, 2:24 PM

Date:	15-Mar-24
Project #	

SUMMARY OF CONTRIBUTION CALCULATIONS
Line Pool - Estimated cost

Facility Name:	Heritage TS 230KV Transmission Line Expansion
Description:	Build 230KV Transmission Line 7Km to supply New Heritage TS
Customer:	ALECTRA UTILITIES CORPORATION

			In-Service Date	<------- Project year ended - annualized from In-Service Date ------->																							
			Month	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1
			Year	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059
									1st true-up					2nd true-up					3rd true-up									
				0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast																												
Load Forecast (MW)				15.3	32.7	51.0	75.7	97.2	116.0	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1
Load adjustments (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				15.3	32.7	51.0	75.7	97.2	116.0	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1
Tariff Applied ($/kW/Month)				0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88
Incremental Revenue - $k				161.5	345.3	538.6	798.9	1,026.1	1,224.5	1,373.3	1,373.3	1,373.3	1,373.3	1,373.3	1,373.3	1,373.3	1,373.3	1,373.3	1,373.3	1,373.3	1,373.3	1,373.3	1,373.3	1,373.3	1,373.3	1,373.3	1,373.3
Removal Costs - $k			0.0																								
On-going OM&A Costs - $k			0.0	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)
Ontario Capital Tax and Municipal Tax - $K				(1,013.8)	(992.9)	(973.8)	(956.2)	(939.9)	(925.0)	(911.3)	(898.7)	(887.0)	(876.4)	(866.5)	(857.5)	(849.2)	(841.5)	(834.5)	(828.0)	(822.0)	(816.5)	(811.5)	(806.8)	(802.6)	(798.6)	(795.0)	(791.7)	(788.6)
Net Revenue/(Costs) before taxes - $k			0.0	(872.3)	(667.7)	(455.2)	(177.2)	66.2	279.5	442.0	454.7	466.3	477.0	486.8	495.9	504.2	511.8	518.9	525.4	531.3	536.8	541.8	546.5	550.8	554.7	558.3	561.6	564.7
Income Taxes - $k			0.0	1,907.1	3,324.3	3,005.1	2,683.7	2,392.3	2,127.7	1,895.5	1,727.8	1,573.5	1,431.5	1,300.9	1,180.8	1,070.2	968.5	875.0	788.9	709.7	636.9	569.8	508.2	451.4	399.2	351.2	307.1	266.4
Operating Cash Flow (after taxes) - $k			0.0	1,034.9	2,656.6	2,549.9	2,506.5	2,458.4	2,407.1	2,337.5	2,182.4	2,039.8	1,908.5	1,787.7	1,676.6	1,574.4	1,480.4	1,393.9	1,314.3	1,241.0	1,173.7	1,111.7	1,054.7	1,002.2	953.9	909.5	868.7	831.1
		Cumulative PV @ 5.68%																										
PV Operating Cash Flow (after taxes) - $k	**(A)**	**24,505.7**	**0.0**	**1,006.7**	**2,445.3**	**2,220.9**	**2,065.8**	**1,917.2**	**1,776.3**	**1,632.2**	**1,442.0**	**1,275.2**	**1,129.0**	**1,000.7**	**888.1**	**789.1**	**702.1**	**625.5**	**558.1**	**498.7**	**446.2**	**400.0**	**359.0**	**322.8**	**290.8**	**262.3**	**237.1**	**214.6**
Capital Expenditures - $k																												
Capital cost before overheads & AFUDC - $k			(120,516.0)																								
- Overheads - $k			0.0																								
- AFUDC - $k			0.0																								
Total upfront capital expenditures - $k			**(120,516.0)**																								
On-going capital expenditures - $k				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $k			0.0																								
Total capital expenditures - $k			**(120,516.0)**																								
Capital Contributions - $k																												
Previous capital contribution/(credit)			0.0																								
Current capital contribution/(credit)			0.0																								
PV of annual capital contribution			0.0																								
Total PV			**0.0**																								
PV Proceeds on disposal of assets - $k			**0.0**																								
PV CCA Residual Tax Shield - $k			**769.6**																								
PV Working Capital - $k			**(0.7)**																								
PV Capital (after taxes) - $k	**(B)**	**(119,747.1)**	**(119,747.1)**																								
Cumulative PV Cash Flow (after taxes) - $k	**(A) + (B)**	**(95,241.4)**	**(119,747.1)**	**(118,740.4)**	**(116,295.1)**	**(114,074.2)**	**(112,008.5)**	**(110,091.3)**	**(108,315.0)**	**(106,682.8)**	**(105,240.9)**	**(103,965.6)**	**(102,836.6)**	**(101,835.8)**	**(100,947.8)**	**(100,158.6)**	**(99,456.6)**	**(98,831.0)**	**(98,272.9)**	**(97,774.3)**	**(97,328.0)**	**(96,928.1)**	**(96,569.0)**	**(96,246.2)**	**(95,955.4)**	**(95,693.1)**	**(95,456.0)**	**(95,241.4)**

Discounted Cash Flow Summary

Economic Study Horizon - Years:		**25**			
Discount Rate - %		**5.68%**			
		Before Cont		**After Cont**	**Impact**
		$k		$k	$k
PV Incremental Revenue		14,901.1		14,901.1	
PV OM&A Costs		(271.0)		(271.0)	
PV Ontario Capital Tax and Municipal Tax		(12,103.3)		(1,121.7)	10,981.6
PV Income Taxes		(846.5)		(4,525.3)	(3,678.8)
PV CCA Tax Shield		23,595.0		2,186.7	(21,408.3)
PV Capital - Upfront	(120,516.0)		(120,516.0)		
Add: PV **Capital Contribution**	**0.0**	(120,516.0)	**109,346.9**	(11,169.1)	109,346.9
PV Capital - On-going		0.0		0.0	
PV Proceeds on disposal of assets		0.0		0.0	
PV Working Capital		(0.7)		(0.7)	
PV Surplus / (Shortfall)		**(95,241.4)**		**0.0**	**95,241.4**
Profitability Index*		**0.2**		**1.0**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Capital Contributions

	Date	PV of Cont $k	Previous Cont Payments $k	Current Cont / (Credit) $k
Initial economic evaluation	2034	109,346.9		109,346.9
Total		**109,346.9**	**0.0**	**109,346.9**
Contribution Required (before HST)				**109,346.9**

Notes:
1) Payment from customer must include HST/GST.

Other Assumptions		**Notes:**
In-Service Date:	1-May-34	
Municipal Tax	0.63%	Transmission system average
Federal Income Tax	19.50%	Federal corporate income tax
Ontario Corporation Income Tax	14.00%	Provincial corporate income tax
Working cash net lag days	17.75	As per Lead Lag study
CCA Rate for Class 47 Assets	8%	100% Class 47 assets

Calculation Time Stamp: 02-Feb-26, 3:27 PM

Date:	12-Mar-24
Project #	

SUMMARY OF CONTRIBUTION CALCULATIONS
Line Pool - Estimated cost

Facility Name:	H29/H30 TX Line Reconductoring
Description:	Upgrade Transmission line to Pleasant TS - Alectra Share 74% based on loading share
Customer:	ALECTRA UTILITIES CORPORATION

			In-Service Date	<------- Project year ended - annualized from In-Service Date ------->																							
			Month	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1	May-1
			Year	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
									1st true-up					2nd true-up					3rd true-up									
				0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast																												
Load Forecast (MW)				10.2	17.9	25.5	34.0	41.7	49.3	52.7	56.1	59.5	61.2	62.9	64.6	66.3	68.9	71.4	74.0	76.6	79.2	81.8	84.5	87.1	89.8	90.1	90.1	90.1
Load adjustments (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				10.2	17.9	25.5	34.0	41.7	49.3	52.7	56.1	59.5	61.2	62.9	64.6	66.3	68.9	71.4	74.0	76.6	79.2	81.8	84.5	87.1	89.8	90.1	90.1	90.1
Tariff Applied ($/kW/Month)				0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88
Incremental Revenue - $k				107.7	188.5	269.3	359.0	439.8	520.6	556.5	592.4	628.3	646.3	664.2	682.2	700.1	727.1	754.1	781.4	808.8	836.4	864.2	892.1	920.2	948.4	951.5	951.5	951.5
Removal Costs - $k				0.0																								
On-going OM&A Costs - $k				0.0	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)
Ontario Capital Tax and Municipal Tax - $K					(176.6)	(173.0)	(169.7)	(166.6)	(163.8)	(161.2)	(158.8)	(156.6)	(154.6)	(152.7)	(151.0)	(149.4)	(148.0)	(146.6)	(145.4)	(144.3)	(143.2)	(142.3)	(141.4)	(140.6)	(139.8)	(139.2)	(138.5)	(138.0)	(137.4)
Net Revenue/(Costs) before taxes - $k				0.0	(88.9)	(4.5)	79.6	172.4	256.0	339.4	377.7	415.8	453.8	473.6	493.2	512.8	532.2	560.4	588.7	617.1	645.6	674.1	702.8	731.5	760.3	789.3	792.9	793.5	794.0
Income Taxes - $k				0.0	311.2	541.8	470.4	399.5	334.9	273.4	229.6	188.3	149.4	118.6	89.9	62.9	37.6	10.9	(14.5)	(38.6)	(61.6)	(83.5)	(104.5)	(124.6)	(143.9)	(162.5)	(171.8)	(179.5)	(186.6)
Operating Cash Flow (after taxes) - $k				0.0	222.3	537.3	550.0	572.0	591.0	612.8	607.3	604.1	603.1	592.2	583.1	575.7	569.8	571.3	574.3	578.5	584.0	590.6	598.3	606.9	616.4	626.8	621.1	614.0	607.4
		Cumulative PV @ 5.68%																										
PV Operating Cash Flow (after taxes) - $k	**(A)**	**7,590.4**		**0.0**	**216.2**	**494.5**	**479.0**	**471.4**	**460.9**	**452.2**	**424.0**	**399.2**	**377.1**	**350.3**	**326.4**	**304.9**	**285.6**	**271.0**	**257.7**	**245.7**	**234.7**	**224.6**	**215.2**	**206.6**	**198.6**	**191.1**	**179.1**	**167.6**	**156.9**
Capital Expenditures - $k																												
Capital cost before overheads & AFUDC - $k				(21,000.0)																								
- Overheads - $k				0.0																								
- AFUDC - $k				0.0																								
Total upfront capital expenditures - $k				**(21,000.0)**																								
On-going capital expenditures - $k					0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $k				0.0																								
Total capital expenditures - $k				**(21,000.0)**																								
Capital Contributions - $k																												
Previous capital contribution/(credit)				0.0																								
Current capital contribution/(credit)				0.0																								
PV of annual capital contribution				0.0																								
Total PV				**0.0**																								
PV Proceeds on disposal of assets - $k				**0.0**																								
PV CCA Residual Tax Shield - $k				**134.1**																								
PV Working Capital - $k				**(0.7)**																								
PV Capital (after taxes) - $k	**(B)**	**(20,866.6)**		**(20,866.6)**																								
Cumulative PV Cash Flow (after taxes) - $k	**(A) + (B)**	**(13,276.2)**		**(20,866.6)**	**(20,650.4)**	**(20,155.8)**	**(19,676.8)**	**(19,205.4)**	**(18,744.5)**	**(18,292.4)**	**(17,868.3)**	**(17,469.2)**	**(17,092.1)**	**(16,741.7)**	**(16,415.3)**	**(16,110.4)**	**(15,824.8)**	**(15,553.9)**	**(15,296.1)**	**(15,050.5)**	**(14,815.8)**	**(14,591.3)**	**(14,376.0)**	**(14,169.4)**	**(13,970.8)**	**(13,779.8)**	**(13,600.6)**	**(13,433.1)**	**(13,276.2)**

Discounted Cash Flow Summary

Economic Study Horizon - Years:		**25**			
Discount Rate - %		**5.68%**			
		Before Cont		**After Cont**	**Impact**
		$k		$k	$k
PV Incremental Revenue		7,813.1		7,813.1	
PV OM&A Costs		(271.0)		(271.0)	
PV Ontario Capital Tax and Municipal Tax		(2,109.0)		(578.2)	1,530.8
PV Income Taxes		(1,820.1)		(2,332.9)	(512.8)
PV CCA Tax Shield		4,111.4		1,127.2	(2,984.2)
PV Capital - Upfront	(21,000.0)			(21,000.0)	
Add: PV **Capital Contribution**	**0.0**	(21,000.0)	**15,242.5**	(5,757.5)	15,242.5
PV Capital - On-going		0.0		0.0	
PV Proceeds on disposal of assets		0.0		0.0	
PV Working Capital		(0.7)		(0.7)	
PV Surplus / (Shortfall)		**(13,276.2)**		**0.0**	**13,276.2**
Profitability Index*		**0.4**		**1.0**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Capital Contributions

	Date	PV of Cont $k	Previous Cont Payments $k	Current Cont / (Credit) $k
Initial economic evaluation	2028	15,242.5		15,242.5
Total		**15,242.5**	**0.0**	**15,242.5**
Contribution Required (before HST)				**15,242.5**

Notes:
1) Payment from customer must include HST/GST.

Other Assumptions		**Notes:**
In-Service Date:	1-May-28	
Municipal Tax	0.63%	Transmission system average
Federal Income Tax	19.50%	Federal corporate income tax
Ontario Corporation Income Tax	14.00%	Provincial corporate income tax
Working cash net lag days	17.75	As per Lead Lag study
CCA Rate for Class 47 Assets	8%	100% Class 47 assets

Calculation Time Stamp: 19-Feb-26, 12:08 PM

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-125

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B14 - Enabling Resiliency & Modernization / pp. 652-653 (pdf Exhibit 2A Part 2 pp. 660-661)

Question(s):

a) Please identify all costs incurred by Alectra Utilities due to meteorological or other events that would qualify as resiliency category events over the historical and bridge periods.

    i. Please separate the costs into capital repairs, O&M costs, and any other costs.

b) Please identify which of the proposed projects listed in Table B14 -15 would have directly mitigated a portion of the costs resulting from the resiliency events listed above, and identify what portion of those costs would have been avoided.

RESPONSE:

a) Please note that the term “resiliency category event” was not defined in Alectra’s evidence or the IR as delivered and is not a recognized industry term. To respond to the question, we assume that “Resiliency category events” refer to “past meteorological or system-stress events that Alectra claims its resiliency investments are designed to mitigate”. Alectra tracks O&M costs for responding to trouble calls and outages at the program level. Reactive Capital investments are tracked at the asset class level. Alectra’s systems and processes do not allow costs to be accurately tracked at the specific event level.

b) Alectra cannot overlay forecasted costs with the projects identified in Table B14-15. Historical costs are not tracked at the event level to provide a basis for accurate forecasted costs related to possible future events.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-126

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B14 Enabling Resiliency & Modernization / p. 571 (pdf Exhibit 2A Part 2 p. 579)

Question(s):

a) Please update Table B14 - 1 to include the past 10 years of actual costs.

RESPONSE:

Alectra Utilities has provided historical actuals consistent with its formation in 2017. Historical actuals before 2017 relate to the former legacy utilities that operated as separate entities under different planning frameworks, capital structures and budgeting approaches that were not developed on a consistent or comparable basis. Note that 2025 has been updated with actuals. As a result, there are 9 years of actual costs in the table.

Table 1 – Enabling Resiliency and Modernization Actuals by Grouping 2017-2031

Investment Type	Historical Spending								Bridge		Forecast Spending				
	2017A	2018A	2019A	2020A	2021A	2022A	2023A	2024A	2025A	2026	2027	2028	2029	2030	2031
SCADA, Automation and System Control	8.9	7.6	11.7	8.9	13.2	13.1	11.3	14.2	18	10.5	9.6	18.4	26.2	26.8	21.1
Rear Lot Conversions	3.8	0	4.5	2.4	0.1	1	0.1	0.1	0.7	0	0	0	20.3	32.7	33.6
Grid Modernization	0	0	0	0	0	0	0	0.7	1.9	3.9	2.5	5.3	7.5	13.2	12.6
Customer Service Technologies	0	0	0	0.1	0.7	5.1	6.1	9.2	1.7	1	2.2	2	2.9	2	2
Total ($MM)	**12.7**	**7.6**	**16.2**	**11.4**	**14**	**19.2**	**17.5**	**24.2**	**22.3**	**15.4**	**14.3**	**25.7**	**56.9**	**74.7**	**69.3**

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-127

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B14 Enabling Resiliency & Modernization p. 611 (pdf Exhibit 2A Part 2 p. 619)

Question(s):

a) Please explain why rear-lot conversion investment spending in the 2021-2028 period is zero or near zero in light of the claimed historic and current issues.

RESPONSE:

As described in Exhibit 2A / Tab 1 / Schedule 1 / Appendix B14 Enabling Resiliency & Modernization - Section 3.5, p. 611, spending was reduced during the historic period 2020 – 2024 to redirect funding towards other higher priority investments, including cable renewal projects. Before construction commences in 2029, time is needed for permitting, customer and stakeholder engagement, and engineering design.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-128

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / DSP Appendix E / pp. 45-58 (pdf Exhibit 2A Part 3 pp. 175-188)

Question(s):

(a) For all figures pertaining to stations assets age distribution and Health Index distribution, please provide the underlying data.

(b) Please provide the underlying data in (a) segregated by operating voltage of the assets.

RESPONSE:

(a) Please see 2-Staff-128_Attach1_Number of Station Assets by Voltage, Age and HI. The attachment provides the underlying data for the station asset age distribution and Health Index distribution figures. Separate worksheets are provided for power transformers, circuit breakers, and station switchgear. Each worksheet summarizes the number of assets by age range, Health Index, and operating voltage.

(b) Please refer to Part (a).

2-Staff-128

Attachment 1
Number of Station Assets by Voltage and HI

Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-129

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix E
Asset Condition Assessment Report / p. 9 (pdf Exhibit 2A Part 3 p. 139)

Question(s):

a) Please provide for each major asset class the annual probability of condition related failure for assets in each of the identified Heath Index categories. For reference, Toronto Hydro-Electric System Limited has stated the annual Probability of Failure for "Wood Poles" that are in the worst health index condition (HI5) is 0.18% to 0.33%[1].

b) If the annual probabilities of failure requested above are not available, please explain how Copperleaf is used to determine the pre and post capital expenditure risk profiles of assets that are being replaced or rehabilitated under any of the System Renewal projects and programs.

RESPONSE:

a) Please refer to response provided to 2-STAFF-57-a.

b) Please refer to response provided to 2-STAFF-57-b.

[1] THESL_Exhibit 2B_Asset Management Process_Part2of3_20231117.PDF

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-130

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix E Asset Condition Assessment Report / p. 33 (pdf Exhibit 2A Part 3 p. 163)

Question(s):

a) Why is age treated as a condition factor if strength tests and field inspections are being conducted? Please discuss.

RESPONSE:

a) Wood pole degradation is driven by multiple interacting factors, including climate, soil conditions, fungal attack, insect damage, and preservative breakdown. These mechanisms accumulate continuously over time, whereas inspections provide periodic snapshots. Strength tests and visual inspections may not capture all forms of deterioration. Accordingly, age is included as a proxy for cumulative, latent degradation that may not be captured by other model inputs.

Age at 15% does not replace condition data. It reflects the reality that older poles have had more cumulative exposure to these stressors. Even when test results appear acceptable, the likelihood of undetected degradation increases with time in service. The weight is intentionally modest so that significant pole test results and visual inspection still drive the final health index score. Age also supports forward-looking risk assessments and can augment condition data in alternative age-based models. Therefore, Alectra Utilities has kept the age factor in the ACA methodology for the time being.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-131

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix E Asset Condition Assessment Report / pp. 48, 54, 58 (pdf Exhibit 2A Part 3 pp. 178, 184, 188)

Preamble:

Alectra Utilities provides the following tables:

Table 11 - Power Transformer Health Index Parameters and Weights

#	Input	Input Weight
1	Insulation	49%
2	Cooling	36%
3	Sealing and Connection	15%
4	Service Record	15%

Table 12 - Circuit Breaker Health Index Parameters and Weight

#	Input	Input Weight (OIL)	Input Weight (AIR)	Input Weight (Vacuum)	Input Weight (SF6)	Input Weight (Switch & Fuse)
1	Insulation	4.8%	5.6%	7.4%	6.1%	6.7%
2	Operating Mechanism	33.3%	38.9%	25.9%	33.3%	46.7%
3	Contact Performance	16.7%	19.4%	25.9%	21.2%	23.3%
4	Arc Extinction	21.4%	16.7%	14.8%	18.2%	-
5	Oil Leaks	7.1%	-	-	-	-
6	Service Record	16.7%	19.4%	26.0%	21.2%	23.3%

Table 14 - Station Switchgear Health Index Parameters and Weights

#	Input	Input Weight
1	Insulation	25%
2	Cooling	37.5%
3	Sealing and Connection	12.5%
4	Service Record	25%

Question(s):

a) How does Alectra Utilities store and extract the Transformer, Circuit Breaker and Switchgear service record data, and how is that data used to create the service record input used in the Health Index calculation?

   i. Please provide example data and calculations for an individual Transformer, Circuit Breaker and Switchgear drawn from each Health Index category.

RESPONSE:

a) Alectra Utilities clarifies that the correct Table 11 (Exhibit 2A / Tab 1 / Schedule 1 / Appendix E Asset Condition Assessment Report / pp. 48) is provided below:

Table 11 - Power Transformer Health Index Parameters and Weights

#	Input	Input Weight
1	Insulation	70%
2	Cooling	7.5%
3	Sealing and Connection	7.5%
4	Service Record	15%

For power transformers, Service Record consists of two factors: Overall Condition and Historical Loading. For circuit breakers and station switchgear, Service Record is solely based on Overall Condition.

Overall Condition is one of the inputs used in asset condition assessment surveys that are completed by Subject Matter Experts (SMEs). It reflects SME's assessment of the asset's condition, informed by the asset's inspection, maintenance, and repair history. The scoring criteria for Overall Condition are provided in Table 1 below.

Table 1 - Overall Condition Scoring Criteria

Score	Scoring Criteria
4	Excellent Service Performance – No material service-related defects; no unplanned maintenance or corrective repairs; asset operates reliably within expected operating context.
3	Good Service Performance – minor service-related issues addressed through routine maintenance; no recurring defects; asset continues to operate reliably within expected operating context.
2	Fair Service Performance – Repeated maintenance or corrective repairs required; emerging issues observed; asset remains operational but requires increased monitoring.
1	Poor Service Performance – Frequent corrective repairs or operational issues; recurring service-related defects; asset performance is no longer consistently within expected operating context.
0	Very Poor Service Performance – Persistent operational issues or failures; asset is at risk of imminent failure or require immediate intervention.

For Historical Loading, a score is calculated based on the number of occurrences when the loading falls within specified ranges. These ranges are based on the percentage of the transformer nameplate capacity rating and assigned a weight, as shown in Table 2 below.

Table 2 - Historical Loading Range Categories and Weights

Loading Category	Ratio of Load to Capacity	Category Weight
A	< 0.6	4
B	≥ 0.6 and < 0.8	3

C	≥ 0.8 and < 1.0	2
D	≥ 1.0 and < 1.2	1
E	≥ 1.2	0

For Historical Loading, score is a continuous function with a maximum value of 4 and is calculated as follows:

[(NA x 4) + (NB x 3) + (NC x 2) + (ND x 1)]/NT

NA is the number of occurrences in category A, NB is the number of occurrences in category B, and so on. NT is the total number of loading records.

Overall Condition scores are recorded in an SQL database. Historical Loading data is extracted from Alectra Utilities' SCADA system and is stored in Excel files. Alteryx is used to extract the Overall Condition from the SQL database and the Historical Loading from the Excel files, and to apply the approved scoring and weighting methodology to calculate the resulting Health Indices.

i. Sample Calculations for Service Record

Power Transformers: Service Record comprises up to 15% of the total Health Index Score for power transformers. 7.5% is attributed to Overall Condition and 7.5% is attributed to Historical Loading.

For simplicity, assume that transformer "X" has 10,000 Historical Loading records (NT) with the following distribution:

NA = 9,500, NB = 450, NC = 45, ND = 5, NE = 0

The Historical Loading score is calculated as follows:

[(9,500 x 4) + (450 x 3) + (45 x 2) + (5 x 1)]/10,000 = 3.94

Also assume that transformer "X" has an Overall Condition score of 3 out of 4.

The Health Index associated with Service Record is then calculated as follows:

[(7.5% x 3/4) + (7.5% x 3.94/4)] = 13%

Circuit Breakers: For this example, assume that the asset is a vacuum circuit breaker. Service Record for a vacuum circuit breaker comprises up to 26% of the total Health Index score. Assume that breaker "Y" has a Service Record score of 2. The Health Index associated with Service Record is calculated as follows:

(26% x 2/4) = 13%

Station Switchgear: Service Record for station switchgear comprises up to 25% of the total Health Index score. Assume that switchgear "Z" has a Service Record score of 3 out of a maximum score of 4. The Health Index associated with Service Record is calculated as follows:

(25% x 3/4) = 18.75%

For each of the above asset classes, the remainder of the asset's overall Health Index score is based on the scores associated with the other input factors.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-132

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix E / p. 34 (pdf Exhibit 2A Part 3 p. 164)

Question(s):

a) Please confirm that the statement "The ACA model does not factor in poles that could be severely undersized according to current CSA standards" means that in general Alectra Utilities "grandfathers" assets when standards are updated to new revisions (e.g., CSA increased strength standards for wood poles).

a. If not confirmed, please explain what is meant by the statement in *general.*

RESPONSE:

a) Not confirmed. Alectra Utilities understands the referenced statement in the 2023 ACA report (Appendix E) to be a technical description of the scope of the ACA Health Index methodology, not a statement of general policy regarding "grandfathering" assets when standards are updated. The ACA Health Index evaluates pole physical condition and degradation and does not assess standards compliance of an existing pole in terms of pole class and loading adequacy for a particular construction configuration under current CSA loading requirements.

As explained in Exhibit 2A, Schedule 1, Tab1, Appendix B01, page 21, Alectra Utilities has evaluated poles to identify those at high risk due to climate trends, specifically, structurally vulnerable poles that do not meet pole loading criteria or lack sufficient framing to withstand location-specific climate loads. This climate-related risk classification is used in conjunction with the ACA results to prioritize pole replacements.

Alectra Utilities will replace 218 high-risk climate poles that are also in deteriorated condition during the 2027-2031 period.

Alectra Utilities may replace poles that do not meet the revised CSA standards when undertaking other asset renewals, such as switch replacements, where pole structural capacity may be insufficient.

Where an existing pole installed under prior legacy standards does not meet current Alectra Design Standards for new construction but is neither in deteriorated condition nor classified as a high-risk structurally overloaded pole, Alectra Utilities continues to maintain and monitor such poles.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-133

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix E - Asset Condition Assessment Report / p. 41 of 58 (pdf Exhibit 2A Part 3 p. 171)

Question(s):

a) Alectra Utilities presents Figure 24 Primary XLPE (cross-link polyethylene) Cable Health Index as a Function of Age. Please provide the degradation (scoring) curve for injected XLPE cables.

RESPONSE:

a) Please refer to Alectra Utilities' response to 2-Staff-86-b.

Alectra Utilities applies the same age-based degradation curve shown in Figure 24 Primary XLPE Cable Health Index as a Function of Age to injected XLPE cable.

For injected XLPE cable, Alectra Utilities reflects the injection by setting the cable's effective age to 20 years at the time of injection, regardless of the cable's actual chronological age. The resulting effective age is then applied to the Figure 24 degradation curve to determine the Health Index.

For example, for a XLPE cable segment injected in 2018, the cable's effective age is set to 20 years at the time of injection. Accordingly, in 2023, the injected XLPE cable's effective age would be 25 years, and the Health Index is determined by applying 25 years to the Figure 24 degradation curve.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-134

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix E / p. 54 (pdf Exhibit 2A Part 3 p. 184)

Preamble:

Alectra Utilities states:

> If the number of breaker operations during fault conditions is within 75% of the maximum number of operations shown in this table [Table 13], then the breaker is considered to be in Very Poor condition and will have a maximum Health Index of 10% (i.e., the calculated Health Index is multiplied by 0.1).

Question(s):

a) Please explain why Alectra Utilities chose 75% rather than 100% of the values shown in Table 13 given that IEEE Standards C37.04, C37.010, and C37.60 already include conservatism (e.g., lower bound thresholds rather than average thresholds) with regards to fault interrupting duty and maintenance intervals.

RESPONSE:

a) Alectra Utilities' selection of a 75% threshold of the maximum breaker duty values shown in Table 13 represents a deliberate asset management planning decision developed through engineering judgment and aligned with Alectra's condition-based Health Index methodology.

IEEE Standards C37.04, C37.010, and C37.60 establish maximum interrupting capabilities and test-based ratings for circuit breakers. These values define equipment design limits but are not intended to serve as condition thresholds or investment decision points within an asset health or risk framework.

In developing the Health Index, Alectra intentionally differentiated between rated capability and asset condition progression. The 75% threshold identifies a point where cumulative fault interrupting duty has advanced sufficiently toward rated limits that remaining operating margin, uncertainty in future performance, and potential consequence of failure become material considerations for planning. While the breaker remains operable and within its rated capability, it has entered a high-risk planning zone from an asset management perspective. The threshold recognizes that the impact of fault duty on breaker condition depends on the magnitude and characteristics of fault events and does not progress uniformly with each operation. It also recognizes that real-world performance is influenced by factors such as aging, maintenance history, and operational variability not explicitly captured in nameplate ratings.

In addition, intervention on station breaker equipment involves extended engineering, procurement, and outage coordination lead times, as well as heightened safety and system risk considerations associated with substation work. Early identification of breakers that have entered a high-risk planning zone enables appropriate technical evaluation, safety planning, and coordinated mitigation in a controlled manner.

Classification as “Very Poor” provides a structured, forward-looking signal to prioritize evaluation and intervention in a planned and cost-effective manner, consistent with prudent utility practice.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-135

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix J Load Forecast & System Adequacy Assessment Report / p. 30 (pdf Exhibit 2A Part 5 p. 65)

Preamble:

Regarding the Future Conservation and Demand Management (CDM) Impact section, Alectra Utilities states that: "By 2034 Alectra Utilities' service area is expected to achieve 242MW in peak demand savings."

Question(s):

a) Please quantify the anticipated peak demand reduction attributable to the full implementation of AMI 2.0. in each of Alectra Utilities' planning zones. Please discuss.

b) Considering the above response, please quantify the peak demand reduction percentage that would not be achievable if AMI 2.0 is not fully implemented, i.e., if the AMI renewal program was kept to like-for-like replacements. Please discuss.

RESPONSE:

a) Alectra Utilities has not quantified any peak demand reduction attributable to the implementation of AMI 2.0. Please see Alectra Utilities' response to 2.0-VECC-13a) for a breakdown of the 242MW of peak demand savings.

b) Not applicable.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-136

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix J Load Forecast & System Adequacy Assessment Report / p. 31 (pdf Exhibit 2A Part 5 p. 66)

Question(s):

a) Please break out the DER forecast in Figure 13 by technology, in tabular form.

b) Have all distribution reinforcement projects intended to facilitate DER connection been tested against expected times of production? For example, do all system reinforcements or enhancements intended to mitigate reverse power flow consider that solar production is zero between sunset and sunrise?

RESPONSE:

a) The table below breaks out the DER forecast by technology. Net Metering DERs are mostly Solar at Alectra. Other refers to natural gas, biomass, and diesel. For each category the forecast annual additions in MW are shown.

DER Technology	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Net Metering	6.45	6.52	6.60	6.68	6.76	6.84	6.92	7.01	7.09	7.18	**68.06**
Energy Storage	2.38	2.46	2.56	2.65	2.75	2.86	2.96	3.07	3.19	3.31	**28.09**
Other	8.28	8.36	8.45	8.53	8.62	8.70	8.79	8.88	8.97	9.06	**86.65**
Totals (Count)	**17.11**	**17.34**	**17.61**	**17.87**	**18.13**	**18.40**	**18.68**	**18.96**	**19.25**	**19.54**	**182.89**

b) Alectra has not planned any distribution reinforcement projects to facilitate DER connections.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-137

Future Electric Vehicles Impact
Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix J Load Forecast & System Adequacy Assessment Report / p. 32 (pdf Exhibit 2A Part 5 p. 67)

Question(s):

a) Please provide analysis done by Alectra Utilities to quantify any changes in this EV load forecast attributable to recent government adjustments in the target dates or percentages of mandatory ZEV sales.

RESPONSE:

Please see the response to 2-Staff-58.

As the Government of Canada's announcement to reduce import tariffs on affordable EVs was made on January 16th 2026 and the announcement indicating the launch of the Electric Vehicle Affordability Program (EVAP) and funding for charging infrastructure was made on February 5th, 2026, the specifics and details related to these government announcements are not yet available. Hence, Alectra Utilities is unable to provide analysis at this time. As the government's announcements identify the policy objectives to accelerate EV uptake by increasing customer options for lower-priced EVs, providing incentives and improving charging infrastructure to reduce customer concerns of range anxiety, the announcements demonstrate a commitment to EV uptake. Alectra Utilities does not expect material changes to its EV projections over the 2027-2031 planning period.

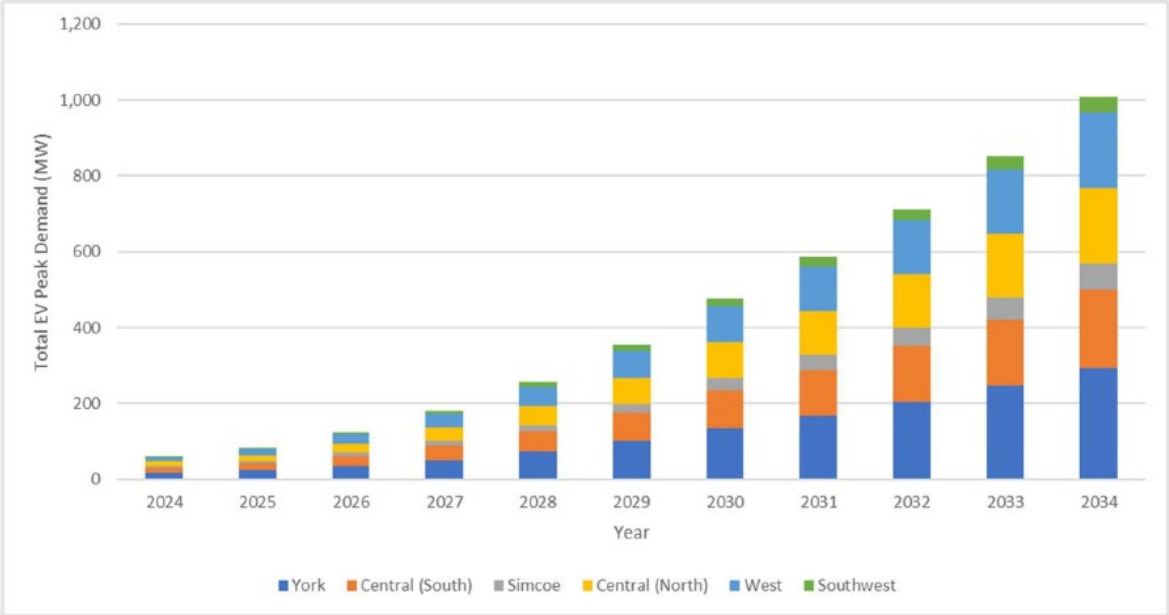
RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-138

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix J Load Forecast & System Adequacy Assessment Report / p. 37 (pdf Exhibit 2A Part 5 p. 72)

Preamble:

Regarding the Future Electric Vehicles Impact section, Alectra Utilities provides *Figure 16. EV Charging Load Peak Demand - Alectra Utilities' Service Area, 2024-2034.*



Question(s):

a) Does Figure 16 show the coincident peak demand (i.e., the coincident demand of all EV charging at the time of summer peak? If no, please provide a revised Figure 16 showing coincident peak demand

RESPONSE:

a) Confirmed, Exhibit 2A, Tab 1, Schedule 1, Appendix J, Figure 16 (p.37) shows the EV coincident peak demand at the time of summer peak.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-139

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix L Historical Reliability Data / pp. 2-4 (pdf Exhibit 2A Part 5 pp. 170-172)

Question(s):

a) Please update Figure L-1, Table L-1, Figure L-2, Table L-3 to include trendlines for SAIDI - Excluding MEDs and SAIFI - Excluding MEDs (including the slope of the trend lines).

RESPONSE:

a) **Figure L – 1 SAIDI vs Adjusted SAIDI from 2019 to 2024**

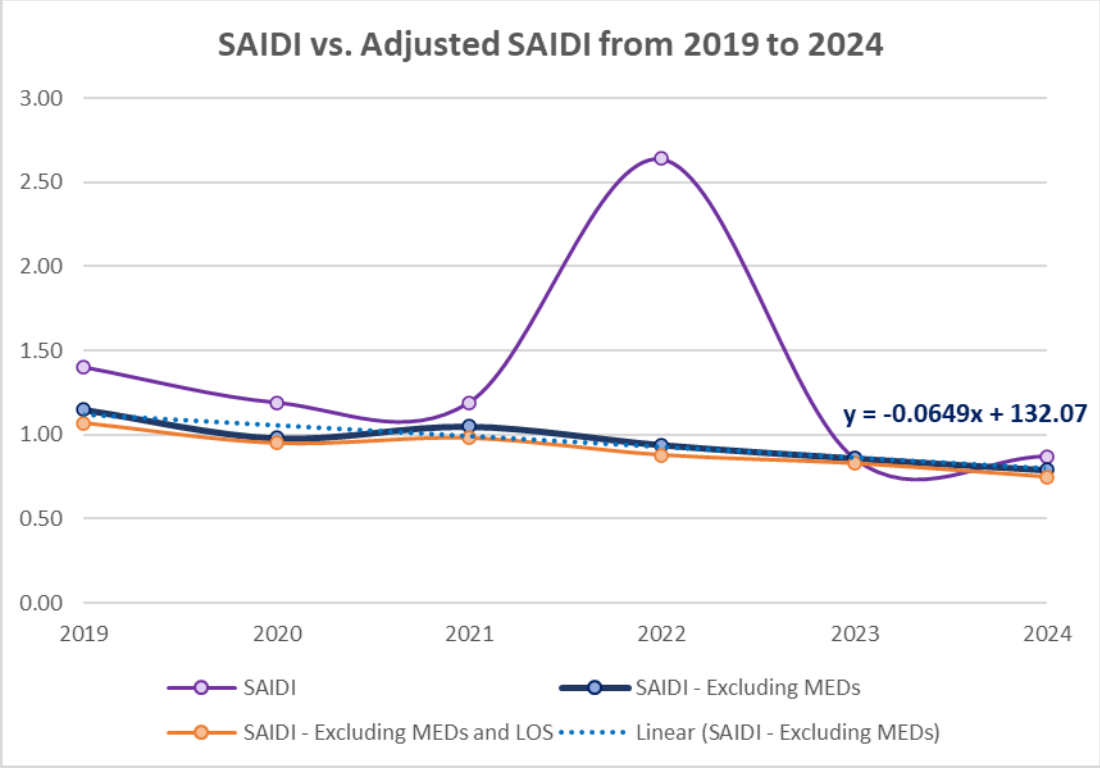


Table L - 1 Alectra Utilities' SAIDI, SAIDI Excluding MEDs, LOS results from 2019 to 2024

Metric (Hours)	2019	2020	2021	2022	2023	2024	Slope
SAIDI	1.40	1.19	1.19	2.64	0.86	0.87	-0.0626
SAIDI - Excluding MEDs	**1.15**	**0.98**	**1.05**	**0.94**	**0.86**	**0.79**	**-0.0649**
SAIDI - Excluding MEDs and LOS	1.07	0.95	0.98	0.88	0.83	0.75	-0.0589

Figure L - 2 SAIFI vs. Adjusted SAIFI from 2019 to 2024

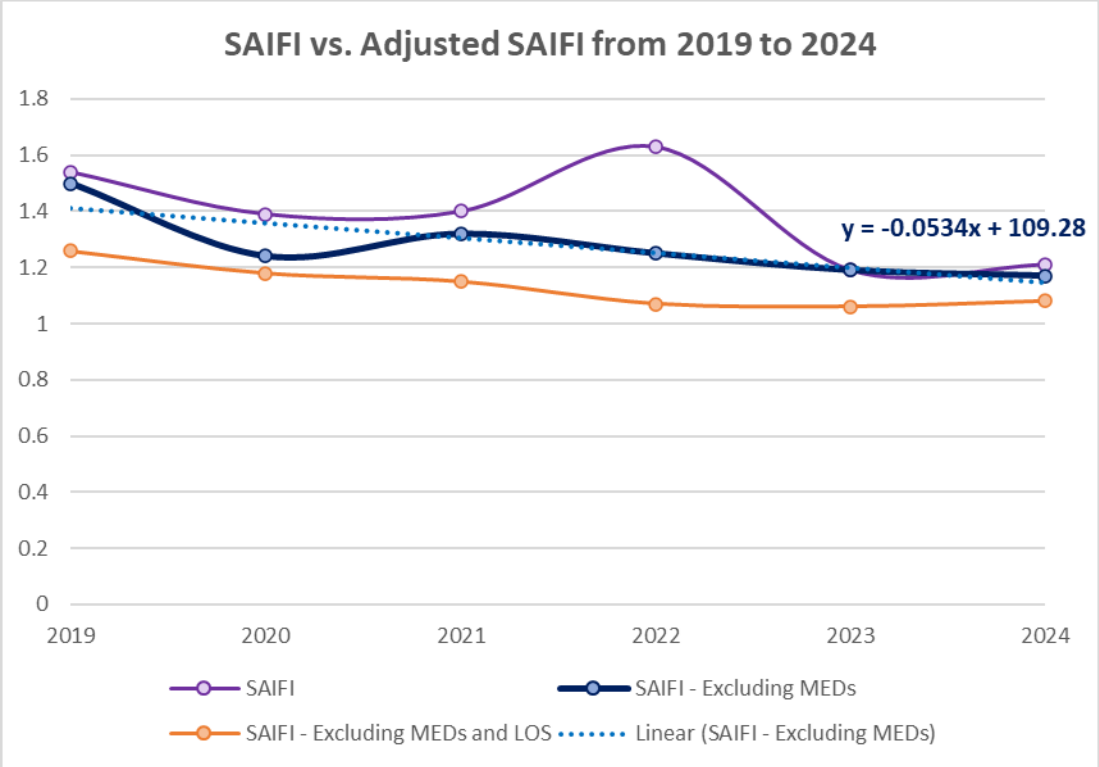


Table L - 3 Alectra Utilities' SAIFI, SAIFI Excluding MEDs, LOS results from 2019 to 2024

Metric (Number of Outages)	2019	2020	2021	2022	2023	2024	Slope
SAIFI	1.54	1.39	1.4	1.63	1.19	1.21	-0.0577
SAIFI - Excluding MEDs	**1.50**	**1.24**	**1.32**	**1.25**	**1.19**	**1.17**	**-0.0534**
SAIFI - Excluding MEDs and LOS	1.26	1.18	1.15	1.07	1.06	1.08	-0.0383

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-140

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix L Historical Reliability Data / p. 15 (pdf Exhibit 2A Part 5 p. 183)
Ref 2: Exhibit 1 / Tab 3 / Schedule 1 / p. 30 (pdf Exhibit 1 p. 200)
Ref 3: Exhibit 1 / Tab 5 / Schedule 2 / Attachment 1-2 / p. 5-6 (pdf Exhibit 1 p. 247-248)
Ref 4: Exhibit 1 / Tab 5 / Schedule 2 / Attachment 1-2 / p. 8 (pdf Exhibit 1 p. 250)

Preamble:
Alectra Utilities has set a SAIDI target that represents a material improvement over its historic SAIDI performance and involves significant incremental capital spending even though residential customers rank reasonable prices (67%) over reliable service (57%), and "residential and GS<50 kW customers placed somewhat higher priority on reasonable prices than reliability".

Question(s):

a) Please explain the differences between the Alectra Utilities SAIDI and SAIFI targets from reference 2 and the OEB SAIDI and SAIFI targets from reference 1. Please provide an explanation why Alectra Utilities claims they are not comparable metrics.

b) Please reconcile the OEB target SAIDI (0.876) and SAIFI (1.106) in Table L-7 of reference 1, with the Figure 1-3-4 SAIDI target (0.74) and absence of a SAIFI target from reference 2. Include in the reconciliation a SAIFI target for Alectra Utilities.

c) Please reconcile the Alectra Utilities Corporation Figure 1-3-4 SAIDI target (0.74) from reference 2 with the top two customer reliability priorities from reference 3 of "Restoration time in extreme weather (57%)" and "No. of outages in extreme weather (50%)", and as part of the reconciliation include an explanation as to why maintaining historic SAIDI

reliability while reducing MED outages times is not the preferred reliability target.

RESPONSE:

a) Alectra Utilities notes that the question requests a comparison between the SAIDI and SAIFI targets shown in Ref 2 and the OEB SAIDI and SAIFI targets shown in Ref 1. However, Ref 2 (Custom Performance Scorecard) presents a SAIDI target and does not present a SAIFI target. Alectra Utilities therefore cannot provide a like-for-like comparison of targets for both indices across the two references.

With respect to SAIDI, the reliability target referred to in Ref 1 was calculated using the OEB's Reliability Benchmarking methodology. The OEB's Reliability Benchmarking methodology is based upon both a utility's historical reliability performance and how its historical performance compares against an OEB defined peer group.

By contrast, the SAIDI target referred to in Ref 2 is an internal performance commitment tied to Alectra Utilities' 2027–2031 Distribution System Plan (DSP). In particular, Ref 2's SAIDI target of 0.74 is based on Alectra Utilities' 2020–2024 five-year average and represents a targeted 20% improvement, excluding MEDs but including LOS. These planned expenditures are designed to be responsive to customer preferences, address critical operational requirements, align with current public policy, and ensure full regulatory compliance.

Given these differences in purpose and scope, the Ref 1 and Ref SAIDI targets are not directly comparable as a single metric.

b) Alectra Utilities is unable to "reconcile" the OEB target SAIDI (0.876) and SAIFI (1.106) in Ref 1 with the Figure 1-3-4 SAIDI target (0.74) in Ref 2 on a like-for-like basis, as these targets are developed using different methodologies and reflect different scopes of interruption events.

Specifically, the OEB's SAIDI performance benchmarking target of 0.876 excludes both MEDs and LOS, whereas the SAIDI target of 0.74 only excludes MEDs but includes LOS. Furthermore, Alectra Utilities' SAIDI target in Ref 2 is a forward-looking performance commitment predicated on the anticipated benefits of proposed DSP investments

With response to SAIDI, Ref 2 does not specify a SAIFI target. Accordingly, Alectra Utilities cannot reconcile SAIFI target where no such target has been proposed in the evidence.

Alectra Utilities notes that it continues to monitor a range of reliability data, including SAIFI, consistent Exhibit 2A, Tab 1, Schedule 1, Page 75, Line 6. However, the current proposal focuses on two specific DSP-related performance measures to track the direct outcomes of the DSP: SAIDI and the total Customer Hours of Interruption attributed to Failed Equipment.

c) Alectra Utilities' notes that the renewal and grid modernization investments proposed within the 2027–2031 Distribution System Plan (DSP) are responsive to the top two customer reliability priorities identified in Ref 3: reducing the number of outages and improving restoration times during extreme weather events. Specifically, a number of proposed investments are directed at improving system resiliency and restoration capability during adverse weather events. In particular:

- Overhead Asset Renewal (Exhibit 2A, Tab 1, Schedule 1, Appendix B01) will strengthen and renew overhead assets that are typically most exposed during extreme weather, thereby increasing system resiliency and reducing weather-related outages.
- Enabling Resiliency & Modernization investments (Exhibit 2A, Tab 1, Schedule 1, Appendix B14) will enable faster and safer restoration through improved fault detection, isolation, and service restoration capabilities, and through removal of inherently hazardous and inaccessible real lot plant (Rear Lot Conversions) that contribute to extended restoration times following storm impacts.

Accordingly, the proposed investments are expected to improve system performance against the two extreme weather priorities identified by customers, and those improvements will also contribute to improved reliability performance outside of extreme weather events.

With respect to the question of why “maintaining historic SAIDI reliability while reducing MED outage times” is not the preferred reliability target, Alectra Utilities notes that the investments directed at resiliency and restoration capability are not limited to extreme weather events / major event days. These investments improve the underlying performance and operability of the distribution system across a broad range of conditions, including non-MED events, and therefore are expected to result in improved overall reliability performance (including lower SAIDI) over the year. Accordingly, setting a target premised on reducing the number of outages in extreme weather and improving restoration time in extreme weather while maintaining historic SAIDI would not align with the expected system-wide reliability benefits of the proposed DSP investments, nor would it reflect the reliability outcomes the DSP is designed to deliver.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-141

Ref 1: Exhibit 2A / Tab 1 / Schedule 1 / Appendix M Major Event Day Report/ pp. 4-7 (pdf Exhibit 2A Part 5 p. 188-191)

Preamble:

Alectra Utilities states that on the Major Event Day of May 21, 2022, 297,650 customers were interrupted and 90% of impacted customers were restored within 12.5 hours.

Question(s):

a) For the May 21, 2022, Major Event Day, please provide a chart of the number of customers that were continuously without power in on hour increments, as shown below. OEB staff recognize that the sum of Number of Customers may exceed the total number of customers interrupted during the MED, as some customers may have been interrupted multiple times. Do not included schedule outages that were required for repairs in subsequent days.

Continuous Outage Duration	Number of Customers
1 minute – 60 minutes	
61 minutes -120 minutes	
121 minutes – 180 minutes	
Etc.	

RESPONSE:

a) There were 250 sustained outages during the Derecho on May 21, 2022, and over 400 lines of outage data. The customers impacted and customer interruptions were very similar due to the nature of the outages, approximately 100 broken poles.

Table 1 – Number of Customers by Outage Duration

Outage Duration (Hours)	Outage Duration (Minutes)	Customers
1	1-61	93,589
2	61-121	24,462
3	121-181	17,056
4	181-241	27,589
5	241-301	20,219
6	301-361	10,691
7	361-421	11,707
8	421-481	12,591
9	481-541	9,804
10	541-601	5,165
11	601-661	6,969
12	661-721	12,788
13	721-781	9,386
14	781-841	2,773
15	841-901	2,331
16	901-961	8,777
17	961-1021	131
18	1021-1081	283
19	1081-1141	498
20	1141-1201	2,040
21	1201-1261	1,772
22	1261-1321	1,021
23	1321-1381	8,491
24	1381-1441	1,125
25	1441-1501	221
26	1501-1561	610
27	1561-1621	349
28	1621-1681	909
29	1681-1741	95
30	1741-1801	583
31	1801-1861	377
32	1861-1921	239
33	1921-1981	337
34	1981-2041	593

Outage Duration (Hours)	Outage Duration (Minutes)	Customers
35	2041-2101	21
36	2101-2161	8
37	2161-2221	219
38	2281-2341	42
39	2341-2401	22
40	2401-2461	33
41	2461-2521	18
42	2521-2581	26
43	2641-2701	235
44	2701-2761	84
45	2881-2941	9
46	2941-3001	79
47	3001-3061	9
48	3061-3121	87
49	3121-3181	146
50	3181-3241	1
51	3241-3301	13
52	3301-3361	114
53	3361-3421	39
54	3421-3481	2
55	3601-3661	31
56	3781-3841	78
57	3901-3961	5
58	3961-4021	2
59	4021-4081	95
60	4081-4141	4
61	4141-4201	13
62	4201-4261	3
63	4261-4321	1
64	4381-4441	16
65	4441-4501	3
66	4561-4621	10
67	4681-4741	1
68	4741-4801	7
69	5041-5101	1
70	5161-5221	58

Outage Duration (Hours)	Outage Duration (Minutes)	Customers
71	5821-5881	9
72	6721-6781	3
73	6961-7021	5
74	14521-14581	146
	Total	297,269

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-142

Fix assets continuity schedule before 2017/2019 for each legacy
Ref 1: Exhibit 2B / Tab 1 / Schedule 1 / Table 2-1-3 / p. 5 (pdf p. 5)
Ref 2: Exhibit 1 / Tab 2 / Schedule 2 / (pdf p. 2, row 24-25)
Ref 3: Alectra_Attach 2B-1_OEB Appendix 2-BA-Fixed Asset Continuity Schedule_20251121
Ref 4: OEB Filing Reqs_Chapter 2_2027-20251216 / Section 2.2.2 / p. 19
Ref 4: Filing Requirements for Electricity Distribution Rate Applications - 2026 Edition for 2027 Rate Applications - Chapter 2 / Section 2.2.2 / p. 19
Ref 5: Exhibit 2B / Tab 3 / Schedule 1 / Background / p. 1 (pdf p. 57)

Preamble:
Chapter 2 of Filing Requirements in reference 4 requires comparisons of historical OEB-approved vs. historical actual (for the most recent historical OEB- approved year). OEB staff notes from

In references 2 and 3, the fixed assets continuity schedule as filed starts from 2017 instead of from the last rebasing years of the legacy utilities, specifically: Enersource (2013), PowerStream (2017), Brampton (2015) and Horizon (2015).

In reference 5, Alectra Utilities states that it continued to use the legacy asset componentization and useful lives to calculate the depreciation expense until 2019 upon harmonization.

Question(s):

a) Please provide four rate zones' (i.e., Enersource rate zone (ERZ), PowerStream rate zone (PRZ), Brampton rate zone (BRZ), and Horizon rate zone (HRZ)) fixed assets

:

continuity schedule separately in excel worksheet from their respective last rebasing years to 2019, which shall:

i. Use each legacy utilities' depreciation rate as approved in their last rebasing applications.

ii. Reconcile the fix assets continuity schedule from 2017 to 2019 in reference 3 to match the total balance of these four legacies' fix assets continuity schedule provided in (i) above.

b) Please provide Guelph rate zone (GRZ)'s fixed assets continuity schedule separately in excel worksheet from its last rebasing application (2016) per reference 2 to 2019, which shall:

i. Use GRZ's useful lives as filed with OEB in its last rebasing application.

ii. Reconcile the 2019 fix assets continuity schedule in reference 3 to match the 2019 total balance of the five legacies' fix assets continuity schedule.

c) Please fill in the following summary table compiled by OEB staff per (a) and (b) above and explain the variances:

Fixed Assets ($M)	2017/2019 (Ref 1) (a)	2017/2019 Actual (b)	Variance (a-b)
ERZ (2017)	517.4		
PRZ (2017)	993.0		
BRZ (2017)	340.5		
HRZ (2017)	433.0		
GRZ (2019)	133.6		
Approved ICM	39.5		

RESPONSE:

a) Please see Attachment 2-Staff-142 Attach 1_Pre_2017 Legacy Fixed Asset Continuity Schedules.xlxs that includes the following legacy continuity schedules:

- ERZ schedules from 2013 to 2016
- BRZ schedules for 2015 and 2016
- HRZ schedules for 2015 and 2016

:

Alectra Utilities continued to use the legacy fixed asset continuity schedules for 2017 and 2018 and consolidated these balances to complete the Appendix 2-BA for each year as filed in Reference 3.

Please see Attachment 2-Staff-142 Attach 2_2017 Legacy Fixed Asset Continuity Schedules.xlxs that provides legacy continuity schedules for 2017 and the reconciliation to the consolidated Appendix 2-BA as presented in Reference 3.

Please refer to Attachment 2-Staff-142 Attach 3_2018 Legacy Fixed Asset Continuity Schedules.xlxs for 2018 legacy continuity schedules and the reconciliation to the consolidated Appendix 2-BA as presented in Reference 3.

b) Please see Attachment 2-Staff-142 Attach 4_2019 Legacy Guelph Fixed Asset Continuity Schedules.xlxs that provides legacy Guelph continuity schedule for 2016 -2019.

Please refer to Attachment 2-Staff-142 Attach 5_2019 Fixed Asset Continuity Schedules reconciliation.xlxs which provides a reconciliation of the opening balances in Appendix 2-BA for 2019, as filed in Reference 3, compared to the individual opening balances of each of the five legacies.

c) Please see the updated table below and the related variance explanations:

T**able 1 - Comparison of Approved vs. Actual Average Fixed Asset Balances**

Fixed Assets ($M)	2017/2019 (Ref 1) (a)	2017/2019 Actual (b)	Variance (a-b)
ERZ (2017)	517.4	678.0	(160.6)
Approved ICM (ERZ)	39.5	-	39.5
Total ERZ	556.9	678.0	(121.1)
PRZ (2017)	993.0	968.9	24.1
BRZ (2017)	340.5	352.9	(12.4)
HRZ (2017)	433.0	451.4	(18.4)
GRZ (2019)	133.6	142.6	(9.0)

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ERZ – The average fixed asset balances for legacy ERZ for 2017 were $121.1M higher than the approved fixed asset balances in rate base (including approved ICM), primarily due to continued investment in overhead and underground distribution assets since the last rebasing in 2013.

PRZ - The average fixed asset balances for legacy PRZ were $24.1M lower than the approved fixed asset balances, primarily due to a lower in-service additions for distribution assets of $11.4M due to delays from customers for service connections and lower computer software additions of $9.7MM mainly due to the delay of the go live of CIS project.

BRZ - The average fixed asset balances for legacy BRZ, were $12.4M higher than its approved fixed asset balances mainly due to the continued investment in distribution assets since its last rebasing in 2015.

HRZ - The average fixed asset balances for legacy HRZ, were $18.4M higher than its approved fixed asset balances mainly due to higher investments to distribution assets since its last full rebasing in 2015.

GRZ - The average fixed asset balances for legacy GRZ, were $9.0M higher than its approved fixed asset balances mainly due to continued investment in distribution assets since its last rebasing in 2016.

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2-Staff-142

Attachment 1
Pre - 2017 Legacy Fixed Asset Continuity Schedules

Please see live Excel

2-Staff-142

Attachment 2
2017 Legacy Fixed Asset Continuity Schedules

Please see live Excel

2-Staff-142

Attachment 3
2018 Legacy Fixed Asset Continuity Schedules

Please see live Excel

2-Staff-142

Attachment 4
2019 Legacy Guelph Fixed Asset Continuity Schedules

Please see live Excel

2-Staff-142

Attachment 5
2019 Fixed Asset Continuity Schedules Reconciliation

Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-143

Comparing capital expenditures to in-service additions

Ref 1: 1 Exhibit 2B / Tab 1 / Schedule 2 / Tables 2-1-6 and 2-1-7 / pp 2-3 (pdf pp. 11-12)

Question(s):

a) Please provide a breakdown of "Adjustments for spares, leases, non-regulated capex" in reference 1.

b) Please provide a breakdown of "capital deferrals to DVA" in reference 1.

RESPONSE:

a) After a detailed review of the differences presented in Tables 2-1-6, Alectra Utilities identified an error in these categories. Some of the adjustments were categorized with capital deferrals but should have been classified as spares and other adjustments. The adjusted differences in Table 2-1-6 are updated as shown below:

Table 1 – Updated Table 2-1-6

	2017	2018	2019	2020	2021	2022	2023	2024
Total CapEx	***271.5***	***278.5***	***333.6***	***270.4***	***277.5***	***271.1***	***330.6***	***334.9***
Change in CWIP(Opening-Closing)	(33.0)	(15.8)	2.2	(11.1)	(26.8)	(21.9)	82.8	1.6
Adjustments for spares, leases, non-regulated capex	19.8	(4.6)	(4.2)	(2.5)	10.0	1.1	32.4	36.9
Less: Capital deferrals to DVA	-	(1.5)	0.7	(2.7)	(6.0)	(2.0)	0.1	(0.2)
Adjusted Additions for Rate Base	**258.4**	**256.6**	**332.3**	**254.1**	**254.8**	**248.3**	**445.8**	**373.3**

*Differences might exist due to rounding

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The following Tables present the breakdown of "Adjustments for spares, leases, non-regulated capex":

Table 2 - Adjustments for Spares, Leases, Non-Regulated Capex (2017-2024)

	2017	2018	2019	2020	2021	2022	2023	2024
Spares	15.5	(9.6)	(8.7)	-	8.1	4.3	33.0	22.5
Leases	-	-	2.3	3.6	2.1	-	0.9	-
Non-regulated additions	(0.5)	(0.2)	-	-	(0.2)	-	-	(0.2)
Borrowing costs	2.5	3.5	-	-	-	-	-	-
Construction deposits	2.3	1.6	2.2	(6.1)	-	-	-	-
OMS Impairment	-	-	-	-	-	(3.2)	-	-
Sale of Assets	-	-	-	-	-	-	(0.8)	-
CapEx to OM&A	-	-	-	-	-	-	(0.7)	-
Reversal of Deferral (Note 1)	-	-	-	-	-	-	-	7.3
Classification error (Note 2)	-	-	-	-	-	-	-	7.3
Total	**19.8**	**(4.6)**	**(4.2)**	**(2.5)**	**10.0**	**1.1**	**32.4**	**36.9**

*Differences might exist due to rounding

Table 3 - Adjustments for Spares, Leases, Non-Regulated Capex (2025-2031)

	2025	2026	2027	2028	2029	2030	2031
Spares	(2.6)	13.3	5.3	3.4	2.8	2.5	3.6
Total	**(2.6)**	**13.3**	**5.3**	**3.4**	**2.8**	**2.5**	**3.6**

Note 1: During the USofA review in 2014, Alectra Utilities reversed capital deferrals related to legacy Horizon stranded meters (cost of $7.2M and accumulated depreciation of $7.2M). These stranded meter balances had already been removed from the IFRS fixed asset subledger, therefore the deferrals effectively understated the cost and accumulated depreciation presented in the MIFRS fixed asset continuity schedule from 2017 to 2019. This deferral had no impact on the net book values reported in these years. The reversal of these deferrals aligned the cost and accumulated depreciation balances for both IFRS and MIFRS reporting. Since these balances represent prior period adjustments, we have updated Appendix 2-BA to

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remove them from the additions and present them in the Reclassification column, as filed in response to IR 2-SEC-24.

Note 2: Alectra Utilities identified a presentation error in the Appendix 2-BA related to the same transaction as explained in Note 1 above. A voided transaction was incorrectly displayed with a debit to additions and a credit to disposals. This had no net impact on either cost or accumulated depreciation ending balances. Appendix 2-BA, as filed in response to IR 1-SEC-24, has been updated to correct this error.

b) The following Tables present the breakdown of "Capital Deferrals to DVAs":

Table 4 - Adjustments for Capital Deferrals (2017-2024)

	2017	2018	2019	2020	2021	2022	2023	2024
1522 - OPEB Deferrals	-	-	-	-	(0.1)	(0.4)	(0.0)	(0.0)
1557 - Meter Deferrals	-	(1.5)	0.7	(2.7)	(5.9)	(1.6)	0.1	(0.1)
Additions for Rate Base	**-**	**(1.5)**	**0.7**	**(2.7)**	**(6.0)**	**(2.0)**	**0.1**	**(0.2)**

*Differences might exist due to rounding

Table 5 - Adjustments for Capital Deferrals (2025-2031)

	2025	2026	2027	2028	2029	2030	2031
1522 - OPEB Deferral	-	-	0.5	-	-	-	-
1557 - Meter Deferrals	-	-	13.8	-	-	-	-
1531 - Renewable Connect.Deferral	-	-	1.2	-	-	-	-
Additions for Rate Base	**-**	**-**	**15.5**	**-**	**-**	**-**	**-**

*Differences might exist due to rounding

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-144

Error checking

Ref 1: Exhibit 2B / Alectra_Attach 2B-1_OEB Appendix 2-BA-Fixed Asset Continuity Schedule_20251121

Preamble:

OEB staff notes there is inconsistency in calculating depreciation expenses of "Stores Equipment" under "Fully Allocated Depreciation" section. It calculates the total balances of Account 1935 and 1940 for 2017, 2023 and 2025 onwards while the rest years only includes Account 1940.

Question(s):

a) Please explain the inconsistency observed by OEB staff.

b) Please update reference 1 as applicable.

RESPONSE:

Parts a) and b) Alectra confirms that account 1935 was incorrectly omitted from Appendix 2BA for the years 2018 to 2022 and for 2024. An updated version of Appendix 2BA is filed in response to 1-SEC-24 part c).

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-145

Guelph Hydro cost

Ref 1: Exhibit 2 B / Alectra_Attach 2B-1_OEB Appendix 2-BA-Fixed Asset Continuity Schedule_20251121 / 2019 Guelph Hydro cost (column E)

Ref 2: Exhibit 2B / Tab 3 / Schedule 1 / Table 2-3-2 / p. 60 (pdf p. 60)

Preamble:

Per reference 1, the total PP&E for Rate Base of Guelph Hydro cost is $193.2 M (cell E246). Reference 2 shows $164.9M closing balance of 2021 for Guelph Hydro.

Question(s):

a) Please explain and reconcile the variance identified above.

RESPONSE:

a) Reference 1 provides the opening cost balances of Guelph Hydro for 2019. Reference 2 provides the 2021 ending balances.

Table 1 below provides the continuity of fixed asset costs for Guelph Hydro from 2019 to 2021.

Table 1 - Fixed Asset Continuity for Guelph Hydro 2019-2021

2019 Opening Cost Balance of Guelph Hydro (Ref 1)	**193,175,009**
Add: 2019 Additions GRZ	12,453,021
Minus: 2019 Disposals GRZ	(127,471)
2019 Closing Cost Balances of Guelph Hydro	**205,500,559**
Add: 2020 Additions	5,676,757
Minus: 2020 Disposals	(143,908)
2020 Closing Cost Balances of Guelph Hydro	**211,033,408**
IFRS 3 adjustments (Ref 1 - column M)	(53,339,442)
Add: 2021 Additions	7,222,171
Minus: 2021 Disposals	-
2021 Closing Cost Balances of Guelph Hydro (Ref 2)	**164,916,137**

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-146

AMI Acceleration of depreciation
Ref 1: Exhibit 2B / Tab 3 / Schedule 1 / Table 2-3-6 / p. 9 (pdf p. 65)
Ref 2: Exhibit 9 / Alectra_Attach 9-15_Accelerated CCA Differences (Bill C-97) _20251014

Preamble:
Per reference 1, Alectra Utilities states that the remaining useful life of existing AMI 1.0 has been shortened to align with their expected replacement date (based on AMI 2.0 deployment schedule), which resulted in the acceleration of depreciation totals $25.2M over the 5-year deployment from 2027 to 2031.

Question(s):

a) Please explain from which year the existing AMI 1.0 useful life was shortened?
   i. Please confirm whether it has the impact on Account 1592 - Sub-account CCA changes?
   ii. If confirmed, please provide excel worksheet to calculate the CCA impacts resulted from this acceleration of depreciation.

b) Has Alectra Utilities discussed with its external auditor this shortened useful life? If so, what was the conclusion on the proper accounting treatment? Was this considered as change of the useful lives of an asset prospectively or is there an asset impairment loss resulted from the lower asset values as well? Please provide explain in detail of the accounting treatment assessed by management and agreed by external auditor as applicable.

c) Please provide excel worksheet to quantify the payments in lieu of taxes (PILs) impact, the revenue requirement impact and rate base impact (change on the opening balance of fixed assets) from 2027 to 2031 by completing the following table compiled by OEB staff:

($M)	Depreciation Expenses	PILs Impact	Revenue Requirement from 2027-2031	Opening Rate Base
Standard depreciation - (a)				
Acceleration of depreciation - (b)				
Variance (a-b)				

RESPONSE:

a) The useful lives of the existing AMI 1.0 meters were shortened effective 2027 which aligns with the start of the mass deployment of AMI 2.0 meters and planned replacement of AMI 1.0 meters.

i. The shortening of useful lives does not impact the calculation of capital cost allowance and does not impact Account 1592 – Sub-account CCA changes.

ii. Refer to (i); CCA impact calculations are not required.

b) Yes, Alectra has discussed the shortened useful life with our external auditors, who agreed with the approach. The change in useful lives of the AMI 1.0 meters is considered a change in estimate and will be applied prospectively in accordance with IAS 8.36.

According to IAS 16.6, the useful life of an asset is defined as the period over which an asset is expected to be available for use by an entity. In addition, IAS 16 Para 56 includes the following list of factors that should be considered when determining the useful life of an asset:

- Change in the asset's expected use by the entity
- The asset's expected physical deterioration through use or the passing of time.
- Technical or commercial obsolescence.

The factors impacting the useful life of post mass deployed AMI 1.0 meters were assessed with results as follows:

- *Change in the asset's expected use by the entity* – AMI 1.0 meters will have shorter lives than initially expected. The useful life of the AMI 1.0 meters that are not fully depreciated will be adjusted to align to the expected deployment schedule of the AMI 2.0 meters as the AMI 1.0 meters will be removed from service at that time.
- *The asset's expected physical deterioration through use or the passing of time* – AMI 1.0 meters are failing at increasing rates, and by 2031, about 89% of these assets will be at or beyond their original useful life (DSP 2025-2031, Appendix B06)
- *Technical or commercial obsolescence* – AMI 1.0 meters will become obsolete as new technologies are implemented. Supply chain constraints and vendor limitations make continued support for AMI 1.0 unsustainable.

Alectra also completed the impairment assessment related to the replacement of AMI 1.0 meters, as required by IAS 36, and concluded that there is no impairment loss to be recognized as the meters do not generate independent cash flows from their sale or use. IAS 36.67 states – "The recoverable amount of an individual asset cannot be determined if the asset does not generate cash flows that are independent from other assets. Assets should be grouped for an impairment test in these circumstances".

As AMI 1.0 meters do not generate independent cash flows, meters should be tested the Alectra Utilities cash generating unit (CGU) level. There was no impairment of assets at the Alectra CGU level.

c) Please see the updated table below and the excel attachment 2-Staff-146_Attach 1_AMI Acceleration of Depreciation.xlsx, which includes the calculations for the items presented in the table.

($M)	Depreciation Expense (2027-2031)	PILs Impact	Revenue Requirement from 2027-2031	Opening 2027 Rate Base
Standard depreciation – (a)	30.2	149.6	4,561	4,313
Acceleration of depreciation – (b)	55.4	157.7	4,589	4,313
Variance (a-b)	(25.2)	(8.1)	(28.7)	-

The PILs variance is the impact of the following changes to the PILs calculation based on the use of AMI standard depreciation:

i) increase in regulatory net income before taxes based on the increase in rate base;

ii) decrease to the depreciation expense add back when determining taxable income; and

iii) the above changes are tax effected at 26.5% and grossed-up by 1/(1-26.5%) to arrive at the PILs variance.

2-Staff-146

Attachment 1
AMI Acceleration of Depreciation

Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-147

Harmonization process
Ref 1: Exhibit 2B / Tab 3 / Schedule 1 / pp. 1-9 (pdf pp. 57-65)
Ref 2: Exhibit 2B / Alectra_Attach 2B-3_OEB Appendix 2-BB-Service Life Comparison 2017-2031_20251014

Per reference 1, Alectra Utilities uses the legacy asset componentization and useful lives approved by OEB in each legacy utility's last rebasing application to calculate the depreciation expense until 2019 upon applying harmonization process (Guelph Hydro applied in 2022). This involved aligning componentization based on management judgement/internal policies and harmonizing the useful lives of the assets by using a weighted average method based on the dollar value of each legacy asset as of December 31, 2018.

Per Table 2-3-3 in reference 1, OEB staff observes that the depreciation rates used by each legacy utility, which was filed with the OEB in their last rebasing application, are different from the rates used by Alectra Utilities for all five rate zones from 2019 to 2024. OEB staff notes that Alectra Utilities has documented the changes of asset useful lives in reference 2.

OEB staff note that in Alectra Utilities' 2020 IRM Decision and Order, the OEB approved the deferral accounts to capture the impacts from the integration process and stated that:

> The OEB concludes that a utility should not be enriched by a change in capitalization policy, whether that change results from a merger or other reason. The OEB has previously determined that a capitalization accounting change is not a benefit arising from integration efficiencies that should accrue to the shareholder. The OEB established the deferral accounts to record the impact of this change. The disposition

of these accounts should ensure the impact of the capitalization policy change is not harmful to customers with respect to the recovery in rates of Alectra Utilities' costs.

Question(s):

a) Please confirm that there were no deferral and variance accounts requested and approved for the depreciation rates change from the integration/harmonization process.
    i. If confirmed, please elaborate on how the impact of the depreciation rates changes arising from the harmonization is not harmful to customers with respect to the recovery in rates of Alectra Utilities' costs.

RESPONSE:

a) Confirmed. Alectra Utilities did not request a deferral and variance account related to the harmonization of asset components and useful lives.

Part i) Alectra implemented a weighted average approach for the harmonization of useful lives in order to preserve total depreciation expense at levels consistent with those prior to the alignment exercise and mitigate any unfavourable outcomes to customers or the utility. The harmonization of useful lives was not detrimental to customers and delivers measurable benefits through lower ongoing operational costs by eliminating legacy structures and processes, reducing the need to maintain multiple systems, and avoiding unnecessary reconciliations of asset information. Maintaining separate systems would otherwise require higher staffing levels, increased system-support costs, and greater operational and compliance risk, all of which would negatively impact customers.

The preamble references Alectra Utilities' 2020 IRM Decision and Order which states that "a utility should not be enriched by a change in capitalization policy, whether that change results from a merger or other reason." Changes in useful lives constitute a change in accounting estimates under IAS 8 rather than a change in accounting policy. Alectra has provided this clarification for completeness. This distinction did not affect the

company's decision to harmonize the useful lives and components using a weighted average approach.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-148

Ref 1: Exhibit 2B / OEB Appendix 2-BB - Service Life Comparison 2017-2031

Question(s):

a) On Tab "Appendix 2-BB 2025-2031" there is an asset listed 1860 - Meter (Compliance Testing) with a TUL of 5 years.
   i. Please describe this asset and its application.
   ii. How many of these are in service? What is the 2024 net book value?

RESPONSE:

a)

i. Account 1860 – Meter (Compliance Testing) relates to a new asset component established in 2025 to capture the cost of inspection and testing of meters, as per guidelines issued by Measurement Canada. Based on IAS 16.14, Alectra has concluded that the costs associated with inspecting and testing meters meet the criteria for recognition as a separate asset component. These costs should be tracked separately from the cost of the meters and will be amortized over the period leading up to the next required inspection, typically averaging 5 years. This change was considered a change of estimate as per IAS 8 and therefore treated prospectively.

ii. Prior to 2025, the cost of compliance testing was not identified separately in the Fixed Asset Subledger but instead was included as part of the cost of meters. As a result there is no separately recorded net book value for 2024.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-149

Appendix 2-ZA and Appendix 2-ZB
Ref 1: Exhibit 2B / Tab 4 / Schedule 1 / Attachments 2B-6, 2B-7, 2B-8, 2B-9, 2B-10 (Excel)
Ref 2: RPP Price Report - November 1, 2025 to October 31, 2026
Ref 3: Chapter 2 Appendices - January 15, 2026
Ref 4: Ontario Electricity Rebate (OER)
Ref 5: Exhibit 8 / Alectra_Attach 8-1_Retail Transmission Service Rate Workform_20251014
Ref 6: EB-2025-0299, Decision and Order, December 11, 2025
Ref 7: Exhibit 3 / Attachment 3-1_OEB Appendix 2-IB - Load Forecast Analysis_20251014

Question(s):

a) Please update Appendix 2-ZA and Appendix 2-ZB in reference 1 using the latest data from the Regulated Price Plan (RPP) Report in reference 2 and the updated 2027 OEB models in reference 3.

b) For Appendix 2-ZB (reference 1):
   i. Please update the OER credit in column B (which shows no value) to reflect the latest percentage of 23.5% (reference 4).
   ii. Please explain why the Transmission - Network rates in cells E36 to E42 and cells I36 to I42 (reference 1) are different from the proposed Transmission - Network rates in Tabs 15, cells K52 to K60 (reference 5) for each of the years from 2027-2031. Please revise the evidence as needed.
   iii. Please explain why the Transmission - Connection rates in cells E51 to E57 and cells I51 to I57 (reference 1) are different from the proposed Transmission -

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Connection rates in Tabs 15, cells K68 to K76 (reference 5) for each of the years from 2027-2031. Please revise the evidence as needed.

iv. Please explain why the Low Voltage rates in cells E126 to E132 and cells I126 to I32 (reference 1) are different from the proposed Low Voltage rates in Tabs 16, columns I to J (reference 5) for each of the years from 2027-2031. Please revise the evidence as needed.

v. Please update the Wholesale Market Service, Class B CBR, and RRRP rates (cells E66 to E72, I66 to I72, E96 to E102, E111 to E117, and I111 to I117) to reflect the latest OEB-approved rates from reference 6 for each of the years from 2027-2031. Please revise the evidence as needed.

vi. Please explain why the total number of customers in cells D141 to D142 and I141 to I142 (reference 1) for each rate class are different from numbers in rows 16 and 17 (reference 7) for each of the years from 2027-2031. Please revise the evidence as needed.

c) Please update the evidence affected by the changes in (a) and (c) as needed.

RESPONSE:

a) Appendix 2-ZA and _Appendix 2-ZB have been updated using the latest data from the RPP Report in reference 2 and the updated 2027 OEB models in reference 3. Please refer to 2-Staff-149_Attach 1_Appendix 2-ZA ZB 2027-2031.

b) For Appendix 2-ZB (reference 1):

i. Appendix 2-ZB has been updated with the OER credit in column B to reflect the latest percentage of 23.5%.

ii. Appendix 2-ZB has been revised so that the transmission network rates are the same as the proposed transmission network rates for 2027-2031.

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iii. The original submission for the Transmission - Connection rates in cells E51 to E57 and cells I51 to I57 (reference 1) represents the forecasted wholesale connection rates. Appendix 2-ZB has been revised so that the transmission connection rates are the same as the proposed transmission connection rates for 2027-2031.

iv. The original submission for the low voltage rates in cells E126 to E132 and cells I126 to I32 (reference 1) represents the forecasted sub-transmission Low Voltage rates. Appendix 2-ZB has been revised so that the low voltage rates are the same as the proposed low voltage rates.

v. The Wholesale Market Service, Class B CBR, and RRRP rates (cells E66 to E72, I66 to I72, E96 to E102, E111 to E117, and I111 to I117) have been updated to reflect the latest OEB-approved rates from reference 6 for each of the years from 2027-2031.

vi. The totals in cells D141 to D142 and I141 to I142 (Reference 1) represent the average forecasted monthly number of customers. The values in rows 16 and 17 (Reference 7) represent the forecasted number of customers for the month of December.

c) The RTSR WorkForm has been updated and is filed in response to 8-VECC-78; the RRWF and Cost Allocation Models have been updated and are filed in response to 1-Staff-1. The updates in response to part a) and b) have been reflected in the updated models.

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2-Staff-149

Attachment 1
Appendix 2 ZA ZB 2027-2031

Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-150

Lead-Lag

Ref: Exhibit 2B / Tab 4 / Schedule 1 / Appendix 2B-5 - Guidehouse Lead-Lag Study / p. 8 (pdf p. 130)

Preamble:

The collections lag is 27.21 days, using receivables aging data provided by Alectra Utilities.

Question(s):

a) What proportion of bills are collected using pre-authorized / automatic payments, and what is the collections lag for these payments?
b) Please provide the derivation of the 27.21 day collections lag, including any bucketing approach used.
c) How many days of collections lag are assigned to uncollectable debts?
d) At what point does Alectra write off a debt against bad debt expense?

RESPONSE:

Response (a-c) prepared by Guidehouse

a) For the period used in the study (ie. the twelve months ended April 30, 2024), the proportion of bills collected using pre-authorized payments is 32.3%. These customers' account balances are included in the *current* A/R aging bucket in Schedule 2-Staff-150b below. Therefore, they are attributed to an average collections lag of 12.5 days.
b) Please see Table 1: A/R Aging Buckets and Table 2: Weighted average Collections Lag Days below for the calculation of 27.21 days collections lag.

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Table 1 - A/R Aging Buckets

A/R Aging Bucket	Days Since Bill Issued	Midpoint (Days)
Current	0-24 Days	12.5
0 to 30 Days in Arrears	25 to 55 Days	39.5
31 to 60 Days in Arrears	56 to 86 Days	70.5
61 to 90 Days in Arrears	87 to 117 Days	101.5
>90 Days in Arrears	118 to 365 Days	241

Table 2 - Weighted Average Collections Lag Days Calculation (Average of Twelve Months Ended Apr 30, 2024)

A/R Aging Bucket	Current	0 to 30 Days in Arrears	31 to 60 Days in Arrears	61 to 90 Days in Arrears	>90 Days in Arrears	Total
Midpoint of Bucket (Days)	12.5	39.5	70.5	101.5	241	
% of Balances Outstanding – 12 Month Trailing Average	86.6%	4.9%	2.3%	1.4%	4.7%	**100%**
Weighted Lag Days	10.83	1.94	1.61	1.46	11.37	**27.21**

c) At the point that an outstanding balance is written off, it is no longer part of the collections lag calculation.

d) When an account is closed or final billed, the customer's remaining balance is due by the due date on their billing statement. Bills are due 24 days from the day the bill is produced. In addition, Alectra has a 3-day grace period from the bill's due date to allow payment to be received prior to a customer incurring any late payment charges. Finally, 26 days after the due date, if the amount is still outstanding the amount is written off in the CIS system. It is important to note that the final bill and write-off dates

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may change modestly as a result of weekends and holidays that conflict with the customers billing cycle. The CIS system write-offs are recorded as part of the bad debt expense.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-151

Lead-Lag

Ref 1: Exhibit 2B / Tab 4 / Schedule 1 / p.1

Ref 2: Exhibit 2B / Tab 4 / Schedule 1 / Appendix 2B-5 - Guidehouse Lead-Lag Study / p. 12 (pdf p. 134)

Question(s):

a) The Interest Expense lead days are calculated based on a weighted average of long-term debt payments and short-term debt payments. Please explain why Interest Expense is included in the working capital allowance calculation, when the working capital allowance is applied to cost of power and OM&A, and not to interest expense.

RESPONSE:

Response reviewed/approved by Guidehouse

a) Interest expense is included in the working capital allowance calculation, even though it is technically a financing cost rather than an operating expense like cost of power or OM&A, because it represents a cash expense for the business that must be funded between the time the company pays it and the time it recovers those costs from ratepayers.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-152

Fixed asset - ICM True-up
Ref 1: Exhibit 9 / Alectra_Attach 9-7 / 9-8 / 9-9_ICM True-Up Models
Ref 2: Exhibit 2B / Tab 5 / Schedule 1 / Table 2-6-1 / p. 1 (pdf p. 142)
Ref 3: Exhibit 9 / Alectra_Attach 9-15_Accelerated CCA Differences (Bill C-97) _20251014

Preamble:
Alectra Utilities confirms that the impacts of accelerated capital cost allowance (CCA) rule change associated with its ICM projects is recorded in Account 1592 - PILs and Tax Variances - CCA Changes.

Question(s):

a) Please provide the CCA and the calculation for each ICM project per reference 1 and reconcile to reference 3 as applicable.

RESPONSE:

a) Please refer to 6-Staff-209_Attach 4 _AIIP Impact_ ICM Projects. This attachment provides the CCA and the calculation for each ICM project per reference 1 and reconcile to the balance shown in Exhibit 9, Tab 3, Schedule 26, page 3, Table 9-3-60.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-153

Depreciation study, Direct Labour Capitalization (DLC) Burden & fix assets continuity schedule
Ref 1: Exhibit 2B / Tab 6 / Sch 2 / Attachment 2B-13
Ref 2: Exhibit 2B / Tab 3 / Sch 1 / Attachment 2B-2
Ref 3: Decision and Rate Order (EB-2025-0055) / Section 10-Accounting Orders Request / p. 29
Ref 4: Alectra_Attach 2B-1_OEB Appendix 2-BA-Fixed Asset Continuity Schedule_20251121

Preamble:
In reference 1, Alectra Utilities engaged Atrium Economics, LLC (Atrium) to support the process of evaluating and updating Alectra's Direct Labour Capitalization (DLC) Rate Methodology used to allocate directly attributable capital costs to capital projects, for those individuals that do not utilize time sheets for the 2027-2031 rate term. Atrium issued the study report in May 2025 and Alectra utilities applied this methodology from January 1, 2025.

In 2024, Alectra Utilities also engaged Alliance Consulting Group and conducted a depreciation study which is the first depreciation study for the combined operations of Alectra Utilities and implemented the updated depreciation study effective from January 1, 2025.

Per reference 3, the OEB has denied Alectra Utilities' request for approval of proposed DVAs to track the impact of changes to asset useful life and direct labour capitalization policies, both of which record the respective revenue requirement impacts effective from January 1, 2025 till the next rebasing (which is 2027 test year).

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Question(s):

a) Please confirm that the fixed continuity schedule filed has applied the results from the depreciation study and the updated DLC Rate methodology from January 1, 2025.
   i. If not confirmed, please explain when these two updates were applied to the merged utilities.
   ii. If confirmed, please explain why Alectra Utilities applied these updates prior to its rebasing year of 2027.

b) Please provide the consolidated fix assets continuity schedule by applying the changes of the depreciation study and DLC study effective from test year 2027 rather than from 2025.
   i. Please quantify the revenue requirement impact and rate base impact (change on the opening balance of fixed assets) using the following table compiled by the OEB staff.

	Revenue Requirement		Rate Base		OM&A	
	Applying both studies from 2025	Applying both studies from 2027	Applying both studies from 2025	Applying both studies from 2027	Applying both studies from 2025	Applying both studies from 2027
2027						
2028						
2029						
2030						
2031						

RESPONSE:

a)

ii) Confirmed. Alectra's fixed asset continuity schedule applied the results from the depreciation study and the updated DLC study effective from January 1, 2025. In accordance with the requirements of IAS 8.34 and IAS 8.36, the results constituted

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new information that yielded changes in estimates, and therefore had to be recognized prospectively, in the period of the change (2025) and for future periods. Once the depreciation study was completed and the results indicated that changes were required to the useful lives, Alectra was required under IFRS to implement these changes in its financial statements. Alectra maintains a single fixed asset subledger for recording asset costs and depreciation. This ensures consistency between IFRS and regulatory reporting, reduces administrative burden, and aligns with the OEB's policies under the Accounting Procedures Handbook ("APH"). Specifically:

On page 32 of Article 410 in the section, *Revision of Depreciation/Amortization Method and Estimated Useful Life* states:

> *"Both IAS 16 and IAS 38 require that the depreciation/amortization method applied and the useful life of assets be reviewed at least each financial year-end. Changes shall be accounted for as a change in accounting estimate in accordance with IAS 8."*

On pages 33-34 it further states:

> *"The Board is mindful that changes in useful life/depreciation methods for general purpose financial statements could occur annually under IFRS regardless of whether or not the Board has approved such changes. However, the Board's general position is to encourage, to the extent possible, symmetry between the financial statements and regulatory reporting for capital assets in order to have more readily available and verifiable information to assist with rate base determination through financial statements."*

On page 34 the APH states:

> *"In order to maintain symmetry in financial and regulatory reporting for capital assets, the Board expects distributors' capital assets for regulatory reporting*

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to be presented on the same basis as in the general purpose financial statements."

The OEB's decision in EB-2025-0055 rejected Alectra Utilities' request to establish new variance accounts to capture the 2025 and 2026 impacts of implementing the noted changes. The decision did not preclude or override Alectra's financial and regulatory reporting requirements to implement these changes in accordance with IFRS and the APH.

b) The premise of the question is that the continuity schedules included in the application should be re-created in a manner that is misaligned with the utility financial records and accounting requirements. Alectra does not agree with this premise. As noted in 2-Staff-153 (a) above, the implementation of the changes as of January 1, 2025 ensures consistency between IFRS and regulatory reporting, reduces administrative burden, and aligns with the APH.

However, for the purpose of understanding the impacts of the depreciation study and the updated DLC study on 2027-2031 rate base and revenue requirement, Alectra Utilities has provided a supporting analysis in *2-Staff-153_Attach 1* and a summary in Table 1 below. Alectra notes that applying these changes as of 2027 for rate-making purposes would create a fundamental and permanent disconnect between the utility's financial records and regulatory reporting for capital assets, contrary to OEB expectations under the APH, as noted above in part (a).

Table 1 - Impact of UL and DLC Changes on Rate Base and Revenue Requirement

	Revenue Requirement	Rate Base	OM&A
Year	Applying both studies from 2027	Applying both studies from 2027	Applying both studies from 2027
2027	807	4,386	352

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	Revenue Requirement	Rate Base	OM&A
Year	Applying both studies from 2027	Applying both studies from 2027	Applying both studies from 2027
2028	863	4,660	370
2029	910	4,984	386
2030	968	5,373	401
2031	1,024	5,773	412

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2-Staff-153

Attachment 1
UL and DLC Impact

Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-154

Depreciation Study

Ref 1: Exhibit 2B / Tab 3 / Schedule 1 / p. 1 (pdf p. 57)
Ref 2: Exhibit 2B / Tab 3 / Schedule 1 / Attachment 2B-2 / p. 7 (pdf p. 73)
Ref 3: Exhibit 2B / Alectra_Attach 2B-1_OEB Appendix 2-BA-Fixed Asset Continuity Schedule_20251121

Preamble:

Per reference 1, Alectra Utilities depreciate assets on a straight-line basis over the estimated useful life of the assets. The depreciation rates were harmonized by using a weighted average method based on the dollar value of each legacy asset as of December 31, 2018 and implemented from January 1, 2019.

Per reference 2, the depreciation study utilizes the item-based, remaining life depreciation methodology. Actuarial analysis (retirement rate method) was not available to be used due to each legacy organization previously using unique units of property and consequently, the lack of historical retirements for Alectra's combined operations.

Question(s):

a) Regarding the retirement rate study, please answer the following questions:

i) Please clarify in detail why the lack of retirement rate study was due to the lack of historical retirements for Alectra's combined operations.
ii) Please explain if Alectra Utilities had asked the consultant to consider the alternative approach for the retirement rate study. If not, why not.
iii) Please explain how the asset disposals have been incorporated into the depreciation study, given the retirement rate study was not conducted.

b) "Life Analysis" section of the depreciation study states that "new object accounts are

proposed for select accounts where a significant portion of investment has a materially different useful service life"

i) Please provide examples of the new object account mentioned above.

ii) Please discuss how Alectra Utilities will do in determining the future new object accounts for which investment has a material different useful life?

RESPONSE:

a) Response to question (a) is prepared jointly by Alliance Consulting Group and Alectra.

i) The depreciation study performed by Alliance included the current assets as recorded on the books of Alectra Utilities as of December 31, 2024. The Company's combined operations fixed asset transactional data (including vintage retirements, additions, transfers and adjustments for each account) are only available beginning in 2021. More than four years of vintage transactional data is required to produce reliable and valid statistical results when using the actuarial life analysis method. While additional transactional data may be available for each legacy entity, as each entity was acquired (beginning in 2017), the historical fixed asset data is recorded in separate fixed asset systems and consist of unique and inconsistent units of property for the acquired fixed assets of each entity. The limited amount of transactional data and fixed asset inconsistencies limit the comparability of historical asset records needed to conduct actuarial life analysis. For example, ERZ recorded pole assets as "fully dressed wood poles," which included poles, conductors, and other devices, whereas PRZ grouped all poles together without distinguishing by category and excluded conductors. As a result, derecognition information from ERZ accounting records is not readily comparable to that of PRZ. This study analyzes the limited retirement experience and life characteristics of the current fixed assets recorded in the Company's combined operations fixed asset records using consistent units of property within each account or asset category when conducting life analysis.

ii) The use of the retirement rate methodology was considered as an alternative to the current item-based depreciation methodology used by Alectra. However, the retirement rate methodology is more frequently relied on when using group depreciation and Alectra has historically recorded its fixed asset records and depreciation accrual using the item-based method. The use of the retirement rate method requires a significant number of years of fixed asset retirement transactions, including the vintage (original in-service year), to develop a pattern of retirements for a group of assets. As discussed previously in response to part i) of this question, the limited amount of historical transactional data and inconsistencies in the fixed asset records would not have produced accurate or reliable statistical results using the retirement rate methodology. In addition, various historical cost adjustments (including IFRS transition adjustments for each legacy utility and IFRS 3 business combination restatements of cost base) would have adversely affected the accuracy of the retirement rate methodology. As a result, the study continues the same item-based remaining useful life depreciation methodology—which uses an asset's net book value in each period and allocates it over its remaining useful life—which was determined to be the most appropriate depreciation method.

iii) The objective when conducting life analysis is to develop a service life that incorporates relevant, historical retirement experience and reflects both the operational life for the current fixed assets and the future expectations for similar assets in each account or fixed asset category. Alliance analyzed the available asset disposal records provided by the Company to identify any observable trends and to calculate an average age of assets being retired for each asset category or type of equipment where possible. Alliance then considered the average age of retirements for different types of equipment or groups of assets when developing the proposed service life for the combined operations fixed assets. For example, operational data was compiled for underground and overhead transformers, such as padmount, pole mount, single and three phase types of transformers. When developing a service life for transformers, the age at retirement ranged from 1 to 75 years depending on the type of transformer. In this particular case, the very limited retirement experience

reflected an average age at retirement from 7 years to 30 years (depending on the type of transformer) and was not thought to be indicative of normal expectations nor hold enough statistical validity to define the life of transformers. Therefore, little weight was given to the available retirement data in this account. Discussions with Company subject matter experts ("SMEs") brought out operational information, along with other factors such as operating environment, trends in technology and materials, and Alectra's maintenance and replacement policies. The Kinectrics Report was also reviewed for the typical useful life range for these types of assets (as available). Mr. Watson's professional judgement obtained while working as a professional engineer and conducting depreciation studies for similar assets for over 40 years was combined with operational experience of Company SMEs along with other factors impacting the life cycle of these assets when developing the proposed 45-year service life for overhead transformers.

b) Based on the Depreciation study, new asset components were established in cases where a significant portion of the assets had a different useful life than that of the original assets.

i) The new components were as follows:

- Underground (UG) transformers (account 120243) previously included both Padmount and Vault transformers, with a useful life of 32 years for the combined account. As a result of the study, UG transformers were split into:
  - Padmount transformers (account 120243) - useful life 30 years
  - Vault transformers (account 120246) - useful life 40 years
- UG conductors and devices - Switchgear (account 120249) previously included Solid dielectric, Oil and SF6 switchgears, with a useful life of 42 years for the combined account. As a result of the study, Switchgears were split into:
  - Switchgear SF6/Oil (account 120249.SF6OIL) - useful life 30 years
  - Switchgear Solid dielectric (account 120249) - useful life 45 years
- Switchgear and relays/protection & controls systems (accounts 120063.MS & 120063.TS) previously included station switchgears, relays, protection and control equipment at either a Municipal Substation (MS) or a Transformer Station (TS), with

a useful life of 36 years for the combined account. As a result of the study, this combined account was split into:

- Switchgear (accounts 120067.MS and 120067.TS) - useful life 40 years
- Relays – Microprocessor (accounts 120063.MS & 120063.TS) - useful life 15 years
- Relays – Solid state/Electromechanical (accounts 120066.MS & 120066.TS) - useful life 30 years
- DC Systems/Battery (accounts 120065.MS and 120065.TS) - 15 years

ii) Based on IFRS requirements (IAS 16.51, IAS 38.104), Alectra is required to review the useful life of assets at least at each financial year-end. If a significant change is identified that requires an adjustment, such a change is accounted for prospectively in the period in which it occurs and in future periods, in accordance with IAS 8.34 and IAS 8.36.

If new information indicates a significant change in the expected pattern of consumption of the future economic benefits embodied in an asset, Alectra is required, pursuant to IAS 16.56, to assess and determine the appropriateness of establishing a new asset component. The determination of useful life considers multiple factors, including discussions with operations and asset management, manufacturer-recommended useful lives, environmental conditions, technological developments, and maintenance practices.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-155

Burden
Ref 1: Exhibit 2B /Alectra_Attach 2B-12_OEB Appendix 2-D-Overhead Expenses_20251014
Ref 2: Decision and Rate Order (EB-2025-0055), Section 10-Accounting Orders Request, p. 29

Preamble:
Per reference 2, the OEB has denied Alectra Utilities' request for approval of proposed DVAs to track the impact of changes to direct labour capitalization policies.

Question(s):

a) Per reference 1, please explain:
    i. For the DLC burden, why 2019 ($15M), 2020 ($16M), 2021 ($17M) were much lower compared with other years which was close or above $20M?
    ii. For the DLC burden, why 2027 is almost $5M higher than 2026?
    iii. For the benefit burden, why does the amount fluctuate from 2019 to 2021?

b) Please update reference 1 assuming that the Direct Labour Capitalization study is to be implemented on the 2027 Test Year rather than 2025.

RESPONSE:

a) Please see 2-Staff-155_Attach_1_Schedule 2D for an updated version of this schedule that includes 2025 actual results. Alectra has amended the schedule to correct the 2017 to 2019 'Direct Labour (DLC)' amounts, and to correct a transposition error that was identified in the 2024 figures. The 2017-2019 amounts provided previously utilized data

from legacy reporting systems which was disaggregated and incorrectly reflected a portion of recoveries that were allocated to OM&A. The OM&A figures presented in Schedule 2-JC were not impacted by this correction.

i. After the update to the 2017-2019 figures (pre-harmonization) noted above, 2017-2019 are now more aligned with one another. The increase in 2020 is primarily attributable to ERP system harmonization which standardized all legacy processes related to DLC capitalization. The standardization resulted in an increase to the DLC pool from certain legacy utilities for Operations staff that were previously directly allocated to capital work orders.

ii. The DLC increases in 2027 are principally due to the addition of DLC applicable positions in Asset Management, Distribution Design, System Control, Stations, Records Mapping and Services, OH Inspections and Maintenance and Network Metering ($3.7MM). The remaining increase is attributable to the capital allocation of labour inflation on existing positions that are eligible for DLC pool capitalization.

iii. The benefit capitalization increases in 2019 are principally due to a higher allocation of internal labour to capital, and additional benefits related to the merger involving Guelph Hydro. The benefit capitalization decreases in 2020 principally due to a lower allocation of labour to capital, as the COVID-19 pandemic resulted in a decrease in customer-initiated connections.

b) Alectra Utilities has implemented the changes of the DLC study as of January 1, 2025 as required by IFRS standards (see 2-Staff-153 part a). The table below illustrates the impact to 2025 and 2026 figures in Schedule 2D if the study results could have been implemented in the 2027 Test Year rather than 2025.

1 **Table 1 - OM&A Capitalization Assuming 2027 Adoption of DLC Study**

OM&A Before Capitalization	2025 Historical Year	2026 Bridge Year
Asset Strategy	$ 21,950,613	$ 27,090,993
Corporate Overheads	$ 85,693,316	$ 80,986,356
Customer Experience	$ 54,847,957	$ 59,909,719
Digital and Innovation	$ 45,686,555	$ 52,401,625
Sustainment	$ 100,801,692	$ 92,975,667
Operations	$ 55,619,274	$ 60,672,855
Property Taxes	$ 5,282,350	$ 6,055,762
Total OM&A Before Capitalization (B)	$ 369,881,757	$ 380,092,978
Capitalized OM&A	**2025 Historical Year**	**2026 Bridge Year**
Vehicle	$ 9,896,740	$ 9,283,356
Material	$ 9,862,973	$ 8,752,378
Direct Labour (DLC)	$ 20,821,256	$ 24,750,164
Benefit	$ 13,697,091	$ 13,518,824
Total Capitalized OM&A (A)	$ 54,278,061	$ 56,304,722

2-Staff-155

Attachment 1
Schedule 2-D

Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-156

Direct Labour Capitalization Study

Ref 1: Exhibit 2B, Tab 6 / Schedule 2 / p. 3 (pdf p. 159)

Ref 2: Exhibit 2B / Tab 6 / Schedule 2 / Attachment 2B-13

Preamble:

Per reference 1, the DLC study involves time-tracking over a six-week period for individuals. The DLC rate is calculated by dividing the total cost (base compensation + payroll benefits) by the eligible distribution capital.

Question(s):

a) Per reference 1, please answer the following questions:
   i. What is included in the payroll benefits in determining the DLC rate?
   ii. Please explain how Alectra Utilities determined the 3rd party contractor cost in terms of DLC portion.

b) Reference 2 (p. 1 or pdf p. 165) states that the study involved time-tracking over a six week period.
   i. Please explain what the criteria is in determining the length of the study (i.e. six-week)?
   ii. Please explain the consideration of the timing of this six-week period chosen from the entire year, assuming the different activity levels?
   iii. Please explain why the 6 week period Alectra gathered the data for the study should be considered to be representative of work conducted over a full year?

c) Alectra Utilities' existing DLC Rate Methodology is based on legacy PowerStream practices per reference 2:
   i. At a high level, please provide a comparison between existing DLC rate methodology based on legacy PowerStream and the methodology developed by this study.
   ii. Atrium recommended that Alectra Utilities conduct an annual review of the DLC rate methodology, implement a rolling time study and continue training of employees using the direct time sheet. Please discuss how Alectra Utilities is planning to adopt these recommendations and whether/how the resulting changes will be incorporated in rates.

d) Per reference 2, the addition of the Control Room into the Labour Pool is one of the main drivers of the increase in directly attributable capital costs. Please explain the consideration for including the control in the DLC labor pool.

e) In terms of the activities mapping, time-tracking system and assumptions used in this study:
   i. Has/will the external auditor reviewed/review the DLC study which includes the mapping of activities to OM&A and Capital based on an assessment of IAS 16? Please explain the external auditor's role in the study and any opinion provided or will be provided.
   ii. Please discuss whether there is any risk that an employee will record time to tasks outside of their assigned department and business unit in web-based time tracking system. If yes, what will be the solutions to avoid it?
   iii. Please confirm whether there are any assumptions used in this study? If yes, provide a summary of all assumptions underlying the DLC study, including productivity factors and allocation percentages. If not, please explain why not.

f) Please indicate whether Alectra Utilities has benchmarked its DLC rate methodology and the resulting rates with industry peers. If yes, please discuss the results of this comparison. If not, why not.

RESPONSE:

a) Response prepared by Alectra Utilities: Per reference 1

i. Alectra Utilities includes the fully burdened cost of an employee including all payroll and benefits costs when determining the DLC rate. The benefit burden is described in Exhibit 2B, Tab 6, Schedule 2, Section 1.1.3.

ii. Third-party party contractor costs are not considered in the DLC pool and do not make up the costs that are recovered via the DLC rate methodology. Only specific internal positions that were in scope of the DLC study are considered for the DLC recovery to capital. Exhibit 2B, Tab 6, Schedule 2, Attachment 2B-13, page 4 describes the internal labour positions that are included in the scope of the DLC study.

b) **Response prepared by Atrium Economics:**

i. The six-week duration was selected to balance data quality and practicality. It is long enough to capture normal variability in work activities across business units while remaining manageable for participants and minimizing reporting fatigue. Six weeks is consistent with common regulatory practice for time studies and provides a sufficient sample size to establish stable capital versus OM&A proportions.

ii. The Company recognizes that activity levels and work mix can vary over the course of a year. In designing the study, the six-week period was intentionally selected to occur during a period of normal operations and typical workload conditions. The study was conducted before the summer period, when employee availability is often affected by higher levels of vacation and PTO and during a time when staff were performing a representative mix of ongoing operational, planning, and support activities. This timing helped ensure strong participation and data completeness.

iii. At the conclusion of the six-week period, Atrium conducted interviews with each Department's Single Point of Contact ("SPOC") to assess whether the six-week period was representative of work performed over the full year. SPOCs confirmed

that while overall workload levels may vary during the year, the relative allocation of effort between capital and OM&A activities remains generally consistent across periods and that the study period reflected typical annual work patterns for their respective groups. Where exceptions were identified (such as vacant positions, outliers, or positions added after the study), these were reviewed and addressed through management interviews and supplemental analysis, as described on pages 11 and 12 of the report. These adjustments were made to improve the accuracy and representativeness of the results. Based on this validation process, the six-week time study, together with the refinements noted in the report, provides a reasonable and representative basis for extrapolating annual capital and OM&A proportions.

c) Response prepared by Alectra Utilities: Per Reference 2:

i. The existing rate methodology is consistent with the rate methodology described in the study.

ii. With respect to the recommendations referenced in Exhibit 2B, Tab 6, Schedule 2, Attachment 2B-13, page 14:

a. Annual Review: Alectra Utilities will assess the DLC rate methodology during the annual budgeting process. Management will review and verify whether any changes in work or circumstances have taken place that would have an impact on the capitalization percentages from the study. If changes are identified, Alectra Utilities will assess the impact and assess next steps, including whether an updated time survey or time study is required.

b. Implementation of a rolling time study for future studies: This option will be taken into consideration when Alectra Utilities undertakes the next time study.

c. Employee training on DLC and time sheeting: The reporting associated with the management review and validation discussed in Part c) ii) a) will keep Managers informed of all positions that are capitalized through the DLC process. Alectra will continue the use of direct time-based allocations (time sheeting) whenever possible.

d) Response prepared by Alectra: Per Reference d) – Control Room: The consideration to include the Control Room staff as part of the DLC study are described below:

Management of the Control Room approached Finance to consider whether it would be appropriate to allocate Control Room staff to capital via the DLC methodology. Control Room Management identified that a significant amount of their time was spent on directly supporting capital projects, however, direct time sheeting or a time study was not possible to complete.

The External Reporting & Accounting Policy team met with Control Room Management to assess the work being completed and the proposed allocation methodology. The External Reporting & Accounting Policy team confirmed that the work directly attributable to capital projects can be capitalized under IAS16.

Management of the Control Room met with Atrium Economics. This is further detailed in Exhibit 2B, Tab 6, Schedule 2, Attachment 2B-13, page 12.

e) In terms of the activities mapping, time-tracking system and assumptions used in this study:

i. Response prepared by Alectra Utilities: Alectra Utilities external auditor had no role in the preparation of the DLC study.

The external auditor has been provided with a copy of the DLC study and has not raised any concerns to Management to date. The audit of Alectra Utilities' 2025 financial statements will be completed on March 5, 2026.

The external auditor's responsibilities are to audit the financial statements of Alectra Utilities and express an opinion on whether the financial statements present fairly in all material respects, its consolidated financial position, its consolidated financial performance and its consolidated cash flows for the year then ended in accordance with IFRS Accounting Standards. A separate report with an opinion on the DLC study

will not be provided. However, as part of their responsibilities for the audit of the financial statements the external auditor is required to evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management (see Exhibit 1, Tab 8, Schedule 2, Attachment 1-6, page 3, PDF page 1537). Any concerns regarding the appropriateness of the DLC methodology would be brought to the attention of Management as part of the audit process.

Alectra Utilities external auditor has not raised any concerns or issued any audit findings related to the DLC methodology in any of their prior audits.

ii. **Response prepared by Atrium Economics:** The web-based time-tracking system was configured so that each participant had access only to the department and business unit to which they were assigned. Users could only record time against the activity-level tasks associated with their assigned department and business unit and did not have the ability to select or charge time to tasks outside of that scope. In addition, Atrium and each department's SPOC reviewed time records on a regular basis during the study to confirm completeness and reasonableness. This review process would have identified any instance of time being recorded to an incorrect Department or Business Unit. No such issues were observed.

iii. **Response prepared by Atrium Economics:** There are no assumptions used in the study; however, there was a reliance on standard and reasonable premises. The DLC percentages are based on actual time recorded by employees through the web-based time tracking system and, where applicable, time surveys supported by operational data (e.g., work order reviews for System Control). As with any time-based study, the methodology relies on standard and reasonable premises, including accurate and consistent time recording by participants, clear activity definitions, sufficient participation, representativeness of the study period (validated with SPOCs), appropriate handling of exceptions, and proper system controls.

f) **Response prepared by Atrium Economics:** Atrium was not asked to benchmark Alectra's DLC Rate or resulting percentages against specific industry peers. This is because DLC rates are highly utility-specific and depend on each utility's organizational structure, the scope of roles included in the burden pool, the use of direct time charging, the project mix, and internal processes, including financial governance and accounting. As a result, direct numerical comparisons of DLC percentages across utilities are not typically meaningful or determinative. While no formal peer comparison was performed, the methodology used to develop Alectra's DLC Rate is consistent with common industry practice, where these studies typically rely on a combination of time studies, time surveys, and management validation to determine the proportion of labour directly attributable to capital versus OM&A activities.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 3-STAFF-157

Customer and Energy Forecast

Ref 1: Exhibit 3 / Tab 1 / Schedule 1 / Attachment 3-2 Sales and Customer Forecast Report / pp. 4-6 (pdf pp. 13-15)

Question(s):

a) Alectra's forecast is based on historic data up to May 2025. Please provide updated customer / connection / energy / demand for each rate class for the most recently available 12 months.

RESPONSE:

a) Please see 3-STAFF-157_Attach 1_Historic Data Recent 12 Months for updated customer / connection / energy / demand for each rate class for the most recently available 12 months.

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3-Staff-157

Attachment 1
Historic Data Recent 12 Months

Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 3-STAFF-158

Customer and Energy Forecast

Ref 1: Exhibit 3 / Tab 1 / Schedule 1 / Attachment 3-2 Sales and Customer Forecast Report / pp. 4-6 (pdf pp. 13-15)

Preamble:

A residential customer forecast is provided by rate zone. Energy forecasts are provided once by rate class (aggregate across rate zones), and once by legacy rate zone (aggregate across rate classes). The forecasts are performed using regression models for each of customers/connections and energy, and for each rate class within each of the legacy rate zones.

Question(s):

a) Please provide customer/connection forecasts by rate zone for each of General Service, Large Use, and USL/Street Light/Sentinel.

b) Please provide energy forecasts by rate zone for each of Residential, General Service, Large Use, and USL/Street Light/Sentinel.

RESPONSE:

a) Alectra Utilities re-ran the Customer and Load Forecast in response to 3-SEC-69. Please see Tables 1 to 5 below for baseline customer/connection forecasts by Rate Class within each rate zone.

Table 1 - Baseline Customer / Connection Forecast – BRZ

	2026	2027	2028	2029	2030	2031
Residential	161,985	162,626	163,552	164,443	165,357	166,288
GS<50 kW	10,388	10,438	10,521	10,611	10,705	10,802
GS>50 kW, Regular	1,591	1,591	1,592	1,593	1,593	1,594
GS>50 kW, Intermediate	113	112	112	112	112	112
Large Use	6	6	6	7	7	7
LUDA	-	-	-	-	-	-
USL	1,735	1,735	1,735	1,735	1,735	1,735
Sentinel	-	-	-	-	-	-
Street Lighting	21,424	21,399	21,389	21,385	21,384	21,383

Table 2 - Baseline Customer / Connection Forecast – ERZ

	2026	2027	2028	2029	2030	2031
Residential	185,485	185,653	185,866	186,098	186,343	186,597
GS<50 kW	19,934	20,051	20,220	20,382	20,549	20,718
GS>50 kW, Regular	3,466	3,466	3,466	3,466	3,466	3,466
GS>50 kW, Intermediate	330	330	330	330	330	330
Large Use	11	11	11	11	11	11
LUDA	-	-	-	-	-	-
USL	3,185	3,185	3,185	3,185	3,185	3,185
Sentinel	-	-	-	-	-	-
Street Lighting	50,930	51,015	51,099	51,185	51,270	51,355

Table 3 - Baseline Customer / Connection Forecast – GRZ

	2026	2027	2028	2029	2030	2031
Residential	52,930	53,309	53,773	54,245	54,727	55,218
GS<50 kW	4,315	4,345	4,383	4,422	4,461	4,501
GS>50 kW, Regular	544	544	544	544	544	544
GS>50 kW, Intermediate	40	40	40	40	40	40
Large Use	4	4	4	4	4	4
LUDA	-	-	-	-	-	-
USL	584	584	584	584	584	584
Sentinel	20	20	20	20	20	20
Street Lighting	14,478	14,507	14,534	14,560	14,584	14,607

Table 4 - Baseline Customer / Connection Forecast – HRZ

	2026	2027	2028	2029	2030	2031
Residential	236,609	237,379	238,098	238,757	239,363	239,919
GS<50 kW	19,448	19,484	19,518	19,549	19,577	19,604
GS>50 kW, Regular	1,937	1,937	1,937	1,937	1,937	1,937
GS>50 kW, Intermediate	-	-	-	-	-	-
Large Use	7	7	7	7	7	7
LUDA	6	6	6	6	6	6
USL	2,750	2,753	2,754	2,754	2,754	2,754
Sentinel	259	251	244	237	230	223
Street Lighting	52,482	52,478	52,474	52,470	52,466	52,462

Table 5 - Baseline Customer / Connection Forecast – PRZ

	2026	2027	2028	2029	2030	2031
Residential	356,459	358,539	360,628	362,711	364,799	366,896
GS<50 kW	34,864	35,061	35,260	35,470	35,679	35,887
GS>50 kW, Regular	4,560	4,560	4,560	4,560	4,560	4,560
GS>50 kW, Intermediate	-	-	-	-	-	-
Large Use	3	3	3	3	3	3
LUDA	-	-	-	-	-	-
USL	3,346	3,390	3,430	3,468	3,507	3,545
Sentinel	133	129	126	122	119	115
Street Lighting	103,466	104,103	104,740	105,376	106,013	106,650

b) Please see Tables 6 to 10 below for baseline energy sales forecasts by Rate Class within each rate zone

Table 6 - Baseline Energy Forecast - BRZ (MWh)

	2026	2027	2028	2029	2030	2031
Residential	1,590,754	1,601,867	1,617,867	1,625,411	1,636,250	1,647,675
GS<50 kW	354,812	355,446	358,743	360,340	362,061	363,961
GS>50 kW, Regular	1,087,765	1,085,339	1,091,722	1,091,162	1,091,200	1,091,981
GS>50 kW, Intermediate	879,162	870,143	874,507	878,461	882,444	886,466
Large Use	300,137	300,137	300,358	325,191	382,468	382,468
LUDA	-	-	-	-	-	-
USL	6,145	6,140	6,140	6,140	6,140	6,140
Sentinel	-	-	-	-	-	-
Street Lighting	19,373	20,084	20,344	20,439	20,474	20,487

Table 7 - Baseline Energy Forecast - ERZ (MWh)

	2026	2027	2028	2029	2030	2031
Residential	1,568,471	1,574,736	1,582,972	1,583,453	1,586,903	1,590,631
GS<50 kW	703,022	705,182	713,336	717,705	722,300	727,269
GS>50 kW, Regular	2,032,114	2,034,346	2,050,203	2,056,505	2,063,597	2,071,631
GS>50 kW, Intermediate	1,672,925	1,672,925	1,672,925	1,672,925	1,672,925	1,672,925
Large Use	1,051,235	1,051,235	1,051,235	1,051,235	1,051,235	1,051,235
LUDA	-	-	-	-	-	-
USL	11,844	11,901	11,958	12,015	12,073	12,130
Sentinel	-	-	-	-	-	-
Street Lighting	13,894	13,849	13,847	13,846	13,846	13,846

Table 8 - Baseline Energy Forecast - GRZ (MWh)

	2026	2027	2028	2029	2030	2031
Residential	401,972	407,025	413,665	417,891	423,161	428,643
GS<50 kW	141,857	141,671	143,220	144,048	144,973	146,010
GS>50 kW, Regular	379,086	379,080	380,963	382,005	383,072	384,256
GS>50 kW, Intermediate	500,542	500,542	500,542	500,542	500,542	500,542
Large Use	207,919	207,919	207,919	207,919	207,919	207,919
LUDA	-	-	-	-	-	-
USL	1,953	1,947	1,946	1,945	1,945	1,945
Sentinel	10	10	10	10	10	10
Street Lighting	3,521	3,587	3,589	3,590	3,590	3,590

Table 9 - Baseline Energy Forecast - HRZ (MWh)

	2026	2027	2028	2029	2030	2031
Residential	1,787,585	1,800,790	1,815,955	1,818,915	1,825,277	1,831,703
GS<50 kW	579,317	580,509	584,191	584,664	585,377	586,333
GS>50 kW, Regular	1,796,475	1,800,316	1,807,466	1,804,892	1,803,312	1,802,729
GS>50 kW, Intermediate	-	-	-	-	-	-
Large Use	231,999	231,999	231,999	231,999	231,999	231,999
LUDA	852,840	852,840	852,840	852,840	852,840	852,840
USL	11,410	11,410	11,410	11,410	11,410	11,410
Sentinel	367	359	351	343	335	327
Street Lighting	17,019	17,019	17,019	17,019	17,019	17,019

Table 10 - Baseline Energy Forecast - PRZ (MWh)

	2026	2027	2028	2029	2030	2031
Residential	3,055,204	3,087,212	3,123,069	3,138,088	3,160,465	3,183,576
GS<50 kW	1,023,866	1,025,476	1,030,306	1,032,946	1,035,932	1,039,130
GS>50 kW, Regular	4,780,592	4,785,515	4,827,840	4,844,957	4,863,078	4,883,827
GS>50 kW, Intermediate	-	-	-	-	-	-
Large Use	345,592	345,592	345,592	345,592	345,592	345,592
LUDA	-	-	-	-	-	-
USL	15,730	16,039	16,347	16,655	16,964	17,272
Sentinel	223	216	209	202	195	189
Street Lighting	39,796	40,032	40,038	40,038	40,038	40,038

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 3-STAFF-159

Energy Forecast

Ref 1: Exhibit 3 / Tab 1 / Schedule 1 / Attachment 3-2 Sales and Customer Forecast Report / pp. 12-6 (pdf pp. 21-15)

Preamble:

An explanatory variable, AftMay20, has been included indicating increased residential energy consumption in the Brampton rate zone. Horizon Rate Zone has a Yr20Plus variable. Other rate zones do not appear to have a variable capturing the impacts of COVID-19 on
residential consumption.

For GS < 50 customers in the Brampton rate zone, a Peel_Retail_Rec variable “captures the sharp drop in 2020 sales resulting from the COVID ‘work at home’ mandate”. In the Enersource Rate Zone a Yrs20_21 variable is included, implicitly capturing the years 2020 and 2021. Other rate zones do not appear to have a variable capturing the impacts of COVID-19 on GS < 50 kW consumption.

Question(s):

a) Please confirm that the AftMay20 variable is a binary variable capturing the time period after May 2020 and has a value of 1 every month after May 2020, and 0 every month prior to May 2020, or explain the values this variable takes. Please confirm that it is intended to capture the ongoing impacts of the COVID-19 pandemic on residential energy consumption.
    i. Please explain why a single variable constructed in this way is appropriate to capture the impacts of COVID-19 on residential consumption.

b) Please indicate which variables would logically capture the impact of COVID-19 on energy consumption.

c) Please explain why most energy regression models do not appear to have variables capturing the impact of the COVID-19 pandemic.

d) Please explain why the variable Peel_Retail_Rec intended to capture a drop in 2020 sales has a positive co-efficient reflecting higher energy consumption.

RESPONSE:

Response provided by Itron

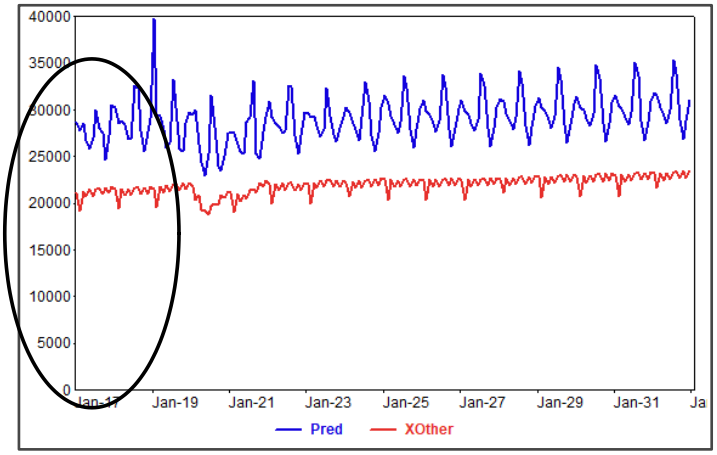
a) Yes. The *AfterMay20* binary variable captures a shift up in residential use because of the COVID work-from-home mandate. To date, we have seen no evidence that this is a temporary shift in usage. We assume that residential base use is higher throughout the forecast period.

b) Any binary variable that captured the shift in usage over this period would be appropriate as the regression model calibrates the shift to the actual shift in usage. Several of the non-residential models include COVID variables constructed with Google mobility data, which captures a decline in activity around business and recreation areas. Also, the economic data captures the impact; there was a significant drop in regional output (GDP) and employment during this period. The residential class saw a significant drop in population and an increase in per capita income.

c) Most models have a variable to account for the shift due to the COVID response. Where there is no explicit variable, the change in sales is captured in the economic data. Figure 1 below shows the impact of XOther on predicted sales in the COVID period in GS<50 kW for the ERZ. While this model included a binary for 2020 and 2021, most of the COVID

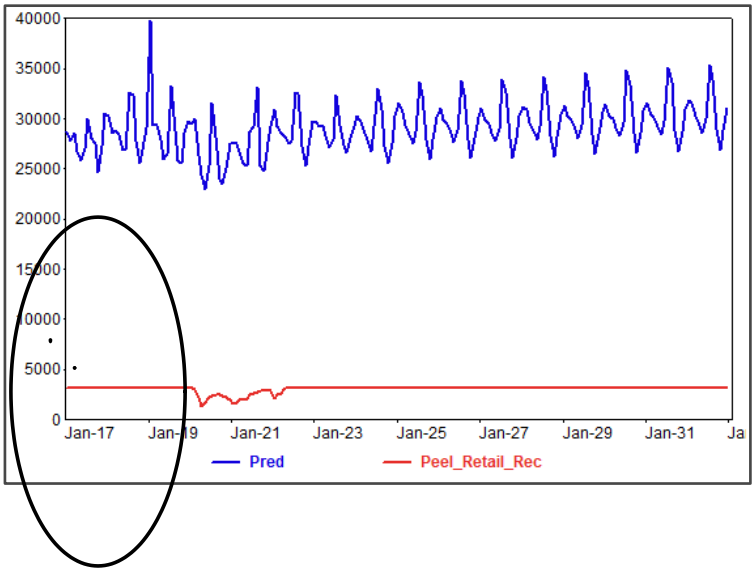
impact is accounted for by the XOther variable. The XOther variable includes employment and GDP.

Figure 1 – Impact of XOther on GS<50 kW Sales Forecast



d) The Peel_Retail_Rec variable correctly has a positive coefficient. It has a value of 1.0 before COVID and drops below 1 with the start of COVID, and eventually returns to 1.0. Figure 2 below shows the negative impact of the variable on sales.

Figure 2 – Peel_Retail-Rec Impact on Energy Sales



RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 3-STAFF-160

Energy Forecast

Ref 1: Exhibit 3 / Tab 1 / Schedule 1 / Attachment 3-2 Sales and Customer Forecast Report / pp. 12,15 (pdf pp. 21,24)

Preamble:

The Brampton rate zone residential class has a variable XCoolLag indicating that the reported monthly billed sales partly reflects consumption in the prior month.

The commercial sales models are noted to have a relatively low Adjusted R-Squared due to adjustments to sales data to accommodate the meter reading schedule.

Question(s):

a) Please confirm that Alectra Utilities uses meters capable of recording hourly or more frequent consumption - i.e., smart meters, interval meters, etc. for all metered customers, or explain where any why this is not the case.

b) For what period does Alectra Utilities have measured energy consumption by calendar month available?

c) Please confirm that going forward, Alectra Utilities will retain energy consumption information at a level of detail sufficient to not require adjustments for the meter reading schedule.

d) Did Itron attempt to use an XHeatLag variable for the same reason as the XCoolLag variable? If so, what was the result. If not, why not?

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RESPONSE:

a) Alectra Utilities confirms that it uses meters capable of recording at hourly or more frequent consumption intervals.

b) Daily meter data, which can be aggregated by calendar month, is available starting at the time each legacy utility was moved onto the Alectra Utilities' consolidated meter data repository (ERZ and PRZ – 2018, BRZ – 2019, HRZ – 2020). GRZ has monthly energy consumption from 2014 onward.

c) Alectra Utilities currently relies on billed data as the base time-series for its rate-setting load forecast. Billed data has been subject to extensive validation processes. Alectra Utilities recognizes the growing analytical value of meter-level data, as it closely aligns customers' consumption patterns with weather and provides an array of insights into customers' energy use, which in turn has the potential to enhance forecast accuracy. As part of its ongoing load forecast improvement efforts, Alectra Utilities intends to explore the use of meter data in future forecasting cycles.

d) **Response prepared by Itron**
The lags of the XHeat (XHeatLag) and XCool (XCoolLag) were tested in all the residential average use models. XHeatLag was statistically insignificant in all the models. XCoolLag was statistically insignificant in the PRZ and ERZ models.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 3-STAFF-161

CDM and NWS in the Load Forecast

Ref 1: Exhibit 3 / Tab 1 / Schedule 5 / CDM and NWS Impact in the Load Forecast / p. 1 (pdf p. 101)

Preamble:

Alectra Utilities indicated that it has not included a separate or discrete conservation & demand management or non-wires solution variable or adjustment in its load and customer forecasts, as their influence is captured in historical trends.

Question(s):

a) Please identify which regression model variables and/or inputs have the historical impacts of conservation & demand management and non-wires solution embedded.

b) Please provide further discussion and evidence as to why the impacts of conservation & demand management and non-wires solutions are believed to be implicitly integrated in the historical load data.

RESPONSE:

Response provided by Itron

a) The impacts of historical CDM are captured both in the sales data itself (which is lower than it would be without CDM) and end-use stock efficiency estimates that are part of the constructed SAE model variables XHeat, XCool, and XOther. The impact of end-use intensities is discussed in the Itron report (pages 23 – 29). Appendix A of the Itron Report provides a detailed description of how stock efficiency and structural integrity index are

incorporated into the model variables (starting page 38).

b) In the residential sector, end-use stock energy efficiency and building shell intensity are explicitly incorporated into the model variables – XHeat, XCool, and XOther. In the commercial model, efficiency is captured in the building intensities that are expressed on a kWh per square foot basis. Forecasts are based on the Energy Information Administration (EIA) 2023 National End-Use Model (NEMS). Forecasts for the East North Central (ENC) census division is used as a proxy for trends in the Toronto MSA. The end-use saturations are a key input, along with the calculated energy intensity, and are calibrated to Ontario end-use saturation data from Natural Resources Canada (NRCan). In the commercial sector, the underlying assumption is that overall building energy intensity in the Toronto Region is like that of the ENC.

Excluding miscellaneous, residential total intensity (which reflects increasing end-use ownership as well as improving efficiency) has averaged 1.2% annual decline over the last ten years. The residential total intensity is projected to continue declining 0.2% through 2032. End-use intensity slows down dramatically, and the source of the largest efficiency savings – lighting - has largely been exhausted. Declining end-use intensities are because efficiency improvements have been greater than the increase in appliance ownership (saturation).

Efficiency gains have been strong across many of the residential end-use. Over the last 10 years, residential lighting efficiency has averaged 8.7% annual gain; this slows to 0.6% over the next seven years. Electric water heating has averaged 0.6% annual efficiency gains, refrigerators 1.5%, freezers 1.0%, dryers 0.4%, furnace fans 0.6%, and central air conditioning and heat pump cooling 1.2%.

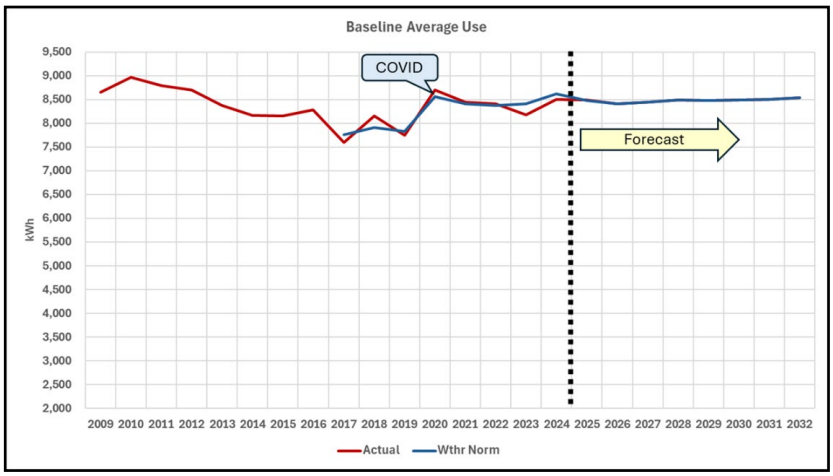
To test whether we have missed additional CDM efficiency gains, we include a trend variable in the initial models. A negative coefficient on the trend variable would indicate that there are additional CDM savings above that captured in the SAE model variables. In every model the trend variable was either statistically insignificant or positive as it was

correlated with the XOther variable. There is no indication that the model is missing the impact of CDM.

One option is to make a future adjustment for CDM savings. This, however, runs the risk of "double-counting" future savings as the model indicates CDM is adequately reflected in the end-use efficiency trends.

The final check is for forecast reasonability - does the resulting forecast look reasonable for purposes of determining revenue requirements. Figure 1 below shows actual and weather-normal average use. The forecast begins in April 2025.

Figure 1 – Residential Baseline Average Use



Since the COVID "bump", average use has been around 8,500 kWh per year. Over the next seven years, we are forecasting flat baseline average use. Efficiency gains (including standards and CDM activity) effectively counter the increase in use due to income growth and associated end-use purchases.

Strong efficiency gains are also incorporated into the non-residential SAE models. Between 2009 and 2020, the total commercial building energy intensity (kWh per square foot) declines 1.7% per year. The intensity rate declined after 2000 to a 1.0% rate. For

the forecast period, commercial building intensity decline is still strong, but declines at a slightly slower 0.7% annual rate. Figure 2 below shows commercial building intensity.

Figure 2 – Commercial Building Intensity Trend

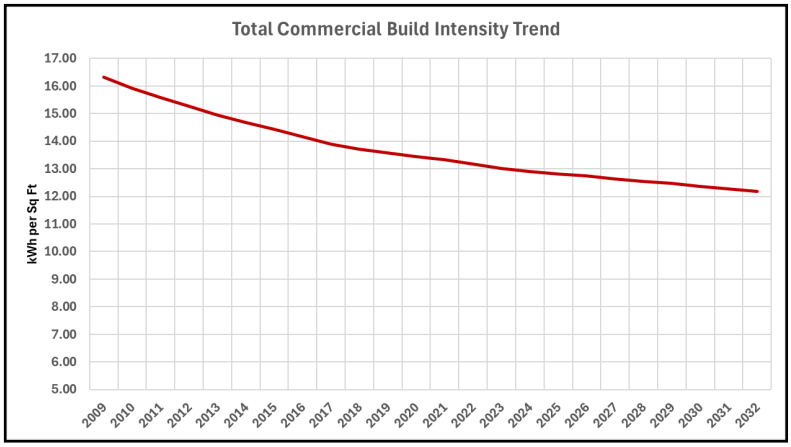
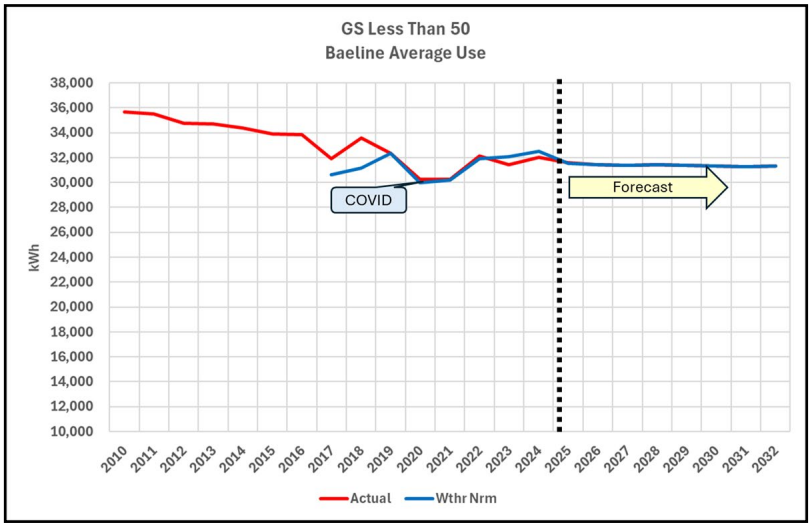


Figure 3 below shows the small GS historical and forecasted average use.

Figure 3 – GS<50 kW Baseline Average Use



GS<50 kW is modeled on a total sales basis. The average use is generated by dividing the sales (both actual and forecast) by customers (both actual and forecast). Average use declined 0.7% per year between 2010 and 2018. In 2020, there was a7.2% drop in

average use because of COVID. The forecast is flat again because improvements in building energy efficiency counter GDP and employment economic growth.

Like residential models, trend variables were used to test potentially missing CDM impacts. In all the commercial sales models, the trend variable is either statistically insignificant or positive as it was correlated with the positive covid recovery accounted for in the XOther variable.

The commercial class sales models include fairly strong efficiency trends derived from the building intensity data and generate reasonable baseline forecasts when compared with recent history.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 3-STAFF-162

Building Electrification

Ref 1: Exhibit 3 / Tab 1 / Schedule 4 / p. 6 (pdf p. 89)

Preamble:

Reference 1 notes the load and customer forecast is based on the medium scenario for building electrification which assumes new residential customers with all-electric homes will ramp up to 100% by 2030 and the number of homes that convert to electric heat and water increases from 1% of the housing stock to 6% by 2030.

Question(s):

a) Based on information in reference 1, please explain how Alectra Utilities coordinated with natural gas distributors to align and validate these electrification assumptions and their impacts.

RESPONSE:

a) Alectra Utilities would first like to clarify there is an error in the preamble, please see response to 3-VECC-37 (b) for the correct assumptions. Alectra Utilities had meetings with natural gas distributors to discuss electrification impacts. As detailed in section 5.2.2 of the DSP, Alectra Utilities coordinates its DSP with various third parties, including customers, municipalities, neighbouring distributors, Hydro One and the IESO. Alectra Utilities participates in municipally initiated Public Utility Coordination meetings attended by municipal planning staff, gas utilities, telecommunications entities and other infrastructure owners. The purpose of these meetings is to coordinate public utilities' activities. Alectra Utilities is actively working with the OEB (EB-2025-0227) and other stakeholders to develop a framework for ongoing gas-electric information sharing and

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coordination in response to the Government of Ontario's directive regarding the implementation of Energy for Generations.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-163

Ref 1: Exhibit 4 / Alectra_Attach 4-3_OEB Appendix 2-JB - Recoverable OM&A Cost Drivers_20251014

Preamble:

Alectra Utilities has filed Appendix 2-JB with cost drivers broken down into labour and non-labour for 2018 - 2031.

Question(s):

a) Please update Appendix 2-JB with cost drivers broken down into detailed categories and aligned with the explanation provided in Exhibit 4.

RESPONSE:

a) Please see the tables that follow for a version of Appendix 2-JB broken down into program categories aligned with the explanations provided in Exhibit 4.

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1 **Table 1 – 2017-2024**

	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Actuals
Opening Balance	**-**	**215,323,703**	**232,182,789**	**264,498,616**	**285,420,067**	**274,765,645**	**288,617,433**	**287,244,923**
Asset Management	5,522,315	(962,675)	1,402,793	(738,373)	(609,687)	282,106	399,966	1,149,682
Cable Locates	6,362,577	(92,616)	(296,976)	284,040	(466,194)	(601,996)	(3,227,110)	(1,500,142)
Corporate Allocations	(9,801,087)	(3,582,563)	1,797,194	(733,934)	(2,533,630)	1,698,068	(859,117)	(449,500)
Corporate Services	12,089,617	834,639	1,220,864	810,839	(965,731)	261,932	(685,087)	(52,341)
Customer Service	32,145,167	4,611,002	10,645,677	14,583,485	(6,766,262)	(5,812,811)	(3,137,546)	3,088,802
Digital and Innovation	27,103,725	2,663,075	5,565,603	(665,503)	(107,428)	2,749,881	3,307,203	3,107,982
Distribution Design	3,905,693	23,758	2,063,475	584,309	(305,035)	608,647	420,024	(211,494)
Facilities	12,518,534	3,061,429	(899,926)	2,317,033	9,489	(287,476)	1,812,602	(3,140,033)
Finance and Treasury	16,850,808	1,969,477	1,351,288	2,716,669	(1,099,152)	(1,128,830)	1,158,365	1,048,218
Fleet Asset Management	9,380,933	760,570	138,054	1,352,536	1,453,480	(402,360)	(638,564)	875,011
Human Resources	14,285,285	(455,390)	1,310,326	(1,888,577)	1,124,401	1,448,644	2,236,725	(924,868)
Network Metering	9,079,540	67,076	621,384	626,578	352,615	(1,134,279)	(965,534)	2,733,790
Overhead Inspections and Maintenance	13,225,863	3,961,123	5,111,275	4,200,494	(2,545,947)	6,781,280	(4,603,417)	91,895
Program Delivery	1,078,228	(312,792)	(55,669)	(41,244)	(40,767)	40,121	(18,415)	107,443
Property Taxes	4,013,750	607,537	342,094	(85,297)	(712,409)	8,727	469,170	437,579
Records and Mapping Services	2,515,432	416,340	(506,721)	574,428	497,586	541,410	443,503	93,593
Stations	7,396,294	1,598,687	(314,157)	(321,589)	624,281	1,314,605	1,422,169	(1,349,721)
Supply Chain Services	7,742,924	1,125,631	348,105	509,365	(526,075)	927,547	1,097,440	(429,872)
System Control	13,327,033	(1,701,621)	1,419,664	284,565	(381,862)	900,825	2,501,554	(374,362)
Underground Inspections and Maintenance	22,060,749	1,930,094	884,438	(3,955,454)	2,603,088	5,450,459	(4,059,256)	1,323,036
Vegetation Management	4,520,322	336,306	167,046	507,084	(259,184)	205,286	1,552,815	(867,378)
Closing Balance	**215,323,703**	**232,182,789**	**264,498,616**	**285,420,067**	**274,765,645**	**288,617,433**	**287,244,923**	**292,002,243**

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1 **Table 2 – 2025 - 2031**

	2025 Actuals	2026 Bridge	2027 Test	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast
Opening Balance	**292,002,243**	**310,939,145**	**318,793,184**	**355,037,333**	**371,946,785**	**389,476,082**	**404,001,407**
Asset Management	1,030,702	2,156,660	(377,246)	1,268,609	568,379	393,891	401,955
Cable Locates	12,955	254,824	7,937,022	271,089	278,625	288,019	298,360
Corporate Allocations	(3,547,805)	(5,431,469)	(555,541)	(2,092,443)	(1,585,197)	(719,479)	(1,225,427)
Corporate Services	448,791	2,811,637	7,009,154	549,045	868,626	616,488	631,646
Customer Service	4,713,377	4,982,688	433,998	2,762,576	1,687,203	2,537,433	2,148,864
Digital and Innovation	1,962,016	6,715,070	5,941,410	1,863,434	4,148,234	4,479,192	2,072,834
Distribution Design	195,652	1,310,058	1,011,823	999,843	803,735	661,986	505,849
Facilities	677,816	(2,717,368)	229,277	284,648	360,227	220,559	307,023
Finance and Treasury	999,210	1,723,227	1,370,060	1,978,778	1,944,834	1,037,928	1,050,561
Fleet Asset Management	386,368	(1,121,441)	293,505	273,605	295,711	184,521	232,385
Human Resources	2,590,881	(658,161)	1,954,911	863,737	1,365,163	718,603	640,553
Network Metering	1,063,906	(57,771)	2,506,065	1,084,419	801,056	118,574	344,712
Overhead Inspections and Maintenance	2,396,395	438,366	1,665,898	1,671,791	1,465,270	1,086,250	1,053,049
Program Delivery	343,924	388,658	147,884	62,888	61,485	59,838	62,606
Property Taxes	201,199	773,412	884,375	856,502	829,268	181,818	174,444
Records and Mapping Services	584,783	(81,811)	270,826	274,653	191,145	179,840	(147,800)
Stations	1,681,760	1,315,319	596,385	483,710	596,370	310,537	416,545
Supply Chain Services	1,619,171	(972,302)	407,303	824,965	908,082	574,405	524,711
System Control	(3,606,425)	1,005,503	1,706,594	938,619	490,251	494,300	541,992
Underground Inspections and Maintenance	4,652,602	(4,524,122)	1,996,317	1,529,859	1,290,659	949,052	919,310
Vegetation Management	529,624	(456,938)	814,129	159,128	160,172	151,570	153,930
Closing Balance	**310,939,145**	**318,793,184**	**355,037,333**	**371,946,785**	**389,476,082**	**404,001,407**	**415,109,508**

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-164

OM&A Cost Drivers

Ref 1: Exhibit 4 / Tab 1 / Schedule 3 / p. 4 (pdf p. 30)

Ref 2: Exhibit 4 / Alectra_Attach 4-2_OEB Appendix 2-JC - OM&A Programs_20251014

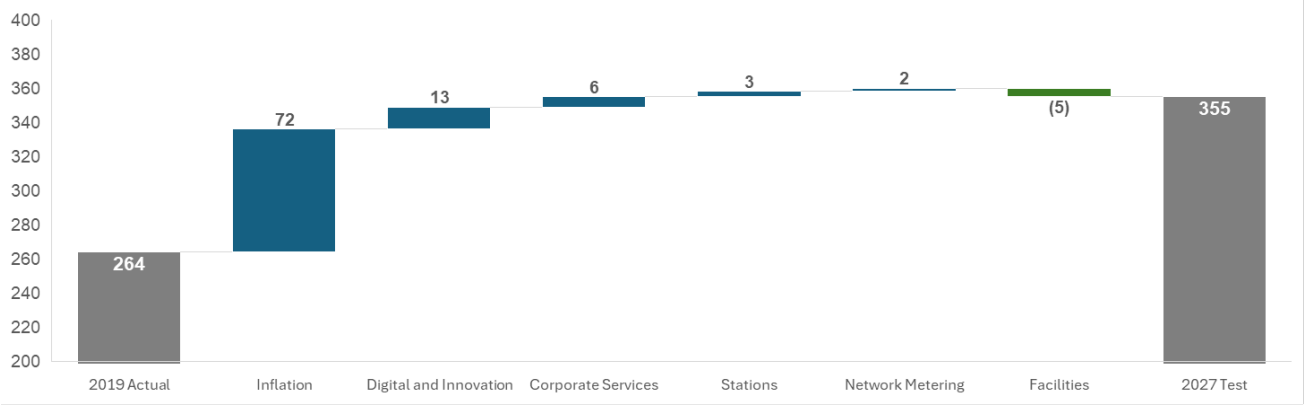
Question(s):

a) Please provide a chart in the same format as Chart 4-1-2 (reference 1) which shows cost drivers using OM&A program costs (i.e., Asset Strategy, Corporate Overheads, Customer Experience, Digital and Innovation, Operations, Sustainment, and Property Taxes) in Appendix 2-JC (reference 2) for the 2019 to 2027 period. Please also provide explanations for these cost drivers.

RESPONSE:

a) Please see below for a chart that bridges the 2019 to 2027 period by program.

Chart 1 – 2019-2027 Bridge by Program ($MM)



The primary drivers in Digital and Innovation are increasing IST Licenses and Maintenance costs and increasing labour. Please see Exhibit 4, Tab 2, Schedule 8 for program details and drivers.

The primary drivers in Corporate Services are the impact of the reset of regulatory deferral costs and the inclusion of 1/5 of the application related costs in 2027. Please see Exhibit 4, Tab 2, Schedule 3, Section 5 for program details and drivers.

The primary driver in Stations program is increasing labour costs. Please see Exhibit 4, Tab 2, Schedule 10 for program details and drivers.

The primary driver in Network Metering is increased IST Licenses and Maintenance costs related to AMI, MV90 and suite metering software. Please see Exhibit 4, Tab 2, Schedule 13 for program details and drivers.

The primary driver in Facilities is lower repairs and maintenance expenditures and lower utilities. Please see Exhibit 4, Tab 2, Schedule 18 for program details and drivers.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-165

OM&A Segments

Ref 1: Exhibit 4 / Alectra_Attach 4-2_OEB Appendix 2-JC - OM&A Programs_20251014

Question(s):

a) Please provide Appendix 2-JC broken down at the segment level.

RESPONSE:

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

4-Staff-165

Attachment 1
JC by Segment

Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-166

Operating Synergies

Ref 1: Exhibit 4 / Tab 1 / Schedule 1 / pp. 6-7 (pdf pp. 6-7)

Question(s):

a) Alectra Utilities has provided OM&A expenditure by programs from 2017 to 2031. Please provide a breakdown of operating synergies achieved by OM&A program (as shown in Appendix 2-JC) as a result of the merger for the years available.

RESPONSE:

a) 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.

Table 1: Operating Synergy Savings by Business Unit

Business Unit ($MM)	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Administration	0.6	1.0	1.6	2.8	2.7	2.8	2.8	2.9	2.9	3.0
Business Transformation	(1.5)	(0.9)	(0.3)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)
Customer Service	5.8	4.3	4.8	5.9	6.4	7.9	8.2	8.3	8.4	8.8
Finance	3.9	4.0	4.7	8.8	5.8	6.0	6.1	6.3	6.4	6.4
Government & Corporate Relations	0.3	0.8	0.9	1.1	1.3	1.3	1.3	1.3	1.3	1.4
Information Technology	3.3	6.3	5.3	3.8	5.1	5.8	5.8	5.1	5.2	5.4
Internal Audit & Enterprise Risk Management	(0.3)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Legal	(0.3)	(0.5)	(0.6)	(0.9)	(0.9)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)
Network Operations - Control Room	2.2	3.8	3.2	3.5	3.3	4.3	4.4	4.4	4.5	4.5
Network Operations - Metering	0.6	1.2	0.7	0.8	1.0	1.2	1.2	1.3	1.4	1.4
Network Operations - Operations	1.8	3.3	3.7	3.2	4.0	4.0	4.1	4.1	4.1	4.2
Network Services	1.9	2.1	1.5	1.1	0.6	0.6	0.6	0.6	0.7	0.7
People and Safety	0.1	(1.0)	1.1	0.0	(0.6)	(1.7)	(2.2)	(2.2)	(2.0)	(2.1)
Regulatory	1.4	1.9	2.1	2.2	2.2	2.3	2.3	2.3	2.4	2.4
Supply Chain Management	1.4	1.5	1.3	1.9	2.0	2.4	2.8	2.8	2.8	3.1
Total	**21.1**	**27.6**	**29.9**	**33.9**	**32.4**	**35.5**	**35.8**	**35.9**	**36.6**	**37.8**

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-167

Climate Change

Ref 1: Exhibit 4 / Tab 1 / Schedule 1 / p. 3 (pdf p.3)

Question(s):

a) Please explain in detail how Alectra Utilities budgeted for additional cost increases for the OM&A programs involved in the efforts to prepare for and respond to projected severe weather events for the forecast period.
   i. Please also provide actual and forecast storm/emergency response costs per year for 2019 to 2027.

RESPONSE:

a) Alectra Utilities budgets for OM&A costs related to severe weather events in the System Reactive Repairs and Trouble Calls segments of both the Overhead Inspection & Maintenance and Underground Inspection & Maintenance programs (reference Exhibit 4 Tab 2 Schedules 16 and 17) as well as the Reactive Tree Trimming segment of the Vegetation Management program (reference Exhibit 4 Tab 2 Schedule 15).

   Alectra's forecasts for System Reactive Repairs and Trouble Calls forecast a CAGR of 4.05% and 3.86% for Overhead Inspection & Maintenance and Underground Inspection & Maintenance, respectively. The primary driver for these increases is increases in labour rates and while Alectra does expect increasing severe weather activity as demonstrated in the Climate Risk & Vulnerability Assessment produced by Hatch (reference Exhibit 2A Tab 1 Schedule 1 Appendix G), those increased costs within these segments is expected to be absorbed within those forecast growth rates.

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Alectra forecasts Reactive Tree Trimming expenditures to increase by a CAGR of 4.82% over the forecast period. Increased storm activity related to reactive vegetation management is expected to be absorbed within those growth rates.

In addition, many severe weather events result in asset damage requiring repairs and replacement under the Storm Damage segment of Reactive Capital investments (see Exhibit 2A Tab 1 Schedule 1 Appendix B05). See response to IR 2A-SEC-51 b, iii. for details as to how increases in severe weather are factored into that program.

i) Alectra Utilities does not currently separate OM&A costs in its Overhead Inspection and Maintenance and Underground Inspection and Maintenance programs by storm/emergency response. As these costs make up a portion of the segments noted in the answer to part (a) above, Alectra has not created a specific forecast for OM&A costs specifically related to storm/emergency response. The historical and forecast costs related to the segments where storm/emergency response exist are itemized in the table below and can be referenced in Exhibit 4 Tab 1 Schedules 15-17) - note that segment level data is not available for 2019 and that severe weather related costs form only a portion of the costs shown below:

Table 1-Historical and forecast costs related to segments where storm/emergency response exist

$MM	2019	2020	2021	2022	2023	2024	2025	2026	2027
Overhead Inspections & Maintenance - System Reactive Repair and Trouble Calls	N/A	16.63	13.18	17.2	13.7	14.26	15	15.5	16.53
Underground Inspections & Maintenance - System Reactive Repair and Trouble Calls	N/A	17.94	19.3	23.96	21.7	23.45	28.29	23.31	25.18

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Vegetation Management - Reactive Vegetation Calls	N/A	0.28	0.26	0.24	0.25	0.31	0.27	0.22	0.24

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-168

FTEs and Overtime

Ref 1: Exhibit 4 / Alectra_Attach 4-6_OEB Appendix 2-K - Employee Costs_20251014

Ref 2: Exhibit 4 / Tab 2 / Schedule 9 / p. 9 (pdf p. 407)

Question(s): -

a) Please provide a revised version of Appendix 2-K that reflects 2025 actuals (or year-to-date actuals) and the 2026/2027 forecast using the current best available information. As part of the response, please also provide the number of employees, total salary and wages (with a further breakout of overtime and incentive pay), total benefits, and total compensation by the following categories: Executive, Management, Union, and Non-Union for each year from 2021 - 2027.

b) Please explain how overtime-related compensation was forecast for the 2027-2031 test years.

c) Alectra Utilities states in reference 2 that System Control expenditure rose in 2023 due to increased overtime costs. Please provide the total overtime related costs. Are there any overtime related costs budgeted for in the forecast period for this segment? If so, please provide the forecast costs.

RESPONSE:

a) See response to 4-AMPCO-80 and attachment 4-AMPCO-80_Attach_1_App 2-K Position Category Breakdown.xlsx.

b) See response to interrogatory 4-SEC-90.

c) The total System Control overtime costs for 2022 and 2023 are provided below.

Table 1-Total System Control Overtime Costs for 2022 and 2023

2022	2023
2,889,526	3,688,030

The total System Control overtime costs during the forecast period are provided below.

Table 2-Total System Control overtime costs during forecast period

2027	2028	2029	2030	2031
894,040	920,861	948,487	976,942	1,006,250

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-169

Vacancy Rate

Ref 1: Exhibit 4 / Tab 2 / Schedule 21 / p. 5 (pdf p. 614)

Ref 2: Exhibit 4 / Alectra_Attach 4-6_OEB Appendix 2-K - Employee Costs_20251014

Question(s):

a) Alectra Utilities states that it applied a 4% vacancy rate across all OM&A programs during the 2025-2031 period. Please confirm whether the forecast FTEs provided in reference 2 incorporates this vacancy rate?

b) Please further explain Alectra Utilities' methodology used to derive the vacancy rate of 4% or provide a spreadsheet (or a table) that supports the derivation of the vacancy assumption numbers of 4% based on historical and current trending which includes attrition (retirement and resignations), internal/external environmental factors and forecasting noted above.

c) Please provide the actual vacancy rate from 2021-2025 (year-to-date) and forecast vacancy rate from 2025-2031.

RESPONSE:

a) The Forecast FTE figures presented in Appendix 2-K do not incorporate the vacancy rate, however, the labour costs forecast in Appendix 2-K and 2-JC do reflect the vacancy provision.

b) The vacancy provision was originally established at 3% in the 2017 Financial Plan based on the historical provision rates utilized by legacy utilities. The provision was

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increased to 4% during the 2022 Financial Plan based on a trend of increased vacancies in 2020, principally attributable to hiring challenges during the COVID-19 pandemic. Please see response to 4-CCC-62 part b) for the calculation of the vacancy rate in this application and a restatement of the effective provision rate.

Alectra assesses the budgeted vacancy rate on an annual basis and considers both management expectations and historical experience when setting the budgeted rate.

c) The historical vacancy rates are provided in the table below:

Table 1-Historical Vacancy Rates

2019	2020	2021	2022	2023	2024	2025
-5.0%	6.5%	3.4%	6.8%	8.6%	7.6%	7.6%

Please see response to 4-CCC-62 part b) for the calculation of the vacancy rate in this application.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-170

Labour Costs

Ref 1: Exhibit 4 / Alectra_Attach 4-2_OEB Appendix 2-JC - OM&A Programs_20251014

Question(s):

a) For each OM&A program listed, please provide, for each year in the 2021-2027 period, a breakdown of the total labour costs between Alectra Utilities labour and contracted labour (e.g., contractors, consultants, etc.). Please also provide a discussion of any year-over-year changes in the proportion of work completed by Alectra Utilities relative to contracted labour.

b) What portion of the total capital budget is due to labour for each year in the forecast period?

RESPONSE:

a) Please see 4-AMPCO-58 for a detailed breakdown of internal and external resources at the segment level.

b) Table 1 below provides the labour % included in the capital budget for the forecast years. The labour % is presented is relative to the planned gross capital expenditures by year.

Table 1 – Portion of Total Planned Expenditures to % Labour and Contract Cost

	Planned Expenditure ($MM)				
	2027	**2028**	**2029**	**2030**	**2031**
Total Capital Expenditures (Gross)	603.0	688.3	791.1	848.6	922.6

	% of Labour (including both Alectra Utilities Labor and Contract Cost[1])	61.8%	63.8%	65.0%	67.4%	67.0%

[1]Contract Cost may include material and equipment costs borne by external contractors.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-171

FTEs

Ref 1: Exhibit 4 / Tab 3 / Schedule 3 / p. 2 (pdf p. 625)

Question(s):

a) Please explain the methodology Alectra Utilities used to determine the number of new positions required for each OM&A Program in Table 4-3-2 for the 2025 - 2031 period.

   i. Please provide any underlying calculations to support how the new positions were determined in 2025 and for the 2026-2031 period.
   ii. Please provide job titles and the number of new positions associated with each title for OM&A program shown in Table 4-3-2.

RESPONSE:

a) Alectra Utilities methodology used to determine the number of new positions is described in Exhibit 1, Tab 3, Schedule 1, page 7. Further details about the direction and support resources provided to support this process are included in interrogatory response 1-SEC-5.

   i. Alectra Utilities did not utilize standardized calculations to determine the Alectra Utilities resource requirements. As part of the workforce planning process, when providing rationale and justification for resource requirements, business units leveraged metrics and data, applicable to their business unit and work function, such as increased workload resulting from an increase in capital expenditure, to support the additional resource requirements. Detailed FTE requirements for each OM&A program are detailed in Exhibit 4, Tab 3, Schedule 3, pages 1-36.

The table below provides a list of job titles and the number of new positions associated with each title for OM&A program shown in Table 4-3-2. Please note that this provides a point in time snapshot of Alectra's workforce plan. To effectively manage its business within the available funding over the rate period, considering the dynamic nature of position changes, workforce movements, and evolving operational requirements, Alectra must continuously assess the jobs/positions to ensure they meet the organization's needs.

This table is populated as positions and does not necessarily equate to FTE. This chart does not show the position reductions in any year which may offset some of the position additions included in the table below.

Table 1 - Positions Added 2025-2031

	2025	2026	2027	2028	2029	2030	2031
Asset Management	**4**	**1**	**20**	**9**	**2**		
Director, Asset Sustainment & Standards			1				
Director, Capital Investment Planning			1				
Director, Design	2		1				
Director, Electrification & System Planning			1				
Director, Grid Modernization				1			
Economist and Specialist, Market Operations					1		
Engineer, Asset Sustainment			2				
Engineer, Capital Investment Planning			2				
Engineer, Data and Analytics			2				
Engineer, Grid Modernization Technology			2				
Engineer, Operational Planning				2	1		

	2025	2026	2027	2028	2029	2030	2031
Engineer, System Planning			3	2			
Inside Co-op Student	2	1	2	2			
Manager, DSO				1			
Manager, Electrification Planning			1				
Project Manager, Copperleaf			1				
Supervisor, Capital Reporting (In-Service Reporting)			1	1			
Cable Locates			**2**				
Inspector - PWU			1				
Senior Inspector			1				
Corporate Services	**1**	**1**	**3**	**1**	**1**		
Advisor, Internal Audit					1		
Auditor, Internal Audit (IT)			1	1			
Manager, Government Relations		1					
Regulatory Analyst, Compliance and Reporting			1				
Regulatory Analyst, Privacy	1						
Specialist, Rates & Settlements (Settlements)			1				
Customer Service	**15**	**4**		**12**	**15**	**9**	**9**
Analyst, Customer Insights						1	
Billing & Ebt Processes Coordinator	1						
Billing Clerk	1				1	1	1
Billing Quality Assurance Coordinator		1					
Collections Clerk	2			1	1		1
CSR I					4		3
CSR II Digital				3	2	2	1
Key Account Representative					1		
Lead Billing Representative	1						

	2025	2026	2027	2028	2029	2030	2031
Manager, Billing	1						
Manager, Customer Service (Guelph)	2						
New Connections Clerk				1		2	1
Program Coordinator, Demand Side Management		1					
Senior Collections Clerk				1			
Senior, Digital					1		1
Senior, Voice					1	2	
Specialist, Billing	1	1					
Specialist, CX Application	3						
Specialist, Payment & Collections					1		
Specialist, Projects & Knowledge Management Support				1			
Specialist, Quality Assurance				1			
Specialist, Reporting & Analytics						1	
Specialist, Reports Development & Data Analysis				1			
Specialist, Training - Contact Centre				2			
Specialist, Training - Payments & Collections				1			
Supervisor, Billing	2						
Supervisor, Collections	1						
Supervisor, Digital Customer Care					1		
Supervisor, Payments & Collections		1			1		
Supervisor, Voice Customer Care					1		1
Digital and Innovation			**6**	**7**	**5**	**5**	**5**
Application Specialist, DERMS & DSO							1
Application Specialist, Manage Work					1		

	2025	2026	2027	2028	2029	2030	2031
Application Specialist, Meter Data							1
Architect, Domain (Asset and Grid)							1
Architect, Integration			1				
Architect, OT Data				1			
Business Analyst, Customer						1	
Business Analyst, Finance							1
Data Engineer				1			
Developer, Testing					1		
Lead, Cyber GRC				1			
Lead, Digital Enablement					1		
Lead, IT Security Operations			1				
Lead, UI/UX					1		
Manager, Engineering & Operations			1				
Manager, Enterprise Architecture & Lead Architect			1				
Platform Manager, Digital Workplace				1			
Platform Manager, ERP, CIS, CX SEW			1				
Product Owner, Finance				1			
Product Owner, Manage Assets						1	
Product Owner, Manage Work						1	
Product Owner, Meter Data					1		
Product Owner, Supply Chain						1	
Specialist, Business Continuity & Disaster Recovery			1				
Specialist, CC&B						1	
Specialist, CX							1
Specialist, IT Security Governance & Risk				1			

	2025	2026	2027	2028	2029	2030	2031
Specialist, Technical/AI				1			
Distribution Design	**18**	**3**	**19**	**18**	**12**	**5**	**1**
Analyst, PTI	1						
Design Technologist	9		12	14	9	4	
Engineer, Process/Technology Improvement	1						
Manager, Distribution Design (Customer Capital)		1					
Manager, Distribution Design (ICI & Layouts)	1						
Manager, Distribution Design (Planned Capital)	1			1			
Manager, Distribution Design (Technical Customer Liaison)		1					
Supervisor, Construction		1					
Supervisor, Construction (Transit Projects)	1						
Supervisor, Design - Customer Capital	1		2				
Supervisor, Design - ICI & Layouts	1		1	1			
Supervisor, Design - Planned Capital	1		3	2	3	1	1
Supervisor, Lines			1				
Supervisor, PTI Technical Training	1						
Finance	**2**	**1**	**7**	**3**	**5**	**5**	
Accounting Analyst			2	1	2	2	
Accounts Payable Associate				2	2	2	
Business Analyst, Accounting		1	1				
Specialist, Financial Planning and Analysis	1						

	2025	2026	2027	2028	2029	2030	2031
Specialist, Financial Systems			1				
Specialist, Tax	1						
Specialist, Treasury			1				
Supervisor, Accounting			1			1	
Supervisor, Accounts Payable			1		1		
Fleet		**1**					
Apprentice Mechanic		1					
Human Resources	**5**		**3**	**4**	**3**		
Administrator, H&S				1			
Advisor, Talent Acquisition	1						
Analyst, Business				1			
Data Analyst, P&T (Total Reward)	1						
Director, Organizational Improvement	1						
HR Business Partner			1				
Inside Co-op Student	1						
Project Manager					1		
Specialist, Change and Transformation			1				
Specialist, Health & Safety			1	1	1		
Specialist, Learning & Org. Development					1		
Specialist, Talent Acquisition				1			
Strategic Advisor, People and Transformation	1						
Network Metering	**9**	**3**	**1**	**1**			
Apprentice Meter Technician	1						
Meter Data Coordinator	1	1					
Meter Technician		1		1			
Quality Inspector Meter Services	1		1				

	2025	2026	2027	2028	2029	2030	2031
Senior Operator	1						
Specialist, Mass Deployment		1					
Specialist, Meter Data Management	3						
Specialist, Wholesale	1						
Supervisor, AMI Operations	1						
Overhead Inspections and Maintenance			**23**	**15**	**12**	**2**	**1**
Apprentice Powerline Tech			9	9	6		
Lead Hand Lines			6				
Manager, Lines			1	1	1		
Network Operations Clerk			2				
Powerline Technician			5	3	3		1
Supervisor, Lines				2	2	2	
Program Delivery	**2**	**2**					
Coordinator, Program Planning & Analysis	2	2					
Records and Mapping Services			**2**	**1**			
Mapping Technician			2	1			
Stations	**15**	**1**	**2**	**1**	**1**		
Engineer, Stations	2		2				
Inside Co-op Student	2						
Network Operations Clerk	1						
Outside/Technical Co-op Student	2						
Protection & Control Technologist		1		1	1		
Protection & Controls Technologist	2						
Station Design Technologist	1						
Station Maintenance Technician	4						
Supervisor, Trades Training	1						
Supply Chain Services	**1**		**1**	**5**			

	2025	2026	2027	2028	2029	2030	2031
Analyst, Supply Chain			1				
Buyer/Planner (3PL Planner)				1			
Buyer/Planner (Corporate)				1			
Buyer/Planner (Material)				2			
Manager, Logistics	1						
Supervisor, 3PL				1			
System Control	**13**		**10**	**7**			
Director, System Control	1						
Supervisor, Trades Training	1						
System Control Planner			2				
System Controller	11		8	7			
Total	**85**	**17**	**99**	**84**	**56**	**26**	**16**

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-172

Distribution Design

Ref 1: Exhibit 4 / Tab 3 / Schedule 3 / p. 2 (pdf p. 625)

Ref 2: Exhibit 4 / Tab 2 / Schedule 2 / p. 15 (pdf p. 95)

Ref 3: Exhibit 4 / Tab 2 / Schedule 2 / pp. 5-8 (pdf p. 85-88)

Question(s):

a) Please provide a more detailed breakout of the Distribution Design program budget for the 2021 - 2027 period using the activities described in reference 3 (or at the level of granularity that is available to Alectra Utilities).

c) In reference 2, Alectra Utilities states that the increase in program costs is driven by an increase of 19 additional resources from 2027 to 2031. Please explain why this does not align with the total FTE increase under Distribution Design of 34 FTEs in reference 1.

RESPONSE:

a) See response to 4-CCC-38 parts a) and b).

c) The statement in reference 2 incorrectly should have stated that 18 additional resources were required in 2028, not 3 resources. The corrected information is as follows.

The increase from 2027 to 2031 is driven by the onboarding of 18 additional resources in 2028, 10 in 2029, 5 in 2030, 1 in 2031 respectively.

This error was in the verbiage only. 18 additional resources were correctly included in the forecasted OMA costs shown in Table 4-2-8.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-173

Corporate Services

Ref 1: Exhibit 4 / Tab 2 / Schedule 3 / pp. 10-12 (pdf pp. 105-107)
Ref 2: Exhibit 9 / Tab 3/ Schedule 3 / Table 9-3-3 / p. 3 (pdf p. 21)
Ref 3: Exhibit 4 / Tab 2 / Schedule 3 / Table 4-2-14 / p. 13 (pdf p. 108)
Ref 4: Exhibit 1 / Tab 9 / Schedule 4 / pp. 11-12 (pdf pp. 1690-1691)

Question(s):

a) Alectra Utilities states in reference 1 that the $1.1M increase in 2019 for this segment is due to higher legal and intervenor costs, as well as an additional headcount from the merger with Guelph Hydro.
    i) Please provide the breakdown of the $1.1M increase by legal, intervenor costs and the additional headcount from the merger with Guelph Hydro.
    ii) What position was the additional headcount from the merger with Guelph Hydro?
    iii) Was this position included in the OM&A payroll-related synergies during the consolidation (reference 4)? Please explain.

b) Alectra Utilities states in reference 1 that the increase of $1.2M in 2025 was primarily due to several temporary vacancies and the addition of a new position. Please provide the positions for these vacancies and if they have been filled in 2025.

c) For 2027, Alectra Utilities attributes the $6.5M increase primarily to OEB cost assessment fees and amortization of one-time application costs (reference 1). Alectra Utilities also states that the 2027 OEB assessment fee increased by $3.6M compared to historical amount built into rates. OEB staff notes that in reference 2, OEB cost assessment amount in rates is $3.1M.

i) Please confirm OEB staff's understanding that the $3.1M is the historical amount built into the rates that Alectra Utilities is referring to, which brings the total 2027 OEB assessment fees to $6.7M.

ii) Please explain Alectra Utilities' assumptions used to derive the 2027 OEB assessment fees.

d) Alectra Utilities states in reference 1 that it plans to hire a Rates and Settlement Specialist and a Compliance and Reporting Specialist in 2027. Please explain the roles and responsibilities of each new position.

e) Under the legal segment, the 2025 expense increased by $1.3M from the previous year based on Table 4-2-14 (reference 3). OEB staff notes that Alectra Utilities provided the variance explanation for 2024-2026. Please breakdown the $1.3M increase from 2024 to 2025.

RESPONSE:

a) For i) ii) iii)

The $1.1MM increase was primarily driven by the following increases: $0.3MM legal; $0.2MM intervenor costs; and $0.6MM in labour costs. The increase in labour costs included the addition of 3 FTEs which included 2 Regulatory Specialists positions from legacy Guelph Hydro, temporary positions to support Rates & Settlements during the integration period of the merger and inflationary increases. The legacy Guelph positions were not included in the OM&A payroll related synergies.

b) Two Specialist Rate Applications positions which were temporarily vacant have been filled.

c)

i) Alectra Utilities confirms OEB staff's understanding that the $3.1M is the historical

amount built into the rates that Alectra Utilities is referring to, which brings the total 2027 OEB assessment fees to $6.7M.

ii) The 2027 OEB assessment fees are based on the 2025 forecasted amount, escalated annually by 2%.

d) The Rates and Settlements Specialist will be responsible for the settlements with the IESO and Hydro One, supporting the increasing complexity of settlement activities as the electricity market continues to evolve. The Compliance and Reporting Specialist will be responsible for assisting with policy and compliance reviews and the preparation and reporting of various OEB materials, such as the RRRs, APB, and annual scorecards.

e) Alectra Utilities provided an updated version of Table 4-2-12 in response to 4-CCC-39 which incorporates 2025 actuals. 2025 actuals in the Legal segment was $1.98MM or $0.23MM higher than 2024 actuals due to increased external legal fees and the addition of a new senior internal counsel during the year. The increase from 2025 to 2026 of $0.78MM is primarily due the cost of the senior legal counsel for a full year, the addition of a new legal clerk and increased external legal fees.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-174

Finance and Treasury

Ref 1: Exhibit 4 / Tab 2 / Schedule 4 / pp. 6 & 9 (pdf pp. 123 & 126)
Ref 2: Exhibit 4 / Tab 2 / Schedule 4 / pp. 15-17 (pdf pp. 132-134)
Ref 3: Exhibit 4 / Tab 2 / Schedule 4 / p. 19 (pdf p. 136)
Ref 4: Exhibit 4 / Alectra_Attach 4-2_OEB Appendix 2-JC-OM&A Programs_20251014
Ref 5: Exhibit 4 / Tab 2 / Schedule 4 / p. 20 (pdf p. 137)

Question(s):

a) Alectra Utilities states in reference 1 that the increase in FTEs for accounts payable and accounting for the 2027-2031 period factored in productivity savings that reduced the required number of FTEs. Specifically, it states that productivity of Accounts Payable Representatives will increase by 21% while accounting productivity will increase by 47%. Please explain further the productivity assumptions used to derive the percentage savings for these positions. Please provide supporting calculations to assist with the explanation as needed.

b) Table 4-2-25 of reference 2 shows a $1.6M increase for 2025 compared to previous year. OEB staff notes that Alectra Utilities provided an explanation for the increase from 2024 to 2026. Please also explain the $1.6M increase in 2025 from 2024.

c) Alectra Utilities states in reference 3 that $1.6M increase in 2018 was mainly due to increased labour costs and bank charges due to its transition to one financial institution.
    i. Please confirm how many positions were filled.

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ii. Please explain why Alectra Utilities transitioned to one financial institution and how much cost was incurred.

d) In reference 3, the increase of $2.3M in 2020 was primarily due to bank fees related to the increase in credit facility during COVID-19 pandemic ($1.8M) and insurance costs ($0.3M).
   i. Please confirm if Alectra Utilities negotiated the fees.
   ii. Please confirm if the fee increase is still in place or has ended. If still in place, please explain why and if there are plans to renegotiate the fees.

e) Reference 4 shows an increase of $1.2M in 2023, $1M in 2024, and $2.2M in 2025. OEB staff notes that Alectra Utilities provided variance explanations by each segment.
   i. The explanation states that no material variances were provided for each segment. Please provide an explanation for the $1.2M increase in 2023 and $1M increase in 2024.
   ii. Alectra Utilities states in reference 2 that the variance from 2024-2026 under the finance segment of $1.5M were due to temporary vacant positions, annual pay increases and an additional position. No material variance explanation was provided under the treasury segment
   iii. Please provide an explanation for the $2.2M increase in 2025.

f) Based on reference 4, an increase of $1.4M is projected in 2027 compared to the previous year. Alectra Utilities states in reference 2 that approximately $0.9M per year is due to additional FTEs and annual pay increase, and $0.2M due to inflation (reference 5). I
   i. Please provide the explanation for the remaining $0.3M.

g) Alectra Utilities states in reference 2 that one additional FTE in 2027 is required to support automation and build in-house finance IT expertise. OEB staff notes that based on reference 1, two FTEs under accounting are projected to be added.

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i. Please confirm if this new position is already included in the two accounting-related positions that Alectra Utilities plans to add in 2027.

ii. Please explain whether the $0.9M increase is due only to the additional of 2 FTEs stated in (f).

RESPONSE:

a) Alectra Utilities has discovered an error in the resourcing requirements provided in Tables 4-2-21 and 4-2-23. The corrected versions of these tables are provided in Tables 1 and 4 below.

Accounts Payable

Table 1: Corrected Table 4-2-21: Resourcing Requirements

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Total Invoices	35,419	35,944	41,638	40,891	44,668	45,667	53,815	58,363	63,516	66,865	70,551
FTE with productivity	9	9	9	9	9	9	11	11	12	14	14
FTE with no productivity	9	9	9	9	10	10	12	14	15	15	17

The corrections noted above impact the calculation of the productivity by Accounts Payable Rep. The revised productivity per FTE is forecast to increase by 15% over the 2025-31 period compared to 2021-24 (as opposed to the initially stated 21%). Tables 2 and 3 provide a calculation of the average number of invoices to be processed by Accounts Payable rep for 2021-2024 and 2025-2031 respectively. The noted 15% productivity is the increase in the average invoices processed per Accounts Payable Rep in Table 3 relative to Table 2 (6,316 invoices is a 15% increase from 5,496 invoices).

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Table 2 – Calculation of Invoices/AP Representative 2021-2024

	2021	2022	2023	2024	Average (2021-2024)
Total Invoices (A)	35,419	35,944	41,638	40,891	
Accounts Payable Reps Included in Resourcing Requirements (B)	7	7	7	7	
Invoices per AP Rep (C = A/B)	5,059	5,135	5,948	5,842	**5,496**

Table 3 – Calculation of Invoices/AP Representative 2025-2031

	2025	2026	2027	2028	2029	2030	2031	Average (2025-2031)
Total Invoices (A)	44,668	45,667	53,815	58,363	63,516	66,865	70,551	
Accounts Payable Reps Included in Resourcing Requirements (B)	7	7	9	9	10	11	11	
Invoices per AP Rep (C = A/B)	6,381	6,524	5,979	6,485	6,352	6,079	6,414	**6,316**

Finance is planning to achieve these productivity targets through enhancements to the ERP and accounts payable systems and optimization of accounts payable processes. Alectra plans to explore opportunities for increased automation in invoice capture, exception handling, and payment workflows.

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Project Accounting

Table 4: Corrected Table 4-2-23: Resourcing Requirements

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Total Work Orders	4,341	5,020	4,968	5,685	6,664	6,734	7,876	8,990	10,329	11,077	12,043
FTE with productivity	23	22	22	22	22	22	24	26	29	32	32
FTE with no productivity	23	22	22	22	28	29	34	39	45	47	51

The corrections noted in Table 4 above impact the calculation of the productivity by Accounting Analyst. The revised productivity per FTE is forecast to increase by 46% over the 2025-31 period compared to 2021-24 (as opposed to the initially stated 47%). Tables 5 and 6 provide a calculation of the average number of work orders to be processed by Accounting Analyst for 2021-2024 and 2025-2031 respectively. The noted 46% productivity is the increase in the average work orders processed per Accounting Analyst in Table 6 relative to Table 5 (402 work orders is a 46% increase from 275 work orders).

Table 5 – Calculation of Work Orders/Accounting Analyst 2021-2024

	2021	2022	2023	2024	Average (2021-2024)
Work Orders (A)	4,341	5,020	4,968	5,685	
Accounting Analysts Included in Resourcing Requirements (B)	19	18	18	18	
Invoices per Accounting Analyst (C = A/B)	228	279	276	316	275

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Table 6 – Calculation of Work Orders/Accounting Analyst 2025-2031

	2025	2026	2027	2028	2029	2030	2031	Average (2025-2031)
Work Orders (A)	6,664	6,734	7,876	8,990	10,329	11,077	12,043	
Accounting Analysts Included in Resourcing Requirements (B)	18	18	20	22	25	27	27	
Invoices per Accounting Analyst (C = A/B)	370	374	394	409	413	410	446	**402**

Finance is planning to achieve these productivity targets by undertaking various process improvements related to the end-to-end work order processes, workflow automation, billing timeline improvements, automation of controls and improving reporting and analysis.

b) The updated 2025 Actual for the Finance segment is $12.6MM, a $1MM increase from 2024. The increase is primarily attributable to annual inflationary pay increases for existing employees expected in 2025, filling 3 vacancies, and the hiring of three co-op students (1 FTE).

c)

i) Prior to the merger, there was not a consolidated Treasury segment. Rather, the tasks and responsibilities of the now formed Treasury segment were performed by 6 FTEs across the finance function of the legacy utilities. In 2017 a Treasury segment was created and the 6 FTEs performing these tasks were assigned to the treasury segment. In addition, 2 positions were added to the now consolidated Treasury function as a results of increased work demands. These positions were filled in late 2017.

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ii) The legacy entities used three different banks as their cash management banks. Following amalgamation, Alectra consolidated its banking arrangements to a single institution to improve operational and financial efficiency. In particular, the consolidation of billing systems and ERP systems required consistency in the communication protocols with the banks. Moving to a single bank provided an opportunity to reduce cash balances and short-term borrowing, simplified the cash forecasting process, consolidated payment processing and improved overall banking controls.

The costs incurred to transition to one bank consisted primarily of: i) internal costs to develop new interfaces with the bank and, ii) bank fees incurred to replicate the account structures at the new bank while maintaining the bank account structures at the legacy banks during the transition period. The total cost of the transition to one bank was $0.3MM.

d)

i) Confirmed. Alectra negotiated the bank fees.

ii) Market conditions have enabled Alectra to negotiate improved pricing since the pandemic; however, pricing has not yet returned to pre-pandemic levels. Alectra will continue to re-negotiate fees at the time of each credit facility extension, based on prevailing market conditions.

e)

i) The 2023 increase of $1.2M is comprised of a $0.7M increase in Finance and $0.5M increase in Treasury. The increase in Finance of $0.7M is mainly driven by annual inflationary pay increases for existing employees and lower capitalized labour in 2023 due to the completion of the Guelph ERP harmonization project.. The increase in Treasury of $0.5M is driven by higher insurance costs of $0.7M due to higher premiums, and a $0.2M increase in debt maintenance fees partially offset by $0.5M in lower bank fees due to lower volumes.

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The 2024 increase of $1M is comprised of a $0.5M increase in Finance and $0.5M increase in Treasury. The increase in Finance of $0.5M is mainly driven by annual inflationary pay increases. The increase in Treasury of $0.5M is mainly driven by an increase in direct labour of $0.3M from resulting from a partial year vacancy that was filled in 2023 and annual pay increases. Additionally, 2024 reflects $0.2M in higher insurance premiums, and $0.2M in higher bank charges; partially offset by lower consulting costs.

ii) The updated 2025 Actual for the Finance and Treasury program is $23.9MM, a $1MM increase from 2024. Please refer to part b) for an explanation of this variance for the Finance segment. There is no material variance in the Treasury segment.

f) The 2027 increase of $1.4MM is comprised of a $1MM increase in Finance and $0.4MM increase in Treasury.

Finance: The $1MM increase in Finance is attributable to an increase in direct labour of $0.8MM and an increase in consulting of $0.2M related to accounting processes. $0.5MM of the direct labour increase in 2027 is attributable to annual inflationary pay increases for existing staff with the remainder primarily attributable to the addition of three permanent positions (1.5FTE – as hiring is expected mid-year).

Treasury: The $0.4M increase in Treasury is attributable to an increase in insurance premiums of $0.3M, increase in direct labour of $0.2M from annual inflationary pay increases and the addition of 0.5 FTE, partially offset by a decrease of $0.2M in consulting.

g)

i) The position added in 2027 that is required to support automation and build in-house finance IT expertise is incremental to the two accounting-related positions added in 2027 described in reference 1. There are 3 new permanent positions added

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in the Finance segment in 2027 (1.5FTE – as positions are expected to be hired mid-year).

ii) Please see response to part f).

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-175

Supply Chain Services

Ref 1: Exhibit 4 / Tab 2 / Schedule 5 / pp. 15-17 (pdf pp. 152-154)

Ref 2: Exhibit 4 / Tab 3 / Schedule 3 / Table 4-3-2 / p. 2 (pdf p.625)

Ref 3: Exhibit 4 / Tab 3 / Schedule 3 / p. 29 (pdf p. 652)

Ref 4: Exhibit 4 / Alectra_Attach 4-2_OEB Appendix 2-JC-OM&A Programs_20251014

Question(s):

a) Alectra Utilities states in reference 1 that the increase of $1.1M in 2018 was primarily resulting from a $0.8M increase in inventory write-offs due to obsolete materials and a $0.3M increase in additional headcount from PowerStream.
   i. What were the obsolete materials that were written off?
   ii. Please provide the position title of the additional headcount from PowerStream.

b) Reference 2 shows a reduction of 5.3 FTEs in 2022 from previous year. In reference 3, Alectra Utilities states a decrease of 3.4 FTEs from productivity gains following the consolidation of ERP systems and mergers. However, reference 4 shows an increase of $0.9M in 2022. Please explain the increase in 2022 despite the decrease in FTEs.

Response:

a) Part i) In 2017, a credit of approximately $0.7M was recorded related to inventory adjustments and legacy utility provisions, which occurred upon consolidation and alignment of accounting policies. This was a one-time adjustment. No comparable credit was recorded in 2018, resulting in normalized expense levels in that year.

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Part ii) This was not just related to PowerStream but all of legacy utilities and it was alignment of head count for 12 months in 2018, compared to 11 months in 2017 and not related to particular positions.

b) There were a number of FTE positions in 2021 that were on LTD and not included in the direct labour costs. These FTE positions were removed in 2022. The $0.9M increase was primarily driven by salary increases for FTE positions included in direct labour, material write-offs, and direct material costs as discussed in Exhibit 4, Tab 2, Schedule 5 on page 16.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-176

Human Resources

Ref 1: Exhibit 4 / Alectra_Attach 4-2_OEB Appendix 2-JC-OM&A Programs_20251014
Ref 2: Exhibit 4 / Tab 2 / Schedule 6 / pp. 11-13 (pdf pp. 165-167)
Ref 3: Exhibit 1 / Tab 6 / Schedule 4 / p. 15 (pdf p. 1496)

Question(s):

a) In reference 2 Alectra Utilities states that corporate-wide severance costs of $0.9M in 2019, $0.5M in 2021, and $1.4M in 2023 contributed to the program cost increase for each period.
i) Please indicate the number of FTEs that accepted the severance package for each year.
ii) Please confirm whether the reductions in FTEs resulted in a cost reduction in the long term.
iii) Please explain the $1M reduction in severance cost in 2022.

b) Based on reference 1, the program cost in 2025 increased by $1.8M and $2M for 2027. OEB staff notes that Alectra Utilities provided variance explanations for the increase in each segment. However, OEB staff is unable to reconcile the variances for 2025 and 2027 given the explanations provided.
i) Please explain and provide a breakdown of the $1.8M increase in 2025.
ii) Please explain and provide a breakdown of the $2M increase in 2027.

c) Alectra Utilities states in reference 3 that it expects to realize a total savings of $3.6M or an average of $1.2M annually from 2024-2026 through the implementation of its Human Capital Management Systems (HCMS), reducing its reliance on manual processes, lowering payroll administration fees, and licensing costs.
i) Please explain how $1.2M annual savings from the HCMS project is reflected in the

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Human Resource OM&A program costs per year.

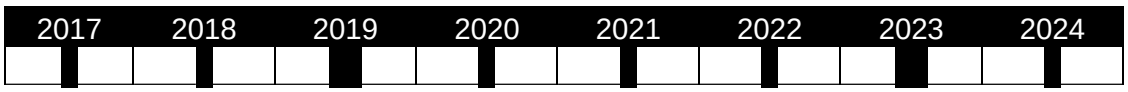
ii) Please explain why there was no decrease in FTEs from 2024-2025 despite the savings mentioned for this program.

RESPONSE:

a)

i) the following chart provides the number of employees that accepted severance packages for each year. As noted in Exhibit 4, Tab 2, Schedule 6 "Any corporate-wide severance costs in all years within the HR program exclude merger integration severance costs, which are included in merger evidence at Exhibit 1, Tab 9, Schedule 1".

Table 1: Severance



ii) As these severances were not related to merger synergies, on an overall basis these reductions did not result in long term cost reductions.

iii) The approximately $1 million reduction in severance costs in 2022 reflects a lower number of employees requiring severance compared to 2021.

b)i) On an overall program basis for the Human Resources program (inclusive of Human Resources, Health & Safety and Environment, and Business Transformation Segments), the $1.8M increase in 2025 is primarily attributable to increase in labour costs of approximately $1M, increase in consulting and recruiting costs of $0.55M and increased training and development costs of $0.30 as compared to 2024.

ii) On an overall program basis for the Human Resources program (inclusive of Human Resources, Health & Safety and Environment, and Business Transformation Segments), the $2M increase in 2027 is primarily attributable to an increase in labour cost of approximately $0.8M, an increase of approximately $0.75M in consulting and

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approximately $0.27M in employee promotional events (e.g., corporate events, town halls, employee appreciation events) and professional services.

c)

i) The $1.2MM annual savings from the HCM project is a combination of capital and OM&A savings. Please refer to the Table 2 below for HCM savings by year by benefit type. As discussed in Reference 3, the OM&A savings from the HCM project include the elimination of redundant licensing fees and FTEs, and labour efficiencies. The portion of the OM&A expected/achieved reduction savings related to the FTE reductions and payroll processing fee reduction have been incorporated into the HR OM&A program financial plan which are $0.1MM in 2024 and $0.4MM in 2025 and 2026. The portion related to licensing cost expected/achieved reductions are found in the Digital and Innovation program. The OM&A Efficiency benefits savings impact the HR program as well as all other OM&A programs due to efficiency gains by all staff using the HCM system.

Table 2- HCM project Savings

Framework Initiatives	2022 (A)	2023 (A)	2024 (A)	2025 (A)	2026 (F)	Avg. 22 - 26	Cumul. 22 - 26
Human Capital Management(HCM) System							
Capital Financial Benefit							
Expected Reduction	-	-	-	0.0	0.0		
Avoided Cost			0.7	-	-		
	-	**-**	**0.7**	**0.0**	**0.0**		
OM&A Financial Benefit							
Expected Reduction	-	-	0.1	0.6	0.6		
Efficiency Benefit	-	-	-	0.4	1.1		
	-	**-**	**0.1**	**1.0**	**1.7**		
Total Human Capital Manageme	**-**	**-**	**0.8**	**1.0**	**1.8**	**1.2**	**3.5**

ii) The implementation of the Human Capital Management system did result in a reduction of 3 FTE as forecasted, the overall FTEs in the Human Resources program did not decrease from 2024-2025 as there were incremental FTE requirements in other segments of the Human Resources program.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-177

Customer Service

Ref 1: Exhibit 4 / Tab 2 / Schedule 7 / pp. 21-22 (pdf pp. 195-196)

Ref 2: Exhibit 4 / Tab 2 / Schedule 7 / pp. 50-51 (pdf pp. 224-225)

Ref 3: Exhibit 1 / Tab 6 / Schedule 4 / pp. 14-15 (pdf pp. 1495-1496)

Question(s):

a) Table 4-2-49 of reference 1 shows the cumulative savings under this program.
   i. Please provide the annual incremental productivity savings (not sustained savings) per year for each initiative for the 2027 to 2031 period.
   ii. Please provide a brief explanation of how the incremental productivity savings for each initiative has been calculated.
   iii. Please provide a spreadsheet that shows supporting calculations used to derive the amount of savings for each initiative per year.
   iv. Please confirm if these savings have been incorporated into the 2027-2031 budget under this program. If not, please indicate which program(s) these savings have been incorporated into.

b) An annual savings of $1.6M is forecasted for the MyAlectra portal project from 2024-2026 (reference 3). It also projects $27M cumulative savings over 2027-2031 from increased adoption of e-billing and enhanced self-service options, reducing postage and labour costs. Reference 1 states that E-billing penetration is expected to increase from 39.8% in 2024 to 68.4% by 2031.
   i. Please breakdown the annual savings between expected postage and labour savings for each year from 2024-2031.
   ii. Please explain further the assumptions that Alectra Utilities used to arrive at 68.4% e-bill penetration rate.

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iii. Please explain why the e-bill penetration could not be higher than 68.4%?

c) OEB staff notes that Customer Information System (CIS) integration contributed to the variances in some years under this program. Please summarize the total costs and expected incremental productivity savings related to the CIS integration per year under this program, including the number of FTEs for each year related to the CIS integration.

RESPONSE

a) Please see Table 1 below for annual incremental productivity savings by initiative. This table shows incremental savings beyond the sustained or incremental savings in 1-SEC-12_Attachment 1_ Framework Initiatives. The incremental portion only for My Alectra portal is defined in 1-SEC-13.

See also 4-Staff-177_Attach 1 Incremental Customer Service Initiatives – tab i - for a reconciliation of the annual incremental productivity savings by initiative shown in Table 1 to the sustained or incremental savings shown in 1-SEC-12_Attachment 1.

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Table 1: Annual Incremental Productivity Savings by Initiative ($MM)

	2027	2028	2029	2030	2031	Total
My Alectra Portal Project (see note 1)	(0.2)	(0.2)	(0.3)	(0.6)	(0.7)	(1.9)
Webchat and AI Chatbot (see note 2)	0.7	0.8	0.8	0.8	0.8	3.9
IVR Enhancements (Knowledge Management System (see note 3))	(0.0)	0.4	0.4	0.4	0.4	1.5
IVR Enhancements (Intelligent Virtual Assistance (see note 4))	0.4	0.5	0.5	0.5	0.5	2.3
IVR Enhancements (Agent Assist (see note 5))	0.3	0.3	0.3	0.3	0.3	1.5
Customer Connections Portal (see note 6)	0.7	0.7	0.7	0.7	0.7	3.6
Collections Enhancement Project (see note 7)	-	0.1	0.4	0.7	1.1	2.3
Bill Redesign (see note 8)	-	-	-	0.3	0.3	0.6
Total	**2.0**	**2.4**	**2.7**	**3.1**	**3.5**	**13.7**

Note 1: See 1-SEC-12_attachment row 44. The negative values in Table 1 are due to the 1-SEC-12 _Attachment 1_ Framework Initiatives forecasted benefits using 2025 actual Canada post rates compared to the pre-filed evidence.

Note 2: See 1-SEC-12_attachment row 94.

Note 3: See 1-SEC-12_attachment row 75.

Note 4: See 1-SEC-12_attachment row 75.

Note 5: See 1-SEC-12_attachment row 75.

Note 6: See 1-SEC-12_attachment row 100.

Note 7: Not included in 1-SEC-12.

Note 8: Not included in 1-SEC-12.

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ii) Please see 4-Staff-177_attach 1 Incremental Customer Service Initiatives – tab ii and iii.

iii) Please see 4-Staff-177_attach 1 Incremental Customer Service Initiatives – tab ii and iii.

iv) The savings associated with the initiatives noted in Exhibit 4, Tab 2, Schedule 7 at Table 4-2-49 (Page 21) have been reflected in Customer Service's OM&A 2027-2031 budget, with the following notes and exceptions:

- MyAlectra Portal – Benefits of $28.5 million are included in the OM&A budget versus $26.6 million as shown in pre-filed evidence. The increased budget savings reflect increased Canada Postage rates incorporated into the postage budget, partially offset by lower third-party cost savings assumed in the contact center.
- IVR Enhancements (Knowledge Management System) – Benefits of $1.5 million from avoided AHT increases have been reflected in Customer Care's OM&A budget versus the $5.2 million reduction noted in the pre-filed evidence. However, the benefits associated with reduced call volumes from this initiative were not explicitly accounted for in the OM&A budget.
- Collections Enhancement Project – Benefits of $1.1 million have been reflected in the OM&A budget versus $2.3 million in the pre-filed evidence. Capital optimization shifted the project implementation timing from 2027 to 2028 and shifted the incremental benefits to 2032.
- Bill redesign project – Benefits were not included in Customer Service's budget for 2030-2031.

In total, the Customer Service OM&A forecast reflects $50 million (93.4%) out of the $53.5 million potential productivity savings shown in Table 4-2-49. This includes $33.9 million (63.4%) in expected reductions; $14.1 million (26.4%) reflects avoided costs, mitigating the need for additional agents or third-party resources; and $2 million (3.6%) in efficiency benefits.

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b) Table 2 differentiates the postage and labour savings associated with the MyAlectra portal project and has been updated with 2024 and 2025 actuals.

Table 2: Summary of Expected Benefits for the MyAlectra Portal Project 2024-2031 ($ Millions)

Savings Type	2024	2025	2026	2027	2028	2029	2030	2031	Total
Expected reduction in postage cost from increased e-bill penetration	0.2	1.6	2.4	3.9	4.6	5.5	6.2	6.8	31.3
Reduction of third-party agents due to automation of moves forms.	-	0	0.3	0.3	0.3	0.30	0.3	0.3	1.8

ii) Table 3 outlines the following assumptions that were used by Alectra to derive the 68.4% e-bill penetration rate. The baseline forecast assumes an average customer opt-in rate of 3% annually through 2029. Beginning in 2030, a lower adoption rate was assumed to reflect customer saturation. In addition, a one-time e-bill adoption campaign was assumed in 2026 targeting paper-bill customers with a MyAlectra account who are actively utilizing the customer portal. As part of this campaign, customers would retain the ability to revert to paper billing through the customer portal. This campaign resulted in a one-time, sustained increase in adoption by approximately 8%.

Table 3: e-Bill Targets

2024A	2025A	2026	2027	2028	2029	2030	2031
45.2%	50.5%	57.8%	59.8%	62.9%	66.0%	67.2%	68.4%

iii) Alectra believes that a 68.4% e-bill penetration rate by 2031 represents an aggressive but achievable target for the utility, with benefits front-loaded in the 2025–2027-time frame, due to the one-time e-bill adoption campaign planned for 2026, which is forecast to increase adoption by 8%. Alectra has not assumed any ability to

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mandate customers to switch to paperless billing or to implement charges for a paper billing.

c) Tables 5 and 6 below outline the OM&A merger costs and savings as an outcome of the Alectra and Guelph CIS Integration projects. For the legacy PowerStream, Enersource, Hydro One Brampton and Horizon consolidation project but excluding Guelph, a reduction of 25 FTEs is forecasted by 2026, resulting in cumulative synergies of $2.2MM. For the Guelph CIS consolidation, synergies include 5 FTE reductions, resulting in forecasted annual synergies of $0.4MM starting 2026. The total ongoing synergies are projected to be $2.6M, corresponding to 30 FTEs. Please note that in 2018 there was a reversal of synergy savings due to budget realignment and the need to bring on temporary back fill positions to support the project until completion of the project in 2019.

Table 5: Summary of Alectra and Guelph CS Cumulative FTE Reductions from IT System Consolidation

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Alectra merger CS - Number of FTE reductions driven by IT System Consolidation	10	1	14	20	20	21	22	22	22	25
Guelph Merger CS – Number of FTE reductions driven by IT System Consolidation	0	0	0	0	0	0	0	0	0	5
Total Synergies (FTE)	10	1	14	20	20	21	22	22	22	30

Table 6: Summary of CIS Integration Costs and Sustained Synergies ($ Million)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Integration Costs	0.97	1.17	0.50	-	-	-	-	-	-	0.37
Alectra Integration CS – FTE savings	0.45	0.10	0.60	1.42	1.69	1.77	1.95	1.98	2.05	2.20
Guelph Integration CS – FTE savings	-	-	-	-	-	-	-	-	-	0.41
Total Synergies	0.45	0.10	0.60	1.42	1.69	1.77	1.95	1.98	2.05	2.61

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Attachment 1
Incremental Customer Service Initiatives

Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-178

Customer Service - Billing Segment

Ref 1: Exhibit 4 / Tab 2 / Schedule 7 / pp. 33-35 (pdf pp. 207-209)

Ref 2: Exhibit 4 / Tab 2 / Schedule 7 / Table 4-2-42 & Table 4-2-43 pp. 8-9 (pdf pp. 182-183)

Question(s):

a) The Billing segment cost increased by $2.6M in 2018 compared to previous year as a result of labour ($1M), postage and printing ($1.8M), and third party cost related to the CIS integration ($0.2M).
   i) Please further explain the increase of $1M in labour cost (e.g., additional FTEs, inflation, etc.).

b) In 2019, Alectra Utilities states that the Billing segment cost increased by $4.1M as a result of labour with the addition of five billing staff from the Guelph merger ($1.5M), postage and printing costs with addition of Guelph Hydro costs ($1.6M), and third party services related to the integration of the Horizon rate zone into the Alectra Utilities CIS ($0.9M).
   i) Please confirm the five positions from the Guelph's merger. Were there other costs that contributed to the $1.5M increase aside from the five additional positions? If so, please explain.
   ii) Please explain the nature of the addition of Guelph Hydro cost and how it relates to the $1.6M increase.

c) In 2025, an increase of $1.7M was the result of temporary increased labour costs in support of the Hamilton and Guelph water bill exit and Guelph CIS integration.
   i) Please provide a breakdown of $1.7M into labour costs and Guelph CIS integration.

ii) How many positions were involved and what were the duties and responsibilities of these positions?

iii) Are these costs expected to continue after 2025?

iv) OEB staff notes that the FTEs in this segment increased by 10 in 2025 (reference 2). Please confirm if the additional 10 FTE is due to the temporary increase in labour from Hamilton and Guelph water billing exit and CIS integration. If not, please explain.

d) In 2026, a $3.4M cost increase is expected resulting from the exit of water billing in 2026, offset by a reduction associated with water billing of $1.1M. Please confirm how much of the $3.4M increase is related to the Hamilton water billing.

RESPONSE:

a) The increase in labour costs in 2018 was required to support Billing operations during the merger transition period, including the backfilling of 14 positions which were vacant in 2017. The labour variance is also attributable to the CIS training which was estimated to account for approximately 3,800 people days of effort in the 12-month period of November 2017 to November 2018 across staff in legacy PowerStream, Horizon Utilities, Brampton Hydro and Enersource.

b) i) Alectra confirms that the Billing Segment's 2019 labour OM&A variance was $1.5 million compared to 2018 and included five positions with billing job titles from the Guelph merger; however, upon review, we can confirm an additional seven Guelph Customer Service Representative positions were included as they performed both contact centre and back-office Billing duties. These 12 Guelph positions contributed to $1.4 million of the $1.5 million labour variance.

ii) To clarify the evidence, in 2019, Guelph Hydro postage and printing costs contributed $0.52 million to the overall postage and printing increase of $1.6 million. The remaining $1.0 million increased postage and printing costs resulted from a transition from bi-monthly billing to monthly billing for some of the legacy utilities: Brampton Hydro and

Horizon utilities transitioned in Q1 2017 while Enersource customers transitioned in mid-2018 with its related CIS integration.

c) i) Of the $1.7M increase in 2025, approximately $0.7 million of the labour costs are attributable to the Guelph CIS Integration project, $0.3 million for the Hamilton water billing exit project, $0.4 million due to new permanent positions and approximately $0.3 million due to wage inflation and filling of vacancies.

ii) 5 temporary staff were added to support the Guelph CIS integration project, performing business process review and analysis, data reconciliation activities, user acceptance testing, and providing critical support to sustain ongoing business operations.

iii) These costs will continue until the end of 2026 with the completion of the CIS Integration project and related operational stabilization. The FTE's and associated labour OM&A are not included in the 2027 budget.

iv) As noted in ii), 5 FTEs are related to the Guelph CIS integration project, with and additional 1 temporary FTE to support the Hamilton water exit to support user acceptance testing and data validation and 1 temporary FTE as a backfill for a long-term disability absence.

d) Alectra confirms that the $3.4M cost increase in 2026 is related to the exit from water billing.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-179

Customer Service - Collections and Payment Segment
Ref 1: Exhibit 4 / Tab 2 / Schedule 7 / pp. 39-42 (pdf pp. 213-216)

Question(s):

a) Table 4-2-53 shows that bad debt as a percentage of revenue starts to decrease in 2030 and 2031 due to collection enhancements initiatives and system automation improvements. Please explain why the benefits of the enhancements and initiatives can only be realized in 2030 and 2031.

b) Bad debt expense decreased in 2026 (Table 4-2-53) and increased again in 2027.
   i) What was the reason for the decrease in 2026?
   ii) What affected the lower net write offs in 2026 and why it cannot be maintained in 2027?

c) Reference 1 (page 40 or pdf page 214) states that an increase of $1M in 2018 was due labour cost. Please explain further the labour costs involved that contributed to the increase including the number of additional FTEs.

d) Reference 1 (page 41 or pdf page 215) states that the overall costs for this segment in 2019 increased by $3.7M, primarily driven by increases of $3.6M in non-labour, $3.1M in bad debt, $0.6M in third party costs, and $0.1M in labour. OEB staff is unable to reconcile the breakdown of the $3.7M increase with the numbers provided. Please explain and reconcile the numbers.

e) Aside from collection and disconnection efforts and assistance through payment arrangements, Low-income Energy Assistance (LEAP) and Ontario Energy Support

Program (OESP), were there other measures that Alectra Utilities undertook to reduce bad debt expense? Please explain.

RESPONSE:

a) Bad debt as a percentage of revenue is projected to decrease in 2030 and 2031, in part, due to the implementation of data analytics and propensity-to-pay modeling to personalize payment and collections communications and alerts, as well as assessments of customer-specific credit risk, and optimization of collection efforts to improve revenue recovery. These tools will be implemented as part of Phase 2 of the Collections Enhancement project, which is scheduled for completion in 2029 – as described in Exhibit 4 Tab 2 Schedule 7, page 25. The associated benefits are expected to materialize in 2030 and 2031 following project completion.

b)

i) The decrease in bad debt expense in 2026 reflected the expected impact of successive “Get Back on Track” collections campaigns in reducing high-risk, aged arrears resulting from COVID-19, resulting in lower forecast write-offs and a smaller required adjustment to the Allowance for Doubtful Accounts.

ii) Lower net write-offs in 2026 reflect the temporary impact of collections initiatives that reduced high-risk arrears. This improvement cannot be maintained in 2027 due to customer growth, higher electricity consumption and bill amounts, and increasing constraints on residential collections arising from the winter disconnection moratorium and payment arrangement rules. These factors are expected to drive higher arrears, AFDA balances, and write-offs, resulting in increased bad debt expense in 2027.

c) During the merger period of 2017-2019, Customer Service segment budgets and allocation of headcount to various functions were completed on a best-efforts basis and job function mapping and departmental organizational structures were not completed

until 2019. At the same time, Customer Service was undergoing 3 virtually simultaneous CIS integration projects, resulting in significant CIS training effort for all Customer Service staff, resulting in an incremental 3,800 people-day effort from November 2017 to November 2018, as well as resourcing for stabilization activities and back log catch up activities, increasing Collection's segment direct labour costs from $3.1 million to $4.2 million.

d) On review Alectra Utilities has discovered an error in the variance explanation provided for 2019 at Exhibit 4 Tab 2 Schedule 7, page 41. The explanation should read:
In 2019, overall costs increased by 3.7MM. Primary contributors to this increase were the $3.1MM increase in bad debt and $0.6MM increase in third party costs for back-office support due to the integration of the Horizon rate zone onto the Alectra Utilities CIS and ongoing support to stabilize the platform.

A more detailed variance explanation for 2019 and 2018 Collections segment costs is provided in the Table 1 below:

Table 1 - Collections Segment OM&A Variance Explanation 2019 to 2018 ($MM)

	OM&A Variance 2019 and 2018 ($MM)
Labour	0.15
Water Billing OM&A Credit	(0.13)
Outside Service Provider (Field Collections and Collection Agency)	0.62
Credit losses	3.14
LEAP	0.11
Other	(0.18)
Total	3.71

e) As discussed in Exhibit 4 Tab 2 Schedule 7 (Page 38), Alectra suspended disconnections efforts post-COVID until mid-2022, to support customers experiencing payment challenges. Alectra commenced limited disconnections in the Summer of 2022, taking a

risk-based approach to collections, prioritizing high-balance accounts. In 2023 and 2024, Alectra launched its 'Get Back on Track' collections campaigns which sent focused communications to high-balance customers who were at risk of disconnections, encouraging them to call to discuss flexible payment arrangements to avoid service disconnections. These actions were complemented by outbound calling to discuss payments options with customers.

In 2023, the Company also created a Customer Assistance Program department to assist vulnerable customers at risk of being disconnection, contributing to improved collections with low-income customers. This function performs a vital customer outreach role in the community by directly engaging customers to increase awareness of customer assistance programs and ways to manage electricity consumption and costs. Beyond LEAP and OESP, this department works with LEAP intake agencies to source external funding opportunities to support utility bill payments. In 2025, the Customer Assistance Program staff attended over 25 customer outreach events and proactively engaged approximately 1,000 customers who may have received a LEAP grant but had not registered for OESP, as well as OESP customers in arrears who may be eligible for LEAP. In 2024, the department introduced a pilot Payment Matching Program where Alectra matches vulnerable customers' payments on a payment arrangement after successfully maintaining the initial 3 months of that payment arrangement.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-180

Customer Service - Customer Care Segment

Ref 1: Exhibit 4 / Tab 2 / Schedule 7 / pp. 46-49 (pdf pp. 220-223)
Ref 2: Exhibit 4 / Tab 2 / Schedule 7 / p. 29 (pdf p. 203)
Ref 3: Exhibit 4 / Tab 2 / Schedule 7 / pp. 21-26 (pdf pp. 195-200)

Question(s):

a) Table 4-2-56 in reference 1 shows net front line agent requirements, including savings from technology investments in reducing FTEs for front line agents.
   i) Please provide how the FTE savings from technology investments were calculated.
   ii) OEB staff notes 48 FTEs from 2026-2031 related to front line agents webchat/backoffice (reference 1). Please clarify if these are new positions or reallocation of existing FTEs.

b) Alectra Utilities states in reference 1 (page 49 or pdf page 223) that $1.4M of the increase in 2026 is due to increased allocated OM&A costs resulting from Hamilton water billing exit and a reallocation of costs from water billing to the electricity line of business.
   i) Please clarify if the $1.4M increase in this period is part of the $3.6M increase due to exit of water billing services in Hamilton (reference 2).
   ii) Please explain the reallocation of costs from water billing to the electricity line of business. Is this a separate or additional costs related to the exit from water billing services?

RESPONSE:

a)

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i) Schedule 4-2-7 p. 19 describes the process that Alectra Utilities used to determine the fewer number of FTEs required for front line agents shown in Table 4-2-56 (which is the same number of FTEs as shown in Tale 4-2-47).

ii) The question misreads Table 4-2-56 to arrive at the 48 FTE number. Table 4-2-56 shows the total number of webchat/back-office agents required by year as compared to 2024 and are not cumulative incremental additions. Specifically, 6 agents are required in 2026, and this increases to a total of 10 agents by 2030 required to support web chat/back-office interactions (rather than the 48 agents cited in the question). The number of internal agents required for webchat/back-office referenced in Table 4-2-56 forms part of the Total Front-Line Agents Required, as calculated in the same Table. The impact of technology is then layered in to derive the net of front-line agents. The Impact of Technology Investments line of Table 4-2-56 represent avoided new internal agent positions and is representative of avoided direct labour costs factored into Customer Service's OM&A budget.

b)

i) Alectra confirms the $1.4 million increase in this period (reference 1) forms part of the total $3.6 million increase due to the exit of water billing services in Hamilton (reference 2).

ii) Please see 4-CCC-45

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-181

Water Billing

Ref: Exhibit 4 / Tab 2 / Schedule 7 / pp. 28-29 (pdf pp. 202-203)

Question(s):

a) Alectra Utilities states that it has decided to discontinue its water billing services to the municipalities of Hamilton, Guelph, Markham, and Vaughn. The impact of the water billing exit related to the Hamilton contract includes a $3.6M annual expense that needs to be absorbed in the OM&A beginning 2026, a reduction of $1.2M in 2027 with the Guelph exit, and $2.3M reduction when Markham and Vaughn exit in 2029. Did Alectra Utilities consider other alternatives apart from absorbing the $3.6M cost from the Hamilton exit?

b) Alectra Utilities states that departure from water billing will strengthen its focus on delivering efficient services, increase overall customer satisfaction, and streamline operations, including the elimination of fifteen positions.

   i) Did Alectra Utilities conduct a study to support the departure from the water billing utilities? If so, please provide the study or explain the result of the study.

   ii) When does Alectra Utilities expect to phase out the $3.6M OM&A cost?

   iii) Please clarify whether the cost related to the elimination of the fifteen positions are included in savings resulting from the exit of Guelph, Markham and Vaughn. Please provide the cost reductions per year.

RESPONSE:

a) Alectra evaluated multiple alternatives in determining whether to exit water billing services with the municipalities.

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The first option considered was offering water billing as a standalone service, separate from electricity billing. This approach would have required significant investment across both commodities and would have diminished the efficiencies and customer benefits associated with the integrated single-bill model.

A second option involved transferring water billing responsibilities to a third-party, with Alectra retaining oversight. This alternative was not pursued due to potential governances concerns and regulatory complexities associated with affiliate arrangements.

Alectra also examined maintaining the status quo under the legacy converged billing model. Various permutations were reviewed, including managing four distinct municipal rate schedules and accommodating differing operational support models and billing processes. Also, consideration was made to continuing water billing services for a limited number of municipalities based on contract value and related terms and conditions. These options were ultimately rejected due to the operational and financial challenges of administering a single bill alongside standalone water processes, resulting in added complexity and inefficiencies across billing, collections and contact centre functions.

Another alternative contemplated transforming water billing services through a major CIS system upgrade and related configurations that would separate water billing from electricity services. This option would have required significant restructuring of municipal contracts to fund initial investments estimated at approximately $8 to $12 million, in addition to ongoing maintenance costs. The magnitude of the required investment was considered impractical for both Alectra and the municipalities.

Finally, Alectra considered winding down water billing services to reduce business support complexities and focus on electricity distribution services. This option was determined to be the most sustainable long-term solution, supporting stable electricity service costs uninfluenced by water service changes, improving operational

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effectiveness, and streamlining customer service processes. It also aligns with the operating model adopted by other large LDCs in the province.

b)

i) Alectra conducted a thorough assessment of the options and impacts to support the evaluation of a long-term water billing service model. This assessment yielded the following outcomes which were foundational to Alectra's decision to depart from water billing:

1. Governance and regulatory complexities associated with an LDC have eroded the synergies of offering a combined water and electric bill (meter reading, bill print, postage costs, and providing a single point of contact for customers related to both commodities). Growing complexities include intermingling with Alectra's five electricity rate zones; the ever-increasing regulatory complexity with electricity distribution services, billing structures and affordability programs (e.g. OESP) – making it increasingly difficult and expensive to maintain the existing legacy business model.
2. Financial impacts related to increasing revenue pressures and eroded merger efficiencies to support four disparate water rate structures and varied, unaligned water billing processes, fully dependent on municipal policies and by-laws. This added significant pressure on Alectra to support increasing service expectations of four municipalities with distinct needs.
3. As the billing service agent for the municipalities, Alectra cannot maintain sufficient control over water meter reading frequency, accuracy and billing processes or policies. This creates inconsistent processes across municipalities and introduces challenges for the utility to deliver on evolving customer expectations.
4. Operational inefficiencies including manual processes, staffing challenges and customer confusion over multiple commodity billing. The Customer Service business unit is challenged to meet core compliance and service levels.

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5. Alectra is the only large utility in Ontario that is performing converged electric and water billing services – exacerbated by providing these services for multiple municipalities.

In summary, the analysis demonstrated that water billing had become increasingly complex to administer amid evolving electricity regulatory requirements and the challenges of managing a multi-commodity bill across four distinct municipal water billing structures, rate schedules, and processes.

The alternatives assessed indicated that substantial restructuring of water billing practices would be necessary to deliver these services efficiently. Such options would require significant investment by both Alectra and the municipalities to separate electricity and water billing operations, thereby diminishing the operational synergies and customer benefits associated with a consolidated single-bill model.

Accordingly, Alectra concluded that exiting water billing services would enable a more focused, effective, and efficient delivery of electricity distribution services, while enhancing the overall customer experience and supporting its obligations as a local distribution company.

ii) Please see 4-CCC-45 for an explanation as to why Alectra does not expect to phase-out the referenced OM&A costs.

iii) Yes, the cost reductions for the 15 redundant positions ($1.72 million) associated with water billing exit have been reflected within Customer Service's OM&A budget by 2029.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-182

LEAP Funding

Ref 1: Filing Requirements for Electricity Distribution Rate Applications - 2026 Edition for 2027 Rate Applications - Chapter 2, December 16, 2025 / Section 2.4.3.5, p. 36

Ref 2: Exhibit 4 / Tab 2 / Schedule 7 / pp. 27-28 (pdf pp. 201-202)

Question(s):

a) Alectra Utilities states in reference 2 that the LEAP fund distribution of $1.2M in 2022 and $1.36M in 2023 were funded from pooling of prior underfunded amounts funded in rates. Please specify the amount per year that was pooled from the underfunded amounts.

b) Reference 1 states that distributors may propose a LEAP fund higher than 0.12% of a distributors OEB-approved distribution revenue requirement if its demographics points to a greater need, and the details of those demographics must be provided. OEB staff notes in reference 2 that Alectra Utilities is requesting that its 2027-2031 LEAP funding increased to more than 0.12%. Please provide the demographic details of Alectra Utilities' customers that lead to the increase in LEAP funding.

a) Alectra Utilities provides the proposed LEAP funding in Table 4-2-51 of reference 2, and states that the amount reflects an average of 4% increase from the 2024 LEAP disbursement of $1.7M. Please explain further the assumptions for the proposed values.

RESPONSE:

a) Alectra Utilities funds the Low-Income Energy Assistance Program (LEAP) through an annual contribution equal to 0.12% of revenue requirement, which represents approximately $675,886 per year.

In 2022 and 2023, total LEAP disbursements were $1.20 million and $1.36 million, respectively, exceeding the annual rate-funded contribution. The incremental funding required to support these higher disbursement levels was sourced from underutilized LEAP funds carried forward from prior years, and which had previously been approved and funded through rates.

For clarity, the amounts referenced as “underfunded” represent LEAP funds that were approved in rates but not fully utilized in earlier years and therefore remained available for future years use. The availability of these prior-year balances was primarily due to a significant decline in LEAP application volumes during the COVID-19 pandemic, and the ongoing disconnection moratoriums between 2020-2022, resulting in a temporary underutilization of program funding.

Table 1 below summarizes LEAP unused balances by year, illustrating the accumulation of prior-year funds that supported higher disbursements in subsequent years.

“Table 1” - LEAP Fund Unused Balances by Year

Year	Unused LEAP Funds From Previous Years
2020	$599,222
2021	$999,825
2022	$1,364,652
2023	$836,883
2024	$153,558

Accordingly, the portion of LEAP funding in 2022 and 2023 that exceeded the annual rate-funded contribution was funded through accumulated prior-year balances. This approach ensured continuity of assistance to eligible customers without increasing the annual LEAP funding requirement beyond the level approved in rates.

b) LEAP funds utilized have been steadily increasing since 2022. In 2022 and 2023, this increase was attributable to the resumption of collection activities by Alectra and

increased demand for LEAP to avoid service disconnections. In 2024, continued emphasis on collections to reduce high arrears, saw continued high demand for LEAP. In addition, LEAP rules[1] changed such that no eligible LEAP applicant should be denied due to lack of funding and enabled the utility to establish a deferral account to record amounts in excess of the LEAP funding in rates for recovery at the utility's next Cost of Service application.

As an update, at year-end 2025, actual LEAP funds utilized increased by a further 17% to $1.97 million, with an 8% increase in applications approved.

Further analysis of rate zone LEAP funds distribution is summarized in Table 2 and LEAP application distribution in Table 3. Table 4 shows that the change in income eligibility thresholds for LEAP is having a positive effect on increasing the number of new applicants to LEAP.

"Table 2" - LEAP Funds Distributed by Rate Zone

Year	ERZ	BRZ	HRZ	PRZ	GRZ	Total	YoY % Change
2020	44,024	15,005	104,739	101,149	13,647	278,564	
2021	13,458	12,206	251,504	109,970	18,189	405,326	45.5%
2022	122,849	59,766	632,896	300,835	87,311	1,203,655	197.0%
2023	136,635	134,774	647,283	372,562	67,957	1,359,210	12.9%
2024	214,689	225,111	755,985	432,348	100,832	1,728,966	27.2%

[1] These changes were referenced in a letter dated February 12, 2024 from the OEB: Regarding Changes to the Low-income Energy Assistance Program Emergency Financial Assistance and Accounting Orders OEB File No. EB-2023-0135

"Table 3" - LEAP Applications by Rate Zone

Year	ERZ	BRZ	HRZ	PRZ	GRZ	Total	YoY % Change
2020	21	26	146	226	26	445	
2021	24	20	443	191	33	711	59.8%
2022	153	73	836	388	127	1577	121.8%
2023	242	244	1146	646	130	2408	52.7%
2024	315	329	1080	648	180	2552	6.0%

"Table 4" - The Number of Repeat and New LEAP Customer

Year	# of Repeat Customers	YoY % Change Repeat Customers	New Customers	YoY % Change New Customers
2021	46	666.67%	665	51.48%
2022	153	232.61%	1424	114.14%
2023	349	128.10%	2059	44.59%
2024	578	65.62%	1974	-4.13%

a) Alectra wishes to correct that the forecast increase for 2025 compared to 2024 actuals was 0.4% not 4%. Please see Table 5 that shows the correct forecast percentage change in funding (in reference to Exhibit 4 Tab 2 Schedule 7, Page 28). Increases in funding from 2026 through 2031 were estimated at 2.5% to account for customer growth, continued growth in LEAP applications approved from both customers who have received LEAP in previous years and customers who have not received LEAP in prior years.

"Table 5" - Proposed LEAP Funding in Rates ($)

	2024	2025	2026	2027	2028	2029	2030	2031
LEAP Funding ($)	1,728,966	1,735,600	1,779,400	1,820,645	1,866,177	1,866,177	1,960,696	2,009,721
% Growth	27.20%	0.4%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-183

IT Costs

Ref 1: Exhibit 1 / Tab 9 / Schedule 5 / p. 3 (pdf p. 1712)

Ref 2: Exhibit 4 / Tab 2 / Schedule 8 / p. 8 (pdf p. 242)

Question(s):

a) Alectra Utilities states in reference 1 that the consolidation of five independent IT environments into a single enterprise architecture generated sustained savings for customers into the 2027-2031 period. Please explain whether there are incremental savings reflected in the Digital and Innovation program and specifically the IT operations segment in the forecast period. If so, please provide the estimated incremental savings amount per year.

RESPONSE:

a) There are no incremental savings in the forecast period (2027-2031) attributable to the consolidation of the IT environments as reported in Exhibit 1, Tab 9, Schedules 1-5. The merger savings that have been reported as sustained savings have been built into forecast period financial plan**;** as outlined in 1-CCC-04 Table 1.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-184

Digital and Innovation

Ref: Exhibit 4 / Tab 2 / Schedule 8 / p. 1 (pdf p. 235)

Question(s):

a) OEB staff notes that at the segment level, Alectra Utilities did not explain drivers of the year-over-year cost increases. However, the total program cost in in reference 1 shows a material increase in 2018, 2022, 2023 and 2024. Please explain drivers of the increase for each of these years at each segment level.

RESPONSE:

a) At the segment level, Alectra Utilities did provide year over year variance analyses that explain the drivers of material cost increases, including those occurring in 2018, 2022, 2023, and 2024. Please refer to the evidence listed below.

Specifically, Exhibit 4, Tab 2, Schedule 8 includes segment level year-over-year variance analysis sections that discuss material increases and their drivers for each historical year within the 2017 to 2024 period.

The relevant sections are as follows:

- Section 5.3 Product Management Year-Over-Year Variance Analysis, p. 14-18.
- Section 6.3 IT Operations Year-Over-Year Variance Analysis, p. 21-24.
- Section 7.3 Digital and Innovation Business Year-Over-Year Variance Analysis, p. 26-31.
- Section 8.3 Cyber Security Year-Over-Year Variance Analysis, p. 33-36
- Section 9.3 GRE&T Centre Year-Over-Year Variance Analysis, p. 39 to 41

These sections identify and explain the underlying drivers of year-over-year changes at the segment level, including the material variances referenced by OEB Staff.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-185

Compensation per FTE

Ref 1: Exhibit 4 / Alectra_Attach 4-6_OEB Appendix 2-K - Employee Costs_20251014

Ref 2: Exhibit 4 / Tab 2 / Schedule 8 / p. 35 (pdf p. 269)

Ref 3: Exhibit 4 / Tab 2 / Schedule 8 / p. 30 (pdf p. 263)

Ref 4: Exhibit 4 / Tab 2 / Schedule 8 / p. 23 (pdf p. 257)

Question(s):

a) Please explain the OM&A cost increase in reference 2 of $1M driven by 3 FTE's (approximately $300k per FTE) for the 2026-2031 period. Please also provide the year(s) in which each of these additional FTE's will be added and explain any other cost driver included here.

b) Please explain the increase in reference 3 of $1.3M driven by 6 FTE's (approximately $200k per FTE) for the 2026-2031 period. Please also provide the year(s) in which each of these additional FTE's will be added and explain any other cost driver included here.

c) Please explain the increase in reference 4 of $2.1M driven by 4 additional roles (approximately $500k per FTE if no other drivers) for the 2026-2031 period. Please provide the year(s) in which each of these additional FTE's will be added and explain and quantify any other cost driver included here. Please also clarify the need for three additional FTEs in 2027 which contribute to the labour cost increase of $0.6M.

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RESPONSE:

a) The $1M OM&A cost increase represents the cumulative incremental labour cost over the 2027–2031 forecast period. As described in Exhibit 4, Tab 2, Schedule 8, page 35, the increase is driven by the addition of three cybersecurity and IT risk management positions within Alectra Utilities' Digital and Innovation program: a Cyber Governance, Risk, and Compliance Lead, a Security Operations Lead, and an IT Governance and Risk Specialist.

As with all positions outlined in this response, estimated job rates for these positions were developed for planning purposes and include salary, burdens, and annual inflationary increases. Final compensation will be determined through Alectra Utilities' standard role evaluation and compensation practices administered by the Total Rewards team, consistent with the compensation strategy described in Exhibit 4, Tab 3.

The incremental FTEs will be added on a phased basis, with the Security Operations Lead added in 2027, and the Cyber Governance, Risk, and Compliance Lead and IT Governance and Risk Specialist added in 2028. The purpose of these roles is to address identified cybersecurity maturity gaps, strengthen governance, risk management, and compliance capabilities as outlined in the Cyber Security segment description in Exhibit 4, Tab 2, Schedule 8, pages 31 - 32.

There are no other cost drivers included in the referenced $1M OM&A increase beyond the phased addition of these three FTEs and their associated fully burdened compensation and inflationary impacts over the 2027–2031 period.

b) The $1.3M OM&A increase reflects the total incremental cost over the 2027–2031 forecast period associated with the phased addition of six Digital and Innovation FTEs. The total reflects partial-year and full-year impacts as positions are added over time, and includes estimated salary, benefits, burdens, and forecast inflation.

The planned timing of additions is as follows: Manager, Enterprise Architecture and Integration Architect in 2027; OT Data Architect and Data Engineer in 2028; and User Interface and Experience Lead and Digital Enablement Lead in 2029. As outlined in the Digital & Innovation Business segment description in Exhibit 4, Tab 2, Schedule 8, pages

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24 – 25, these roles support the execution of Alectra Utilities' Distribution System Plan and associated IT and OT modernization initiatives by providing enterprise architecture governance, secure system integration, OT and enterprise data architecture, data engineering to enable analytics and performance monitoring, user-centred digital design for customer and internal platforms, and coordinated execution of digital initiatives to deliver measurable operational and customer outcomes.

There are no other cost drivers included in the referenced $1.3M OM&A increase beyond the phased addition of these six FTEs and their associated fully burdened compensation and inflationary impacts over the 2027–2031 period.

c) The $2.1M OM&A cost increase represents the cumulative incremental labour cost over the 2026–2031 forecast period. As described in Exhibit 4, Tab 2, Schedule 8, the increase is driven by the addition of four Digital and Innovation roles required to support business continuity, enterprise platforms, digital workplace services, and IT infrastructure operations: a Disaster Recovery and Business Continuity Specialist, a Platform Manager, Enterprise Systems, a Platform Manager, Digital Workplace, and a Manager, Engineering and Operations.

The incremental FTEs will be added on a phased basis as follows: the Disaster Recovery and Business Continuity Specialist, Platform Manager, Enterprise Systems, and Manager, Engineering and Operations will be added in 2027, and the Platform Manager, Digital Workplace will be added in 2028. These roles are required to strengthen organizational resilience, ensure the stable operation of core enterprise and digital workplace platforms, and provide dedicated leadership for increasingly complex IT infrastructure and operations, as described in the Digital and Innovation program narrative in Exhibit 4, Tab 2, Schedule 8.

The reference to a $0.6M labour cost increase associated with three additional FTEs in 2027 reflects the year-over-year increase from 2026 to 2027 within the overall 2026–2031 forecast period. This increase is attributable to the addition of three of the four roles noted above in 2027 and does not represent incremental positions beyond those included in the $2.1M cumulative OM&A labour increase.

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There are no other cost drivers included in the referenced $2.1M OM&A increase beyond the phased addition of these four FTEs and their associated fully burdened compensation and inflationary impacts over the 2026–2031 period.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-186

System Control

Ref 1: Exhibit 4 / Tab 2 / Schedule 9 / pp. 10-13 (pdf pp. 408-411)

Ref 2: Exhibit 4 / Tab 3 / Schedule 3 / Table 4-3-2 / p. 2 (pdf p. 625)

Question(s):

a) Please provide a more detailed breakout of the System Control program budget for the 2021 - 2027 period using the activities described in reference 1 (or at the level of granularity that is available to Alectra Utilities).

b) Alectra Utilities states in reference 1 that program costs are expected to increase in 2027 relative to 2026 due to an additional eight System Control Operators. In 2028, an additional seven operators are required. These numbers do not align with the FTE by OM&A program provided on a year-over year-basis in reference 2. Please reconcile the numbers and revise the evidence as needed.

RESPONSE:

a) Table 1 below provide a breakout of the System Control program costs between labour and other costs for the 2017 -2027 period. The majority of the costs for this program are labour.

"Table 1" - System Control Program Costs ($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**	**17.00**	**17.55**
Direct Labour Costs	11.96	12.98	14.60	15.53	16.01	16.50	17.03
Other	0.41	0.39	0.48	0.49	0.50	0.50	0.52

b) The FTE increases referenced in Reference 1 (i.e., eight additional System Control Operators in 2027 and seven in 2028) reflect incremental System Control Operator positions only. Table 4-3-2 referenced in Reference 2 includes all roles within the Program.

Accordingly, the increase of 10 total FTEs in 2027 shown in Table 4-3-2 consists of the eight additional System Control Operators identified in Reference 1 and two additional System Control Planners. The net increase of four FTEs in 2028 reflects the seven additional System Control Operators identified in Reference 1, offset by a reduction of three FTEs across the remainder of the Program.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-187

System Control

Ref 1: Alectra_Attach 4-6_OEB Appendix 2-K - Employee Costs_20251014

Ref 2: Exhibit 4 / Tab 2 / Schedule 9 / p. 13 (pdf p. 411)

Question(s):

a) Alectra Utilities states that in 2027, program costs are expected to increase by 13% due to 8 additional System Control Operators and in 2028 by an additional 7 Operators. Please provide the dollar increase associated with these additional FTE's in each year.

RESPONSE:

a) In 2027, an increase of $0.85MM is associated with the addition of 8 System Control Operators. In 2028, an increase of $0.76MM is associated with an addition of 7 System Control Operators.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-188

Stations

Ref 1: Exhibit 4 / Tab 2 / Schedule 10 / pp. 12-17 (pdf pp.423-428)
Ref 2: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B01 - Overhead Asset Renewal / p. 45 (pdf Exhibit 2A Part 2 p. 53)

Question(s):

a) Please provide a more detailed breakout of the Stations program budget for the 2021-2027 period using the activities described in reference 1 (or at the level of granularity that is available to Alectra Utilities).

b) Alectra Utilities states that there is an increase in labour costs of $1.3M due to an increase in headcount in 2025: 4 Protection and Control Technologists, 1 Stations Maintenance Technician, 2 Stations Engineers, 1 Station Design Technologist, 1 Technical Trades Supervisor, 1 Engineering Clerk and 2 Co-op students. Please provide an update on the hiring of these positions in 2025.

c) In reference 2, Alectra Utilities states that one of the benefits of voltage conversion would be to decommission some older stations that would otherwise need to be renewed and maintained. Please explain how these benefits are recognized in the overall OM&A costs by program.

RESPONSE:

a) Please refer to the response to 4-CCC-51 (b)

b) The table below shows the status of the hiring of these positions:

"Table 1" – The status of hiring for positions

Position	# of Positions	Hiring Status
Protection and Control Technologists	4	Filled in 2025
Stations Maintenance Technician	1	Filled in 2025
Stations Engineers	2	Filled in 2025
Station Design Technologist	1	Filled in 2025
Technical Trades Supervisor	1	Plan to fill in March 2026.
Engineering Clerk	1	Plan to fill in April 2026.
Co-op Students	2	Filled in 2025

c) When a station is decommissioned, preventative maintenance and inspection activities for electrical equipment are no longer required, and repair costs for this equipment are no longer incurred. However, until Alectra sells the property, activities such as building maintenance, landscaping, and snow removal are still required. Periodic inspections are also carried out to ensure that there are no safety hazards on site and no unauthorized access such as vagrancy. Over the short term, following decommissioning, OM&A costs are still incurred at decommissioned stations. During the forecast period, Alectra Utilities plans to decommission 6 stations in 2028, 2 in 2030, and 1 in 2031.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-189

Cable Locates

Ref 1: Exhibit 4 / Tab 2 / Schedule 12 / pp. 8 - 13 (pdf pp. 451 - 456)

Ref 2: Exhibit 1 / Tab 6 / Schedule 4 / p. 11 (pdf p. 1492)

Question(s):

a) Please provide a more detailed breakout of the Cable Locates program budget for the historical and forecast period attributed to volume increases and locate service provider fees. How are the locate notification volumes forecasted for the 2025 - 2031 period?
    i. Please also provide supporting calculations used to derive the forecast costs per year.

b) Please explain how the annual savings in reference 2 related to Locates have been factored in when preparing the budget for the forecast period?

c) Please provide a table that shows (i) actual and forecast cable locate program costs per year, (ii) the total amount (all five rate zones) recorded in the Getting Ontario Connected Act (GOCA) Variance account 1508 per year, (iii) total cost which is a sum of (i) and (ii) for the 2017 to 2027 period.
    i. Please provide an explanation for year-over-year increases/decreases in the above calculated annual total cost in (c) which is above $1M.

RESPONSE:

a) Please see response to IR 4-CCC-53 (a).
    i. Cable Locates forecast program expenditures are calculated by multiplying the average locate service provider fees by the expected volume and adding in indirect administration/supervisory costs and the forecast Ontario One Call

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costs. For IR 4-CCC-53(a) tables 2 through 6, the total forecast costs per year at the regional level is equal to the number of locates (row i) multiplied by the Average Direct/External Cost Per Locate (row iii) plus Ontario One Call Costs (row v).

b) The savings itemized in table 1-6-34 (reference 2) have been factored into the locate program budget for the forecast period. The annual savings relate to the use of a locate clearing agency to reduce the number of field locates required and complete locate notifications at a lower average rate. A blended rate for the clearing agency and the field locate service providers was used to derive the budget over the forecast period.

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c)

"Table 1"- Cable Locates Costs

$MM	2017	2018	2019	2020	2021	2022
Program Costs	$6.36	$6.27	$5.97	$6.26	$5.79	$5.19
(i) Cable Locate Program Costs (after deferral entry)	$6.36	$6.27	$5.97	$6.26	$5.79	$5.19
(ii) GOCA Variance Account Balance	N/A	N/A	N/A	N/A	N/A	N/A
Sum of (i) and (ii)	$6.36	$6.27	$5.97	$6.26	$5.79	$5.19
**Other Locate Related Costs	N/A	N/A	N/A	N/A	N/A	N/A
	2023	**2024**	**2025**	**2026**	**2027**	
Program Costs	$9.25	$7.46	$8.42	$8.48	$8.67	
(i) Cable Locate Program Costs (after deferral entry)	*$4.20	$5.25	$5.42	$5.55	$8.67	
(ii) GOCA Variance Account Balance	*$3.09	$1.75	$2.52	$2.09	N/A	
Sum of (i) and (ii)	*$7.29	$7.00	$7.94	$7.64	$8.67	
**Other Locate Related Costs	$1.96	$0.46	$0.47	$0.84	N/A	

*Only costs from April 1, 2023 to December 31, 2023 are included due to partial year for GOCA Variance Account.

**Other Locate Related Cost line includes Administrative/Supervisory costs not included in the GOCA Variance Account as well as partial year third party costs from January 1, 2023 to March 31, 2023 not included in GOCA Variance Account due to partial year in 2023.

Variance Explanation 2023 vs 2022:

- Impacts due to Bill 93 led to higher direct locate provider service fees. Total third-party service fees increased from $4.57M in 2022 to $8.65M in 2023 (please refer to IR response 4-CCC-54 (a) for breakdown of total costs.

Variance Explanation 2027 vs 2026:

- Administrative costs were not included in GOCA Variance account amounts from 2023-2027. Total third-party service fees forecast for the Cable Locates program in 2027 are $7.89M vs $7.64M in 2026 which is a variance of $0.25M.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-190

Network Metering

Ref 1: Exhibit 4 / Tab 2 / Schedule 13 / p. 16 (pdf p. 472)
Ref 2: Exhibit 2A / Tab 1 / Schedule 1 / Appendix B09 - Information Technology Systems / p. 349 (pdf Exhibit 2A Part 2 p. 357)
Ref 3: Exhibit 4 / Tab 2 / Schedule 13 / pp. 5-6 (pdf pp. 461-462)

Question(s):

a) In reference 2, Alectra Utilities states that the consolidation of its meter reading systems will reduce duplication of effort related to testing, training, integrations and compliance obligations. In reference 3, Alectra Utilities states that transitioning a portion of MV-90 customers to AMI 2.0 will reduce the need for customers to provide telephone lines, reduce manual effort and contain costs. Please quantify the expected savings from these upgrades in the cost drivers for each year from 2026-2031 provided in reference 1.

RESPONSE:

a) Alectra Utilities has not specifically quantified savings associated with its meter reading system consolidations or the initiative to transition customers from MV90 to AMI 2.0.

Under the 5.5-year AMI Renewal deployment, AMI 1.0 head-end systems are expected to be retired between 2029 and 2032. As a result, licensing and maintenance costs will continue through most of the planning period, as detailed in Interrogatory 4-CCC-54(e).

While some labour efficiencies are expected in later years as system duplication is reduced and meters transition from MV90 to AMI 2.0, this capacity will be redeployed to support enhanced AMI 2.0 functionality rather than generate net cost savings.

Meter system consolidation is not expected to materially affect Outside Service Provider costs.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-191

Vegetation Management

Ref 1: Exhibit 4 / Tab 2 / Schedule 15 / p. 11 (pdf p. 495)

Question(s):

a) Alectra Utilities states that the reactive tree trimming segment focuses on immediate issues and emergencies. Does a portion of the costs in this segment include damages from storm and extreme weather events? If so, please provide the actual amounts spent and budgeted for such extreme weather events from 2020 to 2027.

b) Alectra Utilities states that the majority of tree trimming is performed by third-party contractors whose costs continue to rise. Please also provide the following:

   i. Please explain the procurement process by which Alectra Utilities determined the third-party contractors.

   ii. Please provide an annual actual/forecast tree trimming cost performed by third-party contractors from 2020 to 2027.

RESPONSE:

a) The reactive tree trimming segment includes costs associated with storm and extreme weather events. Alectra does not separately track or forecast storm and extreme weather-related amounts within the reactive tree trimming segment.

b)

   i. Alectra uses a competitive procurement process for vegetation management contracts, consistent with Alectra's internal procurement policies. This process includes a Request for Proposal to establish vendor rates for labour, vehicles and materials by region and contract year, and includes value added mechanisms such as volume discounts, and emergency stand-by availability. Bids are evaluated using a weighted scoring approach that considers various factors such

as pricing and cost competitiveness, experience and technical capability, safety record, productivity and quality of work, capacity, and references. Contractors offering the best overall value are selected. Awards may be made to multiple contractors to ensure adequate capacity, geographic coverage, and operational resilience.

ii. See 4-CCC-56 Table 1.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-192

Overhead Inspections and Maintenance

Ref 2: Exhibit 4 / Tab 2 / Schedule 16 / p. 30 (pdf p. 530)

Ref 3: Exhibit 4 / Tab 2 / Schedule 16 / p. 46 (pdf p. 546)

Question(s):

a) Alectra Utilities states in reference 1 that Disconnect/Reconnects segment costs are expected to increase by $2.07M from 2026 to 2031. This increase is due to expected labour cost increases as disconnect and reconnect work is completed by internal staff.
   i. Please explain whether this work was completed by third party contractors in the historical period and the associated labour costs in the historical period.
   ii. Please also provide the forecast of disconnect/reconnect requests during the forecast period.

b) Alectra Utilities states in reference 2 that increases in labour costs are expected to increase System Reactive Repairs and Trouble Calls segment budget by $1.17M from 2024 to 2026. From 2026 to 2031 costs in this segment increase by $2.85M due to increases in labour rates. Please explain the increase in labour rates and how it was forecasted.

c) Please explain the year-over-year cost increases/decreases above $1M threshold at the program level where segment specific data is not available due to varying legacy financial systems and segmentation approaches (2017-2020).

RESPONSE:

a)

   i. Exhibit 4, Tab 2, Schedule 16, page 30 states that this segment will increase by $2.07MM or approximately $0.4M per year. The average annual $0.4M

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increase it due to annual inflationary increases in both internal labour and third part contractor service rates.

ii. Please refer to the response to IR 4-AMPCO-67 for forecasted disconnect/reconnect volumes.

b) The increased costs forecast for the System Reactive Repairs and Trouble Calls segment are driven primarily by increased labour costs due to increases in FTE within the Overhead Inspections & Maintenance segment (a portion of these FTE labour is spent performing work in this program and segment) as well as inflationary increases to labour rates. Labour dollars are projected to increase in this segment as a result of annual inflationary wage adjustments and the addition of 53 FTE's in the Overhead Inspections & Maintenance program (partially allocated here) between 2026 and 2031.

"Table 1"- System Reactive Repairs and Trouble Calls Segments Costs and Direct Labour

$MM	2024	2025	2026	2027	2028	2029	2030	2031
Segment Cost	$14.33	$14.26	$15.50	$16.53	$17.40	$18.20	$18.80	$19.38
Direct Labour	$9.14	$10.41	$12.53	$13.48	$14.28	$15.01	$15.54	$16.05

Funding in this segment supports Alectra's 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.

c)

2018-2018 Variance Explanation

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From 2017 to 2018 costs in this program increased by $3.90 as a result of a 2.3% increase in Trouble Call volumes. As call volumes increase, the resourcing required to respond to those calls also increases.

2019 -2018 Variance Explanation

From 2018 to 2019 costs in this program increased by $4.4M primarily as a result of:

- The addition of Legacy Guelph Hydro as of 2019 ($1.03M).
- Increased labour cost due to higher resource requirements to respond to increased volumes of disconnect/reconnect requests and storm repairs. Alectra experienced an ice storm on December 1, 2019 affecting 26,096 customers and requiring a large number of resources to respond and repair multiple wire down calls.

2020 -2019 Variance Explanation:

- The response to the COVID-19 Pandemic resulted in increased costs due to the need to maintain availability of employees for emergency response and the use of more vehicles to allow for social distancing, which resulted in higher direct vehicle cost.
- Increased labour cost due to higher resource requirements responding to higher volumes of disconnect and reconnect requests as well as trouble calls and storm repairs. Alectra Utilities experienced a higher number of outages in 2020, including a major wind event on November 15, 2020, which affected 103,486 customers and required a large number of resources responding over a long period of time to repair damage. Higher storm activity led to higher trouble call and reactive repair costs than in 2019. Overall, Alectra experienced a 3.8% increase in trouble call volume in 2020, over 2019 volumes.
- Higher outside service provider costs due to an increase in insulator washing expenditure in response to increasing incidence of pole fires (reference Exhibit 4 Tab 2 Schedule 16, Table 4-2-108)

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-193

Underground Inspections and Maintenance

Ref 1: Exhibit 4 / Tab 2 / Schedule 17 / p. 38 (pdf p. 584)

Question(s):

a) Alectra Utilities states that from 2026 to 2031 System Reactive Repairs and Trouble Calls are expected to increase by $5.98M. Please provide a cost breakdown by inflation related costs, increases in contractor fees, asset inspection contract service fees and additional FTEs. Please explain any year-over-year cost increases that are above $1M.

b) Alectra Utilities further states that in 2027 the additional 25 FTEs under the overall Lines department will impact the System Reactive Repairs and Trouble Calls segment. Please provide the amount related to these FTEs attributed to this segment.

RESPONSE:

a) Please see the detailed forecast below identifying the cost lines within the forecast for System Reactive Repairs and Trouble Calls from 2026 to 2031:

"Table 2" – Forecasting for system reactive and trouble calls

$MM	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	Total
Inflation related costs	$0.49	$0.42	$0.39	$0.41	$0.45	$2.16
Increases in contractor fees	$0.46	$0.14	$0.14	$0.14	$0.15	$1.03
Asset inspection contract fees*	N/A	N/A	N/A	N/A	N/A	N/A
Costs of additional FTE's	$0.75	$0.56	$0.46	$0.11	$0.03	$1.91
Other**	$0.17	$0.18	$0.17	$0.18	$0.18	$0.89
Total	$1.87	$1.30	$1.16	$0.84	$0.81	$5.99

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*Asset inspections are not performed in this segment. Corrective actions are performed by the same contractors through work bundling and these costs are included in the “increases in contractor fees” line.

**Other costs includes premiums, overtime related costs, direct vehicles and materials.

No individual cost line items have a year over year variance of $1M or more.

b) There is a correction to pre-filed evidence. Exhibit 4, tab 2, schedule 17, page 38, line 16 incorrectly stated an increase of 25 FTEs in 2027, however this was a typographical error and the correct number is 23 FTEs, as noted in Exhibit 4, Tab 3, Schedule 3, Table 4-3-2. The cost impact to this segment of the additional 23 FTEs is $0.75M as noted in the response to question (a) above.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-194

Facilities

Ref 1: Exhibit 4 / Tab 2 / Schedule 18 / pp. 6-7 (pdf pp. 590-591)

Question(s):

a) Please provide a more detailed breakout of the Facilities program budget for the 2021 to 2027 period using the activities/cost drivers described in reference 1 (or at the level of granularity that is available to Alectra Utilities).

RESPONSE:

a) Please see response to 4-CCC-59.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-195

Compensation

Ref 1: Exhibit 4 / Tab 3 / Schedule 5 / pp. 2-4 (pdf pp. 673-675)

Question(s):

a) Please provide sources of information that Alectra Utilities used to forecast its merit increases for management and non-union employees.

b) Please provide a table that shows the salary projections for the utility and broader public sectors, and consumer price indices that Alectra Utilities used to determine the merit increases (during the historic period), as well as the resulting merit increase associated with each performance rating. Please comment on whether the merit increases are aligned with these projections.

c) Please provide the average annual merit-based pay as a percentage of the average annual salary for senior management and the executive team for each of the historical years.

d) Reference 1 only shows wage increases for unionized employees. Please provide an average annual salary increase (in %) for management employees per year from 2020 to 2027.

RESPONSE:

a) Tables 1 to Table 5 in response b) provide the sources of information that Alectra Utilities used to forecast its merit increases for management and non-union employees.

b) The following tables show the salary projections for the utility and broader public sectors, and consumer price indices that Alectra utilized to determine the merit increases.

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"Table 1"- Salary Projections 2025

Survey Provider	Geographic Region	Industry	Base Salary Increase	Salary Structure Adjustment
			%	%
Eckler	National	All	3.60%	3.30%
Eckler	Ontario	All	3.40%	N/A
Mercer	National	All	3.20%	2.60%
Mercer	National	Utilities	3.20%	2.40%
Conference Board of Canada	National	All	3.40%	2.70%
Conference Board of Canada	National	Utilities	3.30%	2.40%
TELUS Health	National	All	3.45%	2.72%
TELUS Health	Ontario	All	3.43%	2.84%
TELUS Health	National	Utilities	3.24%	2.17%
World at Work	National	All	3.40%	3.00%
World at Work	Ontario	All	3.40%	2.90%
World at Work	National	Utilities	3.40%	2.70%
World at Work	Ontario	Utilities	3.40%	2.70%
Korn Ferry	National	All	3.50%	2.70%

"Table 2"- Salary Projections 2024

2024				
Survey Provider	Geographic Region	Industry	Base Salary Increase	Salary Structure Adjustment
			%	%
MEARIE	Ontario	Utilities	3.10%	2.90%
Mercer	National	All	3.50%	2.80%
Conference Board of Canada	National	All	3.50%	2.70%
TELUS Health	National	All	3.60%	3.00%
TELUS Health	Ontario	All	3.60%	3.10%
TELUS Health	National	Utilities	3.30%	3.00%
World at Work	National	All	3.50%	2.80%
World at Work	Ontario	All	3.50%	2.90%
World at Work	National	Utilities	3.50%	3.00%
World at Work	Ontario	Utilities	3.20%	2.40%
Korn Ferry	National	All	3.80%	2.70%

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"Table 3" - Salary Projections 2023

2023				
Survey Provider	Geographic Region	Industry	Base Salary Increase	Salary Structure Adjustment
			%	%
MEARIE	Ontario	Utilities	2.60%	2.40%
Mercer	National	All	3.50%	2.80%
Conference Board of Canada	National	All	3.40%	2.50%
Conference Board of Canada	Ontario	All	3.30%	2.60%
Conference Board of Canada	National	Utilities	3.00%	1.70%
LifeWorks (Morneau Shepell)	National	All	3.90%	3.20%
LifeWorks (Morneau Shepell)	Ontario	All	3.80%	3.20%
LifeWorks (Morneau Shepell)	National	Utilities	3.10%	1.80%
World at Work	National	All	3.40%	2.60%
World at Work	Ontario	All	3.30%	2.60%

"Table 4"- Salary Projections 2022

2022				
Survey Provider	Geographic Region	Industry	Base Salary Increase	Salary Structure Adjustment
			%	%
Mearie	Ontario	Utilities	2.00%	2.00%
Korn Ferry	National	All	2.60%	1.90%
Korn Ferry	National	Industrial Sector (includes Utilities)	3.10%	2.10%
Korn Ferry	Ontario	Municipalities	2.00%	2.00%
Mercer	National	All	2.90%	2.00%
Conference Board of Canada	National	All	2.60%	2.00%
Conference Board of Canada	Ontario	All	2.60%	2.00%
Conference Board of Canada	National	Utilities	2.60%	1.90%
LifeWorks (formerly Morneau Shepell)	National	All	2.70%	2.30%
LifeWorks (formerly Morneau Shepell)	National	Utilities	2.40%	2.60%
World at Work	National	All	2.70%	1.80%
World at Work	National	Utilities	2.60%	1.20%

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"Table 5"- Salary Projections 2021

2021			
Survey	Employee Group	2021 Projected Base Salary Increase	2021 Projected Salary Structure Adjustment
		%	%
Korn Ferry	All Employees (National)	2.50%	2.00%
Korn Ferry	All Employees (Utilities)	2.00%	2.00%
Morneau Shepell	All Employees (National)	2.50%	2.10%
Morneau Shepell	All Employees (Ontario)	2.40%	2.00%
Morneau Shepell	Utilities (National)	2.60%	2.00%
Mercer	All Employees (National)	2.50%	2.00%
Conference Board of Canada	All Employees (National)	2.50%	1.90%
Conference Board of Canada	All Employees (Ontario)	2.40%	1.90%
Conference Board of Canada	Utilities (National)	2.20%	1.10%

"Table 6"- CPI changes from 2020-2025

CPI (August) (12 Month % Change)		
Year	CPI Actual (Ontario)	CPI Actual (Canada)
2020	0.10%	0.10%
2021	4.00%	4.10%
2022	6.90%	7.00%
2023	3.80%	4.00%
2024	2.10%	2.00%
2025	1.70%	1.90%

Table 8 provided in item d below details the merit increases for the associated years. Merit increases are based on overall performance level for the given year. Merit increases also include a progression element for eligible employees whose salaries fall below 100% of the established job rate. In these cases, an additional annual progression increase, up to 2%, based on the compa-ratio, is factored into the

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forecast for employees who have not yet reached the full job rate. Merit increases are generally aligned with the annual forecasts in tables provided.

c) The table provides the average annual merit-based pay as a percentage of the average annual salary for senior management and the executive team for each of the historical years.

"Table 7"- Average Annual Merit – Executive and Senior Management

	2018	2019	2020	2021	2022	2023	2024	2025
Average Annual Merit (Executive and Senior Management)	3.93%	3.79%	4.84%	2.83%	3.24%	4.22%	3.97%	4.20%

d) The table provides the average merit increases for 2020-2024. In addition, the chart includes the merit increase assumption for 2026-2027 as referenced in Exhibit 4, Tab 3, Schedule 5, Page 5 of 8.

"Table 8"- Average Annual Merit –Management

	2020	2021	2022	2023	2024	2025	2026	2027
Average Annual Merit (Management)	4.30%	2.87%	3.33%	4.41%	4.07%	4.31%	4.00%	3.50%

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-196

Employee Benefit Costs

Ref 1: Exhibit 4 / Tab 3 / Schedule 5 / p. 6 (pdf p. 677)

Question(s):

a) Please explain the assumptions used to project Alectra Utilities' benefit costs for 2025-2031.

RESPONSE:

a) Alectra Utilities utilized the following assumptions to project benefit costs for 2025-2031:

Payroll taxes, including Canadian Pension Plan and Employment Insurance were estimated by confirming the 2024 rates for employer contributions, and applicable salary thresholds from the official sources, and were applied at the position level. Annual inflation for future years was estimated based on a 3-year historical average.

Other payroll related benefits, including employer OMERS pension contribution, employers Health Tax, and WSIB premiums, were estimated by confirming the 2024 rates for employer contributions and applicable salary thresholds from the official sources, and were applied at the position level. Annual inflation for future years was estimated based on a 3-year historical average.

Employee benefits, including items such as long-term disability premiums, life insurance premiums, health and dental benefits, and Employee Assistance Program were estimated by confirming the most relevant contracted rates with Alectra's vendors, and applied at the position level using a per employee average. Annual inflation for future

years was estimated based on plan inflation estimates if forward looking rates from the vendors were not available.

Additional employee benefits, such as maternity leave, are informed by historical periods.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-STAFF-197

Corporate Allocations and Shared Services

Ref 1: Exhibit 4 / Tab 4 / Schedule 1 / p. 2 (pdf p. 772)
Ref 2: Exhibit 4 / Alectra_Attach 4-2_OEB Appendix 2-JC-OM&A Programs_20251014
Ref 3: Exhibit 4 / Tab 4 / Schedule 1 / Table 4-2-2 / p. 6 (pdf p. 776)

Question(s):

a) Alectra Utilities states in reference 1 that given the utility's organizational changes, it engaged Atrium Economics, LLC to evaluate and update its cost allocation methods in 2020 and 2024 and implemented the changes in 2022 and 2025 respectively.
    i) Does Alectra Utilities plan to conduct another study to assess its shared services and corporate cost allocation processes? If so, please provide a timeline.
b) Please provide the number of positions and position titles that Alectra Inc. allocates to Alecta Utilities, in full or in part.
c) Please provide explanations for the year-over-year cost increases/decreases which exceed $1M in the Corporate Allocations program (reference 2) for 2018, 2019, 2021, 2022, 2005, and 2026.
d) Please explain the drivers of the increases of $1M in 2019, $1.1M in 2020, $3.1M in 2022, and $1.1M in 2024 in the net total line, as shown in reference 3.

RESPONSE:

a) Alectra Utilities plans to conduct another review to assess its shared services and corporate cost allocation processes in time to implement for 2028. This timing aligns with the next scheduled update to the shared services agreements between Alectra Utilities and its affiliates in 2028. The current shared services agreements became

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effective on January 1, 2023, and under the ARC, the term of such agreements cannot exceed five years unless otherwise approved by the OEB.

b) The number of positions and position titles within Alectra Inc. business units for which costs are allocated to Alecta Utilities are provided below. The table also includes the corresponding actual FTEs for 2023 to 2025. For 2026 and 2027, the FTEs are assumed to be equal to the number of approved positions.

"Table 1"- The number of positions, FTEs, and position titles within Alectra Inc. business units.

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		2023		2024		2025		2026		2027	
Business Unit	**Position Title**	**Position**	**FTEs**	**Position**	**FTEs**	**Position**	**FTEs**	**Position**	**FTEs**	**Position**	**FTEs**
Digital & Innovation (in part)	EVP, Chief Digital & Innovation Officer	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Executive Assistant	1.0	1.0	1.0	1.0	1.0	1.0	1.3	1.3	1.0	1.0
Corporate and Financial Stewardship (in part)	President & CEO, Alectra Inc.	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Senior Executive Assistant	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Administrative Assistant	1.0	1.0	1.0	1.0	1.0		1.0	1.0	1.0	1.0
	EVP, Chief Financial Officer	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Executive Assistant	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Internal Audit (part)	VP, Internal Audit	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Legal, Strategy & Corporate Secretary (in part)	EVP, Legal, Strategy, & Corporate Secretary	1.0	1.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Executive Assistant	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Strategy, ERM & Sustainability (in full)	VP, Strategy, Enterprise Risk Management & Sustainability	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Analyst/Coordinator, SES	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
People & Transformation (in part)	EVP, People & Transformation	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Consultant, HCM Implementation		0.5		0.6	0.3					
	Strategic Advisor		0.5	0.6	0.5						
	Executive Assistant, People & Transformation	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Regulatory, Government and Corporate Relations (in part)	SVP, Regulatory, Government & Corporate Relations	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Executive Assistant		1.0		1.0		1.0				
Total		**15.0**	**17.4**	**15.6**	**17.2**	**15.3**	**15.0**	**15.3**	**15.3**	**15.0**	**15.0**

c) The explanations for the year-over-year cost increases/decreases are provided below.

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For 2018 – approximately $3.6MM in decreased AUC costs is mainly driven by higher material recoveries primarily to support capital projects and the OH Inspections and Maintenance programs, and higher fleet recoveries to support capital projects and the OH/UG Inspections and maintenance programs.

For 2019 - approximately $1.8MM in increased AUC costs is driven by higher allocated costs from AES and AI. Lower fleet recoveries to capital projects and the Network Metering program also contribute to the variance.

For 2021 – approximately $2.5MM in decreased costs is driven by higher fleet recoveries to support capital projects and OH / UH Inspections and Maintenance programs.

For 2022 - approximately $1.7MM in increased AUC costs is driven by higher allocated costs from AES and AI; partially offset by higher material and fleet recoveries primarily to support capital projects, and the UH / UG Inspections and Maintenance, and Stations programs.

For 2025 - approximately $3.5MM in decreased AUC costs is due to higher allocated costs from AUC to AES, resulting from the 2024 Atrium review; higher other recoveries due to the over recovery of burden pool costs to OM&A programs; and higher material recoveries due to higher utilization of direct materials to support capital projects, and the Supply Chain and OH / UG Inspections and Maintenance programs.

For 2026 – approximately $5.4MM in decreased AUC costs is attributable to the 2026 plan vacancy provision; partially offset by lower material recoveries to capital and to the Supply Chain and OH / UG Maintenance and Inspection programs, and lower fleet recoveries to capital and to the OH Maintenance and Inspection operating program.

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d) The $1.0M increase in 2019 is driven by higher allocated costs from AES and AI. The $1.1M increase in 2020 is primarily attributable to a higher allocation of AI costs to AUC. The $3.1M increase in 2022 reflects higher allocated costs from AES to AUC related to Corporate Stewardship and Growth Services (refer to 4-SEC-93-d), as well as higher costs at the AI level. The $1.1M increase in 2024 is mainly due to higher AI-related costs.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 4-Staff-198

Corporate Allocations and Shared Services

Ref 1: Exhibit 4 / Alectra_Attach 4-2_OEB Appendix 2-N-Shares Services and Cost Allocation_20251014

Ref 2: Exhibit 4 / Tab 4 / Schedule 1 / p. 2 (pdf p. 772)

Preamble:

OEB staff has summarized the corporate cost allocations for services provided by Alectra Inc. to Alectra Utilities in the tables below.

Alectra Inc. to Alecta Utilities (%)

Services	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Board of Directors	10%	5%	6%	40%	52%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%
Legal, Strategy & Corporate Secretary	98%	97%	97%	98%	100%	95%	95%	95%	100%	95%	95%	95%	95%	95%	95%
Regulatory, Government & Corporate Relations	99%	100%	100%	100%	100%	99%	99%	99%	46%	46%	46%	46%	46%	46%	46%
Corporate and Financial Stewardship	48%	67%	58%	78%	79%	90%	88%	89%	78%	78%	78%	78%	78%	79%	79%
Internal Audit		99%	99%	99%	99%	96%	96%	96%	95%	95%	95%	95%	95%	95%	95%
Digital & Innovation						99%	99%	99%	99%	99%	99%	99%	99%	99%	99%
People & Transformation						98%	97%	97%	97%	97%	97%	97%	97%	97%	97%
Strategy, ERM & Sustainability						100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Alectra Inc. to Alecta Utilities ($M)

Services	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Board of Directors	0.1	0.0	0.0	0.3	0.5	1.0	1.1	1.3	1.3	1.3	1.4	1.4	1.5	1.5	1.5
Legal, Strategy & Corporate Secretary	0.7	1.0	1.0	1.1	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8
Regulatory, Government & Corporate Relations	1.4	1.0	0.9	1.1	1.2	1.1	1.2	1.2	1.1	1.1	1.2	1.3	1.3	1.3	1.4
Corporate and Financial Stewardship	3.9	2.6	3.1	3.3	3.5	3.9	3.3	3.4	4.0	4.1	4.2	4.3	4.4	4.5	4.6
Internal Audit		0.7	0.7	0.7	0.7	0.6	0.6	0.6	0.7	0.4	0.4	0.5	0.5	0.5	0.5
Digital & Innovation						0.6	0.6	0.7	0.7	0.7	1.3	0.9	0.9	1.1	0.8
People & Transformation						0.7	0.9	1.6	1.3	0.7	0.8	0.8	0.9	0.9	0.9
Strategy, ERM & Sustainability						1.0	1.1	1.1	1.0	0.9	1.1	1.0	1.1	1.2	1.1
Total	**6.0**	**5.3**	**5.7**	**6.5**	**6.7**	**9.6**	**9.5**	**10.6**	**10.9**	**10.0**	**11.1**	**10.9**	**11.2**	**11.7**	**11.7**

Question(s):

a) Please explain the reason for allocating Internal Audit services to Alectra Utilities beginning 2018.

b) Please explain the rationale for allocating Digital & Innovation, People and Transformation, and Strategy, ERM & Sustainability services to Alectra Utilities beginning 2022.

i. Is it more cost effective to receive these services through Alectra Inc.?

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c) Please explain drivers of the $3M increase in 2022, $1.1M in 2024, and $1.1M in 2027 for the services provided by Alectra Inc. to Alectra Utilities in the above table.

d) OEB staff notes changes in allocations for 2022 and 2025.

i) Please confirm if these changes were the result of the Atrium's study for 2022 and 2025.

ii) Please explain the difference between the implemented 2022 and 2025 corporate cost allocation methodology.

e) Please briefly describe the services provided to Alectra Utilities related to Corporate and Financial Stewardship.

RESPONSE:

a) Allocating Internal Audit services to Alectra Utilities beginning in 2018 reflects the transfer of the Internal Audit business unit from Alectra Utilities to Alectra Inc. In 2018, the Internal Audit business unit was added to Alectra Inc., as the Internal Audit business unit provides internal audit services across multiple subsidiaries of Alectra Inc.

b) The allocation of Digital & Innovation, People and Transformation, and Strategy, ERM & Sustainability services to Alectra Utilities beginning in 2022 reflects the transfer of these business units from Alectra Utilities to Alectra Inc. In 2022, the Digital & Innovation and People and Transformation business units were added to Alectra Inc. because they serve multiple subsidiaries of Alectra Inc.

i. From a pricing methodology perspective, there is no cost difference between receiving these services through Alectra Utilities or Alectra Inc.

c) The $3M increase in 2022 is attributable to the movement of the Digital & Innovation, People and Transformation, and Strategy, ERM & Sustainability business units from Alectra

Utilities to Alectra Inc. The $1.1M increases in 2024 and 2027 are attributable to higher Alectra Inc-related costs.

d)

i. Alectra Utilities confirms these changes were the result of the Atrium studies for 2022 and 2025.

ii. Atrium's studies for 2022 and 2025 apply the same allocation methodology. As part of the 2025 study, Alectra Utilities retained Atrium to conduct an additional update from the 2022 study, to reflect further organizational changes and in order to reinforce the accuracy and consistency of its cost allocation approach. Please refer to 4-SEC-9- c for specific changes made as a result of the Atrium 2024/2025 study.

e) Corporate and Financial Stewardship represents the Chief Executive Officer and the Chief Financial Officer's business units. Please refer to 4-SEC-92__Attach 1_Alectra Affiliate Allocation Report, Appendix A (pdf p.13) for the services provided by CEO office and CFO Office.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 5-STAFF-199

Debt to Equity Ratio

Ref 1: EB-2024-0063, Cost of Capital Decision, March 27, 2025, p. 65

Ref 2: Exhibit 5 / Alectra_Attch 5-1_OEB Appendix 2-OA Capital Structure and Cost of Capital_20251014

Question(s):

a) Please revise Appendices 2 - OA Capital Structure to show the Capitalization Ratio (% and $), Cost Rate (%), and Return ($) of both Notional Long-term Debt and Actual Long-term Debt. Please ensure the average of the Notional Long-term Debt and Actual Long-term Debt matches the Revenue Requirement Workform.

b) Please provide the actual debt to equity ratio from 2019 to 2027.

c) Please explain material differences between the actual debt to equity ratio for 2019-2027 and the deemed ratio of 60:40, if there is any.

RESPONSE:

a) Alectra Utilities has provided the requested information in attachment, 5-Staff-199_Attach_OEB Appendix 2-OA_Capital Structure and Cost of Capital Notional Debt.xlsx. The weighted average cost of long-term debt for 2027 through to 2031 has been applied to the actual debt and the weighted average cost of actual long-term debt for 2025 (latest actuals) of 3.86%, being lower than the DLTDR of 4.51%, has been applied to the notional debt.

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The notional debt has no material impact on the revenue requirement as it is calculated using the deemed capital structure, which generally aligns to the actual capital structure. In addition, Alectra Utilities borrowing costs have not been adversely impacted by the existence of immaterial allocations of notional debt.

Please note that Alectra Utilities was unable to match the average of the Notional Long-term Debt and Actual Long-term Debt to the RRWF, as requested, however, Alectra Utilities was able to match the sum of the Notional Long-term Debt and Actual Long-term Debt to the RRWF.

b) The actual debt to equity for 2019-2024 and forecast for 2025-2027 is provided in Table 1 below.

Table 1-Actual Debt to Equity for 2019-2024 and forecast for 2025-2027

	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Estimate	2026 Forecast	2027 Forecast
Total Debt to Equity Ratio	1.16	1.20	1.13	1.21	1.24	1.31	1.24	1.29	1.35
% of Total Debt	53.7%	54.5%	53.1%	54.8%	55.4%	56.7%	55.4%	56.2%	57.4%
% of Equity	46.3%	45.5%	46.9%	45.2%	44.6%	43.3%	44.6%	43.8%	42.6%

Notes:
2019-2024 actuals as per Alectra Utilities Scorecard
2025 represents a preliminary estimate
2026-2027 represents a forecast based on budget data

c) The debt-to-equity ratio over the 2019 to 2027 period is calculated on a MIRFS financial statement basis. The underleverage over the periods is a result of the fair market valuation adjustment to equity associated with a deemed acquisition of Enersource and Horizon by PowerStream at the time of the merger and in 2019 the deemed acquisition of Guelph (Totaling $493M). As required by *IFRS 3, Business Combinations* the acquisition method, the former PowerStream was deemed as the acquirer based on its relative size compared to that of the former Enersource and Horizon.

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5-Staff-199

Attachment 1
Appendix 2-OA – Capital Structure and Cost of Capital Notional Debt Final

Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 5-STAFF-200

Issuance Costs of Long-term Debts
Ref 1: Error Checking Round 1, Item 9
Ref 2: Exhibit 5 / Alectra_Attach 5-3_OEB Appendix 2-OB - Debt Instruments_20251014Ref 3: Exhibit 5 / Tab 1 / Schedule 1 / Table 5-1-3, Table 5-1-4 / pdf p. 3

Question(s):

a) Please confirm that the issuance costs are incorporated into the debt interest rate used to set rates.

b) Please confirm whether issuance costs are applied to all debts listed in Table 5-1-3.

c) Please provide the calculation methodology used to determine the issuance cost for each debt.

d) Please explain why it is appropriate to include issuance costs on debts.

RESPONSE:

a) Confirmed.

b) Confirmed.

c) The calculation methodology used to determine the issuance cost for each forecasted debt issuance was based on the last actual long-term debt issuance in October 2024. Alectra Utilities relied on the actual invoices from this issuance to determine that virtually

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all of the fees were variable. These variable fees were either based on a percentage of the total issuance, or hours of effort required to support the issuance. Alectra compared the fees related to total hours of effort charged from the October 2024 issuance to the prior issuance in June 2024 to determine whether these fees were consistent given the close proximity of these issuances. Alectra determined that legal and audit fees were lower as a result of less due diligence effort required in the October 2024 Issuance.

With this information, Alectra estimated the future years' issuance fees by prorating based on the October 2024 actual issuance fees. The 2026 estimate of issuance fees was increased to reflect consistency to the June 2024 issuance as additional due diligence will be required given that Alectra will have been absent from the long-term debt market for two years. After the 2026 issuance, Alectra will be issuing debt regularly, and therefore the due diligence costs will normalize where the proration from the October 2024 issuance was determined to be appropriate.

The forecasted debt issuance costs by tranche are provided in Table 1 below.

Table 1-Forecasted Debt Issuance Costs by Tranche

Year	Total Debt Issued ($ Millions)	Debt Issuance Cost ($ Millions)	
2024	$300.0	$2.0	Actual
2026	$350.0	$2.5	Estimate
2027	$400.0	$2.5	Estimate
2028	$300.0	$2.0	Estimate
2029	$250.0	$1.8	Estimate
2030	$200.0	$1.5	Estimate
2031	$600.0	$4.0	Estimate

The fees included in the long-term debt issuance costs include:

- Agency fees, levied by the dealer banks to support the issuance where these fees are based on a percentage on the amount of debt issued.

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- Credit agency fees (DBRS, Fitch and S&P) support issuing long-term credit ratings and are based on a percentage of the amount of debt issued.
- Legal fees and external auditor (KPMG) fees are based on hours of effort required.
- Security filing fees represent fees payable to the Provinces where the debt is sold.

d) It is appropriate to include issuance costs on debts as these costs represent debt-related transaction costs incurred. In addition, this aligns with the current accounting practice as provided for under IFRS 9 – Appendix A where these issuance costs are amortized over the term of the underlying debt.

Alectra Utilities understands that the OEB's DLTDR is used as a proxy for actual market-based long-term debt, however this rate does not consider issuance costs. Based on the forecasted requirement for annual issuances as provided in Exhibit 5 / Tab 1 / Schedule 1 / Table 5-1-4, Alectra has included issuance costs which are amortized over the life of the issuance for each debt in the rebasing period, where the total interest expense related to the forecasted issuance costs over the 2026 to 2031 is $1.7M.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 5-STAFF-201

Capitalization Ratio

Ref 1: Exhibit 5 / Alectra_Attch 5-1_OEB Appendix 2-OA Capital Structure and Cost of Capital_20251014

Ref 2: Exhibit 1 / Tab 2 / Schedule 2 / p. 2 (pdf p. 29)

Preamble:

Alectra Utilities stated in Reference 2 that the company's predecessor utilities last rebased in 2013 (Enersource), 2015 (Hydro One Brampton), 2015-2019 (Horizon Utilities -CIR), 2016 (Guelph Hydro), 2017 (PowerStream).

Question(s):

a) In Reference 1, the last OEB-approved (rebased) year is 2019. Please confirm whether this 2019 capital structure includes all rate zones. If not, please indicate which rate zones are included in the 2019 capital structure.
b) Please provide the capital structure for each legacy utility as of its last rebasing.

RESPONSE:

a) Confirmed, the 2019 capital structure includes all legacy utility approved capital structures.
b) Please see the capital structure for each legacy utility as of its last rebasing in Table 1 below.

:

Table 1 – Legacy Utility Capital Structures

Rebasing Year	ERZ (2013 COS)	BRZ (2015 COS)	GRZ (2016 COS)	PRZ (2017 COS)	HRZ (2015 CIR)	HRZ (2016 CIR)	HRZ (2017 CIR)	HRZ (2018 CIR)	HRZ (2019 CIR)
Long Term Debt portion	56%	56%	56%	56%	56%	56%	56%	56%	56%
Short Term Debt portion	4%	4%	4%	4%	4%	4%	4%	4%	4%
Equity portion	40%	40%	40%	40%	40%	40%	40%	40%	40%
Cost of Long Term Debt	5.09%	6.07%	4.91%	3.88%	3.47%	3.47%	3.47%	3.62%	3.74%
Cost of Short Term Debt	2.08%	2.16%	1.65%	1.76%	2.16%	1.65%	1.76%	2.29%	2.82%
Cost of Equity	8.93%	9.30%	9.19%	8.78%	9.30%	9.19%	8.78%	9.00%	8.98%

:

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 5-STAFF-202

Credit Rating

Ref 1: Exhibit 1 / Tab 8 / Schedule 4 / Attachment 1-10 Morningstar DBRS Credit Rating Report / p. 2 (pdf pp. 1635)

Preamble:

In reference 1, Morningstar stated Alectra Utilities' capex on the nonregulated business ($100 million in 2024) was higher than normal because of the one-time investments in the Company's gas generation and power restoration business.

Question(s):

a) Please explain how Alectra Utilities ensures that there is no cross-subsidization between its unregulated and regulated businesses.

b) Has Alectra Utilities performed its own analysis that compares its business risk and financial risks to other large electricity companies in Canada or the U.S.? If so, please provide that analysis.

RESPONSE:

a) Alectra conducts regular reviews of cost allocation across all affiliates to ensure there is no cross-subsidization between the unregulated and regulated businesses. Please refer to the evidence in Ex 4, Tab 4, Sch 1 for more information about shared corporate services and corporate cost allocations between Alectra Utilities and affiliated corporate entities.

b) Alectra relies on the credit rating agencies' assessment of the business and financial risks of Alectra and other companies in the energy sector. Alectra also participated in the 2024-2025 OEB Cost of capital generic consultation (EB-2024-0063), where assessment of the financial and business risks of Ontario energy sector was part of the discussion and included in the final report.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 5-STAFF-203

Long-term Debt

Ref 1: Exhibit 5 / Alectra_Attach 5-1_OEB Appendix 2-OA - Capital Structure and Cost of Capital_20251014

Ref 2: Exhibit 5 / Alectra_Attach 5-3_OEB Appendix 2-OB - Debt Instruments_20251014

Question(s):

a) Please update Appendix-OA and Appendix-OB and attach the corresponding promissory notes if there are any updates to the forecasted debt.

b) Please identify the institution(s) from which Alectra Inc. obtains its external debt financing.

c) What due diligence has Alectra Inc. undertaken to ensure its preferred lender is offering a competitive rate and product?

d) Please provide a comparison of the rates Alectra Utilities has recently borrowed, compared to its utility peers of similar size.

RESPONSE:

a) There are no updates to the promissory notes in the forecasted debt.

b) Alectra works with the large Canadian banks that act on behalf of Alectra as lead arrangers and coordinators for long-term debt issuances. The ultimate financing is provided by a diverse group of Canadian lenders, which include institutional investors,

:

insurance companies, asset management firms, pension funds and private wealth management firms.

c) Please refer to Exhibit 5, Tab 1, Schedule 1 - Cost of Capital and Capital Structure, Cost of Long-Term Debt, for an overview of Alectra Utilities long-term debt funding plan.

For every debt issuance there is a financial, operational, strategic, regulatory, and legal due diligence to validate the credit rating analysis which demonstrates that Alectra Inc. is low-risk and can maintain stable cash flows to investors. This due diligence ensures that the issuance secures favourable and competitive rates in the open market where long-term debt rates are established by an auction process. This process has investors submit bids for a certain amount of debt at a specific interest rate where the coupon rate for the debt is determined by the outcome of the auction. All of Alectra's issuances in the market have received a high level of interest from investors where each issuance has been significantly oversubscribed and therefore Alectra is confident that is receiving competitive rates for its debt.

d) Alectra's recent offerings have been competitively priced relative to A-rated utility peers. Please refer to Table 1 below for a peer analysis comparison.

:

Table 1-Alectra Inc. Peer Comparisons of Recent A-Rated Utility Offerings

Date	Issuer	Ratings	Coupon
18-Nov-25	Hydro One Inc.	A (High)/A3/A/ -	4.800%
22-Sep-25	Toronto Hydro Corporation	A/ - /A+/ -	4.750%
20-Aug-25	Hydro One Inc.	A (High)/A3/A/ -	4.950%
20-Aug-25	Hydro One Inc.	A (High)/A3/A/ -	4.300%
9-Dec-24	Hydro One Inc.	A (High)/A3/A/ -	4.460%
9-Dec-24	Hydro One Inc.	A (High)/A3/A/ -	4.250%
2-Dec-24	EPCOR Utilities Inc.	A (Low)/ - / - /A	4.990%
28-Oct-24	**Alectra Inc.**	**A/ - /A-/A**	**4.309%**
24-Sep-24	Toronto Hydro Corporation	A/ - /A/ -	3.990%
15-Aug-24	Hydro One Inc.	A (High)/A3/A/ -	4.850%
15-Aug-24	Hydro One Inc.	A (High)/A3/A/ -	4.250%
11-Jun-24	**Alectra Inc.**	**A/ - /A-/A**	**4.627%**
28-May-24	EPCOR Utilities Inc.	A (Low)/ - /A-/A	4.990%
9-Jan-24	Hydro One Inc.	A (High)/A3/A-/ -	4.390%

:

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 5-STAFF-204

Return on Equity (ROE)

Ref 1: Exhibit 5 / Tab 1 / Schedule 1 / pp. 2 / Table 5-1-1 / p. 2 (pdf p. 2)

Question(s):

a) Please provide the achieved ROE for 2025, or an estimate, if available.

RESPONSE:

a) We are unable to provide an estimate of the achieved ROE at this time. The achieved ROE for 2025 will be finalized upon issuance of the audited financial statements, expected by mid-March and will be provided with Alectra's second round of interrogatories to be filed by April 8, 2026.

:

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 5-Staff-205

Short-term Debt

Ref 1: Exhibit 5 / Tab 1 / Schedule 1 / p. 4 (pdf p. 4)

Ref 2: Exhibit 1 / Tab 8 / Schedule 3 / Attachment 1-9 / p. 30 (pdf p. 1618)

Question(s):

a) Please elaborate more on how the actual interest rate of short-term debt that Alectra Utilities received is determined.

b) Are there any other forms of short-term debt besides commercial paper? If yes, please indicate what they are.

c) Please confirm whether Alectra Utilities receives the same terms of short-term debt that Alectra Inc. receives through third party facilities.

d) Please confirm whether any issuance costs are levied on short-term debt.
    i. If so, please provide the calculation methodology of the issuance costs.

RESPONSE:

a) Alectra Inc. has the ability to issue commercial paper to support the liquidity needs of Alectra Utilities. Rates for commercial paper are determined based on Alectra Inc.'s short-term credit rating and market conditions where the short-term rates are closely tied to the Bank of Canada overnight rate.

b) The only form of short-term debt Alectra relies on is commercial paper, as Alectra has not had to draw down on the credit facility. However, in the event that the commercial

:

paper market lacks investor confidence and is not competitively priced with the revolving credit facility, Alectra can meet its short-term liquidity needs by borrowing from the revolving credit facility at predetermined rates.

c) Confirmed.

d) Pursuant to Alectra Inc.'s agreement with the dealers, dealer fees are levied on the issuance of commercial paper. Dealers act as intermediaries between Alectra and the investors and provide market data to aid Alectra with pricing the issuances. Issuance costs consist of rating agency fees and dealer fees which are charged to Alectra based on the amount of commercial paper issued.

:

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 6-STAFF-206

2025 Tax Return

Ref 1: Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2026 Edition for 2027 Rate Applications, December 16, 2025, p. 43 (pdf p. 49)

Preamble:

Chapter 2 Filing Requirements states that:

> The distributor must provide copies of the most recent Federal and Provincial tax returns.

OEB staff notes that 2025 Federal and Provincial tax return is not submitted in this application.

Question(s):

a) Please provide a copy of 2025 draft Federal and Provincial corporate tax returns and provide a final set of returns when they are available.

RESPONSE:

a) A draft 2025 Federal and Provincial corporate tax return is attached as 6-Staff-206_Attach 1_AUC PILs Return 12312025_DRAFT. This draft is based on draft and unaudited 2025 financial statements and is subject to change.

The following items have not been included in the draft return. This information will be calculated and included in the final return to be filed in June 2026.

a) Scientific Research and Experimental Development Expenditures Claim (Federal and Ontario)
b) Apprenticeship Job Creation Investment Tax Credit
c) Ontario Co-operative Education Tax Credit

Please note that the draft tax return is prepared for Alectra Utilities Corporation and therefore includes its non-distribution activities that are outside of the scope of the Cost of Service proceedings. A breakout of these items is included as attachment 6-Staff-206_Attach 2_PILs Return Regulated Detail.

6-Staff-206

Attachment 1
AUC PILs Return

Public (Redacted) Version

Canada Revenue Agency / Agence du revenu du Canada

Code 1901

Scientific Research and Experimental Development (SR&ED) Expenditures Claim

Use this form:

- to provide technical information on your SR&ED projects;
- to calculate your SR&ED expenditures; and
- to calculate your qualified SR&ED expenditures for investment tax credits (ITC).

To claim an ITC, use either:

- Schedule T2SCH31, Investment Tax Credit – Corporations; or
- Form T2038(IND), Investment Tax Credit (Individuals).

The information requested in this form and documents supporting your expenditures and project information (Part 2) are prescribed information.

In Part 6, a new box is added: Box 758 that must be filled if traditional method is used. The information is required for tax year ends after 2020 and optional for tax year ends before 2021.

Your SR&ED claim must be filed within 12 months of the filing due date of your income tax return.

To help you fill out this form, use the T4088, Guide to Form T661, which is available on our website: **canada.ca/taxes-sred**.

Part 1 – General information

010 Name of claimant ALECTRA UTILITIES CORPORATION	Enter one of the following: [redacted] Business number (BN)
Tax year From 2025-01-01 (Year Month Day) to 2025-12-31 (Year Month Day)	Social insurance number (SIN)
050 Total number of projects you are claiming this tax year:	

100	Contact person for the financial information [redacted]	**105**	Telephone number/extension	**110**	Fax number
115	Contact person for the technical information [redacted]	**120**	Telephone number/extension	**125**	Fax number

DRAFT

151 If this claim is filed for a partnership, was Form T5013 Partnership Information Return filed? . . . . . ☐ Yes ☐ No

If you answered **no** to line 151, complete lines 153, 156 and 157.

153 Names of the partners	**156** %	**157** BN or SIN
1		
2		
3		
4		
5		

Part 2 - Project information

CRA internal form identifier 060
Code 1901

Complete a separate Part 2 for each project claimed this year.

Section A - Project identification

200 Project title (and identification code if applicable)

See schedule

Part 3 – Calculation of SR&ED expenditures

What did you spend on your SR&ED projects?

Section A – Select the method to calculate the SR&ED expenditures

I elect (choose) to use the following method to calculate my SR&ED expenditures and related investment tax credits (ITC) for this tax year.
I understand that my election is irrevocable (cannot be changed) for this tax year.

160 ☐ I elect to use the proxy method
(Enter "0" on line 360 and complete Part 5.)

162 ☐ I choose to use the traditional method
(Enter "0" on line 502. Complete line 360.)

Section B – Calculation of allowable SR&ED expenditures (to the nearest dollar)

- SR&ED portion of salary or wages of employees directly engaged in the SR&ED:
  - a) Employees other than specified employees for work performed in Canada . . . 300 +
  - b) Specified employees for work performed in Canada . . . 305 +
  - **Subtotal** (add lines 300 and 305) . . . 306 =
  - c) Employees other than specified employees for work performed outside Canada (subject to limitations – see guide) . . 307 +
  - d) Specified employees for work performed outside Canada (subject to limitations – see guide) . . . 309 +
- Salary or wages identified on line 315 in prior years that were paid in this tax year . . . 310 +
- Salary or wages incurred in the year but not paid within 180 days of the tax year end . . . 315
- Cost of materials consumed in performing SR&ED . . . 320 +
- Cost of materials transformed in performing SR&ED . . . 325 +
- Contract expenditures for SR&ED performed on your behalf:
  - a) Arm's length contracts . . . 340 +
  - b) Non-arm's length contracts . . . 345 +
- Overhead and other expenditures (enter "0" if you elected to use the proxy method at line 160) . . . 360 +
- Third-party payments (complete Form T1263*) . . . 370 +

Total allowable SR&ED expenditures (add lines 306 to 370; do not add line 315) . . . 380 =

If the above expenditures have been included in your income statement, enter this amount on line 118 of Schedule T2SCH1 or, if you are an individual, include this amount in your self-employment income (lines 135 to 143) reported on your individual income tax and benefit return.

Section C – Calculation of pool of deductible SR&ED expenditures (to the nearest dollar)

Amount from line 380 . . . 420

Deduct

- provincial government assistance for expenditures included on line 380 . . . 429 –
- other government assistance for expenditures included on line 380 . . . 431 –
- non-government assistance for expenditures included on line 380 . . . 432 –
- SR&ED ITCs applied and/or refunded in the prior year (do not include ITCs allocated from a partnership) . . . 435 – 1,240,794
- sale of SR&ED capital assets and other deductions . . . 440 –

Subtotal (line 420 minus lines 429 to 440) . . . 442 = -1,240,794

Add

- repayments of government and non-government assistance that previously reduced the SR&ED expenditure pool . . . 445 +
- prior year's pool balance of deductible SR&ED expenditures (from line 470 of prior year T661) . . . 450 +
- SR&ED expenditure pool transfer from amalgamation or wind-up . . . 452 +
- amount of SR&ED ITC recaptured in the prior year . . . 453 +

Amount available for deduction (add lines 442 to 453) . . . 455 =
(enter positive amount only, include negative amount in income)

- Deduction claimed in the year . . . 460 –
(Corporations should enter this amount on line 411 of schedule T2SCH1)

Pool balance of deductible SR&ED expenditures to be carried forward to future years (line 455 minus 460) . . . 470 =

* Form T1263, Third-Party Payments for Scientific Research and Experimental Development (SR&ED)

DRAFT

Part 4 – Calculation of qualified SR&ED expenditures for investment tax credit (ITC) purposes (to the nearest dollar)

The resulting amount is used to calculate your refundable and/or non refundable ITC.

Total allowable SR&ED expenditures (from line 380)	**492**		
Add			
• payment of prior years' unpaid amounts (other than salary or wages) (see note 1)	**500**	+	
• prescribed proxy amount (complete Part 5) (Enter "0" if you use the traditional method)	**502**	+	
• qualified expenditures transferred to you (see note 3) (complete Form T1146**)	**508**	+	
Subtotal (add lines 492 to 508)	**511**	=	
Deduct			
• provincial government assistance	**513**	–	
• other government assistance	**515**	–	
• non-government assistance and contract payments	**517**	–	
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end (see **note 1**)	**520**	–	
• 80% of the amounts paid in respect of an SR&ED contract to a person or partnership that is not a taxable supplier	**528**	–	
• 20% of the amount on lines 340 and 370	**529**	–	
• prescribed expenditures not allowed by regulations (see guide)	**530**	–	
• other deductions (see guide)	**533**	–	
• non-arm's length transactions			
– assistance allocated to you (complete Form T1145*)	**538**	–	
– expenditures for non-arm's length SR&ED contracts (from line 345)	**541**	–	
– adjustments to purchases (limited to costs) of goods and services from non-arm's length suppliers (see guide)	**542**	–	
– qualified expenditures you transferred (complete Form T1146**)	**544**	–	
Qualified SR&ED expenditures (line 511 minus lines 513 to 544)	**559**	=	
Add			
• repayments of assistance and contract payments made in the year	**560**	+	
Total qualified SR&ED expenditures for ITC purposes (add lines 559 and 560)	**570**	=	

* Form T1145, Agreement to Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length

** Form T1146, Agreement to Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length

Note 1 – For arm’s length contracts, only include 80% of the contract amount.

DRAFT

Part 5 – Calculation of prescribed proxy amount (PPA)

A notional amount representing your overhead and other expenditures.

This part calculates the PPA to enter on line 502 in Part 4. Do not complete this part if you have chosen to use the traditional method in Part 3 (line 162). You can only claim a PPA if you elected to use the proxy method for the year in Part 3 (line 160).

Special rules apply for specified employees. Calculate your salary base in Section A and the PPA in Section B.

Section A – Salary base

Salary or wages of employees other than specified employees (from lines 300 and 307) . . . . . **810** +

Deduct

Bonuses, remuneration based on profits, and taxable benefits that were included on line 810 . . . . . **812** –

Subtotal (line 810 minus 812) . . . . . **814** =

Salary or wages of specified employees

850	852	854	856	858	860
Column 1	**Column 2**	**Column 3**	**Column 4**	**Column 5**	**Column 6**
Name of specified employee	Total salary or wages for the year (SR&ED and non-SR&ED) excluding bonuses, remuneration based on profits, and taxable benefits (to the nearest dollar)	% of time spent on SR&ED (maximum 75%)	Amount in column 2 multiplied by percentage in column 3	2,5 x A x B/365 A = Year's maximum pensionable earnings B = Number of days employed in tax year	Amount in column 4 or 5, whichever amount is less

(Enter total of column 6 on line 816) **816** +

Salary base (total of lines 814 and 816) . . . . . **818** =

Section B – Prescribed proxy amount (PPA)

Enter 55 % of the salary base (line 818) . . . . . **820** =

Enter the amount from line 820 on to line 502 in Part 4 unless the overall cap on PPA applies to you. (See the guide for explanation and example of the overall cap on PPA)

DRAFT

Part 6 – Project costs

Information requested in this part must be provided for **all** SR&ED projects claimed in the year.
Expenditures should be recorded and allocated on a project basis.

* For Box 758, the information is required for tax year ends after 2020 and optional for tax year ends before 2021.

750	752	754	756	758
Project title or identification code	Salary or wages in the tax year (Total of lines 306 to 309)	Cost of materials in the tax year (Total of lines 320 and 325)	Contract expenditures for SR&ED performed on your behalf in the tax year (Total of lines 340 and 345)	Overhead and other expenditures in the tax year* (total of line 360, if applicable)
1 P1: System assets, equip & apparatus improvement (Standards)				
2 P2: Distribution Design Concepts - ICI, Stations, Transporta				
3 P3:Electric power distribution systems - Technical strategy				
4 P4: Asset condition assessment harmonizing methodologies an				
5 P5: Operational Technology - OMS and PC development				
6 P6: Green Renewable Energy and Technology Centre Smart Grid				
7 P7: Sustainable generation systems design and development				

750	752	754	756	758
Project title or identification code	Salary or wages in the tax year (Total of lines 306 to 309)	Cost of materials in the tax year (Total of lines 320 and 325)	Contract expenditures for SR&ED performed on your behalf in the tax year (Total of lines 340 and 345)	Overhead and other expenditures in the tax year* (total of line 360, if applicable)
8 P10: Metering and AMI Development				
9 P11: Grid Modernization Development				
Total				

DRAFT

Part 7 – Additional information

Expenditures for SR&ED performed by you in Canada (line 380 minus lines 307, 309, 340, 345, and 370) **605**

From the total you entered on line 605, estimate the percentage of distribution of the sources of funds for SR&ED performed within your organization.

		Canadian (%)		Foreign (%)
Internal	600			
Parent companies, subsidiaries, and affiliated companies	602		604	
Federal grants (do not include funds or tax credits from SR&ED tax incentives)	606			
Federal contracts	608			
Provincial funding	610			
SR&ED contract work performed for other companies on their behalf	612		614	
Other funding (e.g., universities, foreign governments)	616		618	

For statistical purposes indicate whether the work you performed falls within the realm of Basic or Applied research (to advance scientific knowledge) or Experimental development (to achieve a technological advancement):

620 ☐ Basic or Applied research **622** ☐ Experimental development

Enter the number of SR&ED personnel in full-time equivalents (FTE):

Scientists and engineers	632	
Technologists and technicians	634	
Managers and administrators	636	
Other technical supporting staff	638	

Part 8 – Claim checklist

To ensure your claim is complete, make sure you have:

1. used the current version of this form . . . . . [X]
2. entered the method you have chosen for reporting your SR&ED expenditures in Section A of Part 3 . . . . . [ ]
3. completed Part 2 for each project . . . . . [ ]
4. filed a completed Schedule T2SCH31 or Form T2038(IND) to claim ITCs on your qualified SR&ED expenditures . . . . . [ ]
5. filed a completed Form T1145*, T1146**, T1174*** and/or T1263**** including any required attachments, if applicable . . . . . [ ]

To expedite the processing of your claim, make sure you have:

1. completed Form T2, Corporation Income Tax Return or Form T1, Income Tax and Benefit Return . . . . . [ ]
2. filed the appropriate provincial and/or territorial tax credit forms, if applicable . . . . . [ ]
3. retained documents to support the SR&ED work performed and SR&ED expenditures you claimed . . . . . [ ]
4. checked boxes 231 and 232 on page 2 of your T2 return to indicate attachment of Form T661 and Schedule T2SCH31 . . . . . [ ]

DRAFT

* Form T1145, Agreement to Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length

** Form T1146, Agreement to Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length

*** Form T1174, Agreement Between Associated Corporations to Allocate Salary or Wages of Specified Employees for Scientific Research and Experimental Development (SR&ED)

**** Form T1263, Third·Party Payments for Scientific Research and Experimental Development (SR&ED)

Part 9 – Claim preparer information

Information requested in this part must be provided for each claim preparer that has accepted consideration to prepare or assist in the preparation of this SR&ED claim. Certification is required on lines 935, 970, and 975.

A $1,000 penalty may be assessed if the information requested below about the claim preparer(s) and billing arrangement(s), is missing, incomplete, or inaccurate. Where a claim preparer has prepared or assisted in the preparation of this SR&ED form, the claimant and the claim preparer will be jointly and severally, or solidarily, liable for the penalty.

935 **Was a claim preparer engaged in any aspect of the preparation of this SR&ED claim?**

- [X] Yes (complete the claim preparer information table and lines 970 and 975 below)
- [ ] No (complete lines 970 and 975)

Claim preparer information table

940 Name of claim preparer (company or individual)	945 Business number	950 Billing arrangement code (see codes below*)	955 Billing rate (percentage, hourly/daily rate or flat fee)	960 Other billing arrangement(s) (Maximum 10 words)	965 Total fee paid, payable, or expected to pay
1. Under separate cover by Deloitte LLP	[redacted]				
				Total	

*** Billing arrangement codes**

Code	Type of billing arrangement
1	Contingency fee arrangement – where the fee is based on a percentage of the investment tax credit earned
2	Hourly rate
3	Daily rate
4	Flat fee arrangement (lump sum)
5	Other arrangements – describe the arrangement in 10 words or less

970 I, Danielle Diaz, certify that the information provided in this part is complete and accurate.
Name of authorized signing officer of the corporation, or individual (print)

Signature

975 2026-02-04
Year Month Day

DRAFT

Part 10 – Certification

I certify that I have examined the information provided on this form and on the attachments and it is true, correct, and complete.

165 Danielle Diaz
Name of authorized signing officer of the corporation, or individual

Signature

170 2026-02-04
Date

175 DELOITTE LLP
Name of person/firm who completed this form

Privacy Notice

Personal information is collected pursuant to subsections 37(1), 37(11), and 162(5.1) of the Income Tax Act (the Act) and is used for verification of compliance, administration and enforcement of the Scientific Research and Experimental Development (SR&ED) program requirements.

Information may also be used for the administration and enforcement of other provisions of the Act, including assessment, audit, enforcement, collections, and appeals, and may be disclosed under information-sharing agreements in accordance with the Act. Incomplete or inaccurate information may result in assessment of monetary penalties and delays in processing SR&ED claims.

The social insurance number is collected pursuant to section 237 of the Act and is used for identification purposes.

Refer to Personal Information Bank CRA PPU 441 in the Canada Revenue Agency (CRA) Information about Programs and Information Holdings – Personal Information Banks – Canada.ca. Under the Privacy Act, individuals have a right of access to, protection, and correction of their personal information and to file a complaint with the Privacy Commissioner of Canada regarding our handling of their personal information.

DRAFT

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

200

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal Income Tax Act and Income Tax Regulations. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the General Index of Financial Information (GIFI), to your tax centre. You have to file the return within six months after the end of the corporation's tax year.

For more information see **canada.ca/taxes** or Guide T4012, T2 Corporation – Income Tax Guide.

055 **Do not use this area**

Identification

Business number (BN) . . . . . 001 [redacted]

Corporation's name

002 ALECTRA UTILITIES CORPORATION

Address of head office

Has this address changed since the last time the CRA was notified? . . . . . 010 Yes ☐ No ☒

If **yes**, complete lines 011 to 018.

011 55 JOHN STREET NORTH

012

City	Province, territory, or state
015 HAMILTON	016 ON
Country (other than Canada)	**Postal or ZIP code**
017	018 L8R 3M8

Mailing address (if different from head office address)

Has this address changed since the last time the CRA was notified? . . . . . 020 Yes ☐ No ☒

If **yes**, complete lines 021 to 028.

021 c/o [redacted]

022 2185 Derry Rd W

023

City	Province, territory, or state
025 Mississauga	026 ON
Country (other than Canada)	**Postal or ZIP code**
027	028 L5N 7A6

Location of books and records (if different from head office address)

Has this address changed since the last time the CRA was notified? . . . . . 030 Yes ☐ No ☒

If **yes**, complete lines 031 to 038.

031 55 JOHN STREET NORTH

032

City	Province, territory, or state
035 HAMILTON	036 ON
Country (other than Canada)	**Postal or ZIP code**
037	038 L8R 3M8

040 **Type of corporation at the end of the tax year** (tick one)

- ☒ 1 Canadian-controlled private corporation (CCPC)
- ☐ 2 Other private corporation
- ☐ 3 Public corporation
- ☐ 4 Corporation controlled by a public corporation
- ☐ 5 Other corporation (specify)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . . 043 Year Month Day

To which tax year does this return apply?

Tax year start (060)	Tax year-end (061)
Year Month Day	Year Month Day
2025-01-01	2025-12-31

Has there been an acquisition of control resulting in the application of subsection 249(4) since the tax year start on line 060? . . . . . 063 Yes ☐ No ☒

If **yes**, provide the date control was acquired . . . . . 065 Year Month Day

Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)? . . . . . 066 Yes ☐ No ☒

Is the corporation a professional corporation that is a member of a partnership? . . . . . 067 Yes ☐ No ☒

Is this the first year of filing after:

Incorporation? . . . . . 070 Yes ☐ No ☒

Amalgamation? . . . . . 071 Yes ☐ No ☒

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . . 072 Yes ☐ No ☒

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . . 076 Yes ☐ No ☒

Is this the final return up to dissolution? . . . . . 078 Yes ☐ No ☒

If an election was made under section 261, state the functional currency used 079

Is the corporation a resident of Canada? 080 Yes ☒ No ☐

If **no**, give the country of residence on line 081 and complete and attach Schedule 97.

081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . . 082 Yes ☐ No ☒

If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085

- ☐ 1 Exempt under paragraph 149(1)(e) or (l)
- ☐ 2 Exempt under paragraph 149(1)(j)
- ☐ 4 Exempt under other paragraphs of section 149

Do not use this area

095 096 898

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Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter?	166		T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167	X	T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation own any shares in one or more foreign affiliates in the tax year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the Income Tax Regulations?	170		29
Did the corporation have a total amount over CAN$1 million of reportable transactions with non-arm's length non-residents?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Does the corporation earn income from one or more Internet web pages or websites?	180		88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206	X	6
i) Is the corporation a CCPC and reporting a) income or loss from property (other than dividends deductible on line 320 of the T2 return), b) income from a partnership, c) income from a foreign business, d) income from a personal services business, e) income referred to in clause 125(1)(a)(i)(C) or 125(1)(a)(i)(B), f) aggregate investment income as defined in subsection 129(4), or g) an amount assigned to it under subsection 125(3.2) or 125(8); or ii) Is the corporation a member of a partnership and assigning its specified partnership business limit to a designated member under subsection 125(8)?	207	X	7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or a provincial credit union tax reduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal, provincial, or territorial foreign tax credits, or any federal logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits or zero-emission technology manufacturing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	X	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	33/34/35
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243	X	43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244	X	45
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit?	253		T1131
Is the corporation claiming a film or video production services tax credit?	254		T1177
Is the corporation claiming a Canadian journalism labour tax credit?	272		58
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

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Attachments (continued)

		Yes	Schedule
Did the corporation have any foreign affiliates in the tax year?	271		T1134
Did the corporation own or hold specified foreign property where the total cost amount of all such property, at any time in the year, was more than CAN$100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54
Is the corporation claiming a return of fuel charge proceeds to farmers tax credit?	273		63
Are you an employer reporting a non-qualified security agreement under subsection 110(1.9)?	274		59
Is the corporation claiming an air quality improvement tax credit?	275		65
Is the corporation subject to the additional 1.5% tax on banks and life insurers?	276		68
Is the corporation a covered entity that redeemed, acquired or cancelled equity of the corporation in the tax year?	277		56
Is the corporation subject to the excessive interest and financing expenses limitation (EIFEL) rules contained primarily in sections 18.2 and 18.21, or is it a party to any election under the EIFEL rules?	278		130

Additional information

		Yes	No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	X	
Is the corporation inactive?	280		X
Did the corporation meet the definition of substantive CCPC under subsection 248(1) at any time during the tax year?	290		X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal products mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	POWER DISTRIBUTION	285	100.000 %
286		287	%
288		289	%

		Yes	No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible — 294 — Year Month Day

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 Yes No

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI	300	71,738,419	A
Deduct:			
Charitable donations from Schedule 2	311		
Cultural gifts from Schedule 2	313		
Ecological gifts from Schedule 2	314		
Gifts of medicine made before March 22, 2017, from Schedule 2	315		
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320		
Part VI.1 tax deduction*	325	479,500	
Non-capital losses of previous tax years from Schedule 4	331		
Net capital losses of previous tax years from Schedule 4	332		
Restricted farm losses of previous tax years from Schedule 4	333		
Farm losses of previous tax years from Schedule 4	334		
Limited partnership losses of previous tax years from Schedule 4	335		
Restricted interest and financing expenses from Schedule 4	336		
Taxable capital gains or taxable dividends allocated from a central credit union	340		
Prospector's and grubstaker's shares	350		
Employer deduction for non-qualified securities	352		
Subtotal		479,500 ▶	479,500 B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			71,258,919 C
Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355		D
Taxable income (amount C **plus** amount D)	360		71,258,919

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 9.

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Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income eligible for the small business deduction from Schedule 7	400	71,736,816	A
Taxable income from line 360 on page 3, **minus** 100/28 (3.57143) of the amount on line 632* on page 8, **minus** 4 times the amount on line 636** on page 8, and **minus** any amount that, because of federal law, is exempt from Part I tax	405	71,258,919	B
Business limit (see notes 1 and 2 below)	410	500,000	C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year **divided** by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction

Taxable capital business limit reduction

Amount C 500,000 x **415** *** 13,468,449 / 90,000 D = 74,824,717 E

Passive income business limit reduction

Adjusted aggregate investment income from Schedule 7**** **417** _____ − 50,000 = F

Amount C 500,000 / 100,000 x Amount F _____ = G

The greater of amount E and amount G	422	74,824,717	H
Reduced business limit (amount C **minus** amount H) (if negative, enter "0")	426		I
Business limit the CCPC assigns under subsection 125(3.2) (from line 515 below)			J
Reduced business limit after assignment (amount I **minus** amount J)	428		K
Small business deduction – Amount A, B, C, or K, whichever is the least _____ x 19 % =	430		

Enter amount from line 430 at amount L on page 8.

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior** year **minus** $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current** year **minus** $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

**** Enter the total adjusted aggregate investment income of the corporation and all associated corporations for each tax year that ended in the preceding calendar year. Each corporation with such income has to file a Schedule 7. For a corporation's first tax year that starts after 2018, this amount is reported at line 744 of the corresponding Schedule 7. Otherwise, this amount is the total of all amounts reported at line 745 of the corresponding Schedule 7 of the corporation for each tax year that ended in the preceding calendar year.

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Small business deduction (continued)

Specified corporate income and assignment under subsection 125(3.2)

	L1 Name of corporation receiving the income and assigned amount	L Business number of the corporation receiving the assigned amount 490	M Income paid under clause 125(1)(a)(i)(B) to the corporation identified in column L [3] 500	N Business limit assigned to corporation identified in column L [4] 505
1.				

Total 510 _____ Total 515 _____

Notes:

3. This amount is [as defined in subsection 125(7) **specified corporate income** (a)(i)] the total of all amounts each of which is income (other than specified farming or fishing income of the corporation for the year) from an active business of the corporation for the year from the provision of services or property to a private corporation (directly or indirectly, in any manner whatever) if
   (A) at any time in the year, the corporation (or one of its shareholders) or a person who does not deal at arm's length with the corporation (or one of its shareholders) holds a direct or indirect interest in the private corporation, and
   (B) it is not the case that all or substantially all of the corporation's income for the year from an active business is from the provision of services or property to
   (I) persons (other than the private corporation) with which the corporation deals at arm's length, or
   (II) partnerships with which the corporation deals at arm's length, other than a partnership in which a person that does not deal at arm's length with the corporation holds a direct or indirect interest.
4. The amount of the business limit you assign to a CCPC cannot be greater than the amount determined by the formula A – B, where A is the amount of income referred to in column M in respect of that CCPC and B is the portion of the amount described in A that is deductible by you in respect of the amount of income referred to in clauses 125(1)(a)(i)(A) or (B) for the year. The amount on line 515 cannot be greater than the amount on line 426.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year or substantive CCPCs at any time in the tax year

Taxable income from line 360 on page 3			71,258,919 A
Lesser of amounts 9B and 9H from Part 9 of Schedule 27		_____ B	
Amount 13K from Part 13 of Schedule 27		_____ C	
Personal services business income	432	_____ D	
Amount from line 400, 405, 410, or 428 on page 4, whichever is the least*		_____ E	
Aggregate investment income from line 440 on page 6**		1,603 F	
	Subtotal (**add** amounts B to F)	1,603 ▶	1,603 G
Amount A **minus** amount G (if negative, enter "0")			71,257,316 H
General tax reduction for Canadian-controlled private corporations – Amount H **multiplied** by 13 %			9,263,451 I

Enter amount I on line 638 on page 8.

* This is not applicable to substantive CCPCs.

** Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, a substantive CCPC, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 on page 3			_____ J
Lesser of amounts 9B and 9H from Part 9 of Schedule 27		_____ K	
Amount 13K from Part 13 of Schedule 27		_____ L	
Personal services business income	434	_____ M	
	Subtotal (**add** amounts K to M)	_____ ▶	_____ N
Amount J **minus** amount N (if negative, enter "0")			_____ O
General tax reduction – Amount O **multiplied** by 13 %			_____ P

Enter amount P on line 639 on page 8.

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Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year or substantive CCPCs at any time in the tax year

Aggregate investment income from Schedule 7 . . . . . **440** 1,603 x 30 2 / 3 % = ... 492 A

Foreign non-business income tax credit from line 632 on page 8 . . . . . B

Foreign investment income from Schedule 7 . . . . . **445** x 8 % = C

Subtotal (amount B **minus** amount C) (if negative, enter "0") ▶ D

Amount A **minus** amount D (if negative, enter "0") . . . . . 492 E

Taxable income from line 360 on page 3 . . . . . 71,258,919 F

Amount from line 400, 405, 410, or 428 on page 4, whichever is the least* . . . . . G

Foreign non-business income tax credit from line 632 on page 8 . . . . x 75 / 29 = H

Foreign business income tax credit from line 636 on page 8 . . x 4 = I

Subtotal (**add** amounts G to I) ▶ J

Subtotal (amount F **minus** amount J) 71,258,919 K x 30 2 / 3 % = 21,852,735 L

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 9) . . . . . 10,689,217 M

Refundable portion of Part I tax – Amount E, L, or M, whichever is the least . . . . . **450** 492 N

* This is not applicable to substantive CCPCs. . . . . .

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Refundable dividend tax on hand

Eligible refundable dividend tax on hand (ERDTOH) at the end of the previous tax year (line 530 of the preceding tax year)	520		A
Non-eligible refundable dividend tax on hand (NERDTOH) at the end of the previous tax year (line 545 of the preceding tax year) (if negative, enter "0")	535	3,222	B
Part IV tax payable on taxable dividends from connected corporations (amount 2G from Schedule 3)			C
Part IV tax payable on eligible dividends from non-connected corporations (amount 2J from Schedule 3)			D
Subtotal (amount C **plus** amount D)	▶		E
Net ERDTOH transferred on an amalgamation or the wind-up of a subsidiary	525		F
ERDTOH dividend refund for the previous tax year	570		G
Refundable portion of Part I tax (from line 450 on page 6)		492	H
Part IV tax before deductions (amount 2A from Schedule 3)			I
Part IV tax allocated to ERDTOH (amount E)			J
Part IV tax reduction due to Part IV.1 tax payable (amount 4D of Schedule 43)			K
Subtotal (amount I **minus** total of amounts J and K)	▶		L
Net NERDTOH transferred on an amalgamation or the wind-up of a subsidiary	540		M
NERDTOH dividend refund for the previous tax year	575	3,222	N
38 1/3% of the total losses applied against Part IV tax (amount 2D from Schedule 3)			O
Part IV tax payable allocated to NERDTOH, net of losses claimed (amount L **minus** amount O) (if negative enter “0”)			P
NERDTOH at the end of the tax year (total of amounts B, H, M, and P **minus** amount N) (if negative, enter "0")	545	492	
Part IV tax payable allocated to ERDTOH, net of losses claimed (amount E **minus** the amount, if any, by which amount O exceeds amount L) (if negative, enter "0")			Q
ERDTOH at the end of the tax year (total of amounts A, F, and Q **minus** amount G) (if negative, enter "0")	530		

Dividend refund

38 1/3% of total eligible dividends paid in the tax year (amount 3A from Schedule 3)		AA
ERDTOH balance at the end of the tax year (line 530)		BB
Eligible dividend refund (amount AA or BB, whichever is less)		CC
38 1/3% of total non-eligible taxable dividends paid in the tax year (amount 3B from Schedule 3)	26,134,021	DD
NERDTOH balance at the end of the tax year (line 545)	492	EE
Non-eligible dividend refund (amount DD or EE, whichever is less)	492	FF
Amount DD **minus** amount EE (if negative, enter "0")	26,133,529	GG
Amount BB **minus** amount CC (if negative, enter "0")		HH
Additional non-eligible dividend refund (amount GG or HH, whichever is less)		II
Dividend refund – Amount CC **plus** amount FF **plus** amount II	492	JJ

Enter amount JJ on line 784 on page 9.

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Part I tax

Base amount Part I tax – Taxable income (from line 360 on page 3) **multiplied** by 38 %	550	27,078,389	A
Additional tax on personal services business income (section 123.5)			
Taxable income from a personal services business 555 _____ x 5 % =	560		B
Additional tax on banks and life insurers from Schedule 68	565		C
Total labour requirements addition to tax	580		D
Recapture of investment tax credit from Schedule 31	602		E

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) or substantive CCPC's investment income (if it was a CCPC throughout the tax year or a substantive CCPC at any time in the tax year)

Aggregate investment income from line 440 on page 6		1,603	F
Taxable income from line 360 on page 3	71,258,919		G
Deduct:			
Amount from line 400, 405, 410, or 428 on page 4, whichever is the least*			H
Net amount (amount G **minus** amount H)	71,258,919 ▶	71,258,919	I
Refundable tax on CCPC's or substantive CCPC's investment income – 10 2/3 % of whichever is less: amount F or amount I	604	171	J
Subtotal (**add** amounts A to E and J)		27,078,560	K

Deduct:

Small business deduction from line 430 on page 4			L
Federal tax abatement	608	7,125,892	
Manufacturing and processing profits deduction and zero-emission technology manufacturing deduction from Schedule 27	616		
Investment corporation deduction	620		
Taxed capital gains 624 _____			
Federal foreign non-business income tax credit from Schedule 21	632		
Federal foreign business income tax credit from Schedule 21	636		
General tax reduction for CCPCs from amount I on page 5	638	9,263,451	
General tax reduction from amount P on page 5	639		
Federal logging tax credit from Schedule 21	640		
Eligible Canadian bank deduction under section 125.21	641		
Federal qualifying environmental trust tax credit	648		
Investment tax credit from Schedule 31	652		
Subtotal	16,389,343 ▶	16,389,343	M

Part I tax payable – Amount K **minus** amount M 10,689,217 N

Enter amount N on line 700 on page 9.

* This is not applicable to substantive CCPCs.

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Privacy notice

Personal information (including the SIN) is collected and used to administer or enforce the Income Tax Act and related programs and activities including administering tax, benefits, audit, compliance, and collection. The information collected may be disclosed to other federal, provincial, territorial, aboriginal or foreign government institutions to the extent authorized by law. Failure to provide this information may result in paying interest or penalties, or in other actions. Under the Privacy Act, individuals have a right of protection, access to and correction of their personal information, and to file a complaint with the Privacy Commissioner of Canada regarding the handling of their personal information. Refer to Personal Information Bank CRA PPU 047 on Info Source at **canada.ca/cra-info-source**.

Summary of tax and credits

Federal tax

Part I tax payable from amount N on page 8	700	10,689,217
Part II.2 tax payable from Schedule 56	705	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	137,000
Part VI.2 tax payable from Schedule 67	725	
Part XII.7 tax payable from Schedule 78	726	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		10,826,217

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	7,852,573
Total tax payable	770	18,678,790 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from amount JJ on page 7	784	492	
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Return of fuel charge proceeds to farmers tax credit from Schedule 63	795		
Canadian film or video production tax credit (Form T1131)	796		
Film or video production services tax credit (Form T1177)	797		
Canadian journalism labour tax credit from Schedule 58	798		
Air quality improvement tax credit from Schedule 65	799		
Tax withheld at source	800		
Total payments on which tax has been withheld	801		
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	19,394,200	
Total credits	890	19,394,692	19,394,692 B

Balance (amount A **minus** amount B) -715,902

If the result is negative, you have **a refund**. If the result is positive, you have a **balance owing**.
Enter the amount below on whichever line applies.

Generally, the CRA does not charge or refund a difference of $2 or less.

Refund code 894 2 Refund 715,902 Balance owing

For information on how to enrol for direct deposit, go to **canada.ca/cra-direct-deposit**. For information on how to make your payment, go to **canada.ca/payments**.

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 Yes ☐ No ☒

If this return was prepared by a tax preparer for a fee, provide their: EFILE number 920

RepID 925

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Certification

I, 950 Diaz (Last name) 951 Danielle (First name) 954 EVP & CFO (Position, office, or rank),
am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2026-02-04 (Date (yyyy/mm/dd)) Signature of the authorized signing officer of the corporation 956 (Telephone number)

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 Yes ☐ No ☒

958 [redacted] (Name of other authorized person) 959 (Telephone number)

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français.

990 1

Schedule of Instalment Remittances

Name of corporation contact [redacted]
Telephone number

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	Tax payments during 2025	13,515,251
	Final payment in 2026	2,860,000
	2024 balance transfer	3,018,949

Total amount of instalments claimed (carry the result to line 840 of the T2 Return) 19,394,200 **A**

Total instalments credited to the taxation year per T9 19,394,200 **B**

Transfer

Account number	Taxation year end	Amount	Effective interest date	Description
From:				
To:				
From:				
To:				
From:				
To:				
From:				
To:				
From:				
To:				

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SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
ALECTRA UTILITIES CORPORATION	[redacted]	2025-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
Assets					
	Total current assets	1599	+	767,421,476	786,838,163
	Total tangible capital assets	2008	+	4,817,533,374	4,485,987,943
	Total accumulated amortization of tangible capital assets	2009	–		
	Total intangible capital assets	2178	+	947,686,229	945,303,206
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	8,243,444	7,504,761
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	6,540,884,523	6,225,634,073
Liabilities					
	Total current liabilities	3139	+	999,799,770	1,019,090,764
	Total long-term liabilities	3450	+	3,577,748,786	3,386,376,415
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	4,577,548,556	4,405,467,179
Shareholder equity					
	Total shareholder equity (mandatory field)	3620	+	1,963,335,967	1,820,166,894
	Total liabilities and shareholder equity	3640	=	6,540,884,523	6,225,634,073
Retained earnings					
	Retained earnings/deficit – end (mandatory field)	3849	=	423,201,319	280,242,505

* Generic item

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SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year-end Year Month Day
ALECTRA UTILITIES CORPORATION	[redacted]	2025-12-31

Income statement information

Description	GIFI

Operating name 0001
Description of the operation 0002
Sequence number 0003 01

Account	Description	GIFI		Current year	Prior year
Income statement information					
	Total sales of goods and services	8089	+	4,354,755,160	4,102,994,037
	Cost of sales	8518	–	3,523,370,128	3,356,025,240
	Gross profit/loss	8519	=	831,385,032	746,968,797
	Cost of sales	8518	+	3,523,370,128	3,356,025,240
	Total operating expenses	9367	+	622,972,051	617,870,398
	Total expenses (mandatory field)	9368	=	4,146,342,179	3,973,895,638
	Total revenue (mandatory field)	8299	+	4,433,775,804	4,175,780,257
	Total expenses (mandatory field)	9368	–	4,146,342,179	3,973,895,638
	Net non-farming income	9369	=	287,433,625	201,884,619
Farming income statement information					
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	287,433,625	201,884,619
	Total – other comprehensive income	9998	=	2,934,259	921,788
Extraordinary items and income (linked to Schedule 140)					
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	76,299,103	54,118,191
	Future (deferred) income tax provision	9995	–		
	Total – Other comprehensive income	9998	+	2,934,259	921,788
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	214,068,781	148,688,216

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Schedule 141

General Index of Financial Information (GIFI) – Additional Information

Corporation's name	Business number	Tax year-end Year Month Day
ALECTRA UTILITIES CORPORATION	[redacted]	2025-12-31

- Corporations need to complete all parts of this schedule that apply and include it with their T2 return along with their other GIFI schedules.
- For more information, see Guide RC4088, General Index of Financial Information (GIFI), and Guide T4012, T2 Corporation – Income Tax Guide.

Part 1 – Information on the person primarily involved with the financial information

Can you identify the person* specified in the heading of Part 1? . . . . . **111** Yes [X] No [ ]

If you answered **no**, go to Part 2.

Does that person have a professional designation in accounting? . . . . . **095** Yes [X] No [ ]

Is that person connected** with the corporation? . . . . . **097** Yes [X] No [ ]

* A person primarily involved with the financial information is a person who has more than a 50% involvement in preparing the financial information that the T2 return is based on. For example, if three persons prepared the financial information by doing respectively 30%, 30%, and 40% of the work, answer **no** at line 111. If they did respectively 10%, 20%, and 70% of the work, answer **yes** at line 111 and complete Part 1 by referring only to the third person.

** A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Part 2 – Type of involvement

Choose one or more of the following options that represent your involvement and that of the person referred to in Part 1:

Completed an auditor's report . . . . . **300** [ ]

Completed a review engagement report . . . . . **301** [ ]

Conducted a compilation engagement . . . . . **302** [ ]

Provided accounting services . . . . . **303** [X]

Provided bookkeeping services . . . . . **304** [ ]

Other (please specify) . . . . . **305** Employee of the Corporation prepared the financial information.

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Part 3 – Reservations

If you selected option **1** (300) or **2** (301) in Part 2 above, answer the following question:

Has the person referred to in Part 1 expressed a reservation? . . . . . **099** Yes [ ] No [ ]

Part 4 – Other information

Were notes to the financial statements prepared? . . . . . **101** Yes [ ] No [X]

Did the corporation have any subsequent events? . . . . . **104** Yes [ ] No [X]

Did the corporation re-evaluate its assets during the tax year? . . . . . **105** Yes [ ] No [X]

Did the corporation have any contingent liabilities during the tax year? . . . . . **106** Yes [ ] No [X]

Did the corporation have any commitments during the tax year? . . . . . **107** Yes [ ] No [X]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . **108** Yes [X] No [ ]

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . 200 Yes ☐ No ☒

If **yes**, enter the amount recognized:		**In net income** Increase (decrease)		**In OCI** Increase (decrease)
Property, plant, and equipment	210		211	
Intangible assets	215		216	
Investment property	220			
Biological assets	225			
Financial instruments	230		231	
Other	235		236	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . . 250 Yes ☐ No ☒

Did the corporation apply hedge accounting during the tax year? . . . . . 255 Yes ☐ No ☒

Did the corporation discontinue hedge accounting during the tax year? . . . . . 260 Yes ☐ No ☒

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . 265 Yes ☐ No ☒

If **yes**, you have to maintain a separate reconciliation.

Part 5 – Information on the person who prepared the T2 return

If the person who prepared the T2 return has a professional designation in accounting but is not the person identified in Part 1, choose all of the following options that apply:

Prepared the T2 return and the financial information contained therein . . . . . 310 ☐

The client provided the financial statements . . . . . 311 ☒

The client provided a trial balance . . . . . 312 ☒

The client provided a general ledger . . . . . 313 ☐

Other (please specify) 314

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SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
ALECTRA UTILITIES CORPORATION	[redacted]	2025-12-31

Assets – lines 1000 to 2599

1000	8,281,366	1060	330,604,561	1062	328,192,209
1120	69,677,127	1400	16,977,093	1484	13,689,120
1599	767,421,476	1900	4,817,533,374	2008	4,817,533,374
2010	192,486,296	2012	755,199,933	2178	947,686,229
2200	3,962,900	2242	1	2420	4,280,543
2589	8,243,444	2599	6,540,884,523		

Liabilities – lines 2600 to 3499

2620	432,466,313	2700	305,000,000	2860	79,366,418
2920	34,423,235	2960	89,219,715	2961	59,324,089
3139	999,799,770	3220	945,516,034	3240	231,359,272
3300	2,277,191,070	3320	103,554,066	3321	16,233,643
3323	3,894,701	3450	3,577,748,786	3499	4,577,548,556

Shareholder equity – lines 3500 to 3640

3500	702,585,958	3540	825,874,529	3580	11,674,161
3600	423,201,319	3620	1,963,335,967	3640	6,540,884,523

Retained earnings – lines 3660 to 3849

3660	280,242,505	3680	211,134,522	3700	-68,175,708
3849	423,201,319				

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SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
ALECTRA UTILITIES CORPORATION	[redacted]	2025-12-31

Description

Sequence number **0003** 01

Other comprehensive income – lines 7000 to 7020

7002	3,992,189	**7010**	1,057,930		

Revenue – lines 8000 to 8299

8000	4,354,755,160	**8089**	4,354,755,160	**8100**	5,610,340
8210	-8,114,058	**8230**	81,428,443	**8231**	95,919
8299	4,433,775,804				

Cost of sales – lines 8300 to 8519

8320	3,523,370,128	**8518**	3,523,370,128	**8519**	831,385,032

Operating expenses – lines 8520 to 9369

8670	193,925,160	**8710**	103,378,273	**9270**	325,668,618
9367	622,972,051	**9368**	4,146,342,179	**9369**	287,433,625

Farming revenue – lines 9370 to 9659

9659	0

Farming expenses – lines 9660 to 9899

9898	0

Extraordinary items and taxes – lines 9970 to 9999

9970	287,433,625	**9990**	76,299,103	**9998**	2,934,259
9999	214,068,781				

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Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name	Business number	Tax year-end Year Month Day
ALECTRA UTILITIES CORPORATION	[redacted]	2025-12-31

- Use this schedule to reconcile the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see Guide T4012, T2 Corporation – Income Tax Guide.
- All legislative references are to the Income Tax Act.
- If you need more space, attach additional schedules.

Net income (loss) after taxes and extraordinary items from line 9999 of Schedule 125			214,068,781 A1
Net income (loss) after extraordinary items from line 110 of Schedule 150			0 A2
Total			214,068,781 A

Add:

Provision for income taxes – current	101	77,357,033	
Amortization of tangible assets	104	193,925,160	
Loss on disposal of assets	111	9,059,531	
Taxable capital gains from Schedule 6	113	1,603	
Non-deductible meals and entertainment expenses	121	401,633	
Reserves from financial statements – balance at the end of the year	126	75,436,382	
Subtotal of additions		356,181,342 ▶	356,181,342

Add:

Recapture of SR&ED expenditures from Form T661	231	1,240,794	

Other additions:

	1 Description 605	2 Amount 295
1	Inducement under 12(1)(x) ITA	512,418
2	Solar Sunbelt GP - Taxable income	672,110
3	Interest on capital lease - Addiscott	735,529
4	Interest on capital lease - RFSP	292,041
5	12(1)(x) income	164,347,196
6	ARO Accretion - RFSP	209,638
	Total of column 2	166,768,932 ▶ 296 166,768,932

Subtotal of other additions	199	168,009,726 ▶	168,009,726 D
Total additions	500	524,191,068 ▶	524,191,068
Amount A **plus** line 500			738,259,849 B

Deduct:

Capital cost allowance from Schedule 8	403	257,851,268	
Reserves from financial statements – balance at the beginning of the year	414	77,239,380	
Subtotal of deductions		335,090,648 ▶	335,090,648

Deduct:

Other deductions:

	1 Description 705	2 Amount 395
1	13(7.4) Election	164,347,196
2	ITCs recorded in 2024 Accounting Income	1,663,153
3	Derecognition of customer contributions	2,204,033

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	1 Description 705	2 Amount 395
4	AFUDC - interest capitalized for book purposes - deductible	3,023,462
5	OMERS contributions deductible for tax 20.1(q), capitalized	7,010,686
6	Customer contribution revenue amortization	23,080,479
7	Cash payment on capital leases - Addiscott	1,536,873
8	Cash payment on capital leases - RFSP	987,987
9	ITC accrual in acctg income	496,000
10	Net energy revenue RSVA, not taxable	127,080,913
	Total of column 2	331,430,782 ▶ 396 331,430,782
	Subtotal of other deductions	499 331,430,782 ▶ 331,430,782 E
	Total deductions	510 666,521,430 ▶ 666,521,430

Net income (loss) for income tax purposes (amount B **minus** line 510) . . . . . 71,738,419 C

Enter amount C on line 300 of the T2 return.

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Attached Schedule with Total

Line 395 – Amount

Title Line 395 – Amount

Explanatory note

THE TAXPAYER HEREBY ELECTS, PURSUANT TO SUBSECTION 13(7.4) TO NOT INCLUDE $164,347,196 IN INCOME PURSUANT TO PARAGRAPH 12(1)(x). ACCORDINGLY, THE TAXPAYER HAS REDUCED THE COST OF PROPERTY ACQUIRED DURING THE YEAR BY $164,347,196.

Description	Operator (Note)	Amount
Election 13(7.4)		164,347,196 00
	+	
	+	
	Total	164,347,196 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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Attached Schedule with Total

Line 295 – Amount

Title Line 295 – Amount

Description	Operator (Note)	Amount
ARO Accretion - Solar		209,638 00
	+	
	+	
	Total	209,638 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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Attached Schedule with Total

Line 395 – Amount

Title Line 395 – Amount

Description	Operator (Note)	Amount
2025 Apprenticeship accrual		472,000 00
2025 Co-op accrual	+	24,000 00
	+	
	Total	496,000 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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Attached Schedule with Total

Line 395 – Amount

Title Line 395 – Amount

Explanatory note

Detail of ITCs recorded for accounting

Description	Operator (Note)	Amount
2024 ITCs recording in acctg in 2025		1,663,153 00
	+	
	+	
	+	
	Total	1,663,153 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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Inducement

This form is used to calculate inducements that a corporation must add to its income under paragraph 12(1)(x) ITA. If an amount reduces the capital cost of a property, this amount will be indicated in Part "Tax credits whose amount should reduce the capital cost of property."

If you want to transfer an amount to Schedule 1 and include it in the corporation's income for tax purposes, select the corresponding check box in column A. You can also select the option **Select this check box to add all the amounts to income calculated in Schedule 1** to transfer all the amounts to Schedule 1. In either case, the column A check box will be selected for that amount and it will therefore be updated to Schedule 1.

Tax credits whose amount should be added to income

Federal

A		
[X]	Investment tax credit from apprenticeship job creation expenditures	16,514
[ ]	Investment tax credit from child care spaces expenditures	
[X]	Canadian film or video production tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, consult the Help (F1).	
[X]	Film or video production services tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, consult the Help (F1).	
[ ]	Investment tax credit claimed on contributions made to SR&ED farming organizations	
[X]	Canadian journalism labour tax credit	
[ ]	Return of fuel charge proceeds to farmers tax credit	
[ ]	Air quality improvement tax credit*	
	* Please verify if the credit amount relates to depreciable property For more information, consult the Help (F1).	

Ontario

A		
[X]	Portion of the Ontario research and development tax credit that relates to the prescribed proxy amount (PPA) and portion of the Ontario investment tax credit that relates to contributions made to SR&ED farming organizations	92,295
[X]	Ontario co-operative education tax credit	403,609
[X]	Ontario computer animation and special effects tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, consult the Help (F1).	
[X]	Ontario film and television tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, consult the Help (F1).	
[X]	Ontario production services tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, consult the Help (F1).	
[X]	Ontario interactive digital media tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, consult the Help (F1).	
[X]	Ontario book publishing tax credit	
[ ]	Portion of the Ontario innovation tax credit that relates to the prescribed proxy amount (PPA) and portion of the Ontario investment tax credit that relates to contributions made to SR&ED farming organizations	
[ ]	Ontario business-research institute tax credit	
[X]	Ontario community food program donation tax credit for farmers	

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Tax credits whose amount should reduce the capital cost of property

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Canada Revenue Agency / Agence du revenu du Canada

Schedule 3

Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
ALECTRA UTILITIES CORPORATION	[redacted]	2025-12-31

- Corporations must use this schedule to report:
  - non-taxable dividends under section 83
  - deductible dividends under subsection 138(6)
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (a.1), (b) or (d)
  - taxable dividends paid in the tax year that qualify for a dividend refund (see page 3)
- All legislative references are to the federal Income Tax Act.
- The calculations in this schedule apply only to private or subject corporations (as defined in subsection 186(3)).
- A payer corporation is **connected** with a recipient corporation at any time in a tax year, if at that time the recipient corporation meets either of the following conditions:
  - it controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b)
  - it owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation
- If you need more space, continue on a separate schedule.
- File this schedule with your T2 Corporation Income Tax Return.
- Column A1 – Enter "X" if dividends were received from a foreign source.
  Column F1 – Enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

- Do **not** include dividends received from foreign non-affiliates.
- Complete columns B, C, D, H, H.1, I, I.1, I.2 and L **only if** the payer corporation is **connected**.

Important instructions to follow if the payer corporation is connected

- If your corporation's tax year-end is different than that of the **connected** payer corporation, dividends could have been received from more than one tax year of the payer corporation. If so, **use a separate line** to provide the information according to each tax year of the payer corporation.
- When completing columns J, K and L use the **special calculations provided in the notes**.

	A Name of payer corporation (from which the corporation received the dividend) 200	A1	B Enter 1 if payer corporation is **connected** 205	C Business number of **connected** corporation 210	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYYMMDD 220	E Non-taxable dividends under section 83 230
1			1			

Total of column E (enter amount on line 402 of Schedule 1)

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Part 1 – Dividends received in the tax year (continued)

	F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (a.1), (b), or (d) [1] 240	F1	G Eligible dividends included in column F 242	H Total taxable dividends paid by the **connected** payer corporation (line 460 in Schedule 3 for the tax year in column D) 250	H.1 Total eligible dividends paid by the **connected** payer corporation (line 465 in Schedule 3 for the tax year in column D)	I Dividend refund of the **connected** payer corporation (for tax year in column D) [2] 260
1						

	I.1 Eligible dividend refund of the **connected** payer corporation from its eligible refundable dividend tax on hand (ERDTOH) (amount CC from T2 return for the tax year in column D) 265	I.2 Additional non-eligible dividend refund of the **connected** payer corporation from its ERDTOH (amount II from T2 return for the tax year in column D)	J Part IV tax for eligible dividends. Dividends (from column G) **multiplied** by 38 1/3% [3] 275	K Part IV tax before deductions. Dividends (from column F) **multiplied** by 38 1/3% [4] 280	L Part IV tax before deductions on taxable dividends received from **connected** corporations [5]
1					

Total of column L (enter amount on line 2E in Part 2) _____

Taxable dividends received from connected corporations (total amounts from column F with code 1 in column B) 1A

Taxable dividends received from non-connected corporations (total amounts from column F with code 2 in column B) 1B

Subtotal (amount 1A **plus** amount 1B, include this amount on line 320 of the T2 return) 1C

Eligible dividends received from connected corporations (total amounts from column G with code 1 in column B) 1D

Eligible dividends received from non-connected corporations (total amounts from column G with code 2 in column B) 1E

Part IV tax before deductions on taxable dividends received from connected corporations (total amounts from column K with code 1 in column B) 1F

Part IV tax before deductions on taxable dividends received from non-connected corporations (total amounts from column K with code 2 in column B) 1G

Subtotal (amount 1F **plus** amount 1G) ▶ 1H

Part IV tax on eligible dividends received from connected corporations (total amounts from column J with code 1 in column B) 1I

Part IV tax on eligible dividends received from non-connected corporations (total amounts from column J with code 2 in column B) 1J

Subtotal (amount 1I **plus** amount 1J) ▶ 1K

Part IV tax before deductions on taxable dividends (other than eligible dividends) (amount 1H **minus** amount 1K) 1L

1 If taxable dividends are received, enter the amount in column F, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column K (and column J, if applicable). Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

2 If the **connected** payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

3 For eligible dividends received from **connected** corporations, Part IV tax on dividends is equal to column I **divided** by column H **multiplied** by column G.

4 For taxable dividends received from **connected** corporations, Part IV tax on dividends is equal to column I **divided** by column H **multiplied** by column F.

5 For the purpose of calculating your eligible refundable dividend tax on hand (ERDTOH), Part IV tax on taxable dividends received from **connected** corporations (with a tax year starting after 2018) is equal to the sum of Part IV tax on eligible dividends and non-eligible dividends received from **connected** corporations to the extent that such dividends caused a dividend refund to those corporations from their ERDTOH.

Part IV tax before deductions on taxable dividends received from **connected** corporations for purposes of column L is the sum of (i) and (ii), where

(i) Part IV tax on eligible dividends received from **connected** corporations is equal to amount CC of the **connected** payer corporation (on page 7 of the T2 return) **divided** by line 465 of the **connected** payer corporation, **multiplied** by column G; and

(ii) Part IV tax on non-eligible dividends received from **connected** corporations is equal to amount II of the **connected** payer corporation (on page 7 of the T2 return) **divided** by line 470 of the **connected** payer corporation, **multiplied** by the difference between columns F and G.

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Part 2 – Calculation of Part IV tax payable

Part IV tax on dividends received before deductions (amount 1H in part 1) 2A

Part IV.I tax payable on dividends subject to Part IV tax (from line 360 of Schedule 43) 320

Subtotal (amount 2A **minus** line 320) ▶ 2B

Current-year non-capital loss claimed to reduce Part IV tax 330

Non-capital losses from previous years claimed to reduce Part IV tax 335

Current-year farm loss claimed to reduce Part IV tax 340

Farm losses from previous years claimed to reduce Part IV tax 345

Total losses applied against Part IV tax (total of lines 330 to 345) 2C

Amount 2C **multiplied** by 38 1 / 3 % 2D

Part IV tax payable (amount 2B **minus** amount 2D, if negative enter "0") 360

(enter amount on line 712 of the T2 return)

If your tax year begins after 2018, complete the following part to determine the required amount of Part IV taxes payable in order to calculate the eligible refundable dividend tax on hand (ERDTOH) at the end of the tax year.

Part IV tax before deductions on taxable dividends received from connected corporations (total of column L in part 1) 2E

Amount 4A from Schedule 43 . . . . . 2F

Part IV tax payable on taxable dividends received from connected corporations
(amount 2E **minus** amount 2F, if negative enter "0") 2G

(enter at amount C on page 7 of the T2 return)

Part IV tax on eligible dividends received from non-connected corporations (amount 1J in part 1) 2H

Amount 4C from Schedule 43 . . . . . 2I

Part IV tax payable on taxable dividends received from non-connected corporations
(amount 2H **minus** amount 2I, if negative enter "0") 2J

(enter at amount D on page 7 of the T2 return)

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

If your corporation's tax year-end is different than that of the recipient corporation with which you are connected, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information according to each tax year of the recipient corporation.

	M Name of recipient corporation with which you are connected 400	N Business number 410	O Tax year-end of recipient corporation in which the dividends in column P were received YYYYMMDD 420	P Taxable dividends paid to recipient corporations with which you are connected 430	Q Eligible dividends included in column P 440
1	Alectra Inc.	[redacted]	2025-12-31	67,599,708	
2	Alectra Inc.	[redacted]	2025-12-31	576,000	
3					
				68,175,708	
				(Total of column P)	(Total of column Q)

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Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund (continued)

Total taxable dividends paid in the tax year to other than connected corporations	450	
Eligible dividends included in line 450	455	
Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column P **plus** line 450)	460	68,175,708
Total eligible dividends paid in the tax year (total of column Q **plus** line 455)	465	
Total non-eligible taxable dividends paid in the tax year (line 460 **minus** line 465)	470	68,175,708

Complete this part to determine the following amounts in order to calculate the dividend refund.

Line 465 **multiplied** by 38 1 / 3 % 3A
(enter at amount AA on page 7 of the T2 return)

Line 470 **multiplied** by 38 1 / 3 % 26,134,021 3B
(enter at amount DD on page 7 of the T2 return)

Part 4 – Total dividends paid in the tax year

Complete this part **if** the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above)		68,175,708
Other dividends paid in the tax year (total of 510 to 540)		
Total dividends paid in the tax year	500	68,175,708

Dividends paid out of capital dividend account	510	
Capital gains dividends	520	
Dividends paid on shares described in subsection 129(1.2)	530	
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540	
Subtotal (total of lines 510 to 540)	▶	4A

Total taxable dividends paid in the tax year that qualify for a dividend refund (Line 500 **minus** amount 4A) 68,175,708 4B

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Schedule 5

Tax Calculation Supplementary – Corporations

Corporation's name	Business Number	Tax year-end Year Month Day
ALECTRA UTILITIES CORPORATION	[redacted]	2025-12-31

- Use this schedule if any of the following apply to your corporation during the tax year:
  - it had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only fill out columns A, B, and D in Part 1)
  - it is claiming provincial or territorial tax credits or rebates (see Part 2)
  - it has to pay taxes, other than income tax, for Newfoundland and Labrador or Ontario (see Part 2)
- All legislative references are to the Income Tax Regulations (the Regulations).
- For more information, see the T2 Corporation – Income Tax Guide.

Part 1 – Allocation of taxable income

100 _____ Enter the regulation that applies (402 to 413).

A Jurisdiction. (tick **yes** if your corporation had a permanent establishment in the jurisdiction during the tax year) **Note 1**		B Total salaries and wages paid in jurisdiction	C B **multiplied** by taxable income, **divided** by G	D Gross revenue attributable to jurisdiction	E D **multiplied** by taxable income, **divided** by H	F Allocation of taxable income (C + E x 1/2) **Note 2** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 Yes ☐	103		143		
Newfoundland and Labrador Offshore	004 Yes ☐	104		144		
Prince Edward Island	005 Yes ☐	105		145		
Nova Scotia	007 Yes ☐	107		147		
Nova Scotia Offshore	008 Yes ☐	108		148		
New Brunswick	009 Yes ☐	109		149		
Quebec	011 Yes ☐	111		151		
Ontario	013 Yes ☐	113		153		
Manitoba	015 Yes ☐	115		155		
Saskatchewan	017 Yes ☐	117		157		
Alberta	019 Yes ☐	119		159		
British Columbia	021 Yes ☐	121		161		
Yukon	023 Yes ☐	123		163		
Northwest Territories	025 Yes ☐	125		165		
Nunavut	026 Yes ☐	126		166		
Outside Canada	027 Yes ☐	127		167		
Total		129 G		169 H		

Note 1: **Permanent establishment** is defined in subsection 400(2).
Note 2: For corporations other than those described under section 402, use the appropriate calculation described in the Regulations to allocate taxable income.

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Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the T2 Corporation – Income Tax Guide.
2. If your corporation has provincial or territorial tax payable, fill out Part 2 on the following pages.
3. If your corporation is a member of a partnership and the partnership had a permanent establishment in a jurisdiction, select the jurisdiction in Column A and include your proportionate share of the partnership's salaries and wages and gross revenue in columns B and D, respectively.

T2 SCH 5 E (25)

Canada

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
71,258,919		71,258,919	8,194,776

Ontario basic income tax (from Schedule 500)	270	8,194,776		
Ontario small business deduction (from Schedule 500)	402			
Subtotal (line 270 **minus** line 402)		8,194,776	▶	8,194,776 5A
Ontario transitional tax debits and credits (from Schedule 506)	276			
Recapture of Ontario research and development tax credit (from Schedule 508)	277			
Repayment of Ontario made manufacturing investment tax credit	281			
Subtotal (line 276 **plus** line 277 **plus** line 281)			▶	5B
Gross Ontario tax (amount 5A **plus** amount 5B)				8,194,776 5C
Ontario tax credit for manufacturing and processing (from Schedule 502)	406			
Ontario foreign tax credit (from Schedule 21)	408			
Ontario credit union tax reduction (from Schedule 500)	410			
Ontario political contributions tax credit (from Schedule 525)	415			
Ontario non-refundable tax credits (total of lines 406 to 415)			▶	5D
Subtotal (amount 5C **minus** amount 5D) (if negative, enter "0")				8,194,776 5E
Ontario research and development tax credit (from Schedule 508)	416			
Ontario corporate income tax payable before Ontario corporate minimum tax credit and Ontario community food program donation tax credit for farmers (amount 5E **minus** line 416) (if negative, enter "0")				8,194,776 5F
Ontario corporate minimum tax credit (from Schedule 510)	418	342,203		
Ontario community food program donation tax credit for farmers (from Schedule 2)	420			
Ontario corporate income tax payable (amount 5F **minus** the total of lines 418 and 420) (if negative, enter "0")				7,852,573 5G
Ontario corporate minimum tax (from Schedule 510)	278			
Ontario special additional tax on life insurance corporations (from Schedule 512)	280			
Subtotal (line 278 **plus** line 280)			▶	5H
Total Ontario tax payable before refundable tax credits (amount 5G **plus** amount 5H)				7,852,573 5I
Ontario qualifying environmental trust tax credit	450			
Ontario co-operative education tax credit (from Schedule 550)	452			
Ontario computer animation and special effects tax credit (from Schedule 554)	456			
Ontario film and television tax credit (from Schedule 556)	458			
Ontario production services tax credit (from Schedule 558)	460			
Ontario interactive digital media tax credit (from Schedule 560)	462			
Ontario book publishing tax credit (from Schedule 564)	466			
Ontario innovation tax credit (from Schedule 566)	468			
Ontario business-research institute tax credit (from Schedule 568)	470			
Ontario regional opportunities investment tax credit (from Schedule 570)	472			
Ontario made manufacturing investment tax credit (from Schedule 572)	474			
Ontario refundable tax credits (total of lines 450 to 474)			▶	5J
Net Ontario tax payable or refundable tax credit (amount 5I **minus** amount 5J) (if a credit, enter amount in brackets). Include this amount on line 255.	290			7,852,573

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Summary

Enter the total net tax payable or refundable tax credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable tax credits	255	7,852,573

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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Schedule 6

Summary of Dispositions of Capital Property

Corporation's name	Business number	Tax year-end Year Month Day
ALECTRA UTILITIES CORPORATION	[redacted]	2025-12-31

- Use this schedule if your corporation disposed of (actual or deemed) capital property or claimed an allowable business investment loss (ABIL), or both, in the tax year.
- All legislative references are to the Income Tax Act.
- Also use this schedule to make a designation under paragraph 111(4)(e) if control of the corporation has been acquired by a person or a group of persons.
- For more information, see the section called "Schedule 6, Summary of Dispositions of Capital Property" in the T2 Corporation Income Tax Guide.
- If you need more space, attach additional schedules.

Designation under paragraph 111(4)(e)

Are any dispositions shown on this schedule related to deemed dispositions designated under paragraph 111(4)(e)? . . . . 050 Yes ☐ No ☒

If **yes**, attach a statement specifying which properties such a designation applies to.

In the various sections of this form:

- The abbreviation **FS** (for foreign source) is used to indicate the capital gain or loss arising from foreign property;
- The abbreviation **PA** (for passive asset) is used to indicate the capital gain or loss arising from the disposition of an asset other than an active asset of the corporation.

Part 1 – Shares

1 Number of shares 100	2 Name of corporation in which the shares were held 105	3 Class of shares 106	4 Date of acquisition YYYYMMDD 110	5 Proceeds of disposition 120	6 Adjusted cost base 130	7 Outlays and expenses from disposition 140	8 Gain (or loss) (column 5 **minus** columns 6 and 7) 150	A FS	A PA
			Totals						

Total adjustment under subsection 112(3) to all losses identified in column 8 160

Actual gain or loss from the disposition of shares (total of column 8 **plus** line 160) . . . . . A

Part 2 – Real estate (Do not include losses on depreciable property)

1 Municipal address of real estate (1 = Address 1, 2 = Address 2, 3 = City, 4 = Province, Country, Postal Code and Zip Code or Foreign Postal Code) 200	2 Date of acquisition YYYYMMDD 210	3 Proceeds of disposition 220	4 Adjusted cost base 230	5 Outlays and expenses from disposition 240	6 Gain (or loss) (column 3 **minus** columns 4 and 5) 250	A FS	A PA
Reversal of legal accrual	2017-03-01	3,206	1		3,205		
Brampton							
ON							
	Totals	3,206	1		3,205	**B**	

Part 3 – Bonds

1 Face value of bonds 300	2 Maturity date YYYYMMDD 305	3 Name of bond issuer 307	4 Date of acquisition YYYYMMDD 310	5 Proceeds of disposition 320	6 Adjusted cost base 330	7 Outlays and expenses from disposition 340	8 Gain (or loss) (column 5 **minus** columns 6 and 7) 350	A FS	A PA
			Totals					**C**	

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Part 4 – Other properties (Do not include losses on depreciable property)

1 Description of other property 400	2 Date of acquisition YYYYMMDD 410	3 Proceeds of disposition 420	4 Adjusted cost base 430	5 Outlays and expenses from disposition 440	6 Gain (or loss) (column 3 **minus** columns 4 and 5) 450	A FS PA
Totals						**D**

Other property includes capital debts, debts in respect of the disposition of a personal-use property per subsection 50(2), amounts that arise from foreign currency transactions, and capital gains (losses) allocated from partnerships and trusts.

If you are a member of a partnership, include:

– under column 3 (line 420), any capital gain reported in boxes 151, 270, or 271 of the T5013 slips

– under column 4 (line 430), any capital loss reported in boxes 151, 270, or 271 of the T5013 slips

If you are a beneficiary of a trust, include under column 3 (line 420) the amount reported in box 21 of the T3 slips.

Part 5 – Personal-use property (Do not include listed personal property)

1 Description of personal-use property 500	2 Date of acquisition YYYYMMDD 510	3 Proceeds of disposition 520	4 Adjusted cost base 530	5 Outlays and expenses from disposition 540	6 Gain only (column 3 **minus** columns 4 and 5; if negative, enter "0") 550	A FS PA
Totals						**E**

You **cannot** deduct losses on dispositions of personal-use property (other than listed personal property or a debt that is a personal-use property) from your income.

Part 6 – Listed personal property

1 Description of listed personal property 600	2 Date of acquisition YYYYMMDD 610	3 Proceeds of disposition 620	4 Adjusted cost base 630	5 Outlays and expenses from disposition 640	6 Gain (or loss) (column 3 **minus** columns 4 and 5) Note 1 650	A FS PA
Totals						

Unapplied listed personal property losses from other years (amount from line 530 of Schedule 4, Corporation Loss Continuity and Application) . . . . . **655** _____

Net gains (or losses) from the disposition of listed personal property (total of column 6 **minus** line 655) . . . . . _____ **F**

Net listed personal property losses can only be applied against listed personal property gains.

Note 1: Do **not** include gains arising on the disposition of certain certified cultural property to a designated cultural institution. See subparagraph 39(1)(a)(i.1) for more information.

Part 7 – Property qualifying for and resulting in an allowable business investment loss

1 Name of small business corporation 900	2 Shares, enter **1**; debt, enter **2** 905	3 Date of acquisition YYYYMMDD 910	4 Proceeds of disposition 920	5 Adjusted cost base 930	6 Outlays and expenses from disposition 940	7 Loss only (column 4 **minus** columns 5 and 6) 950	A FS PA
Totals							

Allowable business investment losses (ABILs) . . . . . Total of Column 7 _____ x 1/2 = _____ **G**

Enter amount G on line 406 of Schedule 1, Net Income (Loss) for Income Tax Purposes.

Properties listed in Part 7 should **not** be included in any other parts of this schedule.

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Part 8 – Capital gains or losses

			FS	PA
Total of amounts A to F (do **not** include amount F if it is a loss)		3,205 H		
Capital gains dividend received in the year	875		☐	☐
Capital gains reserve opening balance (from Part 1 of Schedule 13, Continuity of Reserves)	880			
Subtotal (amount H **plus** total of lines 875 and 880)		3,205 I		
Capital gains reserve closing balance (from Part 1 of Schedule 13, Continuity of Reserves)	885			
Capital gains or losses, excluding ABILs (amount I **minus** line 885)	890	3,205		

Part 9 – Taxable capital gains and total capital losses

			FS	PA
Capital gains or losses, excluding ABILs (amount from line 890 in Part 8)		3,205 J		
Deduct the following amounts included in amount J, that are subject to the zero inclusion rate[Note 2]:				
Gain on the donation to a qualified donee of a share, debt obligation, or right listed on a designated stock exchange and other securities under paragraphs 38(a.1)(i) and (iii)	895		☐	☐
Gain on the donation to a qualified donee of ecologically sensitive land under subsection 38(a.2)[Note 3]	896		☐	☐
Exempt portion of the gain on the donation of securities arising from the exchange of a partnership interest under subsection 38(a.3)		a	☐	☐
Subtotal (line 895 **plus** line 896 **plus** line a)		▶ K		
Subtotal (amount J **minus** amount K)		3,205 L		
Deemed capital gain from the donation of property included in a flow-through share class of property to a qualified donee under subsection 40(12):				
Exemption threshold at time of disposition	897			
The total of all capital gains from the actual disposition of the property	898			
Line 897 or line 898, whichever is less		M	☐	☐
Taxable capital gains under section 34.2 (line 275 of Schedule 73, Income Inclusion Summary for Corporations that are Members of Partnerships)	x 2 = 899			
Subtotal (total of amounts L and M **plus** line 899)		3,205 N		
Allowable capital losses under section 34.2 (line 285 of Schedule 73, Income Inclusion Summary for Corporations that are Members of Partnerships)	x 2 = 901			
Subtotal (amount N **minus** line 901)		3,205 O		
Portion of the capital gain that is subject to a 100% inclusion rate per 100(1)[Note 4]	x 2 = 902		☐	☐
Total capital gains or losses (amount O **plus** line 902)		3,205 P		

Taxable capital gains or total capital losses

Total capital losses (if amount P is negative, enter amount P; if amount P is positive, enter "0") . . . . . Q

Enter amount Q on line 210 of Schedule 4.

Taxable capital gains (if amount P is positive, enter the result of amount P 3,205 multiplied by 50.0000 %; if amount P is negative, enter "0") . . . . . 1,603 R

Enter amount R on line 113 of Schedule 1.

Note 2: When a taxpayer is entitled to an advantage in respect of a donation, the zero inclusion rate is restricted to only that part of the taxpayer's capital gain on disposition of the property that is attributable to the eligible amount of the donation. The amount of the gain attributable to any advantage (or benefit) received in respect of the donation is subject to the ordinary capital gains inclusion rate. See section 38.2 for more information.

Note 3: Do **not** include gains on donations of ecologically sensitive land to a private foundation.

Note 4: Do **not** include any portion of the capital gain that is subject to the 50% inclusion rate. Enter any such portion in Part 4. If you are a member of a partnership, include the amount reported in box 289 of the T5013 slip.

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Schedule 7

Aggregate Investment Income and Income Eligible for the Small Business Deduction

Corporation's name	Business number	Tax year-end Year Month Day
ALECTRA UTILITIES CORPORATION	[redacted]	2025-12-31

- Use this schedule if you are a Canadian-controlled private corporation (CCPC) throughout the tax year, or a substantive CCPC at any time in the tax year, to calculate your aggregate investment income and foreign investment income, as defined in subsection 129(4), to determine the refundable portion of Part I tax.
- Use this schedule if you are a CCPC throughout the tax year to calculate:
  - your adjusted aggregate investment income, as defined in subsection 125(7), for the purpose of the business limit reduction
  - your specified partnership income, as defined in subsection 125(7), if you are a member (or designated member) of one or more partnerships, and
  - your income from an active business carried on in Canada eligible for the small business deduction including any specified corporate income as defined in subsection 125(7)
- Use this schedule if another CCPC is making an assignment of business limit under subsection 125(3.2) to you.
- Use this schedule if you are a member of a partnership to assign specified partnership business limit to a designated member under subsection 125(8).

  Note: If you are an individual, a trust, or a corporation that is not a CCPC, **only** complete Table 1 (columns A1, B1, C1, G1, H1 and J1) and Table 3 to make this assignment. Individuals and trusts can attach the pages with these completed tables to their respective tax returns.
- All legislative references are to the Income Tax Act.
- For more information, see **Small Business Deduction** and **Refundable Portion of Part I Tax** in Guide T4012, T2 Corporation – Income Tax.

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Part 1 – Aggregate investment income

Aggregate investment income is all **world** source income.

Eligible portion of taxable capital gains for the year	002	1,603	
Eligible portion of allowable capital losses for the year (including allowable business investment losses)	012		
Net capital losses of previous years claimed on line 332 on the T2 Corporation Income Tax Return	022		
Subtotal (line 012 **plus** line 022)			A
Line 002 **minus** amount A (if negative, enter "0")		1,603	B
Total income from property (include income from a specified investment business carried on in Canada other than income from a source outside Canada)	032		
Exempt income	042		
Amounts received from AgriInvest Fund No. 2 that were included in computing the corporation's income for the year	052		
Taxable dividends deductible (amount deductible under paragraph 113(1)(c) **plus** total of column F on Schedule 3, Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation **minus** related expenses)	062		
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)	072		
Subtotal (**add** lines 042, 052, 062 and 072)			C
Subtotal (line 032 **minus** amount C)			D
Amount B **plus** amount D		1,603	E
Total losses from property (include losses from a specified investment business carried on in Canada other than a loss from a source outside Canada)	082		
Amount E **minus** line 082 (if negative, enter "0") (enter on line 440 of the T2 return)	092	1,603	

Part 2 – Adjusted aggregate investment income

Eligible portion of taxable capital gains for the year (other than taxable capital gains from the disposition of an active asset [13]) 705

Eligible portion of allowable capital losses for the year (including allowable business investment losses) (other than allowable capital losses from the disposition of an active asset [13]) 710

Subtotal (line 705 **minus** line 710) (if negative, enter "0") F

Total income from property [14] 715

Exempt income 720

Amounts received from AgriInvest Fund No. 2 that were included in computing the corporation's income for the year . 725

Dividends from connected corporations 730

Business income from an interest in a trust that is considered property income under paragraph 108(5)(a) 735

Subtotal (**add** lines 720, 725, 730 and 735) ▶ G

Subtotal (line 715 **minus** amount G) ▶ H

Amount F **plus** amount H I

Total losses from property [14] 740

Amount, if any, deducted under subsection 91(4) in computing the corporation's income for the year 741

Adjusted aggregate investment income (amount I **minus** line 740, **plus** line 741) (if negative, enter "0") 745

(enter the total of line 745 and the adjusted aggregate investment income of all associated corporations on line 417 of the T2 return for the tax year ending in the following calendar year)

Part 3 – Foreign investment income

Foreign investment income is all income from sources **outside Canada**.

Eligible portion of taxable capital gains for the year 001

Eligible portion of allowable capital losses for the year (including allowable business investment losses) 009

Subtotal (line 001 **minus** line 009) (if negative, enter "0") J

Total income from property from a source **outside Canada** (net of related expenses) . . . 019

Exempt income 029

Taxable dividends deductible (amount deductible under paragraph 113(1)(c) **plus** total of column F on Schedule 3 **minus** related expenses) 049

Business income from an interest in a trust that is considered property income under paragraph 108(5)(a) . 059

Subtotal (**add** lines 029, 049, and 059) ▶ K

L

Subtotal (line 019 **minus** amount K) ▶ M

Amount J **plus** amount L

Total losses from property from a source **outside Canada** 069

Amount M **minus** line 069 (if negative, enter "0") (enter on line 445 of the T2 return) 079

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Part 3A – Canadian and foreign investment income and adjusted aggregate investment income calculation

	A Canadian investment income	B Foreign investment income	C Adjusted aggregate investment income*	
Eligible portion of the taxable capital gains for the year before taking into account the capital gains reserves (federal) of Schedule 13*	1,603			1.1
Eligible portion of capital gains reserves (addition/deduction)*, **				1.2
Taxable capital gains under section 34.2 (line 275 on Schedule 73)**				1.3
Eligible portion of the taxable capital gains for the year (**add** amounts 1.1, 1.2, and 1.3)	1,603			1
Eligible portion of allowable capital losses for the year (including allowable business investment losses)*				2.1
Net capital losses of previous years (line 332 on the T2 return)				2.2
Allowable capital losses under section 34.2 (line 285 of Schedule 73)**				2.3
Allowable capital losses for the year (**add** amounts 2.1, 2.2 and 2.3)				2
Amount 1 **minus** amount 2 (if negative, enter "0")	1,603			3
Taxable dividends				4.1
Rental property income (under regulation 1100(11))				4.2
Other property income*				4.3
Property income under section 34.2 (line 280 of Schedule 73)**				4.4
Total property income (**add** amounts 4.1, 4.2, 4.3 and 4.4)				4
Exempt income				5.1
Amounts received from AgriInvest Fund No. 2 that were included in computing the corporation's income for the year				5.2
Taxable dividends deductible (amount deductible under paragraph 113(1)(c) **plus** total of column F on Schedule 3 **minus** related expenses)*				5.3
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)				5.4
Add amounts 5.1, 5.2, 5.3 and 5.4				5
Amount 4 **minus** amount 5				6
Amount 3 **plus** amount 6	1,603			7
Rental property losses (under regulation 1100(11))				8.1
Dividend losses				8.2
Other property losses*				8.3
Property losses under section 34.2 (line 280 of Schedule 73)**				8.4
Total property losses (**add** amounts 8.1, 8.2, 8.3 and 8.4)				8
Amount 7 **minus** amount 8 (if negative, enter "0")	1,603			9
Amount, if any, deducted under subsection 91(4) in computing the corporation's income for the year				10
Amount 7 **minus** amount 8 **plus** amount 10 (if negative, enter “0”)				11

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* To calculate the adjusted aggregate investment income under column C:

- On lines 1.1, 1.2, 1.3, 2.1 and 2.3, only capital gains and losses resulting from the disposition of property other than an active asset (as defined under subsection 125(7) ITA) are to be taken into account.
- On line 4.3, include amounts in respect of a life insurance policy that are included in computing the corporation's income for the year (even if those amounts are not included in the calculation of the corporation's investment income in column A and B) as well as the income from a specified foreign investment business.
- On line 5.3, only the dividends received from a connected corporation should be included.
- On line 8.3, include the loss from a specified foreign investment business.

For more information on the calculation of the adjusted aggregate investment income, consult notes 13 and 14 at the end of this form as well as the Help (F1).

** When an amount is entered on these lines in column B, it reduces the corresponding amount in column A. For more information, consult the Help (F1).

Net taxable dividends		Canadian	Foreign	Total
Taxable dividends deducted per Schedule 3				
Less: Expenses related to such dividends	**A***			
Total expenses				
Net taxable dividends				

* Column A – Enter an “X” if the expense is related to a dividend received from a connected corporation.

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Part 4 – Specified partnership income

Table 1 – Specified partnership income

A	A1	1A
Is the corporation a designated member of the partnership?	Partnership name 200	Partnership's account number
Yes ☐ No ☐		

B1	C1	D1	1D	2D	E1	F1
Total income (loss) of partnership from an active business 300	Your share of amount in column B1 310	Income of the corporation from providing (directly or indirectly) services or property to the partnership 311	Prorated amounts calculated under section 34.2[1]	Expenses the corporation incurred to earn partnership income	Adjustments (add or deduct the prorated amounts calculated under section 34.2 [1] and deduct expenses the corporation incurred to earn partnership income) 315	Corporation's income (loss) in respect of the partnership [2] (**add** columns C1, D1 and E1) 320

Total 350 _____

G1	H1	I1	J1	K1	L1	M1
Number of days in the partnership's fiscal period [15] 325	Prorated business limit [2 and 3] (column C1 ÷ column B1) × [$ 500 000 × (column G1 ÷ 365)] (if column C1 is negative, enter "0") 330	Specified partnership business limit **assigned to you** (from column H2 in Table 2) [5] 335	Specified partnership business limit **assigned by you** (from column F3 in Table 3) [6] 336	Specified partnership business limit amount (column H1 **plus** column I1 **minus** column J1)	Column F1 **minus** column K1 (if negative, enter "0")	Lesser of columns F1 and K1 (if column F1 is negative, enter "0") [4] 340

Total 385 _____ 360 _____

Corporation's losses for the year from an active business carried on in Canada (other than as a member of a partnership) – enter as a positive amount . . . . . 370 _____

Specified partnership loss of the corporation for the year – enter as a positive amount (total of all negative amounts in column F1) . . . . . 380 _____

Subtotal (line 370 **plus** line 380) _____ N

Amount at line 385 or amount N, whichever is less . . . . . 390 _____

Specified partnership income (line 360 **plus** line 390) . . . . . 400 _____

(enter at amount R in Part 5)

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Part 4 – Specified partnership income (continued)

Tables 2 and 3 are used to make an assignment of **specified partnership business limit** under subsection 125(8). A person that is a member of a partnership can make an assignment of **specified partnership business limit** under subsection 125(8) to a **designated member**.

If you are a CCPC that is a designated member and **receiving** specified partnership business limit from a person that is a member of the partnership, complete Table 2.

If you are a member of the partnership and are **assigning** specified partnership business limit to a designated member, complete Table 3.

Table 2 – A member is assigning to you specified partnership business limit under subsection 125(8)

A2	2A	B2
Partnership name 405	Partnership's account number	Name of the member 406

C2	D2	E2	F2	G2	H2
Business number of the member (if applicable) 410	Social insurance number of the member (if applicable) 411	Trust account number of the member (if applicable) 412	Tax year start of the member (YYYYMMDD) 415	Tax year-end of the member (YYYYMMDD) 416	Specified partnership business limit assigned to you by the member [7] 420

Table 3 – You are assigning to a designated member (CCPC) specified partnership business limit under subsection 125(8)

A3	3A	B3
Partnership name 425	Partnership's account number	Name of the designated member 426

C3	D3	E3	F3
Business number of the designated member 430	Tax year start of the designated member (YYYYMMDD) 435	Tax year-end of the designated member (YYYYMMDD) 436	Specified partnership business limit assigned by you to the designated member [8] 440

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Part 5 – Partnership income not eligible for the small business deduction

Corporation's income from active businesses carried on in Canada as a member or designated member of a partnership (after deducting related expenses) – from line 350 in Part 4 (if the net amount is negative, enter "0" on line 450) . . . . . O

Specified partnership loss (from line 380 in Part 4) . . . . . P

Subtotal (amount O **plus** amount P) Q

Specified partnership income (from line 400 in Part 4) . . . . . R

Partnership income not eligible for the small business deduction (amount Q **minus** amount R) **450**

(enter at amount Z in Part 6)

Part 6 – Income eligible for the small business deduction

Net income for income tax purposes from line 300 of the T2 return . . . . . 71,738,419 S

Allowable business investment loss from line 406 of Schedule 1, Net Income (Loss) for Income Tax Purposes . . . . . T

Subtotal (amount S **plus** amount T) 71,738,419 ▶ 71,738,419 U

Foreign business income after deducting related expenses [9] **500**

Taxable capital gains from line 113 of Schedule 1 . . . . . 1,603 V

Net property income (line 032 [10] **minus** the total of lines 042, 052 and 082 [9] in Part 1) . . . . . W

Personal services business income after deducting related expenses [9] e1

Other income after deducting related expenses [9] e2

Subtotal (amount e1 **plus** amount e2) [9] ▶ **520**

Subtotal (**add** line 500, amount V, amount W and line 520) 1,603 ▶ 1,603 X

Net amount (amount U **minus** amount X) . . . . . 71,736,816 Y

Partnership income not eligible for the small business deduction (line 450 in Part 5) . . . . . Z

Partnership income allocated to your corporation under subsection 96(1.1) **530**

Income referred to in clause 125(1)(a)(i)(C) **540**

Income referred to in clause 125(1)(a)(i)(B) (from line 615 in Part 7) . . . . . AA

Subtotal (**add** amount Z, line 530, line 540 and amount AA) ▶ BB

Specified corporate income (from line 625 in Part 7) CC

Income eligible for the small business deduction (amount Y **minus** amount BB, **plus** amount CC) . . . . . 71,736,816 DD

(enter amount DD on line 400 of the T2 return - if negative, enter "0")

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Part 7 – Specified corporate income and assignment under subsection 125(3.2)

	1EE Name of the corporation	EE Business number of the corporation	FF Income described under clause 125(1)(a)(i)(B) received from the corporation identified in column EE [11]	GG Business limit assigned from the corporation identified in column EE [12]
		600	**610**	**620**
1				
			Total **615**	Total **625**

See the privacy notice on your return.

Notes

1. Do **not** include expenses that were deducted in computing the income of the corporation in column D1.

   In general, amounts included under subsections 34.2(2) and 34.2(3) or claimed under subsection 34.2(4) are deemed to have the **same character** and be in the **same proportions** as the partnership income they relate to. For example, if a corporation receives $100,000 of partnership income for the partnership's fiscal period ending in its tax year, and that income is made up of $40,000 of active business income, $30,000 of income from property, and $30,000 as a taxable capital gain, the corporation's adjusted stub period accrual (ASPA) in respect of the partnership would be 40% active business income, 30% property income, and 30% taxable capital gains. Add or deduct only the portion of the following amounts that are characterized as **active business income** in accordance with subsection 34.2(5):

   Add:
   - the ASPA under subsection 34.2(2) (column 4 of Schedule 73, Income Inclusion Summary for Corporations that are Members of Partnerships)
   - the income inclusion for a new corporate member of a partnership under subsection 34.2(3) (column 6 of Schedule 73)

   Deduct:
   - the previous-year ASPA under subsection 34.2(4) (column 5 of Schedule 73)
   - the previous-year income inclusion for a new corporate member of a partnership under subsection 34.2(4) (column 7 of Schedule 73)
2. When a partnership carries on more than one business, one of which generates income and another of which realizes a loss, the loss is **not** netted against the partnership's income when calculating the prorated business limit (column H1). Enter on line 380 the total of all losses from column F1.
3. **If** you are a **designated member** of the partnership, enter "0".
4. You must enter "0" **if** the partnership provides services or property to either:

   (A) a private corporation (directly or indirectly in any manner whatever) in the year, if:
   - you (or one of your shareholders) or a person that does **not** deal at arm's length with you (or one of your shareholders) holds a direct or indirect interest in the private corporation, and
   - it is not the case that all or substantially all of the partnership's income for the year from an active business is from providing services or property to
     - persons (other than the private corporation) that deal at arm's length with the partnership and each person that holds a direct or indirect interest in the partnership, or
     - partnerships with which the partnership deals at arm's length, other than a partnership in which a person that does **not** deal at arm's length with you holds a direct or indirect interest, or

   (B) a particular partnership (directly or indirectly in any manner whatever) in the year, if:
   - you (or one of your shareholders) do **not** deal at arm's length with the particular partnership or a person that holds a direct or indirect interest in the particular partnership, and
   - it is not the case that all or substantially all of the partnership's income for the year from an active business is from providing services or property to
     - persons that deal at arm's length with the partnership and each person that holds a direct or indirect interest in the partnership, or
     - partnerships (other than the particular partnership) with which the partnership deals at arm's length, other than a partnership in which a person that does **not** deal at arm's length with you holds a direct or indirect interest.
5. If you are a CCPC that is a **designated member** receiving an assignment of **specified partnership business limit,** complete Table 2 to determine the amounts to enter in Table 1 column I1.
6. If you are a **member** of the partnership and you are assigning **specified partnership business limit**, complete Table 3 to determine the amounts to enter in Table 1 column J1.
7. Add the amounts in column H2 that are for the same partnership and enter it in Table 1 column I1, in the row of the applicable partnership.
8. Add the amounts in column F3 that are for the same partnership and enter it in Table 1 column J1, in the row of the applicable partnership. This amount **cannot** be higher than the amount of prorated business limit you would otherwise be entitled to in Table 1 column H1 for that partnership.
9. If negative, enter amount in brackets, and **add** instead of subtracting.
10. Net of related expenses.
11. This amount is [as defined in subsection 125(7) **specified corporate income** (a)(i)] the total of all amounts, each of which is your income from an active business for the year from providing services or property to a private corporation (directly or indirectly, in any manner whatever) if

    (A) at any time in the year, you (or one of your shareholders) or a person that does not deal at arm's length with you (or one of your shareholders) holds a direct or indirect interest in the private corporation, and

    (B) it is not the case that all or substantially all of your income for the year from an active business is from providing services or property to

    (I) persons (other than the private corporation) with which you deal at arm's length, or

    (II) partnerships with which you deal at arm's length, other than a partnership in which a person that does not deal at arm's length with you holds a direct or indirect interest.

    Do **not** include specified farming or fishing income. If the conditions described in subsection 125(10) are met, do not include income from an associated corporation.
12. The amount of business limit that a CCPC can assign to you cannot be greater than the amount in column FF that is from providing services or property **directly** to that CCPC. If there is an amount included in column FF that is deductible by that CCPC in respect of the amount of its income referred to in clause 125(1)(a)(i)(A) or (B) for its tax year, you need to deduct it from column FF for the purpose of determining the amount that can be assigned to you.

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Notes (continued)

13. Active asset, of a particular corporation at any time, means property that is:

    (A) used at that time principally in an active business carried on primarily in Canada by the particular corporation or by a Canadian-controlled private corporation that is related to the particular corporation,

    (B) a share of the capital stock of another corporation if, at that time,
    - the other corporation is connected with the particular corporation (within the meaning assigned by subsection 186(4) on the assumption that the other corporation is at that time a payer corporation within the meaning of that subsection), and
    - the share would be a qualified small business corporation share (as defined in subsection 110.6(1)) if:
      – the references in that definition to an "individual" were references to the particular corporation, and
      – that definition were read without reference to "the individual's spouse or common-law partner", or

    (C) an interest in a partnership, if:
    - at that time, the fair market value of the particular corporation's interest in the partnership is equal to or greater than 10% of the total fair market value of all interests in the partnership,
    - throughout the 24-month period ending before that time, more than 50% of the fair market value of the property of the partnership was attributable to property described in this paragraph or in paragraph (A) or (B), and
    - at that time, all or substantially all of the fair market value of the property of the partnership was attributable to property described in this paragraph or in paragraph (A) or (B).

14. Income or loss from property of a particular corporation, for the purposes of calculating the corporation's adjusted aggregate investment income, includes income or loss from a specified investment business, as well as all amounts in respect of a life insurance policy that are included in computing the corporation’s income for the year (even if those amounts were not included in the computation of the corporation’s aggregate investment income in Part 1).

15. The maximum number of days that can be entered in column G1 for a partnership's fiscal period is 365, it is not adjusted for a leap year.

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Canada Revenue Agency / Agence du revenu du Canada

Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business number	Tax year-end Year Month Day
ALECTRA UTILITIES CORPORATION	[redacted]	2025-12-31

For more information, see the section called "Capital Cost Allowance" in Guide T4012, *T2 Corporation – Income Tax*.

Unless otherwise stated, all legislative references are to the federal *Income Tax Act*.

Is the corporation electing under subsection 1101(5q) of the *Income Tax Regulations*? **101** Yes ☐ No ☒

Part 1 – Agreement between associated eligible persons or partnerships (EPOPs)

Are you associated in the tax year with one or more EPOPs with which you have entered into an agreement under subsection 1104(3.3) of the Regulations? . . . . . **105** Yes ☐ No ☒

If you answered **yes**, fill out Part 1. Otherwise, go to Part 2.

Enter a percentage assigned to each associated EPOP (including your corporation) as determined in the agreement.

This percentage will be used to allocate the immediate expensing limit. The total of all the percentages assigned under the agreement should not exceed 100%. If the total is more than 100%, then the associated group has an immediate expensing limit of nil. For more information about the immediate expensing limit, see note 12 in Part 2.

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	1 Name of EPOP **110**	2 Identification number **Note 1** **115**	3 Percentage assigned under the agreement **120**
1.			
		Total	

Immediate expensing limit allocated to the corporation (see **Note 2**) . . . . . **125** _____

Note 1: The identification number is the social insurance number, business number, or partnership account number of the EPOP.

Note 2: Multiply 1.5 million by the percentage assigned to your corporation in column 3. If the total of column 3 is more than 100%, enter "0".

Part 2 – CCA calculation

	1 Class number Note 3 200	Description	2 Undepreciated capital cost (UCC) at the beginning of the year 201	3 Cost of acquisitions during the year (new property must be available for use) Note 4 203	4 Cost of acquisitions from column 3 that are designated immediate expensing property (DIEP) Note 5 232	5 Adjustments and transfers Note 6 205	6 Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition Note 7 221	7 Amount from column 5 that is repaid during the year for a property, subsequent to its disposition Note 8 222	8 Proceeds of dispositions Note 9 207
1.	1	GHESI-ENVIDA	1,835,581						0
2.	1		670,424,772	4,780,828					0
3.	1b	200 Kennedy Rd S	47,611,400						0
4.	1b	2185 Derry Rd	2,278,728						0
5.	1b	2185 Derry Rd. 2018	4,451,344						0
6.	1b	2185 Derry Rd. 2022 - 2nd Floor	1,934,987						0
7.	1b	55 John St. 2018	3,899,162						0
8.	1b	Aquitaine Substation	266,640						0
9.	1b	BCM Building	451,749						0
10.	1b	Cityview	336,355						0
11.	1b	Erin Mills Substation	1,028,200						0
12.	1b	GHESI	661,993						0
13.	1b	GHESI (2)	17,326						0
14.	1b	GHESI-ENVIDA	4,732						0
15.	1b	HUC	6,853,941						0
16.	1b	Nebo Rd 2020	864,339						0
17.	1b	Rubin MS	400,608						0
18.	1b	Winston Churchill Substation	75,443						0
19.	2		63,751,868						0
20.	3	Bramp FMV Bump - SH	177,227						0
21.	3		2,010,304						0
22.	6		4,089						0
23.	8	Bramp FMV Bump - SH	5,534						0
24.	8	GHESI-ENVIDA	1,493,222						0
25.	8	Solar Business - Office Equip	167						0
26.	8		14,030,827	3,337,889					0
27.	10	Bramp FMV Bump - SH	308,204						0
28.	10	GHESI-ENVIDA	594						0
29.	10		12,108,677	6,942,324					614,403
30.	10.1	019-07	68						N/A
31.	10.1	020-07	48						N/A
32.	10.1	Dodge Sprinter Van	34						N/A

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	1 Class number Note 3 200	Description	2 Undepreciated capital cost (UCC) at the beginning of the year 201	3 Cost of acquisitions during the year (new property must be available for use) Note 4 203	4 Cost of acquisitions from column 3 that are designated immediate expensing property (DIEP) Note 5 232	5 Adjustments and transfers Note 6 205	6 Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition Note 7 221	7 Amount from column 5 that is repaid during the year for a property, subsequent to its disposition Note 8 222	8 Proceeds of dispositions Note 9 207
33.	10.1	Ford Escape Hybrid	34						N/A
34.	10.1	Ford Escape Hybrid	34						N/A
35.	10.1	Vehicle 023-08	97						N/A
36.	10.1	Vehicle 024-09	97						N/A
37.	12			17,367,905					0
38.	13	Addiscott Ops Centre	546,933						0
39.	13	Barrie Hydro - right to use	170,443						0
40.	13	Leasehold improvements Sandalwood	46,059						0
41.	13	PS Inc - 2005 Addition	37,771						0
42.	14	Churchill Meadows	21,390,037						0
43.	14	Dundas	17,284						0
44.	14	Goreway TS 10Y	4,254,899						0
45.	14	H1 Holland TS - 2020	318,425						0
46.	14	H1 Midhurst CC	633,812						0
47.	14	Nebo Road	1,199,579						0
48.	14	Pleasant CCRA (Brampton)	3,818,033						0
49.	14	Vansickle Substation	4,630,493						0
50.	14	Winona	789,086						0
51.	14.1	2017 Onwards	5,377,738	110,795					0
52.	14.1	2017 Onwards - SH	516,073						0
53.	14.1	Bramp FMV Bump - SH	6,678,822						0
54.	14.1	Bramp GW - SH	86,227,973						0
55.	14.1	GHESI 5	56,948						0
56.	14.1	GHESI 7	1,184,202						0
57.	14.1	GHESI-ENVIDA	24,087						0
58.	14.1	Pre 2017	12,237,826						0
59.	14.1	Pre 2017 - SH	1,382,770						0
60.	17	GHESI-ENVIDA	1,754,470						0
61.	17		522,106						0
62.	42	GHESI	62						0
63.	43.1		4,209						0
64.	43.2	GHESI	51,141						0
65.	43.2	PSI Smart Grid	14,392						0
66.	43.2	Solar Business - Solar Panels	154,275	101,372					0

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	1 Class number Note 3 200	Description	2 Undepreciated capital cost (UCC) at the beginning of the year 201	3 Cost of acquisitions during the year (new property must be available for use) Note 4 203	4 Cost of acquisitions from column 3 that are designated immediate expensing property (DIEP) Note 5 232	5 Adjustments and transfers Note 6 205	6 Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition Note 7 221	7 Amount from column 5 that is repaid during the year for a property, subsequent to its disposition Note 8 222	8 Proceeds of dispositions Note 9 207
67.	45		4,932						0
68.	47	Bramp FMV Bump - SH	40,882,921						0
69.	47		1,919,949,689	316,120,778					0
70.	50	Bramp FMV Bump - SH	765						0
71.	50		3,449,284	1,379,308					0
72.	54	EV Light Trucks and Vehicles	431,434	185,506					0
73.	95		85,752,336			3,032,054			0
74.	95	CIP - Solar				86,688			0
		Totals	3,041,799,734	350,326,705		3,118,742			614,403

	1 Class number 234	Description	9 Proceeds of dispositions of the DIEP (enter amount from column 8 that relates to the DIEP reported in column 4) Note 10 234	10 UCC (column 2 **plus** column 3 **plus** or **minus** column 5 **minus** column 8) Note 11 236	11 UCC of the DIEP (enter the UCC amount that relates to the DIEP reported in column 4) Note 12 238	12 Immediate expensing 225	13 Cost of acquisitions on remainder of Class (column 3 **minus** column 12)	14 Cost of acquisitions from column 13 that are accelerated investment incentive properties (AIIP) or properties included in Classes 54 to 56 Note 13	15 Remaining UCC (column 10 **minus** column 12) (if negative, enter "0")	16 Proceeds of disposition available to reduce the UCC of AIIP and property included in Classes 54 to 56 (column 8 **plus** column 6 **minus** column 13 **plus** column 14 **minus** column 7) (if negative, enter "0")
1.	1	GHESI-ENVIDA		1,835,581					1,835,581	
2.	1			675,205,600			4,780,828	4,780,828	675,205,600	
3.	1b	200 Kennedy Rd S		47,611,400					47,611,400	
4.	1b	2185 Derry Rd		2,278,728					2,278,728	
5.	1b	2185 Derry Rd. 2018		4,451,344					4,451,344	
6.	1b	2185 Derry Rd. 2022 - 2nd Floor		1,934,987					1,934,987	
7.	1b	55 John St. 2018		3,899,162					3,899,162	
8.	1b	Aquitaine Substation		266,640					266,640	
9.	1b	BCM Building		451,749					451,749	
10.	1b	Cityview		336,355					336,355	
11.	1b	Erin Mills Substation		1,028,200					1,028,200	
12.	1b	GHESI		661,993					661,993	

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	1 Class number	Description	9 Proceeds of dispositions of the DIEP (enter amount from column 8 that relates to the DIEP reported in column 4) **234**	10 UCC (column 2 **plus** column 3 **plus** or **minus** column 5 **minus** column 8) **Note 10**	11 UCC of the DIEP (enter the UCC amount that relates to the DIEP reported in column 4) **Note 11** **236**	12 Immediate expensing **Note 12** **238**	13 Cost of acquisitions on remainder of Class (column 3 **minus** column 12)	14 Cost of acquisitions from column 13 that are accelerated investment incentive properties (AIIP) or properties included in Classes 54 to 56 **Note 13** **225**	15 Remaining UCC (column 10 **minus** column 12) (if negative, enter "0")	16 Proceeds of disposition available to reduce the UCC of AIIP and property included in Classes 54 to 56 (column 8 **plus** column 6 **minus** column 13 **plus** column 14 **minus** column 7) (if negative, enter "0")
13.	1b	GHESI (2)		17,326					17,326	
14.	1b	GHESI-ENVIDA		4,732					4,732	
15.	1b	HUC		6,853,941					6,853,941	
16.	1b	Nebo Rd 2020		864,339					864,339	
17.	1b	Rubin MS		400,608					400,608	
18.	1b	Winston Churchill Substation		75,443					75,443	
19.	2			63,751,868					63,751,868	
20.	3	Bramp FMV Bump - SH		177,227					177,227	
21.	3			2,010,304					2,010,304	
22.	6			4,089					4,089	
23.	8	Bramp FMV Bump - SH		5,534					5,534	
24.	8	GHESI-ENVIDA		1,493,222					1,493,222	
25.	8	Solar Business - Office Equip		167					167	
26.	8			17,368,716			3,337,889	3,337,889	17,368,716	
27.	10	Bramp FMV Bump - SH		308,204					308,204	
28.	10	GHESI-ENVIDA		594					594	
29.	10			18,436,598			6,942,324	6,942,324	18,436,598	614,403
30.	10.1	019-07		68					68	
31.	10.1	020-07		48					48	
32.	10.1	Dodge Sprinter Van		34					34	
33.	10.1	Ford Escape Hybrid		34					34	
34.	10.1	Ford Escape Hybrid		34					34	
35.	10.1	Vehicle 023-08		97					97	
36.	10.1	Vehicle 024-09		97					97	
37.	12			17,367,905			17,367,905	17,367,905	17,367,905	
38.	13	Addiscott Ops Centre		546,933					546,933	
39.	13	Barrie Hydro - right to use		170,443					170,443	
40.	13	Leasehold improvements Sandalwood		46,059					46,059	
41.	13	PS Inc - 2005 Addition		37,771					37,771	
42.	14	Churchill Meadows		21,390,037					21,390,037	
43.	14	Dundas		17,284					17,284	

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	1 Class number	Description	9 Proceeds of dispositions of the DIEP (enter amount from column 8 that relates to the DIEP reported in column 4) **234**	10 UCC (column 2 **plus** column 3 **plus** or **minus** column 5 **minus** column 8) **Note 10**	11 UCC of the DIEP (enter the UCC amount that relates to the DIEP reported in column 4) **Note 11** **236**	12 Immediate expensing **Note 12** **238**	13 Cost of acquisitions on remainder of Class (column 3 **minus** column 12)	14 Cost of acquisitions from column 13 that are accelerated investment incentive properties (AIIP) or properties included in Classes 54 to 56 **Note 13** **225**	15 Remaining UCC (column 10 **minus** column 12) (if negative, enter "0")	16 Proceeds of disposition available to reduce the UCC of AIIP and property included in Classes 54 to 56 (column 8 **plus** column 6 **minus** column 13 **plus** column 14 **minus** column 7) (if negative, enter "0")
44.	14	Goreway TS 10Y		4,254,899					4,254,899	
45.	14	H1 Holland TS - 2020		318,425					318,425	
46.	14	H1 Midhurst CC		633,812					633,812	
47.	14	Nebo Road		1,199,579					1,199,579	
48.	14	Pleasant CCRA (Brampton)		3,818,033					3,818,033	
49.	14	Vansickle Substation		4,630,493					4,630,493	
50.	14	Winona		789,086					789,086	
51.	14.1	2017 Onwards		5,488,533			110,795	110,795	5,488,533	
52.	14.1	2017 Onwards - SH		516,073					516,073	
53.	14.1	Bramp FMV Bump - SH		6,678,822					6,678,822	
54.	14.1	Bramp GW - SH		86,227,973					86,227,973	
55.	14.1	GHESI 5		56,948					56,948	
56.	14.1	GHESI 7		1,184,202					1,184,202	
57.	14.1	GHESI-ENVIDA		24,087					24,087	
58.	14.1	Pre 2017		12,237,826					12,237,826	
59.	14.1	Pre 2017 - SH		1,382,770					1,382,770	
60.	17	GHESI-ENVIDA		1,754,470					1,754,470	
61.	17			522,106					522,106	
62.	42	GHESI		62					62	
63.	43.1			4,209					4,209	
64.	43.2	GHESI		51,141					51,141	
65.	43.2	PSI Smart Grid		14,392					14,392	
66.	43.2	Solar Business - Solar Panels		255,647			101,372	101,372	255,647	
67.	45			4,932					4,932	
68.	47	Bramp FMV Bump - SH		40,882,921					40,882,921	
69.	47			2,236,070,467			316,120,778	316,120,778	2,236,070,467	
70.	50	Bramp FMV Bump - SH		765					765	
71.	50			4,828,592			1,379,308	1,379,308	4,828,592	
72.	54	EV Light Trucks and Vehicles		616,940			185,506	185,506	616,940	
73.	95			88,784,390					88,784,390	

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	1 Class number	Description	9 Proceeds of dispositions of the DIEP (enter amount from column 8 that relates to the DIEP reported in column 4) **234**	10 UCC (column 2 **plus** column 3 **plus** or **minus** column 5 **minus** column 8) **Note 10**	11 UCC of the DIEP (enter the UCC amount that relates to the DIEP reported in column 4) **Note 11** **236**	12 Immediate expensing **Note 12** **238**	13 Cost of acquisitions on remainder of Class (column 3 **minus** column 12)	14 Cost of acquisitions from column 13 that are accelerated investment incentive properties (AIIP) or properties included in Classes 54 to 56 **Note 13** **225**	15 Remaining UCC (column 10 **minus** column 12) (if negative, enter "0")	16 Proceeds of disposition available to reduce the UCC of AIIP and property included in Classes 54 to 56 (column 8 **plus** column 6 **minus** column 13 **plus** column 14 **minus** column 7) (if negative, enter "0")
74.	95	CIP - Solar		86,688					86,688	
		Totals		3,394,630,778			350,326,705	350,326,705	3,394,630,778	614,403

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Part 2 – CCA calculation (continued)

	1 Class number	Description	17 Net capital cost additions of AIIP and property included in Classes 54 to 56 acquired during the year (column 14 **minus** column 16) (if negative, enter "0")	18 UCC adjustment for AIIP and property included in Classes 54 to 56 acquired during the year (column 17 **multiplied** by the relevant factor) **Note 14**	19 UCC adjustment for property acquired during the year other than AIIP and property included in Classes 54 to 56 (0.5 **multiplied** by the result of column 13 **minus** column 14 **minus** column 6 **plus** column 7 **minus** column 8) (if negative, enter "0") **Note 15** **224**	20 CCA rate % **Note 16** **212**	21 Recapture of CCA **Note 17** **213**	22 Terminal loss **Note 18** **215**	23 CCA (for declining balance method, the result of column 15 **plus** column 18 **minus** column 19, **multiplied** by column 20, or a lower amount, **plus** column 12) **Note 19** **217**	24 UCC at the end of the year (column 10 **minus** column 23) **220**
1.	1	GHESI-ENVIDA				4	0	0	73,423	1,762,158
2.	1		4,780,828			4	0	0	27,008,224	648,197,376
3.	1b	200 Kennedy Rd S				6	0	0	2,856,684	44,754,716
4.	1b	2185 Derry Rd				6	0	0	136,724	2,142,004
5.	1b	2185 Derry Rd. 2018				6	0	0	267,081	4,184,263
6.	1b	2185 Derry Rd. 2022 - 2nd Floor				6	0	0	116,099	1,818,888
7.	1b	55 John St. 2018				6	0	0	233,950	3,665,212
8.	1b	Aquitaine Substation				6	0	0	15,998	250,642
9.	1b	BCM Building				6	0	0	27,105	424,644
10.	1b	Cityview				6	0	0	20,181	316,174
11.	1b	Erin Mills Substation				6	0	0	61,692	966,508
12.	1b	GHESI				6	0	0	39,720	622,273
13.	1b	GHESI (2)				6	0	0	1,040	16,286
14.	1b	GHESI-ENVIDA				6	0	0	284	4,448
15.	1b	HUC				6	0	0	411,236	6,442,705
16.	1b	Nebo Rd 2020				6	0	0	51,860	812,479
17.	1b	Rubin MS				6	0	0	24,036	376,572
18.	1b	Winston Churchill Substation				6	0	0	4,527	70,916
19.	2					6	0	0	3,825,112	59,926,756
20.	3	Bramp FMV Bump - SH				5	0	0	8,861	168,366
21.	3					5	0	0	100,515	1,909,789
22.	6					10	0	0	409	3,680
23.	8	Bramp FMV Bump - SH				20	0	0	1,107	4,427
24.	8	GHESI-ENVIDA				20	0	0	298,644	1,194,578
25.	8	Solar Business - Office Equip				20	0	0	33	134
26.	8		3,337,889			20	0	0	3,473,743	13,894,973
27.	10	Bramp FMV Bump - SH				30	0	0	92,461	215,743
28.	10	GHESI-ENVIDA				30	0	0	178	416

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	1 Class number	Description	17 Net capital cost additions of AIIP and property included in Classes 54 to 56 acquired during the year (column 14 **minus** column 16) (if negative, enter "0")	18 UCC adjustment for AIIP and property included in Classes 54 to 56 acquired during the year (column 17 **multiplied** by the relevant factor) **Note 14**	19 UCC adjustment for property acquired during the year other than AIIP and property included in Classes 54 to 56 (0.5 **multiplied** by the result of column 13 **minus** column 14 **minus** column 6 **plus** column 7 **minus** column 8) (if negative, enter "0") **Note 15** **224**	20 CCA rate % **Note 16** **212**	21 Recapture of CCA **Note 17** **213**	22 Terminal loss **Note 18** **215**	23 CCA (for declining balance method, the result of column 15 **plus** column 18 **minus** column 19, **multiplied** by column 20, or a lower amount, **plus** column 12) **Note 19** **217**	24 UCC at the end of the year (column 10 **minus** column 23) **220**
29.	10		6,327,921			30	0	0	5,530,979	12,905,619
30.	10.1	019-07				30	N/A	N/A	20	48
31.	10.1	020-07				30	N/A	N/A	14	34
32.	10.1	Dodge Sprinter Van				30	N/A	N/A	10	24
33.	10.1	Ford Escape Hybrid				30	N/A	N/A	10	24
34.	10.1	Ford Escape Hybrid				30	N/A	N/A	10	24
35.	10.1	Vehicle 023-08				30	N/A	N/A	29	68
36.	10.1	Vehicle 024-09				30	N/A	N/A	29	68
37.	12		17,367,905			100	0	0	17,367,905	
38.	13	Addiscott Ops Centre				NA	0	0	36,882	510,051
39.	13	Barrie Hydro - right to use				NA	0	0	32,143	138,300
40.	13	Leasehold improvements Sandalwood				NA	0	0	46,059	
41.	13	PS Inc - 2005 Addition				NA	0	0	15,110	22,661
42.	14	Churchill Meadows				NA	0	0	2,023,631	19,366,406
43.	14	Dundas				NA	0	0	4,509	12,775
44.	14	Goreway TS 10Y				NA	0	0	413,635	3,841,264
45.	14	H1 Holland TS - 2020				NA	0	0	26,535	291,890
46.	14	H1 Midhurst CC				NA	0	0	312,375	321,437
47.	14	Nebo Road				NA	0	0	80,855	1,118,724
48.	14	Pleasant CCRA (Brampton)				NA	0	0	453,640	3,364,393
49.	14	Vansickle Substation				NA	0	0	310,431	4,320,062
50.	14	Winona				NA	0	0	607,045	182,041
51.	14.1	2017 Onwards	110,795			5	0	0	274,427	5,214,106
52.	14.1	2017 Onwards - SH				5	0	0	25,804	490,269
53.	14.1	Bramp FMV Bump - SH				5	0	0	333,941	6,344,881
54.	14.1	Bramp GW - SH				5	0	0	4,311,399	81,916,574
55.	14.1	GHESI 5				5	0	0	2,847	54,101
56.	14.1	GHESI 7				7	0	0	82,894	1,101,308
57.	14.1	GHESI-ENVIDA				5	0	0	1,204	22,883
58.	14.1	Pre 2017				7	0	0	856,648	11,381,178

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	1 Class number	Description	17 Net capital cost additions of AIIP and property included in Classes 54 to 56 acquired during the year (column 14 **minus** column 16) (if negative, enter "0") **Note 14**	18 UCC adjustment for AIIP and property included in Classes 54 to 56 acquired during the year (column 17 **multiplied** by the relevant factor) **Note 14**	19 UCC adjustment for property acquired during the year other than AIIP and property included in Classes 54 to 56 (0.5 **multiplied** by the result of column 13 **minus** column 14 **minus** column 6 **plus** column 7 **minus** column 8) (if negative, enter "0") **Note 15** **224**	20 CCA rate % **Note 16** **212**	21 Recapture of CCA **Note 17** **213**	22 Terminal loss **Note 18** **215**	23 CCA (for declining balance method, the result of column 15 **plus** column 18 **minus** column 19, **multiplied** by column 20, or a lower amount, **plus** column 12) **Note 19** **217**	24 UCC at the end of the year (column 10 **minus** column 23) **220**
59.	14.1	Pre 2017 - SH				7	0	0	96,794	1,285,976
60.	17	GHESI-ENVIDA				8	0	0	140,358	1,614,112
61.	17					8	0	0	41,768	480,338
62.	42	GHESI				12	0	0	7	55
63.	43.1					30	0	0	1,263	2,946
64.	43.2	GHESI				50	0	0	25,571	25,570
65.	43.2	PSI Smart Grid				50	0	0	7,196	7,196
66.	43.2	Solar Business - Solar Panels	101,372	50,686		50	0	0	153,167	102,480
67.	45					45	0	0	2,219	2,713
68.	47	Bramp FMV Bump - SH				8	0	0	3,270,634	37,612,287
69.	47		316,120,778			8	0	0	178,885,637	2,057,184,830
70.	50	Bramp FMV Bump - SH				55	0	0	421	344
71.	50		1,379,308			55	0	0	2,655,726	2,172,866
72.	54	EV Light Trucks and Vehicles	185,506	278,259		30	0	0	268,560	348,380
73.	95					0	0	0		88,784,390
74.	95	CIP - Solar				0	0	0		86,688
		Totals	349,712,302	328,945					257,851,268	3,136,779,510

Enter the total of column 21 on line 107 of Form T2 SCH 1, *Net Income (Loss) for Income Tax Purposes*.
Enter the total of column 22 on line 404 of Form T2 SCH 1.
Enter the total of column 23 on line 403 of Form T2 SCH 1.

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Note 3: If a class number has not been provided in Schedule II of the *Income Tax Regulations* for a particular class of property, use the subsection provided in Regulation 1101.

Note 4: Include any property acquired in previous years that has now become available for use, net of any government assistance received or entitled to be received in the year from a government, municipality or other public authority, or a reduction of capital cost after the application of section 80. This property would have been previously excluded from column 3. List separately any acquisitions of property in the class that are not subject to the 50% rule. See Income Tax Folio S3-F4-C1, *General Discussion of Capital Cost Allowance*, for exceptions to the 50% rule. Do not include any amount in column 3 in respect of property included in column 5 (see note 6). See Guide T4012 for more information about the cost of acquisitions during the year.

Note 5: A DIEP reported in column 4 is a property acquired after April 18, 2021, by a corporation that was a Canadian-controlled private corporation (CCPC) throughout the year, which became available for use in the tax year (before 2024) and was designated as such on or before the day that is 12 months after the filing-due date for the tax year to which the designation relates. It includes all capital property subject to the CCA rules, if certain conditions are met, other than property included in Classes 1 to 6, 14.1, 17, 47, 49, and 51. A property can only qualify as DIEP in the year in which it becomes available for use. See subsection 1104(3.1) of the Regulations for more information.

Note 6: Enter in column 5, "Adjustments and transfers," amounts that increase or reduce the UCC (column 10). Items that increase the UCC include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that reduce the UCC (show amounts that reduce the UCC in brackets) include assistance received or receivable during the year for a property, subsequent to its disposition, if such assistance would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f). See Guide T4012 for other examples of adjustments and transfers to include in column 5.
Also include property acquired in a non-arm's length transaction [other than by virtue of a right referred to in paragraph 251(5)(b)] if the property was a depreciable property acquired by the transferor at least 364 days before the end of your tax year and continuously owned by the transferor until it was acquired by you.

Note 7: Include all amounts of assistance you received (or were entitled to receive) after the disposition of a depreciable property that would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f) if received before the disposition.

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Part 2 – CCA calculation (continued)

Note 8: Include all amounts you have repaid during the year for any legally required repayment, made after the disposition of a corresponding property, of:

- assistance that would have otherwise increased the capital cost of the property under paragraph 13(7.1)(d) and
- an inducement, assistance, or any other amount contemplated in paragraph 12(1)(x) received, that otherwise would have increased the capital cost of the property under paragraph 13(7.4)(b)

Include the UCC of each property of a prescribed class acquired in the course of a corporate reorganization described under paragraph 55(3)(b) (also known as "butterfly reorganization") or include property acquired in a non-arm's length transaction [other than by virtue of a right referred to in paragraph 251(5)(b)] if the property was a depreciable property acquired by the transferor less than 364 days before the end of your tax year and continuously owned by the transferor until it was acquired by you.

Note 9: For each property disposed of during the year, deduct from the proceeds of disposition any outlays and expenses to the extent that they were made or incurred for the purpose of making the disposition(s). The amount reported in respect of the property cannot exceed the property's capital cost, unless that property is a timber resource property as defined in subsection 13(21).
If the cost of a zero-emission passenger vehicle (or a passenger vehicle that was, at any time, a DIEP) exceeds the prescribed amount and it is disposed of to a person or partnership with which you deal at arm's length, the proceeds of disposition will be adjusted based on a factor equal to the prescribed amount as a proportion of the actual cost of the vehicle. The actual cost of the vehicle will be adjusted for payment or repayment of government assistance.

Note 10: If the amount in column 5 (as shown in brackets) reduces the undepreciated capital cost, you must subtract it for the purposes of the calculation. Otherwise, add the amount in column 5 for the purposes of the calculation.

Note 11: The amount to enter in column 11 must not exceed the amount in column 10. If it does, enter in column 11 the amount from column 10. If the amount determined in column 10 is zero or a negative amount, enter "0". The only amounts incurred before April 19, 2021, to be included in this column are certain inventory purchases from arm's length persons or partnerships where the conditions in paragraphs 1100(0.3)(a) to (c) of the Regulations are met.

Note 12: Immediate expensing applies to a DIEP included in column 11. The total immediate expensing for the tax year (total of column 12) should not exceed the lesser of:

- Immediate expensing limit: it is equal to one of the following five amounts, whichever is applicable:
  - $1.5 million, if you are not associated with any other EPOP in the tax year
  - amount from line 125, if you are associated in the tax year with one or more EPOPs
  - nil, if the total of the percentages assigned in Part 1 is more than 100% or you are associated in the tax year with one or more EPOPs and have not filed an agreement in prescribed form as required under subsection 1104(3.3) of the Regulations
  - the amount determined under subsection 1104(3.5) of the Regulations for any second or subsequent tax years ending in a calendar year, if you have two or more tax years ending in the calendar year in which you are associated with another EPOP that has a tax year ending in that calendar year
  - any amount allocated by the minister under subsection 1104(3.4) of the Regulations

The immediate expensing limit has to be prorated if your tax year is less than 365 days. You cannot carry forward any unused amount of the immediate expensing limit.

- UCC of the DIEP: total of column 11

You have to maintain the CCPC status throughout the relevant tax year in order to claim the immediate expensing.

Note 13: An AIIP is a property (other than property included in Classes 54 to 56) that you acquired after November 20, 2018, and that became available for use before 2028.
Classes 54 and 55 include zero-emission vehicles that you acquired after March 18, 2019, and that became available for use before 2028.
Class 56 applies to eligible zero-emission automotive equipment and vehicles (other than motor vehicles) that are acquired after March 1, 2020, and that became available for use before 2028.
See Guide T4012 for more information.

Note 14: The relevant factors for property of a class in Schedule II, that is an AIIP or included in Classes 54 to 56, available for use respectively before 2024 or in 2024 are:

- 2 1/3 or 1 1/2 for property in Classes 43.1, 54, and 56
- 1 1/2 or 7/8 for property in Class 55
- 1 or 1/2 for property in Classes 43.2 and 53
- 0 for property in Classes 12, 13, 14, 15, and 59, as well as properties that are Canadian vessels included in paragraph 1100(1)(v) of the Regulations (see note 19 for additional information) and
- 0.5 or 0 for all other property that is an AIIP

If the tax year begins in 2023 and ends in 2024, the relevant factor is determined under paragraph 1100(2.01)(a) of the Regulations.

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Part 2 – CCA calculation (continued)

Note 15: The UCC adjustment for property acquired during the year (also known as the half-year rule or 50% rule) does not apply to certain property (including AIIP and property included in Classes 54 to 56). For special rules and exceptions, see Income Tax Folio S3-F4-C1, *General Discussion of Capital Cost Allowance*.

Note 16: Enter a rate only if you are using the declining balance method. For any other method (for example, the straight-line method, where calculations are always based on the cost of acquisitions), enter "N/A". Then enter the amount you are claiming in column 23.

Note 17: If the amount in column 10 is negative, you have a recapture of CCA. If applicable, enter the negative amount from column 10 in column 21 as a positive. The recapture rules do not apply to passenger vehicles in Class 10.1. However, they do apply to a passenger vehicle that was, at any time, a DIEP.

Note 18: If no property is left in the class at the end of the tax year and there is still a positive amount in the column 10, you have a terminal loss. If applicable, enter the positive amount from column 10 in column 22. The terminal loss rules do not apply to:

- passenger vehicles in Class 10.1
- property in Class 14.1, unless you have ceased carrying on the business to which it relates
- limited-period franchises, concessions, or licences in Class 14 if, at the time of acquisition, the property was a former property of the transferor or any similar property attributable to the same fixed place of business, and you had jointly elected with the transferor to have the replacement property rules apply, unless certain conditions are met

Note 19: If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See Guide T4012 for more information.
For property in Class 10.1 disposed of during the year, deduct a maximum of 50% of the regular CCA deduction if you owned the property at the beginning of the tax year.
For AIIP listed below, the maximum first year allowance you can claim is determined as follows:

- Class 13: if the capital cost of the property was incurred before 2024, the lesser of 150% of the amount calculated in Schedule III of the Regulations and the UCC at the end of the tax year (before any CCA deduction), and in any other case, the amount for the year calculated in accordance with Schedule III of the Regulations
- Class 14: the lesser of 150% (if the property becomes available for use in the year and before 2024) or 125% (if the property becomes available for use in the year and after 2023) of the allocation for the year of the capital cost of the property apportioned over the remaining life of the property (at the time the cost was incurred) and the UCC at the end of the tax year (before any CCA deduction)
- Class 15: the lesser of 150% (if the property is acquired in the year and before 2024) or 125% (if the property is acquired in the year and after 2023) of an amount calculated on the basis of a rate per cord, board foot, or cubic metre cut in the tax year and the UCC at the end of the tax year (before any CCA deduction)
- Canadian vessels described under paragraph 1100(1)(v) of the Regulations: the lesser of 50% (for property acquired in the year and before 2024) or 33 1/3% (in any other case) of the capital cost of the property and the UCC at the end of the tax year (before any CCA deduction)
- Class 41.2: use a 25% CCA rate. The additional allowance under paragraphs 1100(1)(y.2) (for single mine properties) and 1100(1)(ya.2) (for multiple mine properties) of the Regulations is not eligible for the accelerated investment incentive. The additional allowance in respect of natural gas liquefaction under paragraph 1100(1)(yb) of the Regulations is eligible for the accelerated investment incentive

The AIIP provisions also apply to property (other than a timber resource property) that is a timber limit or a right to cut timber from a limit as well as to an industrial mineral mine or a right to remove minerals from an industrial mineral mine. See the *Income Tax Regulations* for more details.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
ALECTRA UTILITIES CORPORATION	[redacted]	2025-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	Alectra Inc.		[redacted]	1					
2.	Alectra Real Estate Holdings Inc.		[redacted]	2					
3.	Horizon Solar Corp		[redacted]	3					
4.	Alectra Energy Solutions Inc.		[redacted]	3					
5.	Alectra Power Services Inc.		[redacted]	3					
6.	Alectra Energy Services Inc.		[redacted]	3					
7.	Util-Assist Inc.		[redacted]	3					
8.	Holland Power Services Inc.		[redacted]	3					
9.	Alectra Microgrid Services Master G		[redacted]	3					
10.	Alectra Microgrid Services Project G		[redacted]	3					
11.	Alectra Microgrid Services Project (		[redacted]	3					
12.	Alectra Campbell Road GP Inc.		[redacted]	3					
13.	748953 N.B. Ltd.		[redacted]	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

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T2 SCH 9 (11)

Canada

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	Employee future benefits	74,449,091			2,861,484	71,587,607
2	Allowance for doubtful accounts	2,183,193		1,252,899		3,436,092
3	Legal claim provision					
4	Transition Accrual	570,648			157,965	412,683
5	Regulatory Provision					
6	Property Tax Provision - Solar					
7	Environmental Provision	36,448			36,448	
8						
	Reserves from Part 2 of Schedule 13					
	Totals	77,239,380		1,252,899	3,055,897	75,436,382

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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Canada Revenue Agency / Agence du revenu du Canada

Schedule 23

Agreement Among Associated Canadian-Controlled Private Corporations to Allocate the Business Limit

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year must file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group, including those deemed to be associated under subsection 256(2) of the Income Tax Act.

Column 2: Provide the business number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code from the list below that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless association code 5 applies)

2 – CCPC that is a **third corporation** as referred to in subsection 256(2) and has filed Schedule 28, Election not to be Associated Through a Third Corporation

3 – Non-CCPC that is a **third corporation**

4 – Associated non-CCPC

5 – Associated CCPC to which association code 1 does not apply because a **third corporation** has filed Schedule 28

Column 4: Enter the business limit for the year of each corporation in the associated group. Enter "0" if the corporation has association code 2, 3 or 4 in column 3 (except if the corporation is a cooperative or a credit union eligible for the SBD and it has association code 4).

Column 5: Assign a percentage to allocate the business limit to each corporation that has association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A.

Ensure that the total at line A does not exceed $500,000.

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Allocating the business limit

Date filed (do not use this area) . . . . . 025 Year Month Day

Enter the calendar year the agreement applies to . . . . . 050 Year 2025

Is this an amended agreement for the above calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . 075 ☐ Yes ☒ No

	1 Name of associated corporations 100	2 Business number of associated corporations 200	3 Asso-ciation code 300	4 Business limit for the year before the allocation $	5 Percentage of the business limit % 350	6 Business limit allocated* $ 400
1	ALECTRA UTILITIES CORPORATION	[redacted]	1	500,000	100.0000	500,000
2	Alectra Inc.		1	500,000		
3	Alectra Real Estate Holdings Inc.		1	500,000		
4	Horizon Solar Corp		1	500,000		
5	Alectra Energy Solutions Inc.		1	500,000		
6	Alectra Power Services Inc.		1	500,000		
7	Alectra Energy Services Inc.		1	500,000		
8	Util-Assist Inc.		1	500,000		
9	Holland Power Services Inc.		1	500,000		
10	Alectra Microgrid Services Master GP Inc.		1	500,000		
11	Alectra Microgrid Services Project GP (Georgian		1	500,000		
12	Alectra Microgrid Services Project (LNR) GP Inc.		1	500,000		
13	Alectra Campbell Road GP Inc.		1	500,000		
14	748953 N.B. Ltd.		1	500,000		
				Total	100.0000	500,000 A

Business limit reduction under subsection 125(5.1) of the Act

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "large corporation amount" at line 415 of the T2 return. The amount at line 415 is determined using the formula 0.225% x (C - $10,000,000). Another factor is the "adjusted aggregate investment income" from lines 744 and 745 of Schedule 7, Aggregate Investment Income and Income Eligible for the Small Business Deduction. Details of these formulas and variable C are in subsection 125(5.1) of the Act.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules for business limit

Special rules apply under subsection 125(5) if a CCPC has more than one tax year ending in the same calendar year and it is associated in more than one of those tax years with another CCPC that has a tax year ending in that calendar year. The business limit for the second or later tax year will be equal to the lesser of: the business limit determined for the first tax year ending in the calendar year or the business limit determined for the second or later tax year ending in the same calendar year.

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Schedule 33

Taxable Capital Employed in Canada – Large Corporations

Corporation's name	Business number	Tax year-end Year Month Day
ALECTRA UTILITIES CORPORATION	[redacted]	2025-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- If the total taxable capital employed in Canada of the corporation and its related corporations is greater than $10,000,000, file a completed Schedule 33 with your T2 *Corporation Income Tax Return* no later than six months from the end of the tax year.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms **financial institution**, **long-term debt**, and **reserves**.
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, **Taxable capital employed in Canada**.

Part 1 – Capital

Add the following year-end amounts:

Reserves that have not been deducted in calculating income for the year under Part I	101	306,795,653	
Capital stock (or members' contributions if incorporated without share capital)	103	702,585,958	
Retained earnings	104	423,201,319	
Contributed surplus	105		
Any other surpluses	106	825,874,529	
Deferred unrealized foreign exchange gains	107		
All loans and advances to the corporation	108	2,720,881,577	
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109		
Any dividends declared but not paid by the corporation before the end of the year	110		
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111		
The total of all amounts, each of which is the amount, if any, in respect of a partnership in which the corporation held a membership interest at the end of the year, either directly or indirectly through another partnership (see note below)	112		
Subtotal (**add** lines 101 to 112)		4,979,339,036 ▶	4,979,339,036 A

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Note:

Line 112 is determined by the formula (A – B) x C/D (as per paragraph 181.2(3)(g)) where:

A is the total of all amounts that would be determined for lines 101, 107, 108, 109, and 111 in respect of the partnership for its last fiscal period that ends at or before the end of the year if

a) those lines applied to partnerships in the same manner that they apply to corporations, and

b) those amounts were computed without reference to amounts owing by the partnership

(i) to any corporation that held a membership interest in the partnership either directly or indirectly through another partnership, or

(ii) to any partnership in which a corporation described in subparagraph (i) held a membership interest either directly or indirectly through another partnership.

B is the partnership's deferred unrealized foreign exchange losses at the end of the period,

C is the share of the partnership's income or loss for the period to which the corporation is entitled either directly or indirectly through another partnership, and

D is the partnership's income or loss for the period.

Part 1 – Capital (continued)

Subtotal A (from page 1) 4,979,339,036 A

Deduct the following amounts:

Deferred tax debit balance at the end of the year	121		
Any deficit deducted in calculating its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122		
To the extent that the amount may reasonably be regarded as being included in any of lines 101 to 112 above for the year, any amount deducted under subsection 135(1) in calculating income under Part I for the year.	123		
Deferred unrealized foreign exchange losses at the end of the year	124		
Subtotal (**add** lines 121 to 124)		▶	B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190	4,979,339,036	

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend payable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim or similar obligation of, a partnership each member of which was, throughout the year, another corporation (other than a financial institution) that was not exempt from tax under this Part (otherwise than because of paragraph 181.1(3)(d)), or another partnership described in paragraph 181.2(4)(d.1)	406	
An interest in a partnership (see note 2 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	

Notes:

1. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 (other than a non-resident corporation that at no time in the year carried on business in Canada through a permanent establishment).
2. Where the corporation has an interest in a partnership held either directly or indirectly through another partnership, refer to subsection 181.2(5) for additional rules regarding the carrying value of an interest in a partnership.
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation. Refer to subsection 181.2(6) for special rules that may apply.

Part 3 – Taxable capital

Capital for the year (line 190)		4,979,339,036	C
Deduct: Investment allowance for the year (line 490)			D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	4,979,339,036	

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Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 4,979,339,036 x (Taxable income earned in Canada / Taxable income) **610** 71,258,919 / 71,258,919 = **Taxable capital employed in Canada** **690** 4,979,339,036

Notes:
1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . **701**

Deduct the following amounts:

Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada **711**

Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada **712**

Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below) **713**

Total deductions (**add** lines 711, 712, and 713) ▶ E

Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0") **790**

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (amount from line 690) . . . . . F

Deduct: . . . . . 10,000,000 G

Excess (amount F **minus** amount G) (if negative, enter "0") H

Calculation for purposes of the small business deduction (amount H x 0.225%) I

Enter this amount at line 415 of the T2 return.

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Attached Schedule with Total

Part 1 – Reserves that have not been deducted in calculating income for the year under Part I

Title Part 1 – Reserves that have not been deducted in calculating income for the

Description	Operator (Note)	Amount
Schedule 13 - non-deductible reserves		75,436,382 00
Deferred tax liability	+	218,916,575 00
Deferred tax liability	+	12,442,696 00
	Total	306,795,653 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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Attached Schedule with Total

Part 1 – All loans and advances to the corporation

Title Part 1 – All loans and advances to the corporation

Description	Operator (Note)	Amount
Due to related parties (GIFI 2860)		79,366,418 00
Customer deposits liability (GIFI 2961)	+	59,324,089 00
Current portion of loans and borrowings (GIFI 2700)	+	305,000,000 00
Long term loans from parent (GIFI 3300)	+	2,277,191,070 00
	+	
	Total	2,720,881,577 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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Schedule 43

Calculation of Parts IV.1 and VI.1 Taxes

Corporation's name	Business number	Tax year-end Year Month Day
ALECTRA UTILITIES CORPORATION	[redacted]	2025-12-31

- Use this schedule to calculate a corporation's Part IV.1 tax for dividends received on taxable preferred shares and taxable restricted financial institution (RFI) shares, and its Part VI.1 tax for dividends paid on short-term preferred shares and taxable preferred shares.
- Use this schedule to elect under subsection 191.2(1) to pay Part VI.1 tax at a rate of 40% on taxable preferred shares. This rate would apply to all future dividends paid on that class or series of shares.
- All legislative references are to the federal Income Tax Act and Income Tax Regulations.
- **Restricted financial institution**, **taxable RFI share**, **taxable preferred share**, and **short-term preferred share** are terms defined in subsection 248(1).
- If Part IV.1 or VI.1 taxes are payable, file one completed copy of this schedule with your T2 Corporation Income Tax Return no later than six months after the end of the tax year. If you are making an election under subsection 191.2(1), see subsection 191.2(1) of the Act for information on the period in which to make the election.
- For corporations without taxable income that have Part IV.1 or VI.1 taxes payable and that have a permanent establishment in more than one jurisdiction, complete only columns A, B, and D in Part 1 of Schedule 5, Tax Calculation Supplementary – Corporations.
- For Part IV.1 tax, an excepted dividend is a dividend as described in section 187.1 and subsections 191(4) and 191(5).
- For Part VI.1 tax, an excluded dividend is a dividend as described in subsections 191(1), 191(4), 191(5), and 191(6).
- For more information, see the T2 Corporation Income Tax Guide.

Part 1 – Dividend allowance

Basic dividend allowance			500,000 1A
Taxable dividends (other than excluded dividends) paid in the calendar year immediately preceding the calendar year in which the tax year ended. These dividends are on taxable preferred shares or shares that would be taxable preferred shares if they were issued after June 18, 1987, and were not grandfathered shares (see point 1 in Part 2 below if the corporation is associated)	1,472,000 1B		
	1,000,000 1C		
Excess (amount 1B **minus** amount 1C) (if negative, enter "0")	110 472,000	▶	472,000
Dividend allowance (amount 1A **minus** line 110) (if negative, enter "0")		115	28,000

Part 2 – Agreement among associated corporations to allocate the dividend allowance

Date filed (do not use this area) 116 Year Month Day

Is this an amended agreement? 117 ☐ Yes ☒ No

Calendar year to which the agreement applies 118 Year 2025

1. Enter the total of non-excluded dividends paid by all associated corporations at amount 1B in Part 1.
2. Allocate the dividend allowance (line 115 above) among associated corporations in column 140, as shown below.
3. Apply the special rules provided under paragraph 191.1(6)(b) if a corporation has two or more tax years ending in the same calendar year during which it is associated with another taxable Canadian corporation that has a tax year ending in that calendar year.
4. If an associated corporation has more than one tax year ending in a calendar year, it has to file an agreement for each of these tax years.
5. Attach additional schedules if more space is needed.

Allocation of dividend allowance

Name of each associated corporation 120	Business number (If a corporation is not registered, enter "NR") 130	Dividend allowance allocated 140
ALECTRA UTILITIES CORPORATION	[redacted]	28,000
Alectra Inc.		
Alectra Real Estate Holdings Inc.		
Horizon Solar Corp		
Alectra Energy Solutions Inc.		
Alectra Power Services Inc.		
Alectra Energy Services Inc.		
Util-Assist Inc.		
Holland Power Services Inc.		
Alectra Microgrid Services Master GP Inc.		
Alectra Microgrid Services Project GP (Georgi		

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Allocation of dividend allowance

Name of each associated corporation 120	Business number (If a corporation is not registered, enter "NR") 130	Dividend allowance allocated 140
Alectra Microgrid Services Project (LNR) GP I	[redacted]	
Alectra Campbell Road GP Inc.		
748953 N.B. Ltd.		
Total (cannot be more than amount on line 115)		28,000

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Part 3 – Part VI.1 tax payable

Complete the calculation of the dividend allowance in Part 1.

Dividend allowance: amount on line 115 (from Part 1) or, if associated, the total amount allocated on line 140 (from Part 2) **210** 28,000

Note: If the tax year is less than 51 weeks, prorate the dividend allowance based on the number of days in the tax year divided by 365. Enter this amount on line 210 instead of the amount from line 115 or 140.

1. Taxable dividends (other than excluded dividends) paid by the corporation in the year on short-term preferred shares . . . **220**

   Line 210 or 220, whichever is less . . . 3A
   Line 220 **minus** amount 3A . . . 3B **x** 40 % = 3C

2. Taxable dividends (other than excluded dividends) paid by the corporation in the year on taxable preferred shares (other than short-term preferred shares) of all classes for which the corporation **is** making an election under subsection 191.2(1) . . . **230**

   Dividend allowance (line 210) . . . 28,000 3D
   Amount 3A . . . 3E
   Net amount (amount 3D **minus** amount 3E) . . . 28,000 3F
   Line 230 or amount 3F, whichever is less . . . 3G
   Line 230 **minus** amount 3G . . . 3H **x** 40 % = 3I

3. Taxable dividends (other than excluded dividends) paid by the corporation in the year on taxable preferred shares (other than short-term preferred shares) of all classes for which the corporation is **not** making an election under subsection 191.2(1) . . . **240**

   Dividend allowance (line 210) . . . 28,000 3J
   Amount 3A . . . 3K
   Amount 3G . . . 3L
   Subtotal (amount 3K **plus** amount 3L) . . . ▶ 3M
   Net amount (amount 3J **minus** amount 3M) . . . 28,000 3N
   Line 240 or amount 3N, whichever is less . . . 3O
   Line 240 **minus** amount 3O . . . 3P **x** 25 % = 3Q

4. Complete this calculation if the corporation has made an agreement under section 191.3 to pay all or part of a related corporation's Part VI.1 tax otherwise payable for the year (complete and file Schedule 45).

   Part VI.1 tax transferred from a related corporation . . . **250** 137,000
   Subtotal (**add** amounts 3C, 3I, 3Q, and line 250) 137,000 3R
   Part VI.1 tax transferred to a related corporation . . . **260**

Part VI.1 tax payable (amount 3R **minus** line 260) . . . **270** 137,000
Enter amount from line 270 on line 724 of the T2 return.

Note: Part VI.1 tax payable has the same instalment requirements and balance due date as Part I tax payable.

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Part 4 – Part IV.1 tax payable

This tax does not apply to dividends received by financial intermediary corporations or corporations that were private corporations at the time the dividends were received. Part IV.1 tax applies only if the dividend in question was deductible under section 112 or 113 or under subsection 138(6) or 115(1). Part IV.1 tax payable is due on or before the balance due date of the corporation or the restricted financial institution for a tax year.

Taxable dividends (other than excepted dividends) received in the year on taxable preferred shares [other than a share of a class for which the corporation has made an election under subsection 191.2(1)] **310**

Taxable dividends (other than excepted dividends) received in the year by a restricted financial institution on taxable RFI shares (see section 187.3) **320**

Total taxable dividends subject to Part IV.1 tax (line 310 **plus** line 320) **330**

Part IV.1 tax payable (line 330 **multiplied** by 10 %) **340**
Enter amount from line 340 on line 716 of the T2 return.

Part IV tax reduction

Portion of taxable dividends included on line 330 that is also subject to Part IV tax **350**

Portion of taxable dividends included on line 350 received from connected corporations **370**

Part IV tax on taxable dividends reported on line 370 . . . . . **380** x 30 % = 4A

Enter amount 4A at amount 2F of Schedule 3, Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculations.

Portion of taxable dividends included on line 350 received from non-connected corporations . . . . . **390** x 10 % = 4B

Reduction of Part IV tax otherwise payable (amount 4A **plus** amount 4B) **360**
Enter amount from line 360 on line 320 of Schedule 3.

Eligible taxable dividends included on line 390 . . . . . **400** x 10 % = 4C

Enter amount 4C at amount 2I of Schedule 3.

Part IV tax reduction of non-eligible taxable dividends received from non-connected corporations (amount 4B **minus** amount 4C) 4D

Enter amount 4D at amount T of the T2 return.

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SCHEDULE 45

AGREEMENT RESPECTING LIABILITY FOR PART VI.1 TAX

- Use this schedule to transfer all or a part of the Part VI.1 tax liability of a corporation (transferor corporation) to a related taxable Canadian corporation (transferee corporation) (section 191.3). Such transfers are beneficial where the transferor corporation does not have enough Part I tax to use the deduction for Part VI.1 tax under paragraph 110(1)(k).
- The transferee corporation has to be related to the transferor corporation throughout a tax year of the transferor corporation and throughout the last tax year of the transferee corporation ending by the end of that tax year of the transferor corporation. Corporations that are related only because of a right referred to in paragraph 251(5)(b) cannot make this agreement. The Part VI.1 tax liability cannot be transferred if the two corporations are related only by virtue of being controlled by the federal or a provincial or territorial government.
- An agreement or amended agreement has to be filed by the transferor corporation and the transferee corporation:
  - no later than six months after the end of the transferor's tax year for which the Part VI.1 tax would otherwise be payable; or
  - no later than 90 days after the mailing of a notice of assessment of Part I or Part VI.1 tax payable (or notification that no tax is payable) to either corporation for the tax year for which the agreement is filed.
- The transferor and the transferee corporations have to attach certified copies of the resolutions of the directors (or the documents of persons legally entitled to administer the affairs of the corporation) authorizing such an agreement.
- The transferee corporation has to include the amount of tax specified in this agreement in its Part VI.1 tax payable. The transferor corporation will deduct this amount from its Part VI.1 tax otherwise payable. Both corporations remain jointly and severally liable to pay the tax specified in this agreement, including any interest and penalties on this amount of tax.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act*.
- For more information, see the *T2 Corporation Income Tax Guide*.

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Agreement

Date filed (do not use this area) . . . . . **101** Year Month Day

It is hereby agreed that Part VI.1 tax in the amount of **105** 137,000 is transferred from the transferor corporation to the related transferee corporation(s).

110 Name of transferor corporation	**115** Business Number	**120** Tax year-end Year Month Day
Alectra Inc.	[redacted]	2025-12-31

	Name of transferee corporation(s) **225**	Business Number **230**	Part VI.1 tax transferred $ **233**	Tax year-end to which this agreement applies (YYYY/MM/DD) **235**
1.	ALECTRA UTILITIES CORPORATION	[redacted]	137,000	2025-12-31

Total (cannot be more than the Part VI.1 tax on line 105) 137,000

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Schedule 50

Shareholder Information

Corporation's name	Business number	Tax year-end Year Month Day
ALECTRA UTILITIES CORPORATION	[redacted]	2025-12-31

- All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.
- Provide only one number (business number, partnership account number, social insurance number or trust number) per shareholder.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business number or partnership account number (9 digits, 2 letters, and 4 digits. If not registered, enter "**NR**") 200	Social insurance number (9 digits) 300	Trust number (T followed by 8 digits) 350	Percentage common shares 400	Percentage preferred shares 500
1	ALECTRA INC.	[redacted]			100.000	100.000
2						
3						
4						
5						
6						
7						
8						
9						
10						

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Schedule 53

General Rate Income Pool (GRIP) Calculation

Corporation's name	Business number	Tax year-end Year Month Day
ALECTRA UTILITIES CORPORATION	[redacted]	2025-12-31

On: 2025-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- Credit unions are **not** required to complete this schedule.
- All legislative references are to the federal Income Tax Act and Income Tax Regulations.
- When an eligible dividend was paid in the tax year or there was a change in the GRIP balance, file a completed copy of this schedule with your T2 Corporation Income Tax Return. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsection 89(1) defines the terms **eligible dividend**, **excessive eligible dividend designation**, **general rate income pool**, and **low rate income pool**.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? ☐ Yes ☐ No
   If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Has the corporation wound-up a subsidiary in the preceding taxation year? ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

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Part 1 – General rate income pool (GRIP)

GRIP at the end of the previous tax year			100	203,325,228
Taxable income for the year (DICs enter "0")*	110	71,258,919		
Amount on line 400, 405, 410, or 428 of the T2 return, whichever is the least*	130			
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income*	140	1,603		
Subtotal (line 130 **plus** line 140)		1,603 ▶	1,603 A	
Income taxable at the general corporate rate (line 110 **minus** amount A) (if negative enter "0")	150	71,257,316		
After-tax income (line 150 **multiplied** by 0.72 (the general rate factor for the tax year))			190	51,305,268
Eligible dividends received in the tax year	200			
Dividends deductible under section 113 received in the tax year	210			
Subtotal (line 200 **plus** line 210)		▶		B
Becoming a CCPC (amount W5 in Part 4)	220			
Post-amalgamation (total of amount E4 in Part 3 and amount W5 in Part 4)	230			
Post-wind-up (total of amount E4 in Part 3 and amount W5 in Part 4)	240			
Subtotal (**add** lines 220, 230, and 240)	290	▶		
Subtotal (**add** lines 100, 190, 290, and amount B)				254,630,496 C
Eligible dividends paid in the previous tax year	300			
Excessive eligible dividend designations made in the previous tax year	310			
(If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.)				
Subtotal (line 300 **minus** line 310)		▶		D
GRIP before adjustment for specified future tax consequences (amount C **minus** amount D) (amount can be negative)			490	254,630,496
Total GRIP adjustment for specified future tax consequences to previous tax years (amount L3 in Part 2)			560	
GRIP at the end of the tax year (line 490 **minus** line 560)			590	254,630,496

Enter this amount on line 160 of Schedule 55, Part III.1 Tax on Excessive Eligible Dividend Designations.

* For lines 110, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (for example, flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

DRAFT

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2024-12-31

Taxable income before specified future tax consequences from the current tax year 68,799,110 A1

Enter the following amounts before specified future tax consequences from the current tax year:

Amount on line 400, 405, 410, or 428 of the T2 return, whichever is the least B1

Aggregate investment income (line 440 of the T2 return) 10,508 C1

Subtotal (amount B1 **plus** amount C1) 10,508 ▶ 10,508 D1

Subtotal (amount A1 **minus** amount D1) (if negative, enter "0") 68,788,602 ▶ 68,788,602 E1

Future tax consequences that occur for the current year

Amount carried back from the current year to a prior year

Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences F1

Enter the following amounts after specified future tax consequences:

Amount on line 400, 405, 410, or 428 of the T2 return, whichever is the least G1

Aggregate investment income (line 440 of the T2 return) H1

Subtotal (amount G1 **plus** amount H1) ▶ I1

Subtotal (amount F1 **minus** amount I1) (if negative, enter "0") ▶ J1

Subtotal (amount E1 **minus** amount J1) (if negative, enter "0") K1

GRIP adjustment for specified future tax consequences to the first previous tax year

(amount K1 **multiplied** by 0.72) **500**

DRAFT

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Second previous tax year 2023-12-31

Taxable income before specified future tax consequences from the current tax year 38,603,187 A2

Enter the following amounts before specified future tax consequences from the current tax year:

Amount on line 400, 405, 410, or 428 of the T2 return, whichever is the least B2

Aggregate investment income (line 440 of the T2 return) 240,898 C2

Subtotal (amount B2 **plus** amount C2) 240,898 ▶ 240,898 D2

Subtotal (amount A2 **minus** amount D2) (if negative, enter "0") 38,362,289 ▶ 38,362,289 E2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences F2

Enter the following amounts after specified future tax consequences:

Amount on line 400, 405, 410, or 428 of the T2 return, whichever is the least G2

Aggregate investment income (line 440 of the T2 return) H2

Subtotal (amount G2 **plus** amount H2) ▶ I2

Subtotal (amount F2 **minus** amount I2) (if negative, enter "0") ▶ J2

Subtotal (amount E2 **minus** amount J2) (if negative, enter "0") K2

GRIP adjustment for specified future tax consequences to the second previous tax year

(amount K2 **multiplied** by 0.72) **520**

DRAFT

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2022-12-31

Taxable income before specified future tax consequences from the current tax year 54,256,455 A3

Enter the following amounts before specified future tax consequences from the current tax year:

Amount on line 400, 405, 410, or 428 of the T2 return, whichever is the least B3

Aggregate investment income (line 440 of the T2 return) 8,610 C3

Subtotal (amount B3 **plus** amount C3) 8,610 ▶ 8,610 D3

Subtotal (amount A3 **minus** amount D3) (if negative, enter "0") 54,247,845 ▶ 54,247,845 E3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences F3

Enter the following amounts after specified future tax consequences:

Amount on line 400, 405, 410, or 428 of the T2 return, whichever is the least G3

Aggregate investment income (line 440 of the T2 return) H3

Subtotal (amount G3 **plus** amount H3) ▶ I3

Subtotal (amount F3 **minus** amount I3) (if negative, enter "0") ▶ J3

Subtotal (amount E3 **minus** amount J3) (if negative, enter "0") K3

GRIP adjustment for specified future tax consequences to the third previous tax year

(amount K3 **multiplied by** 0.72) **540**

Total GRIP adjustment for specified future tax consequences to previous tax years:

(**add** lines 500, 520, and 540) (if negative, enter "0") L3

Enter amount L3 on line 560

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Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . ☐

- Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.
- Calculate the GRIP addition of a successor corporation following an amalgamation at the end of its first tax year.
- Calculate the GRIP addition of a parent corporation upon wind-up at the end of the tax year that ends immediately after the tax year in which the parent has received the assets of the subsidiary.
- In the calculation below, **corporation** means a predecessor or a subsidiary. Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year			A4
Eligible dividends paid by the corporation in its last tax year	B4		
Excessive eligible dividend designations made by the corporation in its last tax year	C4		
Subtotal (amount B4 **minus** amount C4)		▶	D4
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year) (amount A4 **minus** amount D4)			E4

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the E4 amounts. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

DRAFT

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC . . . . . ☐ Post amalgamation . . . . . ☐ Post wind-up . . . . . ☐

- Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year, or when a corporation has become a CCPC since the end of its previous tax year. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.
- Calculate the GRIP addition of a successor corporation following an amalgamation at the end of its first tax year.
- Calculate the GRIP addition of a parent corporation upon wind-up at the end of the tax year that ends immediately after the tax year in which the parent has received the assets of the subsidiary.
- Calculate the GRIP addition of a corporation that became a CCPC since the end of its previous tax year.
- In the calculation below, **corporation** means a predecessor or a subsidiary, or a corporation that became a CCPC since the end of its previous tax year. Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year A5

The corporation's money on hand immediately before the end of its previous/last tax year B5

Total of subsection 111(1) losses that would have been deductible in calculating the corporation's taxable income for the previous/last tax year if the corporation had had unlimited income from each business carried on and each property held and had realized an unlimited amount of capital gains for the previous/last tax year:

Non-capital losses	C5	
Net capital losses	D5	
Farm losses	E5	
Restricted farm losses	F5	
Limited partnership losses	G5	
Subtotal (**add** amounts C5 to G5) ▶		H5

Total of all amounts deducted under subsection 111(1) in calculating the corporation's taxable income for the previous/last tax year:

Non-capital losses	I5	
Net capital losses	J5	
Farm losses	K5	
Restricted farm losses	L5	
Limited partnership losses	M5	
Subtotal (**add** amounts I5 to M5) ▶		N5
Unused and unexpired losses at the end of the corporation's previous/last tax year (amount H5 **minus** amount N5) ▶		O5
Subtotal (**add** amounts A5, B5, and O5)		P5

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year Q5

Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year R5

All the corporation's reserves deducted in its previous/last tax year S5

The corporation's capital dividend account immediately before the end of its previous/last tax year T5

The corporation's low rate income pool immediately before the end of its previous/last tax year U5

Subtotal (**add** amounts Q5 to U5) ▶ V5

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC (amount P5 **minus** amount V5) (if negative, enter "0") W5

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the W5 amounts. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

DRAFT

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Schedule 55

Part III.1 Tax on Excessive Eligible Dividend Designations

Corporation's name	Business number	Tax year-end Year Month Day
ALECTRA UTILITIES CORPORATION	[redacted]	2025-12-31

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, General Rate Income Pool (GRIP) Calculation, or Schedule 54, Low Rate Income Pool (LRIP) Calculation, whichever is applicable.
- File the schedules with your T2 Corporation Income Tax Return no later than six months from the end of the tax year.
- All legislative references are to the Income Tax Act and the Income Tax Regulations.
- Subsection 89(1) defines the terms **eligible dividend**, **excessive eligible dividend designation**, **general rate income pool**, and **low rate income pool**.
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Do not use this area

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3			
Taxable dividends paid in the tax year **included** in Schedule 3		68,175,708	
Total taxable dividends paid in the tax year	100	68,175,708	
Total eligible dividends paid in the tax year	150		
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")	160	254,630,496	
Excessive eligible dividend designation (line 150 **minus** line 160)			A
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *	180		
Subtotal (amount A **minus** line 180)			B
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount B **multiplied** by 20 %)	190		

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3			
Taxable dividends paid in the tax year **included** in Schedule 3			
Total taxable dividends paid in the tax year	200		
Total excessive eligible dividend designations in the tax year (amount A of Schedule 54)			C
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *	280		
Subtotal (amount C **minus** line 280)			D
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount D **multiplied** by 20 %)	290		

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax.

DRAFT

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Schedule 89

Request for Capital Dividend Account Balance Verification

- If you are a private corporation, use this schedule to summarize the components making up your capital dividend account (CDA) balance as of the date you specify below, on line 003.
- Mail one completed copy of this schedule, separately from any other return to:

  Prince Edward Island Tax Centre
  275 Pope Road
  Summerside PE C1N 6A2
- Unless otherwise stated, all legislative references are to the current version of the Income Tax Act. Since CDA balance components can span several years, the current references in the Act may not apply to older components of your CDA balance. In these cases, see the version of the Act that applies for that particular year.
- For specific details about calculating the CDA balance, see the applicable legislation in the Act.
- All references to paragraphs in subsection 89(1) of the Act are under the definition of **capital dividend account**.
- If you are paying out a capital dividend from your CDA, you must first file Form T2054, Election for a Capital Dividend Under Subsection 83(2). If a capital dividend paid out under this election exceeds the balance of the CDA at the time the dividend becomes payable, you may have to pay Part III tax on the excess dividend (see section 184 of the Act).

Part 1 – Identification

002 Corporation's name		001 Business number
ALECTRA UTILITIES CORPORATION		[redacted]
Address: 2185 Derry Rd W	City: Mississauga	Province: ON / Postal code: L5N7A6
019 Name of contact person: [redacted]		
024 Name of firm	022 Telephone number	023 Extension

Capital dividend account balance as of . . . . . 003 Year Month Day: 2025-12-31

Please check **yes** for **only one** of the following two questions:

Is this a balance verification request? Check **yes** only if this request does not relate to a Form T2054, mentioned at line 005 . . . . . 004 ☐ Yes ☒ No

(if **yes**, then the date on line 003 should be the last tax year-end, included in the CDA balance)

Is this request related to the requirements of subsection 89(1) for Form T2054? . . . . . 005 ☐ Yes ☒ No

(if **yes**, then the date on line 003 should be the earlier of the date the dividend became payable, or the first day on which any part of the dividend was paid)

DRAFT

Part 2A – CDA components (except for eligible capital property) – Summary lines for predecessor corporations (for amounts after July 13, 1990) [1 and 2]

Only complete this part of the schedule if you have any predecessor balances to report. If you do **not** have any predecessor balances, proceed to **Part 2B**.

	1	2	3	4	5	6	7	8
	Predecessor business number	Amalgamation date (YYYY/MM/DD)	The non-taxable portion of capital gains (including the non-taxable portion of capital gains from a trust after September 15, 2016) and non-deductible portion of capital losses per paragraph 89(1)(a)	Capital dividends received per paragraph 89(1)(b)	**Net** proceeds of a life insurance policy per paragraph 89(1)(d)	Non-taxable portion of capital gains from a trust before September 16, 2016 per paragraph 89(1)(f)	Capital dividends from a trust per paragraph 89(1)(g)	Capital dividends payable per subsection 83(2)
	3		4	5		6	6	
	080	082	084	086	088	090	092	094
1.								
	Totals:							

If you need more space, attach additional schedules.

1 For eligible capital property, see parts 3 and 7.

2 The CDA balance may be reduced to nil immediately before the dates referred to in those provisions if you were:
- a private corporation under non-resident control that became Canadian controlled as per subsection 89(1.1)
- or a tax-exempt corporation that became taxable as per subsection 89(1.2), the CDA balance may be reduced to nil immediately before the dates referred to in those provisions

3 For amalgamations and wind-ups after **July 13, 1990**, carry over the amounts of all the CDA components of each predecessor corporation into the calculation of the CDA components of the successor or parent corporation. A negative balance in a component of a CDA of a predecessor corporation must be included in the CDA of the successor or parent corporation. Include a separate CDA calculation on a separate schedule for each predecessor corporation that **does not match** with the amounts in My Business Account.

4 Along with applicable losses, include the non-deductible portion of a business investment loss here. Show losses as a negative.

5 May be adjusted by an excessive dividend election under subsection 184(3). Exclude a dividend that subsection 83(2.1) applies to.

6 The amounts that can be added to the CDA of the corporation in a particular tax year, in respect of amounts received by the corporation, from a trust and that are attributable to capital gains realized by the trust or to dividends received and distributed by a trust, can only be determined after the end of the taxation year of the trust in which the capital gains were realized or the dividends were received and distributed by it.

DRAFT

Part 2B – CDA components (except for eligible capital property) – Detail lines for filing corporation [7 and 8]

	1	2	3	4	5	6	7
	Tax year-end or relevant date (YYYY/MM/DD)	The non-taxable portion of capital gains (including the non-taxable portion of capital gains from a trust after September 15, 2016) and non-deductible portion of capital losses per paragraph 89(1)(a)	Capital dividends received per paragraph 89(1)(b)	**Net** proceeds of a life insurance policy per paragraph 89(1)(d)	Non-taxable portion of capital gains from a trust before September 16, 2016 per paragraph 89(1)(f)	Capital dividends from a trust per paragraph 89(1)(g)	Capital dividends payable per subsection 83(2)
	9	10	11		12	12	
	100	110	120	130	140	150	160
1.	2018-12-31	2,645,263.00					
2.	2019-12-31	2,502,000.00					
3.	2020-12-31	1,166,178.00					
4.	2021-12-31	7,601,936.00					
5.	2022-12-31	8,610.00					
6.	2023-12-31	240,898.00					
7.	2024-12-31	10,508.00					
	2025-12-31	1,603.00					
	Totals:	14,176,996.00					

If you need more space, attach additional schedules.

7 For eligible capital property, see parts 3 and 7.

8 The CDA balance may be reduced to nil immediately before the dates referred to in those provisions if you were:
- a private corporation under non-resident control that became Canadian controlled as per subsection 89(1.1),
- or a tax-exempt corporation that became taxable as per subsection 89(1.2), the CDA balance may be reduced to nil immediately before the dates referred to in those provisions.

9 Include as many tax years as required. Start your list with the tax year that began after the corporation last became a private corporation and that ended after 1971. End your list on the CDA balance date shown on line 003. If you are completing this schedule before your tax year-end, enter the relevant date of the activity.

10 Along with applicable losses, include the non-deductible portion of a business investment loss here. Show losses as a negative.

11 May be adjusted by an excessive dividend election under subsection 184(3). Exclude a dividend that subsection 83(2.1) applies to.

12 The amounts that can be added to the CDA of the corporation in a particular tax year, in respect of amounts received by the corporation, from a trust and that are attributable to capital gains realized by the trust or to dividends received and distributed by a trust, can only be determined after the end of the taxation year of the trust in which the capital gains were realized or the dividends were received and distributed by it.

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Part 3 – CDA components – Eligible capital property (ECP)

Record in these tables the most common amounts included in the eligible capital property (ECP) component of the CDA. This information is not meant to replace the calculation at line 400 in Part 7.

Section A: CDA components – List of ECP acquisitions and dispositions
(for tax years ending before **February 28, 2000**)

	1	2	3	4
	Tax year-end (YYYY/MM/DD) **200**	Cost of eligible capital property acquired **210**	Proceeds of sale (**minus** outlays and expenses not otherwise deductible) from the disposition of all eligible capital property **220**	Non-taxable portion of ECP sales
1				
			Total	

If you need more space, attach additional schedules.

Section B: CDA components – List of ECP dispositions
(for tax years ending after **February 27, 2000** and before **January 1, 2018)**

	1	2	3	4	5
	Tax year-end (YYYY/MM/DD) **250**	Cost of eligible capital property acquired **261**	Proceeds of sale (**minus** outlays and expenses not otherwise deductible) from the disposition of all eligible capital property **262**	Appropriate portion of the amount deducted as a bad debt per subsection 20(4.2) or as an allowable capital loss per subsection 20(4.3). **270**	Non-taxable portion of ECP sales
1					
				Total	

If you need more space, attach additional schedules.

DRAFT

Part 4 – Additional information – Capital dividends received from a corporation

For each capital dividend received, as recorded in column 4 in Part 2A and column 3 in Part 2B, give the name and business number of the corporation that paid the capital dividend and the date the dividend became payable.

	1	2	3
	Corporation's name **300**	Business number **310**	Date the dividend became payable (YYYY/MM/DD) **320**
1			

If you need more space, attach additional schedules.

Part 5 – Additional information – Capital dividends received from a Trust

For each capital dividend received, as recorded in column 7 in Part 2A and column 6 in Part 2B, give the name and trust number of the trust that paid the capital dividend and the date the dividend became payable.

	1	2	3
	Trust's name **330**	Trust account number **335**	Date the dividend became payable (YYYY/MM/DD) **340**
1			

If you need more space, attach additional schedules.

DRAFT

Part 6 – Additional information – Life insurance

Provide the following information if the CDA balance is to include **net** life insurance proceeds.

Please attach a letter from the insurance company stating whether the life insurance policy was a taxable or non-taxable policy.

Policy 1:

350 Name of insured individual		**351** Name of beneficiary	
352 Policy number	**353** Adjusted cost base (ACB)	**354** Total **net** proceeds received	**355** Policy redemption date Year Month Day

Policy 2:

360 Name of insured individual		**361** Name of beneficiary	
362 Policy number	**363** Adjusted cost base (ACB)	**364** Total **net** proceeds received	**365** Policy redemption date Year Month Day

Part 7 – CDA balance

Include the non-taxable portion of capital gains (including the non-taxable portion of capital gains from a trust after September 15, 2016) and the non-deductible portion of capital losses (total of column 3 in Part 2A **plus** total of column 2 in Part 2B. If negative enter "0")		14,176,996.00 7A
Capital dividends received (total of column 4 in Part 2A **plus** total of column 3 in part 2B)		7B
Eligible capital property for tax years ending before January 1, 2018 (as calculated per former paragraphs 89(1)(c), (c.1) and (c.2). If negative, enter "0")	**400**	
Life insurance proceeds (total of column 5 in Part 2A **plus** total of column 4 in Part 2B. If negative, enter "0")		7C
Life insurance CDA [13]	**410**	
Non-taxable portion of capital gains from a trust before September 16, 2016 (total of column 6 in Part 2A **plus** total of column 5 in Part 2B)		7D
Capital dividends from a trust (total of column 7 in Part 2A **plus** total of column 6 in Part 2B)		7E
Amounts from predecessor and subsidiary corporations [14] (For amalgamations and wind-ups before July 14, 1990 **only**)	**420**	
Subtotal (**add** amounts 7A to 7E and lines 400 to 420)		14,176,996.00 7F
Capital dividends that previously became payable (total of column 8 in Part 2A **plus** total of column 7 in Part 2B)		7G
CDA balance (amount 7F **minus** amount 7G. If negative, write "0")	**430**	14,176,996.00

13 Include the balance of the corporation's life insurance CDA immediately before May 24, 1985, in accordance with paragraph 89(1)(e). For more information, see paragraphs 1.61 and 1.62 of Income Tax Folio S3-F2-C1, Capital Dividends.

14 For amalgamations and wind-ups before **July 14, 1990**, calculate the CDA balance of each predecessor or wound-up subsidiary corporation separately. Add these CDA balances to the CDA of the successor or parent corporation. Do not carry forward negative amounts, since these are considered to be nil.

For amalgamations and wind-ups after **July 13, 1990**, please refer to part 2A above.

- For amalgamations, see paragraph 87(2)(z.1).
- For wind-ups, see paragraph 88(1)(e.2).

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Privacy notice

Personal information (including the SIN) is collected to administer or enforce the federal Income Tax Act and related programs and activities including administering tax, benefits, audit, compliance, and collection. The information collected may be used or disclosed for the purposes of other federal acts that provide for the imposition and collection of a tax or duty. It may also be disclosed to other federal, provincial, territorial, or foreign government institutions to the extent authorized by law. Failure to provide this information may result in paying interest or penalties, or in other actions. Under the Privacy Act, individuals have a right of protection, access to and correction of their personal information, or to file a complaint with the Privacy Commissioner of Canada regarding the handling of their personal information. Refer to Personal Information Bank CRA PPU 047 on Info Source at **canada.ca/cra-info-source**.

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Schedule 500

Ontario Corporation Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
ALECTRA UTILITIES CORPORATION	[redacted]	2025-12-31

- Use this schedule if your corporation had a **permanent establishment** (as defined in section 400 of the federal Income Tax Regulations) in Ontario at any time in the tax year and had Ontario taxable income in the tax year.
- Legislative references are to the federal Income Tax Act and Income Tax Regulations.
- This schedule is a worksheet only and is not required to be filed with your T2 Corporation Income Tax Return.

Part 1 – Ontario basic income tax

Ontario taxable income **(Note 1)**	71,258,919	1A
Ontario basic rate of tax for the year	**11.5** %	1B
Ontario basic income tax (amount 1A **multiplied** by amount 1B) **(Note 2)**	8,194,776	1C

Note 1: If your corporation had a permanent establishment only in Ontario, enter the amount from line 360, from page 3 of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Note 2: If your corporation had a permanent establishment in more than one jurisdiction or is claiming an Ontario tax credit in addition to Ontario basic income tax, Ontario corporate minimum tax, or Ontario special additional tax on life insurance corporations payable, enter amount 1C on line 270 of Schedule 5, Tax Calculation Supplementary – Corporations. Otherwise, enter it on line 760 of the T2 return.

Part 2 – Ontario small business deduction (OSBD)

Complete this part if your corporation claimed the federal small business deduction under subsection 125(1).

Line 400 of the T2 return	71,736,816	2A
Line 405 of the T2 return	71,258,919	2B
Line 410 of the T2 return	500,000	2C
Line 415 of the T2 return	13,468,449	2D

Business limit reduction for tax years starting before April 7, 2022

Amount 2C _____ x Amount 2D _____ / 11,250 = _____ 2E

Business limit reduction for tax years starting after April 6, 2022

Amount 2C 500,000 x Amount 2D 13,468,449 / 90,000 = 74,824,717 2F

Amount 2E or amount 2F, whichever applies	74,824,717	2G
Line 515 of the T2 return		2H
Subtotal (amount 2C **minus** amount 2G **minus** amount 2H)	▶	2I
Amount 2A, 2B or 2I whichever is the least	▶	2J

Ontario domestic factor (ODF): Taxable income for Ontario **(Note 3)** 71,258,919.00 / Taxable income for all provinces **(Note 4)** 71,258,919 = 1.00000 2K

Amount 2J **multiplied** by amount 2K		2L
Ontario taxable income (amount 1A)	71,258,919	2M
Ontario small business income (amount 2L or 2M, whichever is less)	▶	2N

Ontario small business deduction for the year

Amount 2N _____ x 8.3 % = _____ 2O

Enter Ontario small business deduction for the year (amount 2O) on line 402 of Schedule 5.

Note 3: Enter amount 1A.

Note 4: Includes the territories and the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

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Part 3 – Ontario adjusted small business income

Complete this part if your corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Ontario adjusted small business income (amount 1A or 2J, whichever is the least) 3A

Enter amount 3A at amount 4B in Part 4 of this schedule or at amount 2E in Part 2 of Schedule 502, Ontario Tax Credit for Manufacturing and Processing, whichever applies.

Part 4 – Credit union tax reduction

Complete this part and Schedule 17, Credit Union Deductions, if the corporation was a credit union throughout the tax year.

Amount 2C of Schedule 17 . . . . . 4A

Ontario adjusted small business income (amount 3A) 4B

Subtotal (amount 4A **minus** amount 4B) (if negative, enter "0") ▶ 4C

Amount 4C x 8.3 % = ... 4D

Ontario domestic factor (amount 2K) 1.00000 4E

Ontario credit union tax reduction (amount 4D **multiplied** by amount 4E) 4F

Enter amount 4F on line 410 of Schedule 5.

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Schedule 510

Ontario Corporate Minimum Tax

Corporation's name	Business number	Tax year-end Year Month Day
ALECTRA UTILITIES CORPORATION	[redacted]	2025-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	6,540,884,523
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	
Total assets (total of lines 112 to 116)		6,540,884,523
Total revenue of the corporation for the tax year **	142	4,433,775,804
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	
Total revenue (total of lines 142 to 146)		4,433,775,804

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

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Part 2 – Adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			210	214,068,781
Add (to the extent reflected in income/loss):				
Provision for current income taxes/cost of current income taxes	220	77,357,033		
Provision for deferred income taxes (debits)/cost of future income taxes	222			
Equity losses from corporations	224			
Financial statement loss from partnerships and joint ventures	226			
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230			
Other additions (see note below):				
Share of adjusted net income of partnerships and joint ventures **	228			
Total patronage dividends received, not already included in net income/loss	232			
281	282			
283	284			
Subtotal		77,357,033 ▶		77,357,033 A
Deduct (to the extent reflected in income/loss):				
Provision for recovery of current income taxes/benefit of current income taxes	320			
Provision for deferred income taxes (credits)/benefit of future income taxes	322			
Equity income from corporations	324			
Financial statement income from partnerships and joint ventures	326			
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330			
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332			
Gain on donation of listed security or ecological gift	340			
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342			
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344			
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346			
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348			
Other deductions (see note below):				
Share of adjusted net loss of partnerships and joint ventures **	328	178,788		
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334	411,000		
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336			
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338			
381	382			
383	384			
385	386			
387	388			
389	390			
Subtotal		589,788 ▶		589,788 B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	290,836,026

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

- exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
- include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

- Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

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Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)					515	290,836,026	
Deduct:							
CMT loss available (amount R from Part 7)							
Minus: Adjustment for an acquisition of control *					518		
Adjusted CMT loss available							C
Net income subject to CMT calculation (if negative, enter "0")					520	290,836,026	
Amount from line 520	290,836,026	x Number of days in the tax year before July 1, 2010 / Number of days in the tax year		x 4 % =			1
Amount from line 520	290,836,026	x Number of days in the tax year after June 30, 2010 / Number of days in the tax year	365 / 365	x 2.7 % =		7,852,573	2
		Subtotal (amount 1 **plus** amount 2)				7,852,573	3
Gross CMT: amount on line 3 above x OAF **					540	7,852,573	
Deduct:							
Foreign tax credit for CMT purposes ***					550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")						7,852,573	D
Deduct:							
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)						8,194,776	
Net CMT payable (if negative, enter "0")							E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** =

Ontario allocation factor 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

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Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *		4,287,877 G		
Deduct:				
CMT credit expired *	600			
CMT credit carryforward at the beginning of the current tax year * (see note below)		4,287,877 ▶	620	4,287,877
Add:				
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)	650			
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)		4,287,877 H		
Deduct:				
CMT credit deducted in the current tax year (amount P from Part 5)		342,203 I		
Subtotal (amount H **minus** amount I)		3,945,674 J		
Add:				
Net CMT payable (amount E from Part 3)				
SAT payable (amount O from Part 6 of Schedule 512)				
Subtotal		▶		K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)	670	3,945,674 L		

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)				4,287,877 M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		8,194,776 1		
For a corporation that is not a life insurance corporation:				
CMT after foreign tax credit deduction (amount D from Part 3)		7,852,573 2		
For a life insurance corporation:				
Gross CMT (line 540 from Part 3)		3		
Gross SAT (line 460 from Part 6 of Schedule 512)		4		
The **greater** of amounts 3 and 4		5		
Deduct: line 2 or line 5, whichever applies:		7,852,573 6		
Subtotal (if negative, enter "0")		342,203 ▶		342,203 N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		8,194,776		
Deduct:				
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)				
Subtotal (if negative, enter "0")		8,194,776 ▶		8,194,776 O
CMT credit deducted in the current tax year (least of amounts M, N, and O)				342,203 P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

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Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin		CMT credit balance *
10th previous tax year	680	
9th previous tax year	681	
8th previous tax year	682	
7th previous tax year	683	
6th previous tax year	684	
5th previous tax year	685	
4th previous tax year	686	
3rd previous tax year	687	
2nd previous tax year	688	
1st previous tax year	689	
Total **		

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . . Q

Deduct:

CMT loss expired * 700

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . . ▶ 720

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) 750

CMT loss available (line 720 **plus** line 750) . . . . . R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . . .

Subtotal (if negative, enter "0") S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) 760

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . . 770 T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

Note: If you entered an amount on line 720 or line 750, complete Part 8.

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Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

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SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
ALECTRA UTILITIES CORPORATION	[redacted]	2025-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	Alectra Inc.	[redacted]	[redacted]	[redacted]
2	Alectra Real Estate Holdings Inc.	[redacted]		
3	Horizon Solar Corp	[redacted]		
4	Alectra Energy Solutions Inc.	[redacted]		
5	Alectra Power Services Inc.	[redacted]		
6	Alectra Energy Services Inc.	[redacted]		
7	Util-Assist Inc.	[redacted]		
8	Holland Power Services Inc.	[redacted]		
9	Alectra Microgrid Services Master GP Inc.	[redacted]		
10	Alectra Microgrid Services Project GP (Georgian) Inc.	[redacted]		
11	Alectra Microgrid Services Project (LNR) GP Inc.	[redacted]		
12	Alectra Campbell Road GP Inc.	[redacted]		
13	748953 N.B. Ltd.	[redacted]		
	Total		**450**	**550**

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Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
- Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

T2 SCH 511

Canada

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Attachment 2
PILs Return Regulated Detail

Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 6-STAFF-207

Tax Credits

Ref 1: Exhibit 6 / Tab 2 / Schedule 1 / Tax Credits, p. 24

Ref 2: Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2026 Edition for 2027 Rate Applications, December 16, 2025, p.43 (pdf p. 49)

Preamble:

Chapter 2 Filing Requirements states that:

> Distributors are expected to exercise sound tax planning and are expected, for rate-setting purposes, to maximize tax credits and take the maximum deductions allowed. The distributor must provide a calculation of tax credits (e.g., Apprenticeship Training Tax Credits, education tax credits, Ontario Regional Opportunities Investment Tax Credits).

Alectra Utilities states that the test year's gross-up PILs includes the impact of the tax credit reclass to other revenue. Alectra Utilities has forecasted $0.56M Scientific Research and Experimental Development (SR&ED) tax credits, $0.35M Apprenticeship Job Creation, and Ontario Co-operative Education Tax Credits of $0.35M based on 2023 actual amounts.

Question(s):

a) Please confirm whether there will be education tax credits or Ontario Regional opportunities Investment tax credits are available in the upcoming rate term.
   i. If so, please provide the estimated amount and explain what the revenue requirement impact would be.
   ii. If not, please explain why not.

b) Please provide an itemized breakdown of the tax credits claimed from 2017 to 2025.

:

i. Please explain why Alectra Utilities used one year (i.e., 2023) claimed amounts for the above-mentioned credits in forecasting the test years' credit amounts.

ii. Please provide a forecast of eligible SR&ED expenditures using alternative approaches with one being the average of most recent three historical years' actual amounts.

iii. Please compare the result from the alternative approach to what was the proposed tax credits and calculate the impact.

c) Please update the PILs model by including the tax credits in the PILs model rather than including them into other revenues.

RESPONSE:

The preamble to the question states that $0.35M Apprenticeship Job Creation, and Ontario Co-operative Education Tax Credits of $0.35M were included in the PILs model. Please note that the $0.35M represents the total of these two tax credits.

a) i) and ii) The only "education tax credits" included in the 2027 – 2031 Test Years is the Apprenticeship Job Creation Tax Credit and the Ontario Co-operative Education Tax Credit. Alectra has not included the Ontario Regional Opportunities Investment Tax Credit as Alectra does not operate in a region that is eligible for this tax credit.

b) Table 1 provides a breakdown of the tax credits received from 2017 to 2024. The 2025 tax credits are not available until the 2025 PILs return is finalized in June 2026.

:

Table 1 - Tax Credits 2017-2024

		2017	2018	2019	2020	2021	2022	2023	2024
Federal	Apprenticeship Job Creation	60,898	72,972	74,649	37,751	43,168	60,112	10,098	16,514
Ontario	Apprenticeship training tax credit	323,785	241,041	113,850	18,511	-	-	-	-
Ontario	Co-op Education Tax Credit	259,025	234,083	327,609	98,865	132,296	358,562	405,336	403,609
		643,708	548,096	516,108	155,127	175,464	418,674	415,434	420,123
Federal	SR&ED	415,493	555,113	367,592	447,708	422,071	529,418	648,397	1,240,794
Ontario	SR&ED	100,465	134,224	88,882	108,254	102,055	128,011	156,780	296,936
Ontario	Business research institute tax credit	2,421	1,200	1,200	-	-	-	-	-
		518,379	690,537	457,674	555,962	524,126	657,429	805,177	1,537,730

i) In reference to Exhibit 6 / Tab 2 / Schedule 1 / Tax Credits, p. 24, it is stated that "Alectra Utilities anticipates rate-regulated expenditures qualifying for Scientific Research and Experimental Development (SR&ED) tax credits in the Test Years will be similar to those experienced in the 2023."

Please note that "those experienced in the 2023." should have been presented as "those experienced up to 2023" as 2024 actual amounts were not finalized until the 2024 PILs return was filed in June 2025. The total estimated tax credits of $915,000 was based on the information that was available at the time and is approximately equal to the 2019 – 2023 five-year average provided in Table 2 of part (iii) of this response.

ii) Forecasting Test Year expenditures that would qualify as eligible SR&ED expenditures is not possible. Determining SR&ED eligible expenditures is dependent on numerous factors, including the type of work involved on the project, the scientific or technical challenges encountered during the project and the subset of project costs that relate specifically to dealing with those challenges. Instead, Table 2 of part (iii) of this response provides a forecast of SR&ED tax credit amounts based on a 3-year and 5-year average tax credit.

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iii) Table 2 is a comparison of 3-year and 5-year averages of the tax credits based on the actual information available at the time of developing the tax credit forecast (i.e up to 2023 actuals):

Table 2 - Tax Credits (2023) - 3 Year and 5 Year Average

		PILs Model Per Test Year	2021 - 2023 3-year Average	2019 - 2023 5-year Average
Federal	Apprenticeship Job Creation		37,793	45,156
Ontario	Co-op Education Tax Credit		298,731	264,534
		350,000	336,524	309,689
Federal & Ontario - SR&ED		565,000	662,244	600,074
Total		915,000	998,768	909,763

Table 3 is a comparison of the 3-year and 5-year averages that incorporate 2024, currently the most recent available actual amounts:

Table 3 - Tax Credits (2024) – 3 Year and 5 Year Average

		PILs Model Per Test Year	2022 - 2024 3-year Average	2020 - 2024 5-year Average
Federal	Apprenticeship Job Creation		28,908	33,529
Ontario	Co-op Education Tax Credit		389,169	279,734
		350,000	418,077	313,262
Federal & Ontario - SR&ED		565,000	1,000,112	816,085
Total		915,000	1,418,189	1,129,347

Based on a 2022-2024 3-year average shown above, the change in the Test Year tax credits is presented in Table 4.

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Table 4 - Change to Tax Credits

	Federal & Ontario - SR&ED	Combined Apprentice and Co-op	Total
2022 - 2024 Average	1,000,112	418,077	1,418,189
As filed	565,000	350,000	915,000
Difference	435,112	68,077	503,189
Gross up adjustment	156,877	24,545	181,422
Grossed-up amount	591,989	92,622	684,611

c) Refer to 6-Staff-207_Attach 1_PILs Model which includes the tax credits in the PILs model rather than including them into other revenues. Table 5 presents a summary of the impact on the grossed-up PILs amount.

Table 5 - Impact to PILs Model

	2027	2028	2029	2030	2031
Revised Grossed-up PILs amount	21,485,579	36,660,809	28,086,237	30,848,401	36,070,596
Grossed-up PILs amount as filed	22,400,579	37,575,809	29,001,237	31,763,401	36,985,596
Decrease	(915,000)	(915,000)	(915,000)	(915,000)	(915,000)
Required corresponding decrease to Other Revenue of originally filed tax credit amount	(915,000)	(915,000)	(915,000)	(915,000)	(915,000)

Alectra Utilities has kept the tax credits within Other Revenue to align with its accounting treatment and continues to remove the impact of the tax credits from Tab “T0 PILs, Tax Provision Test” of the PILs model. The inclusion of the tax credits in the PILs model assumes that the tax credits have not been included in Regulatory Income before Taxes, which is inconsistent with Alectra Utilities set of facts. Furthermore, in calculating taxable income on Tab “T1 Sch 1 Taxable Income Test” of the PILs model that was originally filed, an adjustment is made to add to taxable income the amount of the prior year’s tax credits received, and a deduction is taken for the accrued current-year tax credits that are recorded in Regulatory Income before Taxes. This is consistent with the treatment on Alectra Utilities tax returns. However, if the benefit of the tax credits to ratepayers is included in the PILs model and moved out of Regulatory Income before Taxes, the tax credit deduction to remove tax credits

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accrued in Regulatory Income before taxes must also be removed in calculating taxable income on Tab “T1 Sch 1 Taxable Income Test”.

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6-Staff-207

Attachment 1
PILs Model

Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 6-STAFF-208

PILs Model

Ref 1: Exhibit 6 / Alectra_Attach 6-7_PILs Workform_20251014

Ref 2: Exhibit 2B / Alectra_Attach 2B-1_OEB Appendix 2-BA-Fixed Asset Continuity Schedule_20251121

Preamble:

Per references 1 and 2, OEB staff has complied a table as below, showing the difference of capital additions between PILs model (Schedule 8) and Appendix 2BA (before CWIP addition and excluding land).

Differences of Capital Additions between PILs (Sch8) & 2BA

$	2026	2027	2028	2029	2030	2031
Capital additions (Ref 1) - (a)	325,506,632	432,318,247	466,857,805	568,352,932	618,945,827	610,756,296
Capital additions (Ref 2) - (b)	335,859,635	444,249,000	481,638,492	587,054,910	641,342,021	638,671,938
Variance (b-a)	10,353,003	11,930,753	14,780,687	18,701,978	22,396,194	27,915,642

Question(s):

a) Please reconcile and explain the variances identified in the table above.

b) Please update the evidence as applicable.

RESPONSE:

a) Table 1 provides a reconciliation between accounting additions (before CWIP and excluding land) and additions for tax purposes.

The reconciling items are interest and pension contribution amounts that have been capitalized for accounting purposes but are allowed to be expensed for tax purposes in the year incurred. As a result, these amounts are reduced from tax additions, and a current deduction is taken to reduce taxable income on Schedule 1.

Table 1 - Capital Additions for PILs Reconciliation

		2026	2027	2028	2029	2030	2031
Capital addtions (Ref 2)							
(Additions for Accounting)		335,859,635	444,249,000	481,638,492	587,054,910	641,342,021	638,671,938
Adjustments							
Interest capitalized for accounting; not for tax	[A]	(3,382,506)	(4,199,361)	(6,415,573)	(9,741,191)	(13,037,206)	(18,187,725)
Pension contribution amounts capitalized for accounting, not for tax	[A]	(6,958,143)	(7,731,391)	(8,365,114)	(8,960,787)	(9,358,987)	(9,727,917)
Other		(12,354)					
Total Adjustments		(10,353,003)	(11,930,752)	(14,780,687)	(18,701,978)	(22,396,193)	(27,915,642)
Capital addtions (Ref 1)		325,506,632	432,318,247	466,857,805	568,352,932	618,945,827	610,756,296
(Additions for Tax)							

[A] Corresponding deductions on Schedule 1 in determining taxable income

b) An update to the evidence is not required.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 6-STAFF-209

Accelerated Investment Incentive Program (AIIP)
Designated Immediate Expensing Property (DIEP)
Ref 1: Exhibit 6 / Tab 2 / Schedule 1 / p. 5 (pdf p. 23)
Ref 2: Exhibit 9 / Tab 3 / Schedule 26 / Section 4.2.25 / p. 1 (pdf p. 502)
Ref 3: Alectra_Attach 9-15_Accelerated CCA Difference (Bill C-97) _20251014
Ref 4: Alectra_Attach 9-16_Accelerated CCA Difference (Bill C-19) _20251014
Ref 5: Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2026 Edition for 2027 Rate Applications, December 16, 2025, p. 68 (pdf p. 74)
Ref 6: Exhibit 6 / Alectra_Attach 6-7_PILs Workform_20251014, Schedule 8
Ref 7: Exhibit 2B / Alectra_Attach 2B-1_OEB Appendix 2-BA-Fixed Asset Continuity Schedule_20251121

Preamble:
Per reference 1, Alectra Utilities confirms that it utilized the AIIP and DIEP in all tax years in which they are applicable. The DIEP allows a qualifying corporation to expense up to 1.5M per taxation year, for eligible property acquired on or after April 19, 2021 which becomes available for use before January 1, 2024. The AIIP provides for a first-year increase in capital cost allowance (CCA) deductions on eligible capital assets acquired after November 20, 2018, available for use before 2028.

Per reference 2, Alectra Utilities states that it uses the approved capital additions to calculate the revenue requirement impact and records the full revenue requirement impact of any changes in CCA rules.

Per references 3 and 4, OEB staff notes that Alectra Utilities used the last OEB-approved capital additions for each legacy utility in calculating the Accelerated CCA (Account 1592 continuity schedule). OEB staff notes that total amount indicated in the tab “FP” in

reference 3 starts from 2022 instead of 2018 when AIIP rule is effective from Nov 2018 and the amounts of immediate expense impact are all hardcoded.

OEB staff also notes that tab "FP" does not reconcile to Account 1592 PILs and Tax Variance Sub-Account CCA Changes in the DVA continuity schedule of each rate zone in this application. For example, 2022 PRZ per tab "FP" is a credit ($3,379,080) while the PRZ DVA continuity shows a credit ($3,164,153). This discrepancy applies to the DVA continuity of each rate zone.

Per reference 5, the 2027 filing requirements state that calculations for accelerated CCA differences per year are based on actual capital additions.

Per reference 6, OEB staff notes Alectra Utilities has applied phase-out AIIP from 2025 to 2027 and reversed back to the legacy half-year rule from 2028 to 2031.

Question(s):

a) Please confirm that the AIIP and DIEP has been claimed in Alectra Utilities' actual tax filings for the period from 2018 to 2025 when applicable.

b) Please provide reference of OEB-Approved capital additions of each rate zone used for the current calculation of Account 1592.

c) Please answer the following questions regarding references 3 & 4:
   i. Please add instruction sheet in both references 3 and 4 to explain the methodology/ logical of each tab.
   ii. Please show the calculation of all the amounts without hardcoding (e.g., Tab "FP" Immediate Exp Impact).
   iii. In reference 4 (Tab Summary), please explain why the revenue requirement impact starts from 2013, even though the last rebasing years for each rate zone are different.

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iv. In reference 4, please explain why there is no 1.0 multiplier based on the phase-out impact from 2024.

v. In reference 4, please explain why the AUC tab includes the years until 2029 while the impacts of Bill-19 on Account 1592 are only until 2026.

vi. Please ensure to only include the calculation of relevant years and remove irrelevant periods.

vii. Please reconcile reference 3 to reference 4.

viii. Please provide excel worksheet to consolidate the amounts calculated from reference 3 and 4 and include the following:

1) Please provide a breakdown by each rate zone and also summarize the amounts calculated of each rate zone for the period from 2019 to 2026.
2) Please reconcile this worksheet to Table 9-3-59 in reference 2.
3) Please show the calculation of all the amounts without hardcoding.
4) Please reconcile to the amounts recorded in Account 1592 in DVA continuity for **each rate zone each year**.

d) Please provide a consolidated excel worksheet based on updated references 3 and 4 using **actual capital additions from 2018 to 2026**. Please follow the steps outlined in reference 5 for the calculation.

i. Please update Table 9-3-59 in reference 1 reflecting this scenario results in Account 1592.

ii. Please complete the following summary table compiled by OEB staff to reconcile the amount recorded in Account 1592 in DVA continuity to updated reference 3 and 4 for each rate zone separately (please ensure all the amounts recorded in the following table has its supporting calculation).

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Schedule 8 actual capital additions	CCA without AIIP/DIEP	CCA with AIIP/DIEP	Difference	Tax Rate	Tax Impact	Income Tax (Grossed Up)	Account 1592
Rate Zone	a	b	c=b-a	d	e=c*d	f=e/(1-d)	g=f
2018 actual				26.50%			
2019 actual				26.50%			
2020 actual				26.50%			
2021 actual				26.50%			
2022 actual				26.50%			
2023 actual				26.50%			
2024 actual				26.50%			
2025 actual				26.50%			
2026 forecast				26.50%			
Total						-	-

iii. Please complete the following table compiled by OEB staff to reconcile actual capital additions, undepreciated capital cost (UCC) schedule and CCA amounts (before capital work in progress (CWIP) addition and excluding land) across the three references:

	Capital Additions		UCC		CCA Amount	
	2025	2026	2025	2026	2025	2026
CCA Workform (Ref 3 & 4) (a)						
PILs Workform Sch8 (Ref 6) (b)						
Appendix 2-BA (Ref 7) (c)			n/a	n/a	n/a	n/a
Variance d = (b-a)						
Variance e = (c-a)			n/a	n/a	n/a	n/a

iv. Please explain any variances identified in the table above (highlighted rows)

v. Please compare the balance of Account 1592 sub-account CCA changes using the actual capital additions and the balance of Account 1592 sub-account CCA changes proposed by Alectra Utilities.

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RESPONSE:

a) Confirmed. AIIP and DIEP have been claimed in Alectra Utilities' actual tax filings for the period from 2018 to 2024, when applicable.

b) The reference of OEB-Approved capital additions of each rate zone used the current calculation of Account 1592 is:

Brampton:	Hydro One Brampton Networks Inc. EB-2014-0083 File: HOBNI_2015_Income_Tax_PILs_Work_Form_xlsm_20141223 Document Type: Draft Rate Order Received by OEB: 2014-12-23
Enersource:	Enersource Hydro Mississauga Inc. EB-2012-0033 File: Enersource_DRO_App_4_20121220 Document Type: Draft Rate Order Received by OEB: 2012-12-20
Guelph:	Guelph Hydro Electric Systems Inc. EB-2015-0073 File: Guelph_Settlement_Updated_Test_year_Income_Tax _PILs_Workform_20151020 Document Type: Settlement Proposal Received by OEB: 2015-10-20
Horizon:	Alectra Utilities Corporation EB-2018-0016 File: Alectra_DRO_Attach 3_PILs Workform 2019_HRZ_20190107 Document Type: Draft Rate Order

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Received by OEB: 2019-01-07

PowerStream: PowerStream Inc.
EB-2015-0003
File: E_PowerStream_2017_Tax_PILs_Workform_20161102
Received by OEB: 2016-11-02

c)

i. Please refer to the new "Tab Description" tab in attachments 6-Staff-209_Attach 1_Bill C-97 AIIP and 6-Staff-209_Attach 2_Bill C-19 DIEP which explains the purpose and methodology of each tab.

ii. The calculation for the Immediate Expense Impact amounts without hardcoding in Tab "FP" can be found in attachment 6-Staff-209_Attach 2_Bill C-19 DIEP in the "Summary Tab".

iii. DIEP only applies to Alectra Utilities as a whole, at the legal entity level. In other words, Alectra Utilities can only claim a maximum $1.5MM deduction in each applicable year and not $1.5MM per rate zone per year. To simplify the calculation, the rate zone that had not rebased for the longest period (ERZ – 2013) was chosen to calculate the impact to approved rates as this would result in the highest total IRM increases and the largest amount to give back to ratepayers.

iv. There is no 1.0 multiplier based on the phase-out impact from 2024 in attachment 6-Staff-209_Attach 2_Bill C-19 DIEP because the multiplier is dependent on the year of when DIEP was claimed in relation to the AIIP multiplier applicable for that same year. For example, eligible DIEP additions in 2021 overlap with the AIIP 2018 – 2023 period where 1.5 times the additions amount is eligible for AIIP. Since AIIP is shifting more CCA to the first year and reducing CCA in later years, the same CCA continuity schedule

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containing the 1.5 multiplier must be used to determine the reduced CCA in later years.

The 1.0 multiplier would have been used if DIEP did not end after 2023 and was eligible on 2024 – 2027 additions during the 1.0 multiplier phase-out period of AIIP.

v. The AUC tab includes years after 2026 as part of the original creation of the model in 2021 in the event that those later years were required in the future, but are not relevant now. All years after 2026 after been deleted from attachment 6-Staff-209_Attach 2_Bill C-19 DIEP.

vi. Confirmed that all irrelevant periods have been removed from attachments 6-Staff-209_Attach 1_Bill C-97 AIIP and 6-Staff-209_Attach 2_Bill C-19 DIEP.

vii. Refer to attachment 6-Staff-209_Attach 1_Bill C-97 AIIP, Tab “FP” which presents:

- The impact of AIIP by rate zone and by year.
- The impact of DIEP by rate zone and by year. Note that the supporting calculation for these values are found in 6-Staff-209_Attach 2_Bill C-19 DIEP, Tab “Summary”.
- The cumulative impact of AIIP and DIEP by rate zone.

viii.

1) Please refer to response vii) for a breakdown by rate zone and by year for AIIP and DIEP.
2) The impact of AIIP on Alectra Utilities’ ICM projects is provided in 6-Staff-209_Attach 4 AIIP Impact on ICM Projects. 6-Staff-209_Attach 5 1592 Reconciliation shows that the total of AIIP and DIEP and AIIP impact on ICM projects which reconciles to Table 9-3-59.
3) All amounts show the calculations without hardcoding.

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4) Please refer to the response to 6-Staff-209- c- viii -2. Table 9-3-59 represents the amounts recorded in 1592 in DVA continuity for each rate zone each year.

d) Table 9-3-59 represents the amounts recorded in Account 1592 in DVA continuity for each rate zone each year. Please refer to 6-Staff-209_Attach 5 1592 Reconciliation. Please refer to 6-Staff-209_Attach 3_Actual Additions for the impact of AIIP and DIEP based on actual additions.

i. Please refer to Table 1 below for the updated Table 9-3-59 at the Alectra Utilities entity level in reference 2 reflecting the use of actual capital additions in Account 1592. This table cannot be broken down by rate zone as the fixed asset continuity cannot be prepared by rate zone.

Table 1 – Updated 1592 balance using actual addition approach

	2019	2020	2021	2022	2023	2024	2025	2026	Total
AIIP and DIEP	(9.75)	(8.43)	(4.16)	(5.04)	(10.73)	(1.71)	0.04	(2.84)	(42.62)
AIIP _ICM	(0.47)	0.06	(0.08)	0.04	0.04	0.05	0.05	0.04	(0.27)
Total	(10.22)	(8.37)	(4.24)	(5.00)	(10.69)	(1.66)	0.09	(2.80)	(42.89)

ii. Table 2 is the requested summary table compiled to reconcile the amount recorded in Account 1592 in DVA continuity based on actual additions. Please refer to 6-Staff-209_Attach 3_Actual Additions for the excel version of the table and the supporting calculations.

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Table 2 – AIIP Impact on Actual Additions

	Schedule 8 actual capital additons	CCA without AIIP/DIEP	CCA with AIIP/DIEP	Difference	Tax Rate	Tax Impact	Income Tax (Grossed Up)	Account 1592
[A]	**Alectra Utilties**	a	b	c=b-a	d	e=c*d	f=e/(1-d)	g=f
[B]	2018 Actual	-	-	-	26.50%	-	-	-
	2019 Actual	(222,321,540)	(249,352,515)	(27,030,975)	26.50%	(7,163,208)	(9,745,862)	(9,745,862)
	2020 Actual	(224,913,785)	(248,294,837)	(23,381,052)	26.50%	(6,195,979)	(8,429,903)	(8,429,903)
	2021 Actual	(214,715,118)	(226,255,463)	(11,540,345)	26.50%	(3,058,191)	(4,160,805)	(4,160,805)
	2022 Actual	(212,183,786)	(226,156,587)	(13,972,801)	26.50%	(3,702,792)	(5,037,813)	(5,037,813)
	2023 Actual	(225,836,533)	(255,600,022)	(29,763,489)	26.50%	(7,887,325)	(10,731,054)	(10,731,054)
	2024 Actual	(244,651,777)	(249,394,511)	(4,742,734)	26.50%	(1,256,825)	(1,709,965)	(1,709,965)
	2025 Forecast	(251,464,126)	(251,351,013)	113,113	26.50%	29,975	40,782	40,782
	2026 Forecast	(260,296,080)	(268,172,909)	(7,876,829)	26.50%	(2,087,360)	(2,839,945)	(2,839,945)
	Total	(1,856,382,744)	(1,974,577,857)	(118,195,112)		(31,321,705)	(42,614,564)	(42,614,564)

[A] Note: Actual capital additions cannot be broken out by rate zones. Alectra is not able to create actual fixed asset continuities by rate zone.

[B] Note: Accelerated depreciation was effective November 21, 2018. Amounts related to 2018 would not be material as it would only be for assets purchased between November 21 and December 31 and the asset would have to be available for use (i.e. not in WIP). Based on the expected immaterial additions during this period, AIIP was not taken.

iii. Table 3 is the requested reconciliation between actual capital additions, undepreciated capital cost (UCC) schedule and CCA amounts (before capital work in progress (CWIP) addition and excluding land) across the three references.

Table 3 – Capital Additions Reconciliation

		Capital Additions		UCC		CCA Amount	
		2025	2026	2025	2026	2025	2026
[A]	CCA Workform (Ref 3 & 4) (a)	336,974,337	325,506,633	2,970,715,363	3,049,466,775	251,351,013	268,172,909
[B]	PILs Workform Sch8 (Ref 6) (b)	336,974,337	325,506,632	2,970,715,354	3,049,466,765	251,351,012	268,172,910
	Appendix 2-BA (Ref 7) (c)	346,696,347	335,859,635	n/a	n/a	n/a	n/a
	Variance d = (b-a)	0	(0)	(9)	(11)	(1)	1
	Variance e = (c-a)	9,722,009	10,353,002	n/a	n/a	n/a	n/a

[A] Refer to 6-Staff-209_Attach 3_Actual Additions

[B] PILs Workform Sch 8 does to present 2025 Capital Additions or CCA Amount; however, these amounts were used in the caculation of 2025 ending UCC shown in the PILs model.

iv. The following are the explanations for the variances identified in the table above:

Variance d Explanation: Differences due to rounding.

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Variance e Explanation: Capitalized interest and pension contributions are deducted on a current basis for tax purposes; therefore, these amounts must be removed when calculating capital cost allowance.

Table 4 – Variance e Explanation:

	2025	2026
Interest capitalized for accounting; not for tax	(3,056,630)	(3,382,506)
Pension contribution amounts capitalized for accounting, not for tax	(6,665,379)	(6,958,143)
Other		(12,353)
TOTAL	(9,722,009)	(10,353,002)

v. Table 5 presents the comparison of using actual additions instead of additions approved in rates in calculating 1592 sub-account CCA changes.

Table 5 – Comparison of Actual Additions and Approved in Rates

in $MMs	2019	2020	2021	2022	2023	2024	2025	2026	Total
Actual Additions Methodology (Refer to Table 1)	(10.2)	(8.3)	(4.3)	(5.0)	(10.7)	(1.6)	-	(2.8)	(42.9)
Approved in Rates Methodology (Reference: Table 9-3-60)	(9.0)	(6.9)	(6.6)	(7.0)	(6.1)	0.1	(0.4)	(0.6)	(36.4)
Difference	(1.2)	(1.4)	2.3	2.0	(4.6)	(1.7)	0.4	(2.2)	(6.5)

The above comparison shows the difference between the “Actual Additions” versus the “Approved in Rates” (“Approved Additions”) methodologies. Alectra Utilities has used the “Approved Additions” methodology because it aligns with the purpose and prescribed use of Account 1592 - PILs and Tax Variances under the Accounting Procedures Handbook. Specifically, Account 1592 is to capture the impact of any differences that result from legislative or regulatory changes to tax rates or rules relative to those assumed in the OEB Tax Model that is used to set rates, not differences arising from actual versus forecast capital spending. This treatment is

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reinforced by letter dated July 25, 2019, issued by the Ontario Energy Board regarding "Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance"". The letter states that "The impact of any differences that are not reflected in rates (due to such factors as timing of known changes) are to be recorded in Account 1592 - PILs and Tax Variances"; however, recording any variances that are not reflected in rates is inconsistent with the parameters of Account 1592 under the Accounting Procedures Handbook.

Table 6 presents the difference between net capital additions for tax purposes under the two methodologies.

Table 6 – Actual and Approved Net Capital Additions for Tax Purposes

in $MMs	2019	2020	2021	2022	2023	2024	2025	2026	Total
Actual Net Additions Methodology	334.1	224.1	236.2	241.5	373.5	349.5	336.3	324.8	2,420.0
Approved in Rates Methodology	264.1	264.1	264.1	264.1	264.1	264.1	264.1	264.1	2,112.8
Difference	70.0	(40.0)	(27.9)	(22.6)	109.4	85.4	72.2	60.7	307.2
ICM	32.7	-	11.1	-	16.1	-	-	-	59.8
Net Additions	37.3	(40.0)	(39.0)	(22.6)	93.3	85.4	72.2	60.7	247.4

Under the Actual Additions method, Alectra Utilities will be refunding the impact of the CCA changes on $247MM of capital additions that are not in rate base and in turn, do not underpin rates. When the CCA changes became effective, Alectra Utilities was already in the MAADs deferred rebasing period and has not recovered the corresponding depreciation, deemed interest or return on equity for the difference between actual and approved capital additions. In other words, ratepayers have not been subjected to any of the costs associated with fixed asset additions greater than what is currently in rates, but the Actual Additions methodology for Account 1592 provides the ratepayer with the full benefit of the tax legislation changes on those additions. Based on this, in addition to the Accounting Procedures Handbook definition of Account 1592, the Approved Additions methodology was used to determine the impact of the tax legislation changes to CCA.

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6-Staff-209

Attachment 1
Bill C-97 AIIP

Please see live Excel

6-Staff-209

Attachment 2
Bill C-19 DIEP

Please see live Excel

6-Staff-209

Attachment 3
Actual Additions

Please see live Excel

6-Staff-209

Attachment 4
All Impact on ICM Projects

Please see live Excel

6-Staff-209

Attachment 5
1592 Reconciliation

Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 6-STAFF-210

PILs Model, Sch 8

Ref 1: Exhibit 6 / Alectra_Attach 6-7_PILs Workform_20251014

Question(s):

a) Per reference 1, the CCA amounts in the following accounts are all hardcoded, please provide worksheet showing the CCA calculation of these accounts.

13 $_1$	Lease # 1
13 $_2$	Lease # 2
13 $_3$	Lease # 3
13 $_4$	Lease # 4
14	Limited Period Patents, Franchises, Concessions or Licences

RESPONSE:

a) Refer to 6-Staff-210_Attach 1_Class 13 14 CCA for the calculation of the CCA amounts for Class 13 and Class 14.

6-Staff-210

Attachment 1
Class 13 14 CCA

Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 6-STAFF-211

Other Revenue

Ref 1: Exhibit 6 / Alectra_Attach 6-9_OEB Appendix 2-H- Other Revenues_20251027

Question(s):

(a) Please file an updated Appendix 2-H, with 2025 actuals if available. If not available, please file updated Appendix 2-H with a more recent 2025 estimate.

RESPONSE:

(a) Please refer to 1-SEC-24.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 6-STAFF-212

Other Revenue

Ref 1: Exhibit 6 / Alectra_Attach 6-9_OEB Appendix 2-H- Other Revenues_20251027

Question(s):

a) Please explain in detail Alectra Utilities' assumptions and rationale used to forecast other revenue amounts for each account in reference 1 for the 2025 Bridge year, the 2026 Bridge Year, and the 2027 to the 2031 test years.
    i. Please provide supporting calculations to assist with the explanation as needed.

RESPONSE:

Please see below:

USoA 4082 Retail Services Revenue was forecast based on the prior year actuals. As the actual revenue has been declining since 2021, Alectra didn't forecast an increase after 2027.

USoA 4084 The amounts are not material, the forecast included with account 4082.

USoA 4086 SSS Admin Revenue was based on the customer count multiplied by the SSS rate, with the same rate used from 2026 to 2031. Thus, the year-over-year change is consistent with customer growth assumptions.

USoA 4210 Rent from Electric Property

Please refer to 6-SEC 98 (b)

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USoA 4225 Late Payment charges

Late payment charge revenue is estimated based on monthly forecasted arrears balances.

USoA 4235 Miscellaneous Service Revenue

The specific service charges (SSC) are recorded in account 4235. Most of the SSC are of administrative nature (such as certificates of arrears, statements of account). Consistent with the forecasted growth of the Alectra customer base, an associated increase in the number of services and associated SSC charges are forecast.
For the details of forecasted specific service charges please refer to the 6-SEC-98 (c).

Also recorded in this account are stale-dated cheques revenue, consisting of customer final refund cheques that remain uncashed for an extended period of time. Stale-dated cheques revenue was estimated by analyzing historical averages from 2022-2023 and the 2024 forecast, adjusted by removing one-time items that are not expected to re-occur.

Administration charges revenue includes administrative costs recovered from customers related to damage and accident claims. Administration charges revenue was forecasted by analyzing historical averages from 2019 -2023 and the 2024 forecast and adjusted for one-time items that are not expected to re-occur.

USoA 4305 and 4310 please refer to 6-STAFF 220, 6-STAFF-221.

USoA acct 4360 Gain/Loss on Sale of Assets

Gain/Loss on Sale of Assets was estimated by analyzing historical averages from 2022-2024 by asset type. The averages were adjusted by removing one-time items that are not expected to re-occur.

USoA 4375 Revenues from non-regulated utility operations

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The forecasted revenue in this account includes the water billing revenues and the Envida solar revenues. The water billing revenues are forecast to end when Alectra ceases to provide this service in 2028. For more details, please refer to 6-Staff-229.

USoA 4380 Expenses on non-regulated utility operations

The main component of the forecast non-utility expenses includes the costs of providing water billing services until the planned exit in 2028. In addition, this account includes Envida expenses that are forecasted to remain relatively stable year-over-year adjusted for inflationary increases. For more details, please refer to 6-Staff-229

USoA 4390 Miscellaneous Non-Operating Income

The major items forecasted under this account include:

Early Pay Discounts revenue was estimated by analyzing historical averages from 2019-2023 and 2024 forecast.

Scrap Sales revenue

Scrap Sales revenue was forecast by analyzing historical averages from 2019-2023 and the 2024 forecast.

The scrap sales revenue forecast was then increased compared to historical averages as Supply Chain assumed a higher amount of scrap materials would be available for sale. This assumption was based on an ongoing efficiency project that identifies greater amounts of obsolete inventory that can be sold for scrap materials, along with forecasts of higher scrap metal prices.

SR&ED credits

SR&ED credits are based on the amount of eligible expenditures incurred, which are not readily apparent at the time the budget is created. SR&ED credits were forecast by analyzing historical averages from 2021-2023 and the 2024 forecast. Apprentice and co-op ITCs are based on the amount of approved headcount within the budget, and the

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Tax team provides a forecast of budgeted ITCs as part of their review of Income Tax PILS.

Damage and accident claims

Damage and accident claims revenue is generated when a third party causes a collision with Alectra's distribution assets, and Alectra is reimbursed for the resulting equipment damage. These activities are reactive in nature. Damage and accident claims revenue was forecasted by analyzing historical averages from 2019-2023 and the 2024 forecast and adjusted for one-time items that are not expected to re-occur.

USoA 4405 Interest and dividend Income

Alectra Utilities is a net borrower and receives deposit interest on its cash balances, if any, at a competitive market rate with its cash management bank. As part of Alectra's budget for 2026-2031, Alectra forecasted interest income based on average cash balances of $40MM annually and an average of the large Canadian banks' forecasted overnight rate at the time the budget was created. The resulting interest income based on this calculation should have been included as the forecasted interest income in the rebasing application. The $nil interest income originally filed has been updated to $1.1MM annually, which is the amount included in Alectra Utilities' 2026-2031 budget. Please refer to 1-SEC-24_Attach 6_OEB Appendix 2-H_Other Revenue_20260220 for the actuals and forecasted amounts from 2017-2031.

Alectra Utilities advances its short-term borrowing requirements in relation to the payment of the monthly IESO invoice. This pre-borrowing results in the buildup of cash balances and the generation of interest income. Starting in May 2023 cash balances were higher than normal, primarily because Alectra had to advance the pre-borrowing for the IESO invoices to two weeks from one week. This change was necessitated by market uncertainty because financial conditions had tightened globally and in response to the Bank of Canada's inflation reducing monetary policy actions. This change resulted in higher cash balances which resulted in higher-than-normal short-term interest

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expense and higher interest revenue. In the last quarter of 2025, Alectra implemented a new cash management process whereby Alectra Utilities is able to fund its cash requirement on an as needed basis. It is forecasted that the average cash balance will be lowered to $40MM using this new process. After implementing this change in procedure, the average cash balance for Q4-25 was $28MM.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 6-STAFF-213

Account 4082 - Retail Services Revenues
Ref 1: Exhibit 6 / Alectra_Attach 6-9_OEB Appendix 2-H- Other Revenues_20251027
Ref 2: Exhibit 8 / Tab 3 / Schedule 1 / p. 1 (pdf p. 67)

Preamble:
In reference 2, Alectra Utilities states that it is not proposing any retail service charges apart from those established on a generic basis. For the purpose of this application, the proposed retail service charges are equal to the OEB's approved 2026 retail service charges from EB-2025-0199.

In reference 1, the forecast year-over-year increase in retail services revenue shows 0% from 2026 to 2031.

Question(s):

a) Did Alectra Utilities use the OEB's generic retail service charges to calculate the 2026 revenue? If so, why is there no year-over-year revenue increase in 2026 compared to 2025 based on the OEB's approved 2026 inflation adjustment? Please explain.

b) Is the retail service revenue for the 2027 to 2031 period, which is forecast to increase by 0.0%, just a placeholder?

c) Please confirm whether Alectra Utilities is proposing to update the retail service revenue every year to reflect the OEB's approved retail service charges as part of its annual custom IR update for the 2028 to 2031 period. If not, please explain why not.

RESPONSE:

a) Yes, Alectra used the OEB's generic service charges in calculating 2026 Retail services revenue. At the time the forecast was prepared, the OEB-approved inflation adjustment was not available.

b) Yes, it is a placeholder. 0.0% increase was the best available information at the time.

c) Confirmed that Alectra Utilities is proposing to update the retail service revenue every year to reflect the OEB's approved retail service charges as part of its annual custom IR update for the 2028 to 2031 period.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 6-STAFF-214

Account 4210 - Rent from Electric Property
Ref 1: Exhibit 6 / Alectra_Attach 6-9_OEB Appendix 2-H- Other Revenues_20251027
Ref 2: Exhibit 6 / Tab 3 / Schedule 1 / p. 5 (pdf p. 262)

Preamble:
Alectra Utilities states in reference 2 that from 2026 - 2027, pole attachment revenues are forecasted to increase by approximately $2.6M, reflecting a change in the accounting treatment of pole attachment revenues.

Reference 2 also states that Alectra Utilities proposes to continue charging the provincially approved rate per pole per month for pole attachments.

Reference 1 shows that the pole attachment revenues are forecast to increase by 1.8% per year from the 2028 to 2031 period which is less than the OEB's current approved 2026 inflation of 3.7%.

Question(s):

a) Is the 2026 - 2027 increase in pole rental revenue within Account 4210 solely attributable to Alectra Utilities' proposal to adopt the latest OEB-approved pole attachment charge? Please provide Alectra Utilities' supporting calculations used to derive the pole attachment revenue for 2027.

b) Is the forecast 1.8% increase in pole attachment revenue (reference 1) for the 2028 to 2031 period just a placeholder? Please confirm whether Alectra Utilities is proposing to update the pole attachment revenue every year for the 2028 to 2031 to reflect the OEB's

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approved distribution pole attachment charge as part of its annual custom IR update for the 2028 to 2031 period. If not, why not?

RESPONSE:

a) Please refer to 6-SEC-98 (b) which provides the method of calculation of pole rental revenue.

b) Confirmed – this is a placeholder. The pole attachment revenue will be updated annually to reflect the OEB approved charge as part of Alectra's annual custom IR update.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 6-STAFF-215

Account 4086 - SSS Administration Revenue

Ref 1: Exhibit 6 / Alectra_Attach 6-9_OEB Appendix 2-H- Other Revenues_20251027

Preamble:

The other revenue data in Account 4086 show an annual increase of $2.6M in 2019 which exceeds the materiality threshold of $1M:

Question(s):

a) Please provide the following.
   i. Explanation for drivers of the increase.
   ii. Supporting calculations to assist with the explanation if needed.

RESPONSE:

a) Until 2019, the SSS Administration revenue for all rate zones, except Enersource, in Alectra's GL was mapped to the OEB account 4080. Therefore, the 2017-2018 historical balances in account 4086 include ERZ SSS revenue only. The SSS administration revenue mapping has been harmonized in 2019, when SSS administration revenue in all rate zones has been re-mapped to account 4086.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 6-STAFF-216

Account 4225 - Late Payment Charges
Ref 1: Exhibit 6 / Alectra_Attach 6-9_OEB Appendix 2-H- Other Revenues_20251027
Ref 2: Exhibit 6 / Tab 3 / Schedule 1 / pp. 3-4 (pdf pp. 260-261)

Preamble:
Alectra Utilities explained in reference 2 that the year-over-year changes in this account are mainly driven by changes in collection activities.

For 2021 to 2023, reference 2 states that the revenue increases are mainly due to overdue account balances. However, OEB staff notes that there is a significant year-over-year increase of $4.9M in revenue in 2021.

Question(s):

a) Please explain the significant revenue increase of $4.9M in 2021.

RESPONSE:

a) Changes in Late Payment revenues are directly correlated to changes in arrears balances. The correlation is demonstrated in 2021 where customer arrears increased from $386 million in 2020 (on an annualized basis) to $528 million in 2021. The related Late Payment revenues increased from $6.0 million in 2020 to $10.9 million in 2021 which is reflected in the revenue increase of $4.9 million in 2021.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 6-STAFF-217

Account 4235 - Miscellaneous Service Revenues
Ref 1: Exhibit 6 / Alectra_Attach 6-9_OEB Appendix 2-H- Other Revenues_20251027
Ref 2: Exhibit 6 / Tab 3 / Schedule 1 / pp. 1-3 (pdf pp. 258-260)

Preamble:
In reference 2, Alectra Utilities provides explanations for some of the year-over-year increases and decreases in other revenue in Account 4235 for 2020 - 2023 and 2027 - 2031.

For 2023, Alectra Utilities states that revenues related to reconnections increased to normal levels in 2023 and then atypically high levels in 2024. For 2025, Alectra Utilities states that revenues return to normal levels. However, OEB staff notes that the 2025 other revenue is more than $1M above the 2023 amount.

Between 2027-2031, Alectra Utilities states that an increase of $3.6M annually is expected due to new specific charges proposed in this application related to customer-requested or distributor-requested disconnection and reconnection. However, OEB staff notes that there is no annual increase of $3.6M from 2027 to 2031.

OEB staff also notes that there are no specific explanations provided for the following year-over-year increases and decreases which exceed the materiality threshold of $1M:

- Increase of $6.5M in 2018
- Decrease of $4.9M in 2019
- Increase of $2.1M in 2024
- Decrease of $1.1M in 2025
- Increase of $1.5M in 2027

Question(s):

a) Please confirm whether the increase of $3.6M per year has been incorporated into the forecast 2027-2031 in reference 2. If not, please revise the evidence as needed.

b) What revenue level is considered normal when the 2025 other revenue, considered normal by Alectra Utilities, is more than $1M above the 2023 level, which is also considered normal?

c) Please explain why the other revenue in year 2024 increased to an atypically high level.

d) Please confirm whether the amounts recorded in Account 4235 include MicroFit-related revenues. If not, please update Account 4235 data in reference to include MicroFit-related revenues if applicable.

e) Please provide the following:
   i. Explanation for drivers of the other increase/decrease for years 2018, 2019, 2024, 2025, and 2027.
   ii. Please provide a detailed calculation to support the 2027 other revenue.

RESPONSE:

a) Confirmed that the increase of $3.6M per year has been incorporated into the forecast 2027-2031 in reference 2.

b) On going forward basis, the 2025 amount should be considered “normal”, as it includes approximately $1M of “administration fees” that have not been previously mapped to this account. Please see response to (c) below.

c) The 2024 increase in UsoA account 4235 is due to re-mapping of $1.2M of “administration fee[s]” that was previously mapped to UsoA account 4375.

d) Confirmed that the amounts recorded in Account 4235 include MicroFit-related revenues.

e) For the details of specific charges calculations please refer to 6-SEC-98 (c) and 8-CCC-71 (b) and 8-CCC-71 (c2). Please note that the detailed information prior to 2019 (pre-JDE conversion) is not available. We believe that this historical information is not relevant for the decision-making process for this application.

Please see (c) above for an explanation of the increase in 2024. The increase in 2027 reflects the introduction of new specific service charges, offset by elimination of some previous charges, as explained in the Exhibit 6 / Tab 3 / Schedule 1 / pp. 2-3 (pdf pp. 259-260) and 6-SEC-98 (c).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 6-STAFF-218

Account 4245 - Government and Other Assistance Directly Credited to Income

Ref 1: Exhibit 6 / Alectra_Attach 6-9_OEB Appendix 2-H-Other Revenues_20251027

Preamble:

The other revenue data in Account 4245 show the following year-over-year increases and decrease which exceed the materiality threshold of $1M:

- Increase of $2.8M in 2018
- Increase of $1.6M in 2019
- Decrease of $10.3M in 2020

Question(s):

a) Please provide the following.
   i. Explanation for drivers of the increase/decrease for each of the years in the preamble.
   ii. Supporting calculations to assist with the explanation if needed.

RESPONSE:

a) The balances in Account 4245 balances for the years 2017 to 2019 represent the amortization of deferred revenue balances recorded in Account 2440. Beginning in 2020, these amounts are recorded in Account 5705 Depreciation Expense.
   The increase of the amortization of deferred revenue for 2018 relates to the increase of customer contributions as explained in Exhibit 2B, Tab 2, Schedule 2 (page 7).
   The increase of the amortization of deferred revenue for 2019 relates to the increase of customer contributions as explained in Exhibit 2B, Tab 2, Schedule 2 (page 10).

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 6-STAFF-219

Ref 1: Exhibit 6 / Alectra_Attach 6-9_OEB Appendix 2-H-Other Revenues_20251027

Preamble:

USoA 4245 (Government and Other Assistance Directly Credited to Income) ceases to be assigned to Other Revenue after 2019.

Question(s):

a) Please provide an explanation for where the amounts associated with Government and Other Assistance Directly Credited to Income were allocated after 2019.

b) If the amount remained allocated to Other Revenue, please indicate where.

c) If not, please provide the rationale for why the amount in this account was no longer allocated to Other Revenue after 2019.

RESPONSE:

a) Please refer to 6-STAFF-218

b) Please see (a) above

c) Please see (a) above

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 6-STAFF-220

Account 4305 - Regulatory Debits

Ref 1: Exhibit 6 / Alectra_Attach 6-9_OEB Appendix 2-H-Other Revenues_20251027

Preamble:

The other revenue data in Account 4305 show the following year-over-year increases and decreases which exceed the materiality threshold of $1M:

- Decrease of $1.7M in 2019
- Decrease of $6M in 2020
- Decrease of $4.8M in 2023
- Decrease of $28.7M in 2026
- Increase of $41M in 2027

Question(s):

a) Please provide the following:
   i. Explanation for drivers of the increase/decrease for each of the years in the preamble.
   ii. Supporting calculations to assist with the explanation if needed.

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RESPONSE:

a) Table 1 below provides Account 4305 year-over-year changes in the updated Appendix 2-H as provided in 1-SEC-24-f.

Table 1 – Account 4305 Year-over-year changes

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capitalization Policy Impact	-	(1.7)	(7.7)	(8.2)	(7.2)	(7.8)	(7.3)	(9.8)	(7.5)	-
Locate Revenue	-	-	-	-	-	(4.2)	(5.2)	(5.4)	(6.9)	-
Total	**-**	**(1.7)**	**(7.7)**	**(8.2)**	**(7.2)**	**(12.0)**	**(12.5)**	**(15.2)**	**(14.4)**	**-**
Changes		**(1.7)**	**(6.0)**	**(0.5)**	**1.0**	**(4.8)**	**(0.5)**	**(2.7)**	**0.9**	**14.4**

i. The primary drivers behind the increases or decreases for each year where the variance exceeds $1M are summarized below:

In 2019, the $1.7M decrease is attributable to the impact of the capitalization policy for ERZ. Alectra Utilities began recording the offsetting entry related to ERZ ‘s capitalization policy impact to Account 4305 Regulatory Debit in 2019.

In 2020, the $6M decrease is attributable to the impact of the capitalization policy for HRZ. Alectra Utilities began recording the offsetting entry related to HRZ ‘s capitalization policy impact to Account 4305 Regulatory Debit in 2020.

In 2023, the $4.8M decrease is attributable to the cost of locates embedded in rates. Alectra Utilities began recording this amount to Account 4305 Regulatory Debit in 2023 following OEB’s accounting order in EB-2023-0143, Decision and Order, Getting Ontario Connected Act Variance Account, October 31, 2023.

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In 2025, the $2.7M decrease is attributable to the higher capitalization policy, which reflects higher capital expenditures in System Access and System Renewal.

The decrease in 2027 of $14.3M reflects the discontinuation of the deferral account for capitalization policy impact and the incremental cost of locates deferral account in 2027. As a result, these offsetting entries are no longer required.

ii. Please refer to Table 1, which provides the calculations for the variance.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 6-STAFF-221

Account 4310 - Regulatory Credits

Ref 1: Exhibit 6 / Alectra_Attach 6-9_OEB Appendix 2-H-Other Revenues_20251027

Preamble:

The other revenue data in Account 4310 show the following year-over-year increase and decrease which exceed the materiality threshold of $1M:

- Increase of $2.2M in 2019
- Decrease of $3.1M in 2027

Question(s):

a) Please provide the following:
   i. Explanation for drivers of the increase/decrease for each of the years in the preamble.
   ii. Supporting calculations to assist with the explanation if needed.

RESPONSE:

a) Table 1 below provides Account 4310 year-over-year changes in the updated Appendix 2-H as provided in 1-SEC-24-f.

Table 1 – Account 4310 year-over-year changes

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capitalization Policy Impact	-	2.2	2.1	3.0	2.8	2.5	2.9	4.0	3.1	-
Changes		2.2	(0.1)	0.9	(0.2)	(0.3)	0.4	1.0	(0.9)	(3.1)

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i. The primary drivers behind the increases or decreases for each year where the variance exceeds $1M are summarized below:

In 2019, the $2.2M increase is attributable to the impact of the capitalization policy for BRZ. Alectra Utilities began recording the offsetting entry related to BRZ 's capitalization policy impact to Account 4305 Regulatory Debit in 2019.

The decrease in 2027 of $3.1M reflects the discontinuation of the deferral account for capitalization policy impact. As a result, the offsetting entries are no longer required.

ii. Please refer to Table 1, which provides the calculations.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 6-STAFF-222

Account 4355 - Gain on Disposition of Utility and Other Property

Ref 1: Exhibit 6 / Alectra_Attach 6-9_OEB Appendix 2-H- Other Revenues_20251027

Preamble:

The other revenue data in Account 4355 show the following year-over-year increase and decrease which exceed the materiality threshold of $1M:

- Increase of $1.3M in 2018
- Increase of $3.2M in 2023
- Decrease of $2.1M in 2024
- Decrease of $1.1M in 2025

Question(s):

a) Please provide the following:

i. Explanation for drivers of the increase/decrease for each of the years in the preamble.

ii. Supporting calculations to assist with the explanation if needed.

RESPONSE:

Please refer to 6-Staff-223.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 6-STAFF-223

Account 4360 - Loss on Disposition of Utility and Other Property

Ref 1: Exhibit 6 / Alectra_Attach 6-9_OEB Appendix 2-H- Other Revenues_20251027

Preamble:

The other revenue data in Account 4360 show the following year-over-year increases and decreases which exceed the materiality threshold of $1M:

- Increase of $2M in 2019
- Decrease of $1.4M in 2020
- Increase of $11.1M in 2021
- Decrease of $20.1M in 2022
- Increase of $2.6M in 2023
- Decrease of $4.9M in 2024
- Increase of $4.2M in 2025

Question(s):

a) Please provide the following:
   i. Explanation for drivers of the increase/decrease for each of the years in the preamble.
   ii. Supporting calculations to assist with the explanation if needed.

RESPONSE:

a) Alectra Utilities notes that there were inconsistencies in the presentation of Appendix 2H related to accounts 4355,4360 and 4362 for 2017 and 2018, which affect the year-over-year variances.

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Table 1 below displays these account balances as originally filed, while Table 2 restates these balances consistently with the presentation from 2019 and later years.

Table 1: As Filed - Combined (Loss)/Gain on asset disposition in accounts 4355, 4360, 4362 ($M)

Breakdown as filed	2017	2018	2019	2020	2021	2022	2023	2024	2025
4355	(1.1)	0.3	0.1	0.0			3.2	1.1	
4360	(0.0)	0.0	2.0	0.5	11.7	(8.5)	(5.8)	(10.7)	(6.6)
4362	(2.1)	(4.8)							
Total	**(3.2)**	**(4.5)**	**2.0**	**0.5**	**11.7**	**(8.5)**	**(2.6)**	**(9.6)**	**(6.6)**

Table 2: Updated - Combined (Loss)/Gain on asset disposition in accounts 4355, 4360, 4362 ($M)

Breakdown updated	2017	2018	2019	2020	2021	2022	2023	2024	2025
4355 (Note 1)	0.5	0.7	0.1	0.0			3.2	1.1	
4360 (Note 2)	(3.4)	(1.8)	2.0	0.5	11.7	(8.5)	(5.8)	(10.7)	(6.6)
4362 (Note 3)	(2.1)	(5.2)							
Total	**(5.0)**	**(6.3)**	**2.0**	**0.5**	**11.7**	**(8.5)**	**(2.6)**	**(9.6)**	**(6.6)**
YOY change		**(1.3)**	**8.4**	**(1.5)**	**11.2**	**(20.2)**	**5.9**	**(7.0)**	**3.2**

*Differences might exist due to rounding

Note 1: In 2017, the gains and losses on the disposition of assets for legacy Horizon were combined and recorded in Account 4355 for a total net loss of $1.2M. Of this amount, $1.6M in losses has been reallocated to Account 4360 and $0.4M remain in Account 4355.
Note 2: In 2017 and 2018, the loss on derecognition for legacy Enersource was classified as depreciation expense. Losses of $1.8M for each year have been added to Account 4360 in Table 2 above.

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Note 3: In 2018, the gains and losses on the disposition of assets for legacy Horizon were combined and recorded in Account 4362 for a total net loss of $2.0M. Of this amount, $0.4M in gains have been reallocated to Account 4355 and $2.4M remain in Account 4362.

Below is the explanation of drivers of the increases or decreases in the balances for historic years.

- 2018 decrease of $1.3M - due to a higher loss on the derecognition of distribution assets, mainly line transformers.
- 2019 increase of $8.4M: The net gain on disposition in 2019 was $2M, resulting from the gain on the sale of land of $7M, partially offset by a $5M loss on the derecognition of distribution assets. This represents an increase of $8.4M, as compared to the 2018 loss of derecognition of $6.4M;
- 2020 decrease of $1.5M - The net gain on disposition in 2020 was approximately $0.5M ($1.5M lower than in 2019). The 2020 balance consists of the gain on sale and leaseback of Sandalwood operation centre and sale of land ($6M), partially offset by $4.5M losses on derecognitions of distribution assets;
- 2021 Increase of $11.2M – the increase in derecognition of PP&E is primarily due to gain on sale and lease back of Mavis operation centre and sale of land ($13M);
- 2022 decrease of $20.2M – The net loss on disposition in account 4360 was $8.3M; the decrease in gain on derecognition of PP&E is primarily due to the 2021 gain on the sale and leaseback of Mavis operation centre;
- 2023 Increase of $5.9M is the result of lower loss on derecognition of assets by $2.5M, as compared to 2022. In addition, in 2023 Alectra recorded gains on property sales of $2.0M and a gain on the sales of other assets, primarily fleet.
- 2024 decrease of $7.0M: The increased loss on the derecognition of assets is primarily related to higher derecognition of distribution assets and meters removed from service, partially offset by realized $1.1M gain on the disposition of fleet assets.
- 2025 forecasted increase of $3.2M is based on a forecasted loss on the derecognition of assets of $6.6M, which is calculated based on historical averages and normalized for one-time events.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 6-STAFF-224

Account 4362 - Loss from Retirement of Utility and Other Property

Ref 1: Exhibit 6 / Alectra_Attach 6-9_OEB Appendix 2-H-Other Revenues_20251027

Preamble:

The other revenue data in Account 4360 show the following year-over-year increase and decrease which exceed the materiality threshold of $1M:

- Decrease of $2.6M in 2018
- Increase of $4.7M in 2019

Question(s):

a) Please provide the following:
   i. Explanation for drivers of the increase/decrease for each of the years in the preamble.
   ii. ii. Supporting calculations to assist with the explanation if needed.

RESPONSE:

Please refer to 6-Staff-223.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 6-STAFF-225

Account 4375 - Revenues from Non Rate-Regulated Utility Operations

Ref 1: Exhibit 6 / Alectra_Attach 6-9_OEB Appendix 2-H-Other Revenues_20251027

Preamble:

The other revenue data in Account 4375 show the following year-over-year increases and decreases which exceed the materiality threshold of $1M:

- Increase of $25.3M in 2018
- Decrease of $19.3M in 2019
- Decrease of $30.9M in 2020
- Increase of $15.5M in 2021
- Decrease of $24.6M in 2022
- Decrease of $7.2M in 2023
- Decrease of $5.3M in 2024
- Decrease of $7.9M in 2026
- Decrease of $4M in 2029

Question(s):

a) Please provide the following:
   i. Explanation for drivers of the increase/decrease for each of the years in the preamble.
   ii. Supporting calculations to assist with the explanation if needed.

RESPONSE:

a) USoA account 4375 includes water billing revenues and revenues related to CDM programs, run by Alectra in 2017-2024.

Water billing revenues have been relatively stable during the historic period, and therefore most of the variances in this account have been a result of changes in CDM program revenues, driven by participant activities. The programs, run by Alectra, included Retrofit Pay-For-Performance ("P4P") program, and Full Cost Recovery ("FCR") programs. In 2019, the IESO notified all LDCs that it terminated the Energy Conservation Agreement ("ECA"), and instructed LDCs to conduct an orderly wind down of the delivery of CDM pursuant to the ECA. Further to multiple ministerial directives to extend the in-service deadlines and other time periods in participant agreements the wind down activities of the CDM programs finally concluded in 2024.

USoA 4375 also includes miscellaneous non-utility revenues, such as:

- compensation for damage claims (accident related), either from insurance or customers,
- other ad hoc recoveries that do not fall under defined revenue categories.

The major drivers of the year-over-year variance are discussed below:

- 2018 revenue increase of $25.3M is the result of an increase in CDM revenue (OPA and IESO incentives) of approximately $39M, offset by the $15M decrease in "miscellaneous" revenue. The $15M decrease is due to the erroneous inclusion of solar PV revenue in the UsoA 4375 in 2017;
- 2019 revenue decrease of $19.3M is the result of a decrease in CDM revenue by approximately $20M;
- 2020 revenue decrease in revenue of $30.9M is mainly driven by lower OPA revenue, due to the commencement of winding down of CDM programs;
- 2021 revenue increase of $15.5M is the result of higher revenue from CDM programs, driven by higher volume of activities in the P4P CDM program;

- 2022 revenue decrease in revenue of $24.6M is mainly driven by a decrease in OPA revenue, due to the continuing winding down of CDM programs;
- 2023 revenue decrease of $7.2M is due to the further decrease in CDM program revenues;
- 2024 revenue decrease of $5.3M is the result of lower OPA revenue of approximately $4M, and reclassification of administration fees revenue of $1.2M to account 4235;
- Forecasted 2026 revenue decrease of $7.9M is the result of the discontinuation of water billing services to the cities of Hamilton and Guelph;
- Forecasted 2029 revenue decrease of $4M is the result of the discontinuation of the water billing services to the cities of Markham and Vaughan.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 6-STAFF-226

Account 4380 - Expenses of Non Rate-Regulated Utility Operations
Ref 1: Exhibit 6 / Alectra_Attach 6-9_OEB Appendix 2-H-Other Revenues_20251027

Preamble:
The other revenue data in Account 4380 show the following year-over-year increases and decreases which exceed the materiality threshold of $1M:

- Increase of $10.6M in 2019
- Increase of $33.5M in 2020
- Decrease of $3.1M in 2021
- Increase of $12.3M in 2022
- Increase of $11.9M in 2023
- Increase of $5.9M in 2026

Question(s):

a) Please provide the following.
   i. Explanation for drivers of the increase/decrease for each of the years in the preamble.
   ii. Supporting calculations to assist with the explanation if needed.

RESPONSE:

a) Please note that USoA 4380 pertains to non-utility expenses rather than revenues, as mentioned in the preamble. As a result, the signs of the variances in the question should be reversed accordingly.

Two types of non-utility expenses recorded in UsoA account 4380 include water billing costs and the expenses related to CDM programs, run by Alectra in 2017-2024.

The costs of water billing have been relatively stable during the historic period, and therefore most of the variances in the costs in this account have been a result of changes in the cost of CDM programs as described below:

- The decrease of $10.6M in 2019 is mainly due to decreased costs of CDM programs, as compared to 2018, mainly driven by a decline in participant incentives;
- The decrease of $33.5M in 2020 is attributed to a $29.0M reduction in participant incentives and a decrease in internal CDM - related expenses, particularly in labour ($4MM) and in professional services from CDM program delivery service providers;
- The increase of $3.1M in 2021 results from a $4M rise in CDM expenses due to higher participant incentives driven by increased activities in Retrofit P4P, partially offset by a decrease in CDM related internal costs;
- The decrease of $12.3M in 2022 is mainly due to the $10.7MM reduction in participant incentives owing to ongoing winding down of CDM programs;
- Similarly, the decrease of $11.9M in 2023 is driven by the $10.8MM reduction in CDM costs, $9M of which pertain to participant incentives;
- The forecasted decrease of $5.9M in 2026 results from Alectra’s exit from the water billing business in 2026 as no water billing costs were forecasted in this account after 2025 as they have been included in OM&A.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 6-STAFF-227

Account 4390 - Miscellaneous Non-Operating Income
Ref 1: Exhibit 6 / Alectra_Attach 6-9_OEB Appendix 2-H-Other Revenues_20251027

Preamble:
The other revenue data in Account 4390 show the following year-over-year increases and decreases which exceed the materiality threshold of $1M:

- Increase of $3.8M in 2019
- Decrease of $3.4M in 2020
- Increase of $1.7M in 2023
- Decrease of $2.4M in 2024

Question(s):

a) Please provide the following.
   i. Explanation for drivers of the increase/decrease for each of the years in the preamble.
   ii. Supporting calculations to assist with the explanation if needed.

RESPONSE:

The increase of $3.8M in 2019 and subsequent decrease of $3.4M in 2020 are related to the one-time increase in 2019, driven by the GRE&T Centre revenue from the RPP Roadmap Pilot Project of $4.1M. In 2020, the revenue decreased, due to the non-recurrence of the RPP project.
The increase in revenue for 2023 was attributed to a higher number of billings and insurance compensation for damages to our distribution assets, relating to accidents such as pole hits

and transformer damages. The decrease in revenue for 2024 is primarily attributable to a change in the recognition of accident and damage claims revenue, whereby such revenue is now recognized upon receipt of payment rather than as costs are incurred.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 6-STAFF-228

Accounts 4375 and 4380 - Revenues and Expenses from Non Rate-Regulated Utility Operations
Ref 1: Exhibit 1 / Tab 8 / Schedule 3 / Attachment 1-9 / p. 8 (pdf p. 1596)
Ref 2: Exhibit 6 / Alectra_Attach 6-9_OEB Appendix 2-H-Other Revenues_20251027

Preamble:
In reference 1, Alectra Utilities states that it also has a competitive commercial rooftop solar photovoltaic generation business (Solar PV Business) under which it develops, constructs, owns, finances, and operates rooftop photovoltaic generation equipment.

Question(s):

a) Please explain whether the revenue and expenses from the Solar PV Business have been recorded in Accounts 4375 and 4380 in reference 2. If not, please explain where in the application the revenue and expenses have been recorded.

RESPONSE:

a) The revenues and expenses of competitive businesses are excluded from this application.

The only Solar PV assets Included in AUC financial statements are the Envida Solar assets. These are non-distribution assets, and therefore related revenues and expenses have been recorded in accounts 4375 and 4380, with the revenues being approximately $0.1M.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 6-STAFF-229

Other Revenues - Water Billing

Ref 1: Exhibit 6 / Alectra_Attach 6-9_OEB Appendix 2-H-Other Revenues_20251027

Ref 2: Exhibit 6 / Alectra_Attach 6-9_OEB Appendix 2-N-Shared Services and Corporate Allocation_20251014

Question(s):

a) OEB staff observes that no water billing expenses (Account 4380) are forecasted for 2026-2028 in reference 1, while revenues are expected for the same years from the municipalities of Markham and Vaughn in reference 2. Please explain why no corresponding expense is forecasted to match the expected revenue.

RESPONSE:

a) For municipalities of Markham and Vaughan, the water billing costs are captured within Customer Services' OM&A budget, and thus are not recorded separately in Account 4380. Please refer to Exhibit 4, Tab 2, Schedule 7, Page 28-29 for water billing details provided in the Customer Service OM&A program evidence.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 6-STAFF-230

Custom Price Index Deficiency for 2028-2031
Ref 1: Exhibit 6 / Revenue Requirement Workform for 2028 - 2031 / Tabs 9 and 13
Ref 2: Alectra_Responses_Error Checking_Alectra_20251121, Item # 3

Preamble:
In reference 1, Tab 9, the "Base Revenue Requirement" amount in Line 10 is not equal to the "Distribution Revenue" amount in Line 11. Alectra Utilities clarified in reference 2 that the difference between the two lines reflect the Custom Price Index Deficiency (shown in reference 1, Tab 13, cell AO52) which recognizes that its proposed rate framework does not recover all of its forecast costs over the 2028 to 2031 period.

In reference 1 (Tab 13, cell AO52), the Custom Price Index Deficiency amounts for 2028, 2029, 2031, and 2031 are $3.3M, $6.2M, $6.2M, and $2.2M respectively.

Question(s):
a) Please provide and explain drivers of the Custom Price Index Deficiency amount for each year for the 2028 to 2031 period.

b) Please explain why the Custom Price Index Deficiency amount shows a large increase in 2029 and 2030 and then decreases significantly below the 2028 level in 2031.

RESPONSE:

a) The variance in Custom Price Index Deficiency by year is principally driven by the following factors:
   - Productivity and Stretch Factor ("X") funding reductions included within the CPCI;

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- Variances in revenue growth from billing determinant growth on a year-over-year basis; and,
- Variances between projected OM&A (which underpins forecast revenue requirement) and indexed OM&A funding underpinning distribution revenue (as derived based on 2027 OM&A escalated by inflation, an econometric growth factor based on costs from customer and demand growth, and the Input Price Differential). In examining these OM&A variances it is important to note that 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. However, its rates are proposed to be established on the basis of an index. The onus is on the utility to manage its actual OM&A expenditures within the available funding provided.

The 2028 year shows the smallest Custom Price Index Deficiency, as the X factor has only been implemented in one year's rates (i.e. 2028) and has not begun to accumulate. In 2029, the X factor begins to accumulate in impact, while single year OM&A expenditure increases of approximately 4.7% drive a larger deficiency. In 2030, an OM&A expenditure increase of approximately 3.7% is offset by a larger accumulated X factor. The OM&A expenditure increase for 2031 is the smallest projected increase in OM&A over the 5 year term, resulting in a smaller Custom Price Index Deficiency in that year, despite the larger accumulated X-factor.

b) Please see response to part a) above.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 7-STAFF-231

Asset Breakout

Ref 1: Exhibit 7 / Tab 2 / Schedule 1 / pp. 3-4 (pdf pp. 5-6)

Preamble:

Alectra Utilities has determined the breakout of assets between primary and secondary using information from its Enterprise Resource Planning and Geographic Information Systems.

For account 1830 (Poles, Towers and Fixtures), it is common practice for distributors attach both primary and secondary conductors to the same pole.

Question(s):

a) Please confirm that for accounts 1835 (Overhead Conductors and Devices), 1840 (Underground Conduit), and 1845 (Underground Conductors and Devices), the assets used are specific to one voltage, and are identified as such. If not, please explain.

b) For account 1830, please explain the approach for apportioning poles between rate classes where a pole supports conductors operating at both primary and secondary voltage.

RESPONSE:

a) Alectra Utilities considers secondary assets and primary assets to be assets operating at voltages equal to or less than 750V and assets operating at voltages greater than 750V, respectively.

For accounts 1835 and 1840, assets were identified as secondary or primary assets based on the secondary or primary categorization within Alectra Utilities' Geographic Information Systems. Similarly, for account 1845, assets were identified as secondary or primary assets based on the account details within Alectra Utilities' Enterprise Resource Planning system.

b) For account 1830, where a pole supports conductors operating at both primary and secondary voltage, the pole has been allocated to the primary sub-account, 1830-2 (Primary). Poles that only support secondary conductors have been allocated to the secondary sub-account, 1830-3 (Secondary).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 7-STAFF-232

Weighting Factors

Ref 1: Exhibit 7 / Tab 2 / Schedule 1 / p. 6 (pdf p. 8)

Preamble:

Alectra Utilities determined Billing and Collecting weighting factors by assessing relative time, and cost to provide services to each rate class.

Question(s):

a) Please provide the derivation of the billing and collecting weighting factor, including the determination of each cost assigned to each rate class.

RESPONSE:

a) The derivation of the billing and collection weighting factor uses an effort-based methodology. This methodology compares the time and resource requirements associated with billing and collection tasks for each customer rate class, relative to a residential customer, taking into account any additional effort arising from task complexity or specific rate class requirements.

In Table 1, the number of accounts is captured in Column A and the approximate time spent by the total number of billing clerks in each rate class is captured in Column B. The billing weight in Table 1, Column D, is derived by taking the calculated FTE requirement per account in each rate class (Column C) and dividing it by the FTE requirement for the equivalent residential customer (Column C). For collection tasks, a management estimate is used as the collection and severance processes are standardized, except for sentinel, unmetered scattered loads and streetlight rate classes which are not subject to

collections. As such Collections efforts are assigned either a 1 (comparable to residential) or 0 (no effort required). In Column F, the billing and collection weights are scaled by the relative number of FTE's in each group and added together.

Table 1 – Derivation of the Billing and Collections Weighting Factors

Customer Type	Number of Accounts (Column A)	Biller FTE Allocation by Rate Class (Column B)	FTE requirement Per Account Column C = (Column B / Column A)	Billing Weighting Normalized to Residential Customer (Column D = Column C For Each Rate Class / Column C Residential Rate Class)	Collection Effort Relative toa Residential Customer Column E = Management Estimate	Total Weighting Column F =(Column E* Total Number of Collection Resources + Column D* Total Number of Billing Resources)/Total Number of Billing and Collection Resources
Residential	930,819.00	32.401	0.0000348	1.0	1	1.0
GS <50 kW	83,461.00	3.950	0.0000473	1.4	1	1.2
GS>50 kW	12,550.00	2.244	0.0001788	5.1	1	3.5
Large user	25.00	0.133	0.0053074	152.5	1	92.9
LUDA	5.00	0.027	0.0053074	152.5	1	92.9
Embedded Distributor	9.00	0.048	0.0053074	152.5	1	92.9
Unmetered Scattered Load	5,135.00	0.181	0.0000352	1.0	0	0.6
Sentinel	200.00	0.007	0.0000348	1.0	0	0.6
Street Light	31.00	0.008	0.0002652	7.6	0	4.6
Total	**1,032,235.00**	**39.00**				

	Number of FTE's
Billing Resource (BR)	59.7
Collection resource (CR)	38.7

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 7-STAFF-233

Load Profiles

Ref 1: Exhibit 7 / Tab 2 / Schedule 1 / p. 14 (pdf p. 16)

Preamble:

Upon assessment of available methodologies to prepare updated load profiles, Alectra Utilities stated that it is of the view that Historical Average methodology is the most appropriate. Alectra Utilities explains that it has used four years of data, when the minimum to be sufficient would be three years.

Question(s):

a) In addition to feasibility of data gathering, please provide any reasons why the historical average method was deemed to be more appropriate than a weather normalized regression.

RESPONSE:

a) Alectra Utilities found the Historical Average methodology to be appropriate in light of its effectiveness and direct reliance on historical data, which provides a clear view of actual load patterns amongst its customer classes over an extended period of time. Further, Alectra Utilities is aware of several rebasing applications in which the Historical Average methodology has been accepted[1] and is not aware of any express concerns or disagreement regarding the Historical Average methodology written into settlement proposals and is aware of at least one example where the Historical Average methodology was explicitly accepted[1].

[2] EB-2023-0053, Settlement Proposal, page 26.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 7-STAFF-234

Revenue-to-Cost

Ref 1: Exhibit 7 / Tab 2 / Schedule 3 / pp. 4-5 (pdf pp. 34-35)

Preamble:

Alectra Utilities is proposing to reduce the revenue-to-cost ratio for the Sentinel Light rate class from 83% to 71% to mitigate the bill impact to customers in the PowerStream rate zone. This is a move away from unity, and from within the range to below the range.

Question(s):

a) Has Alectra Utilities considered other opportunities for mitigating the bill impact to the sentinel light customers other than a revenue-to-cost adjustment away from unity?

b) Would Alectra Utilities consider a multi-year phase-in of harmonization to mitigate impacts?

RESPONSE:

a) Alectra Utilities relied on applying a consistent approach across all rate classes where bill mitigation was required. For any class with a bill impact above 10%, Alectra used the same mitigation approach – adjusting the relevant revenue-to-cost ratios – so long as this did not materially impact other classes. This approach was applied uniformly to all affected rate classes, including the Sentinel Light rate class.

b) Given the low materiality level of this rate class to the rest of Alectra Utilities' customer base, Alectra Utilities proposes to keep the proposed one-year harmonization. As per the Application, the net adjustment to this class resulted in a revenue deficiency of $(10,338),

which is proposed to be recovered from the Residential rate class, whose revenue-to-cost ratio is below 100%. For comparative context, this revenue re-allocation is equal to only 0.002% of 2027 residential distribution revenue, and it is less than a 10^{th} of the difference in revenues due to volumetric rate rounding in 2027 (i.e., $108,300).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 8-STAFF-235

Rate Harmonization

Ref 1: Exhibit 8 / Tab 1 / Schedule 1 / pp. 6-11 (pdf pp. 6-11)

Preamble:

Alectra Utilities performed analysis of eight options class structure of the GS 50-4,999 customers. This appears to have included impacts experienced by a typical customer with a monthly demand of 250 kW, consuming 100,000 kWh per month. This was shown on page 9, in Table 8-1-2.

Question(s):

a) Please provide three additional total bill impact scenarios:
   i. for lower volume customers at 50kW / 20,000 kWh
   ii. for higher volume customers at 2500 kW / 1,000,000 kWh per month
   iii. for lower load factor customers at 250 kW / 10,000 kWh per month

b) For the scenario provided, and the three scenarios identified above, please also indicate the distribution bill impact.

RESPONSE:

a) In response to 1-Staff-1, Alectra Utilities has updated its analysis to incorporate the 2026 distribution rates (EB-2025-0055). In addition, Alectra Utilities has updated its load forecast in response to 3-SEC-69, which affects the notional harmonized rates. The tables below align with the updated analysis. Please see 8-SEC-101 (b) for updated versions of Table 8-1-2 and Table 8-1-3 from Alectra Utilities rate application for the 250 kW / 100,000 kWh scenario.

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Tables 1 to 3 below present additional total bill impacts for the requested scenarios in parts a (i), (ii), and (iii) of this question, respectively.

Table 1 – Average Total Bill Impact (%) for 50 kW / 20,000 kWh

Rate Zone	Rate Class	Current Fixed Charge	Current Volumetric Charge	kW	kWh	Current Dx Bill	Current Total Bill	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7	Option 8
BRZ		$157.66	$3.5709	50	20,000	$336	$3,477	4.97%	3.42%	3.99%	4.39%	4.57%	4.71%	4.84%	4.89%
ERZ		$96.60	$5.8135	50	20,000	$387	$3,613	3.19%	1.70%	2.24%	2.63%	2.80%	2.94%	3.06%	3.11%
GRZ	GS>50 kW,	$226.26	$3.4474	50	20,000	$399	$3,569	2.86%	1.36%	1.91%	2.30%	2.47%	2.61%	2.74%	2.79%
HRZ	Regular	$479.71	$3.2215	50	20,000	$641	$3,849	-4.45%	-5.85%	-5.34%	-4.98%	-4.82%	-4.69%	-4.57%	-4.52%
PRZ		$177.34	$5.2880	50	20,000	$442	$3,566	1.50%	-0.01%	0.54%	0.93%	1.11%	1.25%	1.38%	1.42%
Average				50	20,000	**$441**	**$3,615**	**1.51%**	**0.02%**	**0.56%**	**0.95%**	**1.12%**	**1.26%**	**1.38%**	**1.43%**
BRZ		$1,422.54	$4.1453	50	20,000	$1,630	$4,981	-25.88%	-11.57%	-9.82%	-9.84%	-10.17%	-10.35%	-12.53%	-11.87%
ERZ		$2,199.73	$2.9914	50	20,000	$2,349	$5,817	-36.14%	-23.89%	-22.38%	-22.40%	-22.68%	-22.84%	-24.70%	-24.14%
GRZ	GS>50 kW,	$715.71	$3.8267	50	20,000	$907	$4,143	-11.40%	5.80%	7.91%	7.89%	7.49%	7.27%	4.65%	5.44%
HRZ	Intermediate														
PRZ															
Average				50	20,000	**$1,629**	**$4,980**	**-25.86%**	**-11.55%**	**-9.79%**	**-9.81%**	**-10.14%**	**-10.32%**	**-12.50%**	**-11.85%**

Table 2 – Average Total Bill Impact (%) for 2,500 kW / 1,000,000 kWh

Rate Zone	Rate Class	Current Fixed Charge	Current Volumetric Charge	kW	kWh	Current Dx Bill	Current Total Bill	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7	Option 8
BRZ		$157.66	$3.5709	2,500	1,000,000	$9,085	$165,096	1.65%	2.16%	1.98%	1.88%	1.84%	1.80%	1.75%	1.73%
ERZ		$96.60	$5.8135	2,500	1,000,000	$14,630	$175,286	-2.02%	-1.54%	-1.71%	-1.80%	-1.84%	-1.88%	-1.93%	-1.95%
GRZ	GS>50 kW,	$226.26	$3.4474	2,500	1,000,000	$8,845	$165,904	1.81%	2.32%	2.13%	2.04%	2.00%	1.96%	1.90%	1.88%
HRZ	Regular	$479.71	$3.2215	2,500	1,000,000	$8,533	$165,891	2.02%	2.53%	2.35%	2.25%	2.21%	2.17%	2.11%	2.10%
PRZ		$177.34	$5.2880	2,500	1,000,000	$13,397	$168,463	-1.27%	-0.77%	-0.95%	-1.05%	-1.09%	-1.12%	-1.18%	-1.20%
Average				2,500	1,000,000	**$10,898**	**$168,128**	**0.40%**	**0.90%**	**0.73%**	**0.63%**	**0.59%**	**0.55%**	**0.50%**	**0.48%**
BRZ		$1,422.54	$4.1453	2,500	1,000,000	$11,786	$170,268	-0.19%	-0.45%	-0.37%	-0.35%	-0.36%	-0.38%	-0.37%	-0.41%
ERZ		$2,199.73	$2.9914	2,500	1,000,000	$9,678	$169,014	1.22%	0.95%	1.04%	1.06%	1.05%	1.03%	1.04%	0.99%
GRZ	GS>50 kW,	$715.71	$3.8267	2,500	1,000,000	$10,282	$167,531	0.82%	0.55%	0.64%	0.66%	0.65%	0.63%	0.64%	0.59%
HRZ	Intermediate														
PRZ															
Average				2,500	1,000,000	**$10,582**	**$168,937**	**0.61%**	**0.35%**	**0.44%**	**0.46%**	**0.44%**	**0.42%**	**0.44%**	**0.39%**

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Table 3 – Average Total Bill Impact (%) for 250 kW / 10,000 kWh

Rate Zone	Rate Class	Current Fixed Charge	Current Volumetric Charge	kW	kWh	Current Dx Bill	Current Total Bill	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7	Option 8
BRZ		$157.66	$3.5709	250	10,000	$1,050	$4,588	8.31%	8.73%	8.59%	8.59%	8.59%	8.58%	8.50%	8.48%
ERZ		$96.60	$5.8135	250	10,000	$1,550	$5,545	-3.30%	-2.95%	-3.07%	-3.07%	-3.07%	-3.08%	-3.15%	-3.17%
GRZ	GS>50 kW,	$226.26	$3.4474	250	10,000	$1,088	$4,739	7.15%	7.56%	7.42%	7.42%	7.42%	7.41%	7.33%	7.31%
HRZ	Regular	$479.71	$3.2215	250	10,000	$1,285	$4,995	2.32%	2.71%	2.58%	2.58%	2.59%	2.57%	2.50%	2.48%
PRZ		$177.34	$5.2880	250	10,000	$1,499	$4,945	-2.55%	-2.16%	-2.29%	-2.29%	-2.28%	-2.30%	-2.37%	-2.39%
Average				250	10,000	**$1,295**	**$4,962**	**2.12%**	**2.51%**	**2.38%**	**2.38%**	**2.39%**	**2.37%**	**2.30%**	**2.28%**
BRZ		$1,422.54	$4.1453	250	10,000	$2,459	$6,392	-18.93%	-9.26%	-7.82%	-7.79%	-8.06%	-8.23%	-9.76%	-9.40%
ERZ		$2,199.73	$2.9914	250	10,000	$2,948	$7,057	-24.98%	-16.22%	-14.91%	-14.88%	-15.13%	-15.28%	-16.67%	-16.34%
GRZ	GS>50 kW,	$715.71	$3.8267	250	10,000	$1,672	$5,399	-5.96%	5.49%	7.20%	7.24%	6.92%	6.71%	4.90%	5.34%
HRZ	Intermediate														
PRZ															
Average				250	10,000	**$2,360**	**$6,283**	**-17.48%**	**-7.64%**	**-6.17%**	**-6.14%**	**-6.42%**	**-6.59%**	**-8.15%**	**-7.77%**

b) Please see 8-SEC-101 (a), Table 1, for the distribution bill impacts associated with the 250 kW / 100,000 scenario. Tables 4 to 6 below provide the distribution bill impact of customers in the scenarios described in parts a (i), (ii), and (iii) of this question, respectively. As described in part a of this response, the tables below align with the updated analysis.

Table 4 – Average Distribution Bill Impact (%) for 50 kW / 20,000 kWh

Rate Zone	Rate Class	Current Fixed Charge	Current Volumetric Charge	kW	kWh	Current Dx Bill	Current Total Bill	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7	Option 8
BRZ		$157.66	$3.5709	50	20,000	$336	$3,477	45.48%	31.33%	36.48%	40.16%	41.78%	43.12%	44.32%	44.75%
ERZ		$96.60	$5.8135	50	20,000	$387	$3,613	26.30%	14.01%	18.48%	21.68%	23.08%	24.24%	25.29%	25.66%
GRZ	GS>50 kW,	$226.26	$3.4474	50	20,000	$399	$3,569	22.70%	10.76%	15.10%	18.21%	19.58%	20.70%	21.72%	22.08%
HRZ	Regular	$479.71	$3.2215	50	20,000	$641	$3,849	-23.67%	-31.10%	-28.39%	-26.46%	-25.61%	-24.91%	-24.28%	-24.05%
PRZ		$177.34	$5.2880	50	20,000	$442	$3,566	10.72%	-0.05%	3.87%	6.67%	7.91%	8.92%	9.84%	10.17%
Average				50	20,000	**$441**	**$3,615**	**10.93%**	**0.14%**	**4.06%**	**6.87%**	**8.11%**	**9.12%**	**10.05%**	**10.37%**
BRZ		$1,422.54	$4.1453	50	20,000	$1,630	$4,981	-69.99%	-31.29%	-26.55%	-26.60%	-27.50%	-27.98%	-33.88%	-32.10%
ERZ		$2,199.73	$2.9914	50	20,000	$2,349	$5,817	-79.18%	-52.34%	-49.05%	-49.08%	-49.70%	-50.04%	-54.13%	-52.90%
GRZ	GS>50 kW,	$715.71	$3.8267	50	20,000	$907	$4,143	-46.08%	23.45%	31.98%	31.88%	30.27%	29.41%	18.81%	22.00%
HRZ	Intermediate														
PRZ															
Average				50	20,000	**$1,629**	**$4,980**	**-69.97%**	**-31.25%**	**-26.50%**	**-26.55%**	**-27.45%**	**-27.93%**	**-33.83%**	**-32.06%**

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Table 5 – Average Distribution Bill Impact (%) for 2,500 kW / 1,000,000 kWh

Rate Zone	Rate Class	Current Fixed Charge	Current Volumetric Charge	kW	kWh	Current Dx Bill	Current Total Bill	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7	Option 8
BRZ		$157.66	$3.5709	2,500	1,000,000	$9,085	$165,096	26.57%	34.77%	31.86%	30.31%	29.66%	29.01%	28.07%	27.79%
ERZ		$96.60	$5.8135	2,500	1,000,000	$14,630	$175,286	-21.41%	-16.31%	-18.12%	-19.08%	-19.48%	-19.89%	-20.47%	-20.65%
GRZ	GS>50 kW,	$226.26	$3.4474	2,500	1,000,000	$8,845	$165,904	30.00%	38.43%	35.44%	33.85%	33.18%	32.52%	31.55%	31.26%
HRZ	Regular	$479.71	$3.2215	2,500	1,000,000	$8,533	$165,891	34.75%	43.48%	40.38%	38.73%	38.04%	37.35%	36.35%	36.05%
PRZ		$177.34	$5.2880	2,500	1,000,000	$13,397	$168,463	-14.17%	-8.61%	-10.59%	-11.64%	-12.07%	-12.51%	-13.15%	-13.35%
Average				2,500	1,000,000	**$10,898**	**$168,128**	**5.51%**	**12.35%**	**9.92%**	**8.63%**	**8.09%**	**7.55%**	**6.76%**	**6.53%**
BRZ		$1,422.54	$4.1453	2,500	1,000,000	$11,786	$170,268	-2.44%	-5.78%	-4.68%	-4.42%	-4.62%	-4.87%	-4.69%	-5.29%
ERZ		$2,199.73	$2.9914	2,500	1,000,000	$9,678	$169,014	18.81%	14.74%	16.07%	16.40%	16.15%	15.84%	16.07%	15.33%
GRZ	GS>50 kW,	$715.71	$3.8267	2,500	1,000,000	$10,282	$167,531	11.83%	8.00%	9.25%	9.56%	9.33%	9.04%	9.25%	8.55%
HRZ	Intermediate														
PRZ															
Average				2,500	1,000,000	**$10,582**	**$168,937**	**8.66%**	**4.94%**	**6.16%**	**6.45%**	**6.23%**	**5.95%**	**6.15%**	**5.48%**

Table 6 – Average Distribution Bill Impact (%) for 250 kW / 10,000 kWh

Rate Zone	Rate Class	Current Fixed Charge	Current Volumetric Charge	kW	kWh	Current Dx Bill	Current Total Bill	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7	Option 8
BRZ		$157.66	$3.5709	250	10,000	$1,050	$4,588	32.13%	33.76%	33.22%	33.20%	33.22%	33.16%	32.85%	32.77%
ERZ		$96.60	$5.8135	250	10,000	$1,550	$5,545	-10.46%	-9.36%	-9.72%	-9.73%	-9.72%	-9.76%	-9.97%	-10.02%
GRZ	GS>50 kW,	$226.26	$3.4474	250	10,000	$1,088	$4,739	27.55%	29.12%	28.60%	28.59%	28.61%	28.54%	28.24%	28.17%
HRZ	Regular	$479.71	$3.2215	250	10,000	$1,285	$4,995	8.00%	9.33%	8.89%	8.88%	8.89%	8.84%	8.59%	8.53%
PRZ		$177.34	$5.2880	250	10,000	$1,499	$4,945	-7.44%	-6.29%	-6.67%	-6.68%	-6.67%	-6.71%	-6.93%	-6.98%
Average				250	10,000	**$1,295**	**$4,962**	**7.20%**	**8.53%**	**8.09%**	**8.08%**	**8.09%**	**8.04%**	**7.79%**	**7.73%**
BRZ		$1,422.54	$4.1453	250	10,000	$2,459	$6,392	-43.56%	-21.31%	-17.99%	-17.92%	-18.55%	-18.94%	-22.46%	-21.61%
ERZ		$2,199.73	$2.9914	250	10,000	$2,948	$7,057	-52.92%	-34.36%	-31.59%	-31.53%	-32.05%	-32.38%	-35.31%	-34.61%
GRZ	GS>50 kW,	$715.71	$3.8267	250	10,000	$1,672	$5,399	-17.01%	15.70%	20.57%	20.68%	19.76%	19.18%	14.01%	15.25%
HRZ	Intermediate														
PRZ															
Average				250	10,000	**$2,360**	**$6,283**	**-41.18%**	**-18.00%**	**-14.54%**	**-14.47%**	**-15.12%**	**-15.53%**	**-19.19%**	**-18.32%**

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 8-STAFF-236

Rate Harmonization

Ref 1: Exhibit 8 / Tab 1 / Schedule 1 / p. 13 (pdf p. 13)

Preamble:

Alectra Utilities proposes to maintain the Large Use with Dedicated Asset (LUDA) rate class and extend it to all rate zones. In doing so, it indicates that no additional customers qualified under the LUDA definition.

Question(s):

a) Please confirm that the definition used included all customers served by a dedicated feeder back to the transmission station or explain.

b) If part a) is confirmed, please confirm that there are no customers on dedicated feeders in any other parts of Alectra Utilities' service territory or explain.

RESPONSE:

a) In Exhibit 8 / Tab 1 / Schedule 1 / p. 13, Alectra Utilities stated that no additional customers qualified under the current LUDA definition. Upon reviewing this interrogatory, Alectra Utilities determined that this statement requires further clarification.

In assessing whether any other Large User customers met the LUDA rate class criteria, Alectra Utilities considered whether existing Large User customers had clear, verifiable historical records identifying dedicated assets installed specifically to serve them, together with the discrete financial costs, including contributed capital records, of those assets. Such records would be necessary for Alectra Utilities to directly assign the

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associated costs to these customers to determine the cost-to-serve these dedicated asset customers. Alectra Utilities established that insufficient historical records existed for the current Large User customers. As a result, Alectra Utilities did not propose transitioning other Large User customers into the LUDA rate class. Further, Alectra Utilities expects that any simplified or prorated cost assignments to LUDA, combined with the shift of customer revenue from Large User to the LUDA class, could create significant rate instability.

At this time, Alectra Utilities' intention is that only the six (6) existing customers remain in the LUDA rate class.

b) Please refer to the response for part a).

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 8-STAFF-237

Fixed/Variable Split

Ref 1: Exhibit 8 / Tab 2 / Schedule 2 / pp. 3-6 (pdf pp. 33-36)

Preamble:

Alectra Utilities proposes to maintain the fixed/variable split from its current rate period to design the proposed monthly service charge for all rate classes in 2027. Maintaining the fixed/variable charge while applying the rate harmonization would result in increased fixed charges for some rate zones. Combining this with a rate increase puts further upward pressure on rates.

Question(s):

a) What variable charge would result from leaving the fixed charges at the Notional Harmonized 2026 Monthly Service Charge in the GS < 50 kW, GS > 50 kW, and Large Use rate classes?

RESPONSE:

a) Table 1 below presents the 2027 distribution charges for the GS<50 kW, GS>50 kW, and Large Use rate classes as proposed, and after the notional harmonized 2026 monthly service charge was applied to 2027. In response to 1-Staff-1, Alectra Utilities has updated its models to reflect its interrogatory responses, including the load forecast and the 2026 notional rates. The table below aligns with these updates.

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Table 1 – 2027 Distribution Charges Before and After Application of Notional Harmonized 2026 Monthly Service Charge

Rate Class	Notional Harmonized 2026 Fixed	2027 Before (Proposed)		2027 After	
		Fixed	Variable	Fixed	Variable
GS<50 kW	$42.55	$47.08	$0.0207	$42.55	$0.0224
GS>50 kW	$264.43	$294.98	$5.2004	$264.43	$5.3309
Large Use	$14,971.02	$15,733.81	$3.9406	$14,971.02	$4.0130

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 8-STAFF-238

Standby Rate

Ref 1: Exhibit 8 / Tab 2 / Schedule 2 / p. 17 (p. 47)

Preamble:

Alectra Utilities is proposing to eliminate its standby rate class, and apply standby rates through the GS > 50, Large Use, and Large Use with Dedicated Assets rate classes. Customers on Gross Load Billing are permitted to remain on Gross Load Billing. The standby volume reflects the difference between the contracted capacity, and the demand on the distribution system.

Question(s):

a) Please differentiate between the proposed standby rates and Gross Load Billing, outlining situations where they might be different.

b) How does Alectra Utilities intend to address a capacity overrun where a customer places more demand on the distribution system than the contract provides for?

RESPONSE:

a) Gross Load Billing applies metered gross demand to the Distribution Volumetric rate for the customer's rate class (i.e., General Service > 50 kW, Large Use, and Large Use with Dedicated Assets). Alectra Utilities proposes to set standby rates equal to the Distribution Volumetric rate for the respective harmonized General Service > 50 kW, Large Use, and Large Use with Dedicated Asset classes. Therefore, there is no difference in the proposed standby rates and the rates applied for Gross Load Billing. However, the billing application differs between the two:

- Gross Load Billing requires a meter to measure generation output for purposes of determining gross demand. Gross Load Billing applies the Distribution Volumetric rate to metered gross demand.
- Alectra Utilities' proposed standby will not require a meter to measure generation output. The customer and Alectra Utilities will agree to establish a contracted total load requirement that represents the facility's estimated gross demand. The standby rate is applied to the customer's contracted demand less metered distribution demand, where maximum standby demand cannot exceed generator nameplate capacity.

b) Alectra Utilities intends to monitor standby customers' actual demand vs. their contracted standby capacity and may require customers to adjust their contracted standby capacity if substantial capacity overruns occur repeatedly.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 8-STAFF-239

Gross Load Billing
Ref 1: Exhibit 8 / Tab 2 / Schedule 2 / p. 18 (pdf p. 48)
Ref 2: Exhibit 8 / Tab 2 / Schedule 5 / pp. 1-3 (pp. 58-60)

Preamble:
Alectra Utilities discusses the option of remaining on Gross Load Billing in the context of Standby Rates, but not in the context of Retail Transmission Service Rates (RTSRs).

Question(s):

a) Does Alectra Utilities currently apply Gross Load Billing to RTSRs?

b) Does Alectra Utilities pay UTRs or host RTSRs with respect to distributed generation owned by its customers?

c) Does Alectra Utilities propose to charge Gross Load Billing for RTSRs to its customers? If so, how would the charge be determined?

RESPONSE:

a) Alectra Utilities applies gross load billing to RTSRs - Line and Transformation Connection Service charges to demand billed load customers with Load Displacement Generation ("LDG") capacity exceeding 1 MW for non-renewable (2 MW for renewable).

b) Alectra Utilities is required to pay gross load billing to Hydro One for UTRs – Line and Transformation Connection Service charges with respect to demand billed load customers with LDG capacity exceeding 1 MW for non-renewable (2 MW for renewable).

c) Alectra Utilities proposes to apply RTSRs – Line and Transformation Connection Service rates on a gross load basis for all LDG customers in the harmonized General Service > 50 kW, Large Use, and Large Use with Dedicated Assets classes with generation capacity exceeding 1 MW for non-renewable generation or 2 MW for renewable generation. RTSRs – Line and Transformation Connection Service charges will be applied to the customer's gross metered demand or contracted demand.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 8-STAFF-240

Specific Service Charges

Ref 1: Exhibit 8 / Tab 3 / Schedule 2 / p. 4 (pdf p. 72)

Preamble:

Alectra Utilities is proposing to apply the standard level of charge from the OEB Handbook for Utility Rate Applications (the handbook) where the fixed charge varies between rate zones. OEB staff notes that variances from the handbook usually arise as a result of distributors putting forth new rates based on cost causation specific to their utility and service territory.

Question(s):

a) Does Alectra Utilities intend to review specific service charges for future proceedings?

b) Please provide revenue by service charge, or an estimate as applicable for revenue from service charges for each of:
   i. The most recent historic year at the existing rates.
   ii. The most recent historic year at the proposed rates.
   iii. The 2027 rate year at the proposed rates.

RESPONSE:

a) Alectra Utilities has reviewed its specific service charges as part of this proceeding as detailed in Exhibit 8, Tab 3, Schedule 2.

   Alectra Utilities may review its specific services charges in future proceedings, if warranted. The OEB's Chapter 2 Filing Requirements state that distributors requesting either a new specific service charge or a change to the level of an existing charge

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should describe the purpose of such charges, or the reason for the proposed change to an existing charge and provide calculations supporting the determination of each new or revised charge. In future proceedings, Alectra may review whether the above requirements are applicable and conduct a review, as needed.

b) Table 1 below provides a summary of:
   i. 2025 revenue at existing rates,
   ii. 2025 revenue at proposed rates, and
   iii. 2027 revenue at proposed rates.

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Table 1 – Revenue by service charge

	2025 Revenue at Existing Rates			2025 Revenue at Proposed Rates			2027 Revenue at Proposed Rates			
	Existing Rate	Volume of Charges	Revenue ($MM)	Proposed Rate	Volume of Charges	Estimated Revenue ($MM)	Proposed Rates	Volume of Charges	Estimated Revenue ($MM)	
Customer Administration										
Arrears certificate	15	1,413	$ 0.02	15	1,413	$ 0.02	15	1,491	$ 0.02	
Statement of account	15	3	$ 0.00	15	3	$ 0.00	15	17	$ 0.00	
Pulling of post-dated cheques	15	-	$ -							
Duplicate invoices for previous billing	15	123	$ 0.00	15	123	$ 0.00	15	116	$ 0.00	
Request for other billing information	15	15	$ 0.00	15	15	$ 0.00	15	21	$ 0.00	
Easement letter	15	84	$ 0.00	15	84	$ 0.00	15	301	$ 0.00	
Income tax letter	15	11	$ 0.00	15	11	$ 0.00	15	10	$ 0.00	
Notification Charge	15	-	$ -							
Account history	15	9	$ 0.00	15	9	$ 0.00	15	14	$ 0.00	
Credit Check (plus credit agency costs)	15	135	$ 0.00	15	146	$ 0.00	15	334	$ 0.01	
Credit Check (plus credit agency costs) - General Service	25	11	$ 0.00							
Returned cheque (plus bank charges)	varies	7,608	$ 0.13	15	7,608	$ 0.11	15	3,203	$ 0.05	
Charge to certify cheque	15	-	$ -							
Legal letter charge	15	-	$ -							
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	varies	74,311	$ 2.23	30	88,494	$ 2.65	30	97,440	$ 2.92	1
Account set up charge/change of occupancy charge (plus credit agency costs if applicable) - Residential	20	14,183	$ 0.28							
Special meter reads	30	-	$ -	30	-	$ -	30	1	$ 0.00	
Meter dispute charge plus Measurement Canada fees (if meter found correct)	varies	-	$ -	30	-	$ -	30	1	$ 0.00	
Credit Card Convenience Charge	15	-	$ -							
Interval Meter request change	40	-	$ -							
Special billing service (aggregation)	125	12	$ 0.00	125	12	$ 0.00	125	12	$ 0.00	
Special billing service (sub-metering charge per meter)	25	12	$ 0.00	25	12	$ 0.00	25	12	$ 0.00	
Credit service charge for paperless bill	(10)	5,554	$ (0.06)							
Non-Payment of Account										
Reconnection at meter - during regular hours	varies	7,518	$ 0.40	65	7,518	$ 0.49	65	6,444	$ 0.42	1
Reconnection at meter - after regular hours	varies	3,924	$ 0.73	185	3,924	$ 0.73	185	193	$ 0.04	1
Reconnection at pole - during regular hours	varies	67	$ 0.01	185	421	$ 0.08	185	489	$ 0.09	1
Reconnection at pole - after regular hours	varies	-	$ -	415	116	$ 0.05	415	7	$ 0.00	1
Reconnection for >300 volts - during regular hours	60	354	$ 0.02							
Reconnection for >300 volts - after regular hours	155	116	$ 0.02							
Other										
Disconnect/reconnect at meter - during regular hours	varies	-	$ -	295	-	$ -	295	1,549	$ 0.46	2
Disconnect/reconnect at meter - after regular hours	varies	-	$ -	470	-	$ -	470	16	$ 0.01	2
Disconnect/reconnect at pole - during regular hours	185	-	$ -	525	-	$ -	525	5,414	$ 2.84	2
Disconnect/reconnect at pole - after regular hours	415	1	$ 0.00	1,090	1	$ 0.00	1,090	56	$ 0.06	2
Disconnect/reconnect - cancelled appointment		-	$ -	500		$ -	500	357	$ 0.18	2
Service Call - customer owned equipment	varies	-	$ -	30	-	$ -	30	-	$ -	
Service Call - after regular hours	varies	-	$ -	165	-	$ -	165	-	$ -	
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)	39.14	139,206	$ 5.45	40.10	139,206	$ 5.58	40.10	139,206	$ 5.58	
Administrative billing charge	150	-	$ -							
Overhead bond connection - per connection	105	88	$ 0.01							
Underground bond connection - per connection	100	-	$ -							
TOTAL			$ 9.25			$ 9.72			$ 12.68	

Notes:
1. Revenue at proposed rates is $0.5MM higher in total compared to 2025 revenue at existing rates due to the proposed harmonization of charges at the standard charge amount per the OEB Distribution Rate Handbook. The existing rate for some charge types varies by rate zone, as indicated. Refer to Exhibit 8, Tab 3, Schedule 2, Table 8-3-2 for further information.
2. Increases in 2027 revenue at proposed 2027 rates pertain primarily to proposed disconnect/reconnect charges for customer-requested or distributor-required purposes.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 8-STAFF-241

Rate Harmonization Proposal and Customer Engagement
Ref 1: Filing Requirements for Electricity Distribution Rate Applications - 2026 Edition for 2027 Rate Applications - Chapter 2, December 16, 2025, pp. 12
Ref 2: Exhibit 8 / Tab 1 / Schedule 1 / p. 6 (pdf p. 6)

Preamble:
In reference 1, the filing requirements for application-specific customer engagement states that "Customer engagement should also include customers uniquely affected by a proposal(s) in the application, such as new rate classes, changes to the existing rate classes and changes such as Retail Service Charges, Specific Service Charges, standby rates, and unmetered-load customers. Such communication should take place when proposing changes to the level of the rates and charges, or the introduction of new rates and charges."

Reference 2 states that General Services greater than 50 kW (GS>50 kW), Regular and Intermediate, Large Use with Dedicated Assets (LUDA), Standby Power, Embedded Distributor, and Distributed Generation (DGEN) rate classes do not demonstrate consistency across rate zones, and proposes changes to the existing rate design structure to facilitate consolidation.

Question(s):

a) Please confirm whether all customers under these rate classes have been informed of the proposed changes to the existing rate design structure.
    i. If yes, please provide additional information on the consultation/engagement process, as well as feedback from these customers based on the proposed changes.

ii. If not confirmed, please explain.

RESPONSE:

a) A summary of the various customer engagement activities conducted for customers uniquely affected by the proposals in the application are summarized below:

- Alectra Utilities engaged Innovative Research Group Inc. (Innovative), an independent public opinion research and consultation firm, to design, execute and document the results of its application-specific customer engagement process. In the Phase 2 customer engagement survey, customers were informed that as part of its rebasing application, Alectra Utilities will propose a plan to harmonize its rates into a single rate zone. Customers in each rate class and rate zone were presented with the rate impact from Alectra's harmonization proposal. Please refer to Exhibit 1, Tab 5, Schedule 2, Attachment 1-2, Innovative Customer Engagement Report, for the rate harmonization impacts presented to customers and the feedback from customers (residential pdf pp. 895-902; GS<50 pdf pp. 1007-1013; GS>50 pdf pp. 1102-1108; Large Use pdf pp. 1189-1195).

- As identified in Exhibit 8, Tab 3, Schedule 2, pdf p. 75, Alectra proposes to establish five new or revised specific service charges. In the Phase 2 customer engagement survey, customers in all rate classes were informed of the new specific service charges being proposed. Please refer to Exhibit 1, Tab 5, Schedule 2, Attachment 1-2, Innovative Customer Engagement Report for the information presented to customers and the feedback from customers (residential pdf pp. 903-906; GS<50 pdf pp. 1014-1016; GS>50 pdf pp. 1109-1111; Large Use pdf pp. 1196-1198).

- As identified in Exhibit 8, Tab 1, Schedule 1, pdf p.16, Alectra Utilities consulted with its embedded distributor and shared its direct cost allocation approach in the spring of 2025. Alectra Utilities provided Hydro One staff with its detailed proposal to allocate costs to the embedded distributor class. Please also see 1-Staff-1 for Alectra's updated proposal with respect to the embedded distributor class.

- Alectra proposes to eliminate the Distributed Generation (DGEN) class and transfer all customers to the GS<50kW rate class. Legacy Brampton was the only legacy utility with a rate class dedicated to FIT customers, with all other legacy utilities including these customers within General Service rate classes. As provided in Exhibit 8, Tab 2, Schedule 2, p.14, DGEN customers were contacted to inform them of Alectra's plan to eliminate the rate class and transition the affected customers to the GS<50kW rate class. No feedback was received from customers regarding the proposed changes.

- As identified in Exhibit 8, Tab 2, Schedule 2, pdf pp. 50, Alectra Utilities' current standby customers were contacted to inform them of Alectra Utilities' plan to finalize its standby rate design. The affected customers were given notice of Alectra Utilities' plan to seek approval of the proposed changes to the current standby rates and were provided with information on Alectra's rate application, the public hearing process and how they can be involved. Feedback was received from 11 customers who requested clarification on the proposed standby methodology and how Alectra will implement the changes, if approved.

- Alectra Utilities proposed to maintain the Large Use with Dedicated Assets class, therefore no additional customer engagement was undertaken for customers in this rate class.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 8-STAFF-242

Bill Impacts for 2027

Ref 1: Exhibit 8 / Tab 5 / Schedule 1 / pp. 3-4 (pdf pp. 254-255)

Preamble:

Alectra Utilities' proposed rates result in distribution bill impacts of 20.8% to 99% in the Residential, GS < 50 kW, GS > 50 kW, Large Use, and USL rate classes. In addition, the distribution bill impacts for GS < 50 kW and GS > 50 kW in the Guelph rate zone are 38.8% and 23.8% respectively.

Question(s):

a) Please provide any details that would substantiate that the underlying costs to serve customers has changed in each rate zone commensurate with the changes in rates.

b) Has Alectra Utilities considered any options for mitigation of the increases in 2027, such as a multi-year harmonization?

c) Please outline any benefits that accrue specifically to the ratepayers of Brampton and Guelph rate zones as a result of the consolidation.

RESPONSE:

a) The cost to serve Alectra Utilities' customers has not been assessed or approved since the rebasing application of Alectra's predecessor utilities, and as such, distribution rates have not been realigned with the cost to serve for more than a decade. Alectra Utilities has provided detailed evidence on the cost to serve its customers, as summarized in Exhibit 6, with supporting capital and operational

details in Exhibits 2 and 4, respectively. Alectra Utilities expects that the cost to serve customers has changed substantially since the respective rebasing applications of its legacy utilities, due to growth, changes in technology, changes in costs and regulatory requirements, and changes to Alectra Utilities' operations due to its consolidation, among other factors. As such, there is no change in the cost to serve customers between 2026 and 2027, which aligns with the change in rates; the 2027 change in rates aligns distribution rates and charges with the cost to serve customers for the first time since Alectra Utilities was formed.

b) Alectra Utilities is of the view the most appropriate approach is to complete rate harmonization in 2027, such that all Alectra Utilities customers share fairly in Alectra Utilities' costs, which have been harmonized for some time. To the degree the OEB determined rate mitigation beyond that proposed in Alectra Utilities' application was warranted, Alectra Utilities has discussed possible approaches to rate mitigation in response to 8-SEC-102.

c) Please see 1-Staff-42(b).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-243

DVA disposition

Ref 1: Exhibit 9

Question(s):

a) Please verify that the depreciation rates used in all the ICM true up models and MIST Meter revenue requirement workforms are based on each legacy's depreciation rate approved in their last rebasing application instead of the new rates per 2025 Alliance Depreciation Study.

b) Please update Group 2 DVA balances as of December 31, 2025, using most updated actual numbers.

c) Please explain when the audited numbers would be available.

d) Please confirm all the interest rates have been updated per the most recent OEB prescribed interest rate.

e) Please confirm that the disposition of both Group 1 and Group 2 accounts is on a final basis over one-year period from January 1, 2027 to December 31, 2027 in the application. If not confirmed, please explain why not.

RESPONSE:

a) In Alectra Utilities' October 14, 2025 submission, the ICM true-up models for the period 2018 to 2024 applied Alectra Utilities' depreciation rates in effect during those years. For

2025 and 2026, the depreciation rates used in the ICM true-up models reflected the updated rates from the 2025 Alliance Depreciation Study.

As stated in Exhibit 2B, Tab 3, Schedule 1, p.1, Alectra Utilities continued to use the legacy useful lives to calculate depreciation expense until 2019, when it converged the four legacy ERP systems into one ERP system. The useful life rates were then harmonized and implemented with an effective date of January 1, 2019. Upon further review, Alectra Utilities has revised all applicable ICM true-up models to apply each legacy utility's depreciation rates for 2018, consistent with the depreciation rates in effect in that year. No changes have been made to the depreciation rates for the years 2019 through 2026 in the updated models.

Please refer to the response to 9-Staff-248- d-ii, 9-Staff-249-d-ii and 9-Staff-250-c-ii for the updated ICM true-up models.

No changes have been made to the depreciation rates for MIST Meter revenue requirement models as the depreciation rates for Account 1860 Meters used for the model remain unchanged.

b) The Group 2 DVA balances have been updated as of December 31, 2025, using most updated actual numbers.

c) Alectra Utilities has estimated that the audited numbers would be available by March 11, 2026.

d) All the interest rates have been updated per the most recent OEB prescribed interest rate.

e) Alectra Utilities proposes that the disposition of Group 1 accounts be final as part of this proceeding. For Group 2 Accounts, Alectra Utilities is proposing to include the projected principal and interest activities in 2026 as part of the Group 2 DVA disposition request.

Alectra Utilities made this request on the basis that it provides ratepayers with the immediate and full benefit of the proposed distribution rate reduction, and it enhances regulatory efficiency by eliminating the need for a process to examine and clear the 2026 balances. Alectra Utilities is proposing a true-up process for its 2026 Group 2 DVA. Any variance between the approved forecast 2026 Group 2 DVA balances and the Actual 2026 Group 2 DVA balances will be recorded in Account 1595 to be reviewed in future proceedings.

Alectra Utilities proposes that the disposition of Group 1 and Group 2 accounts over a one-year period from January 1, 2027, to December 31, 2027.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-244

Ref 1: Exhibit 9 / Tab 1 / Schedule 1 / Attachments 9-1, 9-2, 9-3, 9-4, and 9-5 (DVA Continuity Schedules for all rate zones)
Ref 2: Exhibit 6 / Tab 1 / Schedule 3 / Attachments 6-1, 6-2, 6-2, 6-4, and 6-5 (Revenue Requirement Workform for 2027-2031)

Preamble:
Footnote #5 in Tab 4 of reference 1 states that the revenue amounts which are used to derive the service charges should be used to derive the DVA rate riders. Therefore, these distribution revenues should include the transformer ownership allowance from the Revenue Requirement Workform, Tab 13. Rate Design, column O + column Y.

Question(s):

a) Please confirm whether the sum of distribution revenue amounts for all rate zones (Tab 4, Column I in reference 1) are equal to the distribution revenue amount including transformer ownership allowance (Tab 13, column O + Y) in reference 2 or not. If not, please update Tab 4, Column I in reference 1 for each rate zone, as well as update all the evidence that is affected by this change as needed.

RESPONSE:

a) The sum of distribution revenue amounts for all rate zones (Tab 4, Column I in reference 1) was not equal to the distribution revenue amount including transformer ownership allowance (Tab 13, column O + Y) in reference 2.

Tab 4, Column I in reference 1 for each rate zone has been updated to equal the distribution revenue amount, including transformer ownership allowance (Tab 13, column

:

O + Y) in reference 2. The updated DVA continuity schedules capturing this change are provided in 9-Staff-247_Attach 1_DVA Continuity Schedule_HRZ, 9-Staff-248_Attach 1_DVA Continuity Schedule_BRZ, 9-Staff-249_Attach 1_DVA Continuity Schedule_PRZ, 9-Staff-250_Attach 1_DVA Continuity Schedule_ERZ and 9-Staff-251_Attach 1_DVA Continuity Schedule_GRZ.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-245

BRZ, PRZ, ERZ, GRZ

Account 1508 Sub-account Collection Charge Lost Revenue

Ref 1: Exhibit 9 / Tab 3 / Schedule 13 / Section 4.2.12 / p. 1 (pdf p. 457)

Preamble:

Alectra Utilities states that the lost collection of account charge revenue that would have been recorded is calculated by multiplying the number of disconnection notices sent to the customers for non-payment by the legacy collection of account charges.

Question(s):

a) Please discuss whether there are any savings included when calculating the account balances.

   i. If yes, please complete the following table compiled by OEB staff indicating annual savings from 2019 to 2026:

	Year (actual/forecast)
# of Collection Notices issued	
Savings incurred	

   ii. If no, please explain why there is no savings recorded to offset the account balance? (e.g., lower account write-offs, less time allocating resources to consumer complaints, and other similar benefits)

RESPONSE:

a) There were no savings included when calculating the account balances.

   i. N/A

ii. Alectra Utilities did not realize any savings from the elimination of the collection of account charge. Alectra Utilities continued to incur ongoing operating costs to provide these services which include collection activities, reminder notices, out-bound calls, final notices and management of field activities. Alectra Utilities did not experience a decrease in call volumes, collections or complaints as a result of the elimination of the charge.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-246

Account 1508 Sub-account - Useful Life Changes
Account 1508 Sub-account - Direct Labour Capitalization Changes
Ref 1: Exhibit 9 / Tab 3 / Schedule 9 / Section 4.2.8 / p. 1 (pdf p. 443)
Ref 2: Exhibit 9 / Tab 3 / Schedule 11 / Section 4.2.10 / p. 1 (pdf p. 453)
Ref 3: EB-2025-0055, Decision and Rate Order, December 16, 2025, p. 32
Ref 4: Exhibit 9 / Tab 1 / Schedule 1 / Attachments 9-1, 9-2, 9-3, 9-4, and 9-5 (DVA Continuity Schedules for all rate zones)

Preamble:
In references 1 and 2, Alectra Utilities is seeking disposition of a credit $40.2M for Account 1508 Sub-account Useful Life Changes and a credit $11.7M for Account 1508 Sub-account Direct Labour Capitalization Changes.

Per reference 3, the OEB has denied Alectra Utilities' request for approval of proposed DVAs to track the impact of changes to asset useful life and direct labour capitalization policies.

Question(s):

a) Please remove the balances for both DVAs and update the DVA continuity schedule.

RESPONSE:

a) Alectra Utilities has removed the balances for both DVAs and update the DVA continuity schedule. The updated continuity schedules are filed as 9-Staff-247_Attach 1_DVA Continuity Schedule_HRZ, 9-Staff-248_Attach 1_DVA Continuity Schedule_BRZ, 9-

Staff-249_Attach 1_DVA Continuity Schedule_PRZ, 9-Staff-250_ Attach 1_DVA Continuity Schedule_ERZ and 9-Staff-251_Attach 1_DVA Continuity Schedule GRZ.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-247

HRZ

DVA Continuity schedule

Ref 1: Exhibit 9 / Alectra_Attach 9-1 DVA Continuity Schedule_HRZ_Updated 20251121
Ref 2: EB-2014-0002, 7 0 2015_EDDVAR_Continuity_Schedule_CoS_v2.0 (2013 Actual) - Revised 12
Ref 3: EB-2023-0241, Decision and Rate Order, December 14, 2023, p. 22
Ref 4: EB-2025-0055, Decision and Rate Order, December 16, 2025, p. 24

Question(s):

a) For LRAMVA, the 2024 OEB-approved disposition for principal amount is $1,465,772 per reference 3 while it shows $2,179,377 in reference 1, please explain the discrepancy.

b) For LRAMVA, please record 2026 OEB-approved disposition per reference 4.

RESPONSE:

a) For LRAMVA, the 2024 OEB-approved disposition totals $2,179,377. This amount comprises the LRAMVA principal balances for 2022 and 2023 of $1,465,772, as well as the prospective 2024 LRAMVA balance of $713,606. The 2024 balance is approved as set out in EB-2023-0241, Decision and Rate Order, December 14, 2023, p. 22, Table 8.2.

b) For LRAMVA, the 2026 OEB-approved disposition balance in Reference 4 has been recorded in 9-Staff-247_Attach 1_DVA Continuity Schedule_HRZ.

9-Staff-247

Attachment 1
DVA Continuity Schedule_HRZ

Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-248

BRZ
DVA Continuity schedule
Ref 1: Exhibit 9 / Alectra_Attach 9-2 DVA Continuity Schedule_BRZ_Updated 20251121
Ref 2: EB-2014-0083 / HOBNI_2015_EDDVAR_Continuity_Schedule_xlsm_20141223
Ref 3: EB-2023-0241, Decision and Rate Order, December 14, 2023, p. 22
Ref 4: EB-2025-0055, Decision and Rate Order, December 16, 2025, p. 24
Ref 5: Exhibit 9 / Alectra_Attach 9-11_MIST Meter Revenue Requirement_BRZ_20251014 / Tab 4
Ref 6: Exhibit 9 / Alectra_Attach 9-7_ICM True-Up Model

Question(s):

a) For LRAMVA, the 2024 OEB-approved disposition for principal amount is $ 3,372,225 per reference 3 while it shows $5,054,126 in reference 1, please explain the discrepancy.

b) For LRAMVA, please record 2026 OEB-approved disposition per reference 4.

c) For Account 1557 MIST Meter, please fill in Tab 4 (rate rider collection) in reference 5 and reconcile to the rate rider collection per RRR report in reference 1 (i.e. $1,631,538 Cell E106 in Tab 3)

d) For Account 1508 Sub-account Incremental Capital Expenditures, OEB staff notes that Alectra Utilities grouped all the projects:
    i. Please provide breakdown of principal and interest based on each project and record them separately using ICM sub-accounts in reference 1.

ii. Please reconcile the total balance of the sub-accounts in (i) to reference 6

iii. OEB staff notes that the ICM rate rider collections from 2018 to 2024 (i.e. $7,909,813) in Tab 3 of reference 1 does not match the total amount (i.e. $8,655,121) per sheet 7 in reference 6. Please explain the variance.

e) Per reference 6, OEB staff notes that Alectra Utilities has used the new depreciation rates from the depreciation study which had not been approved in its 2026 IRM application:

i. Please confirm OEB staff's observation.

ii. If confirmed, please update all the ICM Ture up Models (i.e. reference 6) by using legacy Horizon's depreciation rates for 2025 and 2026.

iii. Please reconcile and update reference 1 accordingly.

iv. If not confirmed, please explain why not.

RESPONSE:

a) For LRAMVA, the 2024 OEB-approved disposition principal amount totals $5,054,126. This amount comprises the LRAMVA principal balances for 2022 and 2023 of $ 3,372,225, as well as the prospective 2024 LRAMVA balance of $1,681,901. The 2024 balance is approved as set out in EB-2023-0241, Decision and Rate Order, December 14, 2023, p. 22, Table 8.2.

b) For LRAMVA, the 2026 OEB-approved disposition balance in Reference 4 has been recorded in 9-Staff-248_Attach 1_DVA Continuity Schedule_BRZ.

c) No rate riders were approved and collected for the BRZ 1557 MIST Meter project. As noted in Reference 1, $1,631,538 represented the incremental capital costs related to the MIST meter project and the associated carrying charge, which is reported in 2024

RRR 2.1.7 Account 1557. Alectra Utilities has updated the MIST Meter Revenue Requirement model for BRZ with the 2025 actual depreciation amount. The updated model is provided as 9-Staff-248_Attach 5_MIST RR_BRZ.

d)

i. The breakdown of principal and interest based on each project has been recorded separately using ICM sub-accounts in 9-Staff-248_Attach 1_DVA Continuity Schedule_BRZ.

ii. The total claim balance for each sub-account recorded in (i) is equal to the respective true up balance from the BRZ ICM models as follows:

- 9-Staff-248_Attach 2__ICM True-Up Model_2018_Pleasant TS CCRA, Tab 9, Cell Y31
- 9-Staff-248_Attach 3__ICM True-Up Model_2021 Goreway Road Widening, Tab 9, Cell T31
- 9-Staff-248_Attach 4_ICM True-Up Model 2021 Goreway TS CCRA, Tab 9, Cell T31

The above ICM models have been updated using the 2025 actual rate rider collection amounts.

iii. The amount of $8,655,121 per sheet 7 in Reference 6 includes interest on the rate rider collections.

e)

i. Alectra Utilities used the new depreciation rates from the depreciation study for 2025 and 2026 in its October 14, 2025 submission.

ii. The true-up model for 2018 Pleasant TS CCRA has been updated by using the legacy Hydro Once Brampton depreciation rates for 2018.

iii. 9-Staff-248_Attach 1_DVA Continuity Schedule_BRZ has been reconciled and updated accordingly.

iv. Please refer to 9-Staff-243-a for the treatment of the depreciation rates in ICM True up models.

9-Staff-248

Attachment 1
DVA Continuity Schedule_BRZ

Please see live Excel

9-Staff-248

Attachment 2
ICM True-Up Model_2018_Pleasant TS CCRA

Please see live Excel

9-Staff-248

Attachment 3
ICM True-Up Model_2021_Goreway Road Widening

Please see live Excel

9-Staff-248

Attachment 4
ICM True-Up Model_2021_Goreway TS CCRA

Please see live Excel

9-Staff-248

Attachment 5
MIST RR_BRZ
Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-249

PRZ DVA Continuity schedule

Ref 1: Exhibit 9 / Alectra_Attach 9-3 DVA Continuity Schedule_PRZ_Updated 20251121

Ref 2: EB-2015-0003 / PowerStream_Schedule K - EDVAR Continuity Schedule and Rate Riders_20160912

Ref 3: EB-2023-0241, Decision and Rate Order, December 14, 2023, p. 22

Ref 4: EB-2025-0055, Decision and Rate Order, December 16, 2025, p. 24

Ref 5: Exhibit 9 / Alectra_Attach 9-8_ICM True-Up Model

Ref 6: Exhibit 9 / Alectra_Attach 9-12_MIST Meter Revenue Requirement_PRZ_20251014 / Tab 4

Preamble:

Per references 1 and 2, OEB staff has compiled the following reconciling the 2014 ending balances.

	Closing principal as of Dec 2014	**Closing interest as of Dec 2014**
	Reference 2	
#1508 Other Regulatory Assets-Sub Account Other	**$844,185**	**$123,632**
	Reference 1	
#1508 Other Post-Employment Benefits (a)	($2,062,259)	0
#1508 CGAAP IFRS Differential (b)	$2,665,445	$120,542
#1508 Hydro One Charges (c)	$240,999	$3,090
Total (a+b+c)	**$844,185**	**$123,632**

Question(s):

a) Please confirm that the account balance of Account 1508 Other Regulatory Assets-Sub Account Other was grouped with three accounts balance per the table above.
   i. If confirmed, in reference 1, please reconcile 2015 OEB-approved disposition recorded under 1508 CGAAP IFRS Differential (i.e. $603,185 for principal and $94,305 for interest) and 2016 OEB-approved disposition recorded under 1508 Hydro One Charges (i.e. $241,000 for principal and $34,006 for interest) by splitting the amount into the right accounts.
   ii. If not confirmed, please provide evidence to reconcile the ending 2014 balance and the opening 2015 balance of these three accounts.

b) For LRAMVA, the 2024 OEB-approved disposition for principal amount is $ 6,815,160 per reference 3 while it shows $10,323,587 in reference 1. Please explain the discrepancy.

c) For LRAMVA, please record 2026 OEB-approved disposition per reference 4.

d) For Account 1508 Sub-account Incremental Capital Expenditures, OEB staff notes that Alectra Utilities grouped all the projects together.
   i. Please provide a breakdown of principal and interest based on each project and record them separately using ICM sub-accounts in reference 1.
   ii. Please reconcile the total balance of the sub-accounts in (i) to reference 5
   iii. OEB staff notes that the ICM rate rider collections from 2018 to 2024 (i.e. $17,607,584) in Tab 3 of reference 1 does not match the total amount (i.e. $19,347,282) per sheet 7 in reference 5. Please explain the variance.

e) For Account 1557 MIST Meter, please fill in Tab 4 (rate rider collection) in reference 6 and reconcile to the rate rider collection per RRR report in reference 1 (i.e. $10,467,185 in Cell E106 of Tab 3)

f) Per reference 5, OEB staff notes that Alectra Utilities has used the new depreciation rates from the depreciation study which was not approved in its 2026 IRM application:
   i. Please confirm OEB staff's observation.
   ii. If confirmed, please update all the ICM Ture up Models (i.e. reference 5) by using legacy PowerStream's depreciation rates for 2025 and 20206.
   iii. Please reconcile and update reference 1 accordingly.
   iv. If not confirmed, please explain why not.

RESPONSE:

a) Alectra Utilities confirms that the account balance of Account 1508 Other Regulatory Assets-Sub Account Other was grouped with three account balances per the table above.

   i. The OEB-approved disposition for 2016 of $241,000 (principal) and $34,006 (interest) reflects the OEB-approved disposition for Account 1508 – Hydro One Charges for that year. PRZ did not request the disposition of Account 1508 – Other Post-Employment Benefits or Account 1508 CGAAP IFRS Differential in its application EB-2025-0003, 2016–2020 Custom IR Application.

   Alectra Utilities also identified that the OEB-approved 2015 disposition amounts of $603,185 (principal) and $94,305 (interest), recorded under Account 1508 – CGAAP IFRS Differential, had been inadvertently entered. The DVA schedule for PRZ has been updated by removing the $603,185 (principal) and $94,305 (interest) and adding these balances to the 2015 transactions. The corrected 2015 transactions and interest amounts have now been included in this account in the updated DVA schedule. These corrections do not change the total amount claimed for this account. Please refer to 9-Staff-249 _Attach 1_DVA Continuity Schedule PRZ for the updated DVA schedule for PRZ.

   ii. N/A.

b) For LRAMVA, the 2024 OEB-approved disposition principal amount totals $10,323,587. This amount comprises the LRAMVA principal balances for 2022 and 2023 of $6,815,160, as well as the prospective 2024 LRAMVA balance of $3,508,428. The 2024 balance is approved as set out in EB-2023-0241. Decision and Rate Order, December 14, 2023, p.22, Table 8.2.

c) For LRAMVA, the 2026 OEB-approved disposition balance in Reference 4 has been recorded in 9-Staff-249_Attach 1_DVA Continuity Schedule PRZ.

d)

i. The breakdown of principal and interest based on each project has been recorded separately using ICM sub-accounts in reference 1.

ii. The total claim balance for each sub-account recorded in (i) is equal to the respective true up balance from the PRZ ICM models as follows:

- 9-Staff-249_Attach 2_ICM True-Up Model 2018, Road Authority YRRT, Tab 9. IRR, Cell Y31
- 9-Staff-249_Attach 3_ICM True-Up Model 2019 Bathurst Road Widening, Tab 9. IRR, Cell Y31
- 9-Staff-249_Attach 4_ICM True-Up Model 2019 Road Authority YRRT Yonge St., Tab 9. IRR, Cell Y31
- 9-Staff-249_Attach 5_ICM True-Up Model 2021, Rutherford Road Widening, Tab 9. IRR, Cell Y31
- 9-Staff-249_Attach 6_ICM True-Up Model 2023, Cable Renewal, Tab 9. IRR, Cell Y31
- 9-Staff-249_Attach 7_ICM True-Up Model 2024, Cable Renewal, Tab 9. IRR, Cell Y31

The above ICM models have been updated using the 2025 actual rate rider collection amounts.

iii. The amount of $19,374,282 per sheet 7 in reference 6 included interest on the rate rider collections.

e) No rate riders were approved and collected for the PRZ 1557 MIST Meter project. As noted in Reference 1, $10,467,185 represents the incremental capital costs related to the MIST meter project and the associated carrying charge, which is reported in 2024 RRR 2.1.7 Account 1557. Alectra Utilities has updated the MIST Meter Revenue Requirement model for PRZ with the 2025 actual depreciation amount. The updated model is provided as 9-Staff-249_Attach 8_MIST RR_PRZ.

f)

i. Alectra Utilities used the new depreciation rates from the depreciation study for 2025 and 2026 in its October14, 2025 submission.

ii. The true-up model for the 2018 Road Authority YRRT has been updated by using legacy PowerStream depreciation rates for 2018.

iii. 9-Staff-249_Attach 1_DVA Continuity Schedule_PRZ has been reconciled and updated.

iv. Please refer to 9-Staff-243-a for the treatment of the depreciation rates in ICM True up models.

9-Staff-249

Attachment 1
DVA Continuity Schedule PRZ

Please see live Excel

9-Staff-249

Attachment 2
ICM True-Up Model 2018 Road Authority YRRT

Please see live Excel

9-Staff-249

Attachment 3
ICM True-Up Model 2019 Bathurst Road Widening

Please see live Excel

9-Staff-248

Attachment 4
ICM True-Up Model 2019 Road Authority
YRRT Yonge St

Please see live Excel

9-Staff-248

Attachment 5
ICM True-Up Model 2021 Rutherford Road Widening

Please see live Excel

9-Staff-248

Attachment 6
ICM True-Up Model 2023 Cable Renewal

Please see live Excel

9-Staff-248

Attachment 7
ICM True-Up Model 2024 Cable Renewal

Please see live Excel

9-Staff-248

Attachment 8
MIST RR_PRZ

Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-250

ERZ DVA Continuity schedule
Ref 1: Exhibit 9 / Alectra_Attach 9-4 DVA Continuity Schedule_ERZ_Updated 20251121
Ref 2: EB-2012-0033 / Enersource_APPL_Excel_Deferral_Accounts_Continuity_Schedule 20120427
Ref 3: EB-2023-0241, Decision and Rate Order, December 14, 2023, p. 22
Ref 4: EB-2025-0055, Decision and Rate Order, December 16, 2025, p. 24
Ref 5: Exhibit 9 / Alectra_Attach 9-9_ICM True-Up Model
Ref 6: Exhibit 9 / Alectra_Attach 9-13_MIST Meter Revenue Requirement_ERZ_20251014 / Tab 4

Question(s):

a) For LRAMVA, the 2024 OEB-approved disposition for principal amount is $ 5,885,851 per reference 3 while it shows $8,442,446 in reference 1. Please explain the discrepancy.

b) For LRAMVA, please record 2026 OEB-approved disposition per reference 4.

c) For Account 1508 Sub-account Incremental Capital Expenditures, OEB staff notes that Alectra Utilities grouped all the projects together.
   i. Please provide a breakdown of principal and interest based on each project and record them separately using ICM sub-accounts in reference 1.
   ii. Please reconcile the total balance of the sub-accounts in (i) to reference 5
   iii. OEB staff notes that the ICM rate rider collections from 2018 to 2024 (i.e. $10,084,642) in Tab 3 of reference 1 does not match the total amount (i.e. $10,951,881) per sheet 7 in reference 5. Please explain the variance.

:

d) For Account 1557 MIST Meter, please fill in Tab 4 (rate rider collection) in reference 6 and reconcile to the rate rider collection per RRR report in reference 1 (i.e. $3,805,259 in Cell E106 of Tab 3)

e) Per reference 5, OEB staff notes that Alectra Utilities has used the new depreciation rates from the depreciation study which was not approved in its 2026 IRM application:
   i. Please confirm OEB staff's observation.
   ii. If confirmed, please update all the ICM Ture up Models (i.e. reference 5) by using legacy Enersource's depreciation rates for 2025 and 20206.
   iii. Please reconcile and update reference 1 accordingly.
   iv. If not confirmed, please explain why not.

RESPONSE:

a) For LRAMVA, the 2024 OEB-approved disposition principal amount totals $8,442,446. This amount comprises the LRAMVA principal balances for 2022 and 2023 of $5,885,851, as well as the prospective 2024 LRAMVA balance of $2,556,595. The 2024 balance is approved as set out in EB-2023-0241, Decision and Rate Order, December 14, 2023, p.22, Table 8.2.

b) For LRAMVA, the 2026 OEB-approved disposition balance in Reference 4 has been recorded in 9-Staff-250_Attach 1_DVA Continuity Schedule_ERZ.

c)

i. The breakdown of principal and interest based on each project has been recorded separately using ICM sub-accounts in reference 1.

ii. The total claim balance for each sub-account recorded in (i) is equal to the respective true up balance from the ERZ ICM models as follows:

- 9-Staff-250_Attach 2_ICM True-Up Model 2018 Leaking Transformer Overhead, Tab 9. IRR, cell Z31

:

- 9-Staff-250_Attach 3_ICM True-Up Model 2018 Leaking Transformer Padmount, Tab 9 IRR, cell Z31
- 9-Staff-250_Attach 4_ICM True-Up Model 2018 York MS Civil Construction, Tab 9.IRR, cell Z31
- 9-Staff-250_Attach 5_ICM True-Up Model 2019 Leaking Transformer, Tab 9. IRR, cell Z31
- 9-Staff-250_Attach 6_ICM True-Up Model 2023 Cable Renewal, Tab 9.IRR, cell Z31

iii. The amount of $10,951,881 per sheet 7 in reference 6 included interest on the rate rider collections.

d) No rate riders were approved and collected for the ERZ 1557 MIST Meter project. As noted in Reference 1, $3,805,259 represented the incremental capital costs related to the MIST meter project and the associated carry charge, which is reported in 2024 RRR 2.1.7 Account 1557. Alectra Utilities has updated the MIST Meter Revenue Requirement model for ERZ with the 2025 actual depreciation amount. The updated model is provided as 9-Staff-250_Attach 7_MIST RR_ERZ.

e)

i. Alectra Utilities used the new depreciation rates from the depreciation study for 2025 and 2026 in its October14, 2025 submission.

ii. The true-up models for 2018 projects have been updated by using the legacy Enersource depreciation rates for 2018.

iii. 9-Staff-250 Attach 1 DVA Continuity Schedule ERZ has been reconciled and updated.

iv. N/A.

:

9-Staff-250

Attachment 1
DVA Continuity Schedule_ERZ

Please see live Excel

9-Staff-250

Attachment 2
ICM True-Up Model 2018 Leaking Transformer Overhead

Please see live Excel

9-Staff-250

Attachment 3
ICM True-Up Model 2018 Leaking Transformer Padmount

Please see live Excel

9-Staff-250

Attachment 4
ICM True-Up Model 2018 York MS Civil Construction

Please see live Excel

9-Staff-250

Attachment 5
ICM True-Up Model 2019 Leaking Transformer

Please see live Excel

9-Staff-250

Attachment 6
ICM True-Up Model 2023 Cable Renewal

Please see live Excel

9-Staff-250

Attachment 7
MIST RR_ERZ

Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-251

GRZ DVA Continuity Schedule
Ref 1: Exhibit 9 / Alectra_Attach 9-5 DVA Continuity Schedule_GRZ_Updated 20251121
Ref 2: EB-2015-0073 / Guelph Settlement Updated EDDVAR Continuity Schedule CoS 20151020
Ref 3: Exhibit 9 / Alectra_Attach 9-14_MIST Meter Revenue Requirement_GRZ_20251014 / Tab 4
Ref 4: EB-2023-0241, Decision and Rate Order, December 14, 2023, p. 22

Question(s):

a) For Account 1557 MIST Meter, please fill in Tab 4 (rate rider collection) in reference 3 and reconcile to the rate rider collection per RRR report in reference 1 (i.e. $507,674 in Cell E101 of Tab 3)

b) For LRAMVA, the 2024 OEB-approved disposition for principal amount is $ 2,011,935 per reference 4 while it shows $3,047,295 in reference 1. Please explain the discrepancy.

c) For LRAMVA, please explain the principal adjustments for both 2018 and 2016 in reference 1.

RESPONSE:

a) No rate riders were approved and collected for the GRZ 1557 MIST Meter project. As noted in Reference 1, $507,674 represented the incremental capital costs related to the MIST meter project and the associated carrying charge, which is reported in 2024 RRR

:

2.1.7 Account 1557. Alectra Utilities has updated the MIST Meter Revenue Requirement model for GRZ with the 2025 actual depreciation amount. The updated model is provided as 9-Staff-251_Attach 1_MIST RR_GRZ.

b) For LRAMVA, the 2024 OEB-approved disposition totals $ 3,047,295. This amount comprises the LRAMVA principal balances for 2022 and 2023 of $ 2,011,935, as well as the prospective 2024 LRAMVA balance of $1,035,361. The 2024 balance is approved as set out in EB-2023-0241, Decision and Rate Order, December 14, 2023, p. 22, Table 8.2.

c) The principal adjustment for 2016 of $239,788 was related to the exclusion of the persistence of the 2011 to 2013 program savings in 2016. The OEB only approved the persistence of the 2014 to 2015 program savings as part of its LRAMVA lost revenue in 2016 (refer to EB-2017-0044, Guelph Hydro 2018 IRM, Decision and Rate Order, December 14, 2017, p. 11).

The principal adjustment for 2018 of $150,588 was related to the exclusion of the persistence of the 2011 to 2013 program savings in 2018. The OEB only approved the persistence of the 2014 to 2017 program savings as part of its LRAMVA lost revenue in 2018 (refer to EB-2020-0002, Alectra Utilities 2021 IRM, Decision and Rate Order, December 17, 2020, p. 35).

The updated DVA continuity schedule for GRZ is provided as 9-Staff-251_Attach 2_DVA Continuity Schedule_GRZ to reflect the 2025 actuals.

:

9-Staff-251

Attachment 1
MIST RR_GRZ

Please see live Excel

9-Staff-251

Attachment 2
DVA Continuity Schedule_GRZ

Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-252

Account 1509 Impacts Arising from the COVID-19 Emergency

Ref 1: Exhibit 9 / Tab 4 / Schedule 3 / Section 5.3 / p. 1 (pdf p. 511)

Preamble:

Alectra Utilities is not seeking disposition of Covid-19 DVA and there are no deferral balances recorded.

Question(s):

a) Please confirm that COVID-19 related costs have not been requested for all rate zones in the past years and will not be requested in the future.

b) Please confirm Alectra Utilities is discontinuing this account in this application.

RESPONSE:

a) Alectra Utilities confirms that COVID-19 related costs have not been requested for any rate zone in the past years and will not be requested in the future.

b) Alectra Utilities confirms that it is discontinuing this account in this application.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-253

Account 1522 Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges
Ref 1: Exhibit 9 / Tab 3 / Schedule 18 / Section 4.2.17 / p. 1 (pdf p. 485)
Ref 2: Exhibit 9 / Tab 1 / Schedule 1 / Attachments 9-1, 9-2, 9-3, 9-4, and 9-5 (DVA Continuity Schedules for all rate zones)
Ref 3: EB-2015-0040, Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs, September 14, 2017

Preamble:
Per reference 1, Alectra Utilities proposes the clearance of a $2.0MM credit balance in Account 1522 and also proposes to discontinue this account as it does not anticipate the annual balances remaining material in the future.

Per reference 2, this variance account was established as a generic account to track the carrying charges between the cash basis and accrual basis of OPEB. The primary account will accrue carrying charges to be returned to ratepayers when the cumulative opening monthly balance of the account is in a credit position. Disposition can only result in a credit refund of carrying charges to ratepayers. If utilities record journal entries on an annual basis instead of doing separate monthly entries, it may do so provided that they can demonstrate that ratepayers will not be disadvantaged as a result. The interest rate shall be the CWIP rate prescribed by the OEB.

Question(s):

a) Please provide excel worksheet showing the calculation of this account balance for each rate zone and reconcile to reference 2.

b) Please confirm whether the CWIP rate prescribed by the OEB has been used for calculating this account balance. If not confirmed, please update the schedule and balance.

c) Please confirm whether Alectra Utilities has recorded journal entries monthly or on an annual basis. If the journal entries were recorded on an annual basis, please demonstrate that ratepayers will not be disadvantaged as a result.

d) Please provide Alectra Utilities' position on continuing this account as required by the OEB's Pension and OPEB report.

RESPONSE:

a) The excel worksheet showing the calculation of this account balance for each rate zone and reconcile to reference 2 has been provided as 9-Staff-253_Attach 1_1522 Reconciliation.

b) Alectra Utilities confirms the CWIP rate prescribed by the OEB has been used for calculating this account balance.

c) Alectra Utilities recorded journal entries monthly.

d) Upon further consideration, Alectra Utilities proposes to continue this account. Although the annual balances have not been material —averaging approximately $0.2M since 2018—the cumulative impact over the five-year rate term could become material.

9-Staff-253

Attachment 1
Account 1522 Reconciliation

Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-254

PRZ

Account 1508 Sub-account Other Post-Employment Benefit (OPEB) Deferral Account

Ref 1: Exhibit 9 / Tab 3 / Schedule 4 / Section 4.2.3 / p. 1 (pdf p. 27)

Ref 2: EB-2012-0161, Rate Order, January 31, 2013, Appendix B

Ref 3: EB-2015-0003 / PowerStream_Schedule K - EDVAR Continuity Schedule and Rate Riders_20160912

Ref 4: Exhibit 9 /Alectra_Attach 9-3 DVA Continuity Schedule_PRZ_Updated 20251121

Ref 5: EB-2015-0040, Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs, September 14, 2017

Ref 6: EB-2012-0033 / Decision and Order Rates, December 13, 2012, Issue 9.2, p. 59

Preamble:

In reference 1, PRZ established this DVA in its 2013 COS to record cumulative actuarial gains and losses of OPEB. Alectra Utilities states that PRZ has not requested the disposition of this account in the past proceeding. It is seeking disposition of a credit amount of $4.7MM over a one-year period and is proposing to continue the account.

In reference 2, the accounting order states that the balance in this account as of December 31, 2012 is approximately debit $1.4M. Effective from 2013, this DVA will record changes in the cumulative actuarial gains and losses in PRZ's OPEB as supported by updated actuarial report. The recovery shall be over the average employee remaining service years per the settlement agreement.[1]

In reference 3, OEB staff observes that this account balance was grouped with other two accounts.

[1] EB-2012-0161, Decision and Order, December 21, 2012, Settlement Agreement, Issue 5.2, p. 51

OEB staff has compiled the following table reconciling the 2014 ending balance based on references 3 and 4.

	Closing principal as of Dec 2014	Closing interest as of Dec 2014
	Reference 3	
#1508 Other Regulatory Assets-Sub Account Other	**$844,185**	**$123,632**
	Reference 4	
#1508 Other Post-Employment Benefits (a)	($2,062,259)	0
#1508 CGAAP IFRS Differential (b)	$2,665,445	$120,542
Subtotal (a+b)	**$603,186**	**$120,542**
#1508 Hydro One Charges (c)	$240,999	$3,090
Total (a+b+c)	**$844,185**	**$123,632**

OEB staff also observes that Alectra Utilities recorded $603,185 as OEB-approved disposition during 2015 for Account 1508 CGAAP IFRS Differential (see screenshot below). However, this amount is the sum of Account 1508 Other Post-Employment Benefits and Account 1508 CGAAP IFRS Differential based on the highlighted amount in the table above.

Account Descriptions	Account Number	2015							
		OEB-Approved Disposition during 2015	Principal Adjustments(1) during 2015	Closing Principal Balance as of Dec 31-15	Opening Interest Amounts as of Jan-1-15	Interest Jan-1 to Dec-31-15	OEB-Approved Disposition during 2015	Interest Adjustments(1) during 2015	Closing Interest Amounts as of Dec-31-15
Group 2 Accounts									
Deferred IFRS Transition Costs	1508			-$136,421	-$7,897	-$1,625			-$9,522
Pole Attachment Revenue Variance[5]	1508			$0	$0				$0
Retail Service Charge Incremental Revenue[6]	1508			$0	$0				$0
Customer Choice Initiative Costs[7]	1508			$0	$0				$0
Local Initiatives Program Costs[9]	1508			$0	$0				$0
Green Button Initiative Costs[10]	1508			$0	$0				$0
Designated Broadband Project Impacts[13]	1508			$0	$0				$0
ULO Implementation Cost[14]	1508			$0	$0				$0
GOCA Variance Account[15]	1508			$0	$0				$0
LEAP EFA Funding Deferral Account[17]	1508			$0	$0				$0
Energy East Consultation Costs	1508			$0	$0				$0
OEB Cost Assessments	1508			$0	$0				$0
Other Post-Employment Benefits	1508			-$2,422,187	$0				$0
Impact of Post-merger Capitalization Policy Change	1508			$0	$0				$0
Incremental Capital Expenditures[16]	1508	$9,881,950		-$49,465	$7,764		$24,138		-$16,374
Collection of Account Charge-Related Lost Revenue	1508			$0	$0				$0
CGAAP IFRS Differential	1508	$603,185		$1,243,635	$120,542	$118,971	$94,305		$145,208
Advanced Pricing Project	1508			$0	$0				$0
Hydro One Charges	1508			$242,006	$3,090	$2,882			$5,972

Per reference 5, the OEB established a new DVA (i.e. Account 1522 Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential variance account) and utilities is

required to begin record entries in this new DVA from January 2018 of which disposition can only result in a credit refund of carrying charge to ratepayers.

Per reference 6, ERZ has established the same account as PRZ and was ordered to continue until the earlier of:

- A decision by the Board to implement a policy respect to the OPEB which differs from the approach approved here, and
- The next rebasing application for Enersource

Question(s):

a) Please confirm OEB staff's observations.
   i. If a) is confirmed, please confirm this account has been disposed of in 2015.
   ii. If a) is confirmed, please update the DVA continuity in reference 4 to reflect the OEB-approved disposition amount in 2015 for Account 1508 Other Post-Employment Benefits and Account 1508 CGAAP IFRS Differential separately.
   iii. If a) is not confirmed, please explain why not and provide the reconciliation between references 3 and 4.

b) Per reference 6, please confirm this account shall be discontinued as of December 31, 2017 since the OEB has established new DVAs per reference 5.
   i. If b) is confirmed, please remove all the account balance from 2018 onwards and discontinue the account.
   ii. If b) is not confirmed, please explain why not.

c) Alectra Utilities is proposing one-year disposition period. Please explain why Alectra Utilities is not proposing disposition of the balance over the average employee remaining service years, as per the settlement agreement.[2]

[2] EB-2012-0161, Decision and Order, December 21, 2012, Settlement Agreement, Issue 5.2, p. 51

RESPONSE:

a) Alectra Utilities confirms OEB staff's observations that this account balance was grouped with the other two accounts in reference 3 (i.e. the DVA continuity schedule for the legacy PowerStream approved by the OEB). Alectra Utilities also confirms OEB staff's observation that Alectra Utilities recorded $603,185 in reference 4 and this amount is the sum of Account 1508 Other Post-Employment Benefits and Account 1508 CGAAP IFRS Differential based on the highlighted amount in the table above.

i. This account has not been disposed of in 2015. Please refer to 9-Staff-249-a-i for more details.

ii. Please refer to 9-Staff-249-a-i. The 2015 OEB-approved disposition for 1508 CGAAP IFRS Differential has been removed. The updated DVA continuity for PRZ filed as 9-Staff-249_Attach 1 DVA_Continuity Schedule_PRZ reflects this update.

iii. The account balance for Account 1508 Other Regulatory Assets-Sub Account Other in reference 3 comprised three account balances (i.e. Account 1508 Other Post-Employment Benefits, 1508 CGAAP IFRS Differential and Account 1508 – Hydro One Charges). The $603,185 was entered in reference 3 under Principal Disposition during 2015 so that the model would derive a closing principal balance as of December 31, 2014, adjusted for the disposition in 2015 of $241,000. This balance of $241,000 represents the 2015 OEB-approved disposition principal balance for Account 1508 – Hydro One Charges only.

b) Alectra Utilities proposes to continue this account over the rate term of this application.

i. N/A.

ii. The OEB has already approved the use of this deferral account for PRZ to capture cumulative actuarial gains and losses related to post-retirement benefits. Alectra Utilities is now proposing the disposition of this account, as the gains and losses recorded have not substantially offset over time.

As noted in Ref. 3, EB-2015-0040, Regulatory Treatment of Pension and Other Post-employment Benefits Costs, September 14, 2017, under the Accounting Frameworks discussion, page. 12–13, the OEB has not made a determination on a generic approach to the regulatory treatment of actuarial gains and losses under IFRS.

In its report, the OEB stated that "utilities may propose disposition of the account in future cost-based rate proceedings if the gains and losses that are tracked in this account do not substantially offset over time." The OEB further noted that this issue "was not the focus of this consultation" and, as a result, it "has not made a determination on a generic approach to the regulatory treatment of actuarial gains and losses under IFRS and will consider the potential need for further analysis and guidance on this matter in due course."

c) The average remaining service life of PowerStream employees is estimated at 18 years. Maintaining balances over such a long period would require ongoing administrative resources, which could outweigh any potential benefit of spreading the balance. In addition, long-term amortization introduces uncertainty in future rates and raises concerns regarding intergenerational equity.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-255

ERZ

Account 1508 Sub-account Other Post-Employment Benefit (OPEB) Deferral Account

Ref 1: Exhibit 9 / Tab 3 / Schedule 4 / Section 4.2.3 / p. 2 (pdf p. 27)

Ref 2: EB-2012-0033 / Decision and Order Rates, December 13, 2012, Issue 9.2, p. 59

Ref 3: EB-2015-0040, Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs, September 14, 2017

Preamble:

Per reference 2, this account was established in the absence of Board policy on the OPEB issue and it will continue until the earlier of:

- A decision by the Board to implement a policy respect to the OPEB which differs from the approach approved here, and
- The next rebasing application for Enersource

Per reference 3, the Board has issued an OPEB report to establish a new OPEB DVAs (i.e. Account 1522 Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential variance account) and utilities are required to begin record entries in this new DVA from January 2018 of which disposition can only result in a credit refund of carrying charge to ratepayers.

Question(s):

a) Please confirm this account shall be discontinued as of December 31, 2017 since the OEB has established new DVAs per reference 3.
   i. If a) is confirmed, please remove all the account balance from 2018 onwards and discontinue the account.
   ii. If a) is not confirmed, please explain why not.

RESPONSE:

a) Alectra Utilities proposes to continue this account over the rate term of this application.

i. N/A.

ii. The OEB has already approved the use of this deferral account for ERZ to capture cumulative actuarial gains and losses related to post-retirement benefits. Alectra Utilities is now proposing the disposition of this account, as the gains and losses recorded have not substantially offset over time.

As noted in Ref. 3, EB-2015-0040, Regulatory Treatment of Pension and Other Post-employment Benefits Costs, September 14, 2017, under the Accounting Frameworks discussion, page. 12–13, the OEB has not made a determination on a generic approach to the regulatory treatment of actuarial gains and losses under IFRS.

In its report, the OEB stated that “utilities may propose disposition of the account in future cost-based rate proceedings if the gains and losses that are tracked in this account do not substantially offset over time.” The OEB further noted that this issue “was not the focus of this consultation” and, as a result, it “has not made a determination on a generic approach to the regulatory treatment of actuarial gains and losses under IFRS and will consider the potential need for further analysis and guidance on this matter in due course.”

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-256

GRZ
Account 1508 Sub-account Other Post-Employment Benefit (OPEB) Deferral Account
Ref 1: Exhibit 9 / Tab 3 / Schedule 4 / Section 4.2.3 / p. 1 (pdf p. 27)
Ref 2: EB-2015-0073, Settlement Proposal, Section 4.2, p. 30
Ref 3: EB-2015-0040, Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs, September 14, 2017
Ref 4: Exhibit 9 / Alectra_Attach 9-5 DVA Continuity Schedule_GRZ_Updated 20251121

Preamble:
In reference 1, GRZ agreed to the recovery of OPEB costs on a cash basis as an interim measure pending on the outcome of OEB's OPEB consultation.

Per reference 2, Guelph Hydro agreed to the recovery of OPEB on a cash basis vs. the accrual basis of accounting and established a new deferral account (i.e. Account 1508 OPEB Forecast Cash versus Forecast Accrual Differential Deferral Account) for the purpose of recording, each year starting in the test year, the difference in revenue requirement between (i) both the capitalized and OM&A components of OPEBs accounted for using a forecasted cash basis (as would be reflected in rates if this settlement is accepted by the Board) and (ii) both capitalized and OM&A components of OPEBs accounted for using a forecasted accrual basis. Carrying charges will not apply to this deferral account. Guelph Hydro will be permitted to seek disposition of this account to recover the amounts recorded in its next cost of service rate application if the Board determines that LDCs may recover OPEBs in rates using a forecasted accrual accounting methodology.

Per reference 3, the Board supports using the accrual method as the default method for calculating the amount of pension and OPEB costs to go into rates.

OEB notes that GRZ has recorded balance in Account 1508 Sub-account Other Post-Employment Benefit (OPEB) Deferral Account, however, it does not have approval to establish this account.

OEB staff notes Account 1508 OPEB Forecast Cash versus Forecast Accrual Differential Deferral Account was not in the DVA continuity per reference 4.

Question(s):

a) Please confirm OEB staff's observations.
   i. If a) is confirmed, please update the DVA continuity to reflect the correct DVA account and remove all the balance in Account 1508 Sub-account Other Post-Employment Benefit (OPEB) Deferral Account
   ii. If a) is confirmed, please update Account 1508 OPEB Forecast Cash versus Forecast Accrual Differential Deferral Account with correct balance
   iii. If a) is not confirmed, please explain the reason and provide the related accounting order showing GRZ was approved to establish Account 1508 Sub-account Other Post-Employment Benefit (OPEB) Deferral Account.

b) Please confirm that GRZ's OPEB expense is based on an accrual basis in this application.

c) Please provide excel worksheet showing the calculations of revenue requirement between two methods (cash vs accrual) which should be recorded in this account.
   i. Please provide the breakdown of both the capitalized and OM&A components.

RESPONSE:

a) Alectra Utilities confirms OEB staff's observations. The incorrect description for this account was inadvertently used.

i. Alectra Utilities has updated the DVA continuity to reflect the correct DVA account and remove all the balances in Account 1508 Sub-account Other Post-Employment Benefit (OPEB) Deferral Account.

ii. Alectra Utilities has updated Account 1508 OPEB Forecast Cash versus Forecast Accrual Differential Deferral Account with the correct balances.

iii. N/A

b) Alectra Utilities confirms that GRZ's OPEB expense is based on an accrual basis in this application.

c) Alectra Utilities has provided an Excel worksheet showing the calculations between two methods (cash vs accrual) in 9-Staff-256_Attach 1_Cash vs Accrual. The OPEB accrued amount is based on the total of current service costs and interest costs as per Alectra Utilities Actuarial Valuation Post -Retirement Non-Pension Benefits Appendix - Accounting Schedules, Estimated Benefit Expense for Guelph Hydro, Section C - Change in the present value of Defined Benefit Obligation. The OPEB cash amount is based on the actual benefit paid.

i. The breakdown of both the capitalized and OM&A components has been included in the attachment above.

9-Staff-256

Attachment 1
Cash vs Accrual

Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-257

Account 1511 Incremental Cloud Computing Implementation Costs
Ref 1: Exhibit 9 / Tab 3 / Schedule 16 / Section 4.2.15 / p. 1 (pdf p. 471)
Ref 2: EB-2024-0063, Decision and Order, March 27, 2025, Section 3.8, p. 102
Ref 3: Filing Requirements for Electricity Distribution Rate Applications - 2026 Edition for 2027 Rate Applications - Chapter 2 / Section 2.9.1.9 / p. 70

Preamble:
Per reference 1, Alectra Utilities is seeking disposition of a $2.0M debit balance which captures the incremental cloud computing implementation costs and related offsetting savings for its new Human Capital Management System (HCM) implemented in 2024. Alectra Utilities is proposing to continue the account and states that the 2025 forecasted balances reflect expected second phase implementation expenses and ongoing licensing costs.

Per reference 2, the utility can propose the treatment of any future cloud solutions at the next rebasing rate application following establishment of the account in November 2023, which could include a new cloud solution deferral account. If no proposal is made in that rebasing rate application, the account will be closed.

Question(s):

a) Please confirm that Alectra Utilities has not included any of second phase implementation costs in the rates in this application, given that its proposal is to continue the deferral account.
    i. If confirmed, please explain why estimated amount could not be forecasted in the rate term and be included in the rates.

b) Please discuss the methodology used to measure the incremental costs and offsetting savings.

c) Per reference 3, please provide breakdown of actual or forecast amounts, types of expenditure (e.g., capital or OM&A), and nature of costs (e.g., data migration)

d) Please reconcile c) to Table 9-3-44 in reference 1.

e) Please provide Alectra Utilities' position on discontinuing this account per reference 2.

RESPONSE:

a) Alectra Utilities has not included any of second phase implementation costs in the rates in this application. The HCM implementation project has been completed, therefore, no estimated amount is required in the rate term.
    i. N/A

b) All costs included in Account 1511 are compliant with the requirements set out in the OEB's Accounting Order 003-2023 and the guidance provided the in Q&A session that followed. The HCM system is a net new cloud-based solution for Alectra and there are no amounts in base rates that pertain to the system implementation. Alectra reviewed the nature of the expenses being charged to the HCM work order and whether these costs were included in base rates. As identified in Table 1 below, internal labour costs and non-labour costs were assessed to determine their eligibility to be recorded in the account.

Table 1 – Cost Groupings

Cost Grouping	Outcome	Assumptions
Internal Labour	Exclude	The internal labour resources seconded to the implementation project were determined to not be incremental as these positions were included in base rates.
Non-Labour	Include - Conditional	Non labour expenses which could be directly attributed to implementation and licensing were determined to be incremental to the costs included in base rates.

All implementation costs were tracked via project work order and IT license schedules. All project costs were identifiable and measurable. Only applicable costs incurred after the December 1, 2023 effective date were included in the account.

The expected savings were also reviewed to identify any cost offsets that should be considered. Please refer to 9-SEC-111 for the methodology used to measure the offsetting savings. Offsetting savings were identified related to redundant payroll FTEs and the reduced licencing requirements from the elimination of legacy payroll systems.

c) A summary of actual costs and savings is provided in Table 3 below. All costs recorded are OM&A costs.

Table 2 – Summary of Costs and Savings

Cost Grouping	Type	2024 Actual	2025 Actual	Total
Non Labour	Implementation	903,981	479,140	1,383,121
Non Labour	System Integration	79,650	22,800	102,450
Non Labour	Change Management	197,625	20,155	217,780
Non Labour	Licensing	178,400	488,918	667,318
A: Total Cost		**1,359,656**	**1,011,013**	**2,370,669**
Savings				
Non Labour	Licensing	27,006	227,614	254,620
Labour	FTE	67,454	263,440	330,894
B: Total Savings		**94,460**	**491,054**	**585,514**
Total in Account (A-B)		**1,265,196**	**519,959**	**1,785,155**

d) The total amounts in Table 3 above are consistent with Total Deferral Account amounts shown in Table 9-3-44 in reference 1.

e) Alectra Utilities proposes continuing Account 1511 to capture incremental cloud computing implementation costs and any related offsetting savings, provided that the amount exceeds the amount built into the rate term in this application. The cloud computing costs included in the 2027-2031 revenue requirements are provided in 9-SEC-111 b).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-258

Account 1508 Sub-account - GOCA Variance Account

Ref 1: Exhibit 9 / Tab 3 / Sch 14 / Section 4.2.13 / p. 1 (pdf p. 462)

Preamble:

Alectra Utilities considers the difference between actual locate costs and the amounts embedded in rates to be incremental and attributable to the impacts of Bill 93. The actual locate costs are based on the invoices from various third-party service providers.

Alectra Utilities proposes the clearance of a $9.5MM debit balance in this account.

Question(s):

a) Please confirm Alectra Utilities has reflected the GOCA impact in the locate costs of the test year's revenue requirement.
   i. If not confirmed, please explain why not.

b) Please complete the following table compiled by OEB staff to provide a detailed breakdown of the GOCA variance account by cost category (e.g., internal labour, third-party locators, materials, administrative cost) for both actual and forecast numbers.

Cost Category	Internal or external	Nature of costs	2023 actual	2024 actual	2025 actual	2026 forecast

c) Please discuss the methodology used to measure incremental costs which ensures that only eligible and prudently incurred GOCA related costs were recorded in the variance account

d) Please explain how Alectra Utilities assessed that the costs recorded in the GOCA Variance Account were directly related to Bill 93.

e) Please confirm that all amounts recorded in the variance account were of expense nature (not capital expenditures).

RESPONSE:

a) Alectra Utilities confirms that the GOCA impact in the locate costs has been reflected in the test years' revenue requirement.

b) Table 1 provides a detailed breakdown of the GOCA variance account by cost category.

Table 1 - Breakdown of the GOCA variance account in $MM

Cost Category	Internal or External	Nature of Costs	2023 Actual	2024 Actual	2025 Actual	2026 Forecast
Third-party Locators	External	OM&A	7.0	6.5	7.4	7.0
Administrative Costs	External	OM&A	0.3	0.5	0.5	0.6
Amount in Rates			4.2	5.2	5.4	5.5
GOCA Variance Account			**3.1**	**1.8**	**2.5**	**2.1**

c) Alectra Utilities measures incremental costs by comparing the total actual costs charged by external locate service providers (refer to Table 1) against the amounts embedded in rates. Bill 93 has resulted in material incremental costs for Alectra Utilities, due to higher fees charged by locate service providers. These higher fees reflect both the legislative changes introduced by Bill 93 and labour shortages within the locate service provider industry, which have collectively driven upward pressure on labour and service costs. Alectra Utilities prudently incurred these costs to comply with the mandated locate service requirements and associated legislative obligations.

d) Please see response to 9-CCC-73 c).

e) Alectra Utilities confirms that all amounts recorded in the variance account are of expense nature (not capital expenditures).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-259

Account 1508 Sub-account Energy East Consultation Costs (HRZ, PRZ, ERZ)
Account 1508 Sub-account Long-term Load Mitigation (HRZ)
Account 1531 Renewable Connection Capital Deferral Account (ERZ)
Account 1532 Renewable Connection OM&A Deferral Account (ERZ)
Account 1536 Smart Grid Funding Adder Deferral Account (PRZ)
Account 1555 Smart Meter Capital and Recovery Offset Variance Account, Sub-account Stranded Meter Costs (HRZ, PRZ, ERZ)
Ref 1: Exhibit 9 / Tab 3 / Schedule 2 / Section 4.2.1 / p. 1 (pdf p. 17)
Ref 2: Exhibit 9 / Tab 3 / Schedule 12 / Section 4.2.11 / p. 1 (pdf p. 456)
Ref 3: Exhibit 9 / Tab 3 / Schedule 19 / Section 4.2.18 / p. 1 (pdf p. 487)
Ref 4: Exhibit 9 / Tab 3 / Schedule 20 / Section 4.2.19 / p. 1 (pdf p. 488)
Ref 5: Exhibit 9 / Tab 3 / Schedule 23 / Section 4.2.22 / p. 1 (pdf p. 492)
Ref 6: Exhibit 9 / Tab 3 / Schedule 24 / Section 4.2.23 / p. 1 (pdf p. 493)

Preamble:
Per reference 1, Alectra Utilities is seeking approval to clear the $0.2M debit balance and also proposes to discontinue the account.

Per reference 2, Alectra Utilities is seeking approval to clear the $0.01M credit balance and also proposes to discontinue the account.

Per reference 3, Alectra Utilities is seeking the disposition of a debit $0.5M by transferring the balance to the fixed assets and also proposes to discontinue the account.

Per reference 4, Alectra Utilities is seeking the disposition of a debit of $0.1M and also proposes to discontinue the account.

Per references 5 and 6, Alectra Utilities is seeking disposition of a debit $0.003MM for Account 1536 which is a residual amount from legacy PowerStream's rate rider for disposition of Smart Grid True-up Variance Account (2014 Balance). Alectra Utilities is also seeking disposition of a debit $0.1M for Account 1555 which is the residual amount of the legacy Rate Riders for recovery of stranded meter assets and approved stranded meter costs carrying charges

Question(s):

a) Per reference 2, please provide the accounting order showing that the legacy Horizon Utilities got approval from the OEB to establish this DVA.

b) Please explain why the above accounts are proposed for disposition while the account balances are below the materiality threshold (i.e. $1M)

RESPONSE:

a) The accounting order showing that legacy Horizon Utilities received approval from the OEB to establish this DVA is provided in EB-2017-0096, Niagara-on-the-lake Hydro Inc. Alectra Utilities Corporation, Joint Application for Elimination of Load Transfer Arrangements, May 25, 2017, Appendix A, page 6.

b) Alectra Utilities assesses materiality from the perspective of the total Group 2 account balance. In the Report of the Board on Electricity Distributor's Deferral and Variance Account Review Initiative ("EDDVAR"), July 31, 2009, Section 5.1 Disposition Threshold, page 13, the OEB indicated that using the net balance of all accounts to determine disposition is a practical approach. Accordingly, Alectra Utilities is proposing disposition of the total Group 2 balance including the above accounts, as the total Group 2 balance meets the OEB's materiality threshold.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-260

PRZ
Account 1508 Sub-account CGAAP IFRS Differential
Ref 1: Exhibit 9 / Tab 3 / Schedule 5 / Section 4.2.4 / p. 1 (pdf p. 427)
Ref 2: EB-2012-0161, Rate Order, January 31, 2013, Appendix B
Ref 3: EB-2015-0003 / PowerStream_Schedule K - EDVAR Continuity Schedule and Rate Riders_20160912
Ref 4: Exhibit 9 / Alectra_Attach 9-3 DVA Continuity Schedule_PRZ_Updated 20251121

Preamble:
Per references 1 and 2, OEB staff notes that the account name is "CGGAP IFRS Differential" which is different from the account name in reference 2 (i.e. "CGAAP-CWIP Differential Deferral Account").

Per references 3 and 4, OEB staff notes that this account balance was grouped with the other two accounts. OEB staff also notes that, for OEB approved disposition amount, the amount is incorrect in 2015 and is missing in 2016.

Question(s):

a) Please confirm OEB staff's observations.
   i. Please update the DVA continuity in reference 4 to reflect the correct OEB-approved disposition amount in 2015 and 2016 and reconcile to reference 5.
   ii. If not confirmed, please explain why not and provide the reconciliation between references 3 and 4.

b) Please explain why this account is proposed for disposition while the account balance is below the materiality threshold (i.e. $1MM).

RESPONSE:

a) Alectra Utilities confirms all OEB staff's observations in preamble.

i) ii) Legacy PowerStream did not request the disposition of Account 1508 CGAAP IFRS Differential in its application EB-2015-0003. Accordingly, Alectra Utilities has removed the OEB-approved disposition amount in 2015 and kept the OEB-approved disposition during 2016 blank in the updated DVA schedule for PRZ. Please refer to 9-Staff-249 Attach 1 DVA Continuity Schedule_PRZ.

b) Alectra Utilities assessed materiality from the perspective of the total Group 2 account balance. In the Report of the Board on Electricity Distributor's Deferral and Variance Account Review Initiative ("EDDVAR"), July 31, 2009, Section 5.1 Disposition Threshold, page 13, the OEB indicated that using the net balance of all accounts to determine disposition is a practical approach. Accordingly, Alectra Utilities is proposing disposition of the total Group 2 balance including this account, as the total Group 2 balance meets the OEB's materiality threshold.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-261

PRZ

Account 1508 Sub-account Hydro-One Charge

Ref 1: Exhibit 9 / Tab 3 / Schedule 6 / Section 4.2.5 / p. 1 (pdf p. 428)

Ref 2: EB-2015-0003 / PowerStream_Schedule_K_-_EDVAR_Continuity_Schedule_and_Rate_Riders_20160912

Ref 3: Account Procedures Handbook (APH) - Frequently Asked Questions, October 2009, Q17(2), p. 16

Ref 4: Exhibit 9 / Alectra_Attach 9-3 DVA Continuity Schedule_PRZ_Updated 20251121

Preamble:

Alectra Utilities is seeking approval to clear the $0.1M debit balance in this account and states that this account balance reflects the percentage allocation of the HONI's approved rate riders from EB-2008-0187, EB-2012-0136 and EB-2013-0141 allocated to 1508. Alectra Utilities allocated (8%) of the Rider 3A amount to 1508 based on HONI's 1508 balance contribution to the total approved DVA balances. Alectra Utilities also states that the same allocation approach was applied for several HONI's volumetric rate riders.

Pre reference 3, the rate rider 3A amount charge to the distributor is then multiplied by the account's percentage to arrive at an amount to be recorded in the particular account (e.g., charge/billed accounts related accounts 1584 RSVAnw and 1586 RSVAcn).

Question(s):

a) Please provide the accounting order showing that the legacy PowerStream received approval from the OEB to establish this DVA.

b) Per references 2 and 4, this account balance was grouped with the other two accounts. Please update the DVA continuity to reflect the correct amount.

c) Please explain why Alectra Utilities recorded Rider 3A in this DVA instead of in the related RSVAs per reference 3.

d) Please provided a reference showing that the legacy PowerStream is approved by the OEB to record HONI's volumetric rate riders (EB-2012-0136, EB-2013-0141) in this account.

e) Please complete the following table to provide breakdown and to reconcile the HONI's rate rider to the amount recorded in reference 4:

Year	Hydro One's rate rider	% allocated to PRZ	Amount calculated (a)	Amount recorded in Ref 4 (b)	Variance (a-b)

f) Please update the balance as applicable based on the above questions and explain why this account is proposed for disposition if the updated account balance is below the materiality threshold (i.e. $1MM).

RESPONSE:

a) Legacy PowerStream followed the APH guidance in Reference 3 to record the percentage of Hydro One's approved rate riders in this account. The balance in the account as of December 31, 2014 was approved for disposition by the OEB, as documented in Reference 2: EB-2015-0003. Legacy PowerStream did not receive an accounting order from the OEB for this account.

b) Alectra Utilities has updated the DVA continuity schedule to reflect the correct amounts. Please refer to 9-Staff-249_Attach 1 _DVA Continuity Schedule PRZ for the updated version.

c) Please refer to the response to part a).

d) Legacy PowerStream followed the APH guidance as noted in Reference 3: APH – Frequently Asked Questions, October 2009, Q17(2), p. 16, to record the percentage of HONI's approved rate riders in this account.

e) Upon further review, Alectra Utilities identified that a total principal amount of $50,470 had been incorrectly recorded in the 2015, 2016, and 2021 transactions. Alectra Utilities will record the correcting entry in 2026. The DVA continuity schedule has been updated to include $57,022 in projected 2026 principal transactions to reflect this correction, representing the combined adjustment for the $50,470 and associated carrying charges.

f) Alectra Utilities has updated the PRZ DVA continuity schedule to reflect the corrections noted above. Following these adjustments, the ending balance for this account is $0. Accordingly, Alectra Utilities PRZ has withdrawn its request for disposition of this account in the PRZ.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-262

Account 1508 Sub-account LEAP Emergency Financial Assistance Funding Deferral Account
Ref 1: Exhibit 9 / Tab 3 / Schedule 15 / Section 4.2.14 / p. 1 (pdf p. 468)
Ref 2: EB-2023-0135, Final Rate Order, February 12, 2024, Schedule A - Electricity Accounting Order

Preamble:
Alectra Utilities proposes the clearance of a $3.2MM debit balance in this account, including $0.8M LEAP Agency administrative fees.

The OEB's final rate order issued in February 12, 2024 established LEAP EFA Funding Deferral sub-account and the order states that distributors may record prudently incurred incremental LEAP EFA contributions made on and after March 1, 2024 that are beyond the amounts currently embedded in distribution rates.

Question(s):

a) Please explain why LEAP Agencies for Administrative Fees was recorded in this account.

b) Please confirm that Alectra Utilities has recorded prudently incurred incremental LEAP EFA contributions made on and after March 1, 2024 for all rate zones in this account.

RESPONSE:

a) On February 12, 2024, the OEB issued its letter Changes to the Low-income Energy Assistance Program Emergency Financial Assistance and Accounting Orders. In the

letter, the OEB agrees that no eligible LEAP applicant should be denied assistance due to a lack of funding.

For regulatory efficiency, the OEB established a generic deferral account, effective March 1, 2024, allowing distributors to record prudently incurred LEAP contributions that exceed the funding amounts embedded in rates.

Under the generic funding mechanism, in place since 2011, each distributor provides the greater of 0.12% of their total OEB-approved distribution revenue requirement or $2,000 each year for LEAP EFA. Alectra Utilities' approved LEAP funding is $675,885, which represents 0.12% of the total approved revenue requirement.

LEAP funding disbursed by Alectra Utilities includes LEAP grants provided to eligible customers and agency administration and program delivery fees, calculated at 15% of the grants disbursed to customers. LEAP agencies are responsible for assessing applicants' eligibility for LEAP EFA. The associated agency administration and program delivery fees form part of Alectra Utilities' total LEAP contributions. The total LEAP contributions, including associated agency fees, that exceed the funding amounts embedded in rates have been prudently incurred and recorded in this account.

b) Alectra Utilities confirms that it has recorded prudently incurred incremental LEAP EFA contributions made on and after March 1,2024 for all rate zones in this account.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-263

Account 1508 Sub-account Earnings Sharing Mechanism (Year 9 and 10 of 3 Deferred Rebasing Period)
Ref 1: Exhibit 9 / Tab 4 / Schedule 1 / Section 5.2 / p. 1 (pdf p. 509)
Ref 2: Exhibit 9 / Alectra_Attach 9-1 DVA Continuity Schedule_HRZ_Updated 20251121

Preamble:
Alectra Utilities states that it has not triggered ESM in years 6 to 8 of the rebasing deferral period (2022-2024). Per reference 2, HRZ has principal activities recorded from 2016 to 2020.

Question(s):

a) Please provide the accounting order showing that Alectra Utilities got approval from the OEB to establish this DVA.

b) Please explain the nature of the transactions recorded in reference 2

RESPONSE:

a) Alectra Utilities uses Account 1508 – ESM to track the ESM impacts for years six to ten (2022-2026) of Alectra's rebasing deferral period, using the same account the OEB approved for the HRZ ESM during its 2015–2019 CIR rate term. In Alectra Utilities' 2020 EDR Application, EB-2019-0018, Partial Decision and Order, December 12, 2019, p.45, the OEB approved Alectra's ESM proposal for years six to ten of the rebasing deferral period, stating that the proposal was consistent with the OEB's MAADs policy. The OEB did not issue an accounting order to establish a DVA account for this matter.

b) The transactions recorded in reference in reference 2 are related to the ESM for HRZ under its 2015-2019 CIR rate term.

Upon further review, Alectra Utilities noted that the OEB-approved disposition for 2019 was inadvertently included in the 2019 transactions. Alectra Utilities has updated the DVA for HRZ to separate the 2019 transaction amount of $1,302,486 and the OEB-approved disposition amount of $695,975. Please refer to 9-Staff-247_Attach 1_DVA Continuity Schedule_HRZ for the updated DVA schedule.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-264

HRZ, BRZ, ERZ, GRZ

Account 1508 Sub-account Impact of Post-merger Capitalization Policy Change

Ref 1: Exhibit 9 / Tab 3 / Schedule 8 / Section 4.2.7 / p. 1 (pdf p. 437)

Ref 2: EB-2022-0185, Decision and Order, December 8, 2022, Table 9.1, p. 24

Ref 3: EB-2025-0055, Decision and Rate Order, December 16, 2025, p. 29

Preamble:

OEB staff has provided tables below showing that the amount recorded in the respective rate zone from 2017 to 2021 are different between references 1 and 2.

Table 9-3-17: Account 1508 Sub-account - Impact of Post-merger Capitalization Policy Change($MM)

	Actual						Forecast				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
HRZ	—	(1.0)	1.0	(6.3)	(5.8)	(6.3)	(6.1)	(5.0)	(5.0)	(8.0)	(42.6)
Carrying Charges	—	—	—	—	—	—	—	—	—	—	—
Total Proposed for Disposition	**—**	**(1.0)**	**1.0**	**(6.3)**	**(5.8)**	**(6.3)**	**(6.1)**	**(5.0)**	**(5.0)**	**(8.0)**	**(42.6)**
BRZ	1.2	1.7	2.2	2.1	3.0	2.4	2.5	2.9	3.2	4.6	25.8
Carrying Charges	—	—	—	—	—	—	—	—	—	—	—
Total Proposed for Disposition	**1.2**	**1.7**	**2.2**	**2.1**	**3.0**	**2.4**	**2.5**	**2.9**	**3.2**	**4.6**	**25.8**
ERZ	—	(1.9)	(2.9)	(1.3)	(1.4)	(0.9)	(1.2)	(1.7)	(1.4)	(2.5)	(15.3)
Carrying Charges	—	—	—	—	—	—	—	—	—	—	—
Total Proposed for Disposition	**—**	**(1.9)**	**(2.9)**	**(1.3)**	**(1.4)**	**(0.9)**	**(1.2)**	**(1.7)**	**(1.4)**	**(2.5)**	**(15.3)**
GRZ	—	—	—	(0.7)	(1.0)	0.5	(0.5)	(0.6)	(0.4)	(0.5)	(3.2)
Carrying Charges	—	—	—	—	—	—	—	—	—	—	—
Total Proposed for Disposition	**—**	**—**	**—**	**(0.7)**	**(1.0)**	**0.5**	**(0.5)**	**(0.6)**	**(0.4)**	**(0.5)**	**(3.2)**
Alectra Total - Principal Balance	**1.2**	**(1.1)**	**0.2**	**(6.3)**	**(5.1)**	**(4.3)**	**(5.3)**	**(4.4)**	**(3.7)**	**(6.5)**	**(35.2)**
Alectra Total - Carrying Charges	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Alectra Total	**1.2**	**(1.1)**	**0.3**	**(6.3)**	**(5.1)**	**(4.3)**	**(5.3)**	**(4.4)**	**(3.7)**	**(6.5)**	**(35.2)**

Reference 1

Table 9.1: Impact Analysis of Capitalization Policy Change

Capitalization Policy Impact ($000s)	2017	2018	2019	2020	2021
Enersource RZ	1,866	1,712	1,490	1,491	1,601
Brampton RZ	(1,831)	(1,610)	(1,976)	(2,283)	(3,293)
Horizon RZ				6,512	6,092
Guelph RZ				432	367
Net PP&E Change	**36**	**102**	**(485)**	**6,153**	**4,766**
Enersource RZ	(47)	(89)	(127)	(164)	(204)
Brampton RZ	46	86	135	192	275
Horizon RZ				(163)	(315)
Guelph RZ				(11)	(20)
Depreciation Impact	**(1)**	**(3)**	**9**	**(145)**	**(264)**
Enersource RZ	1,819	1,622	1,364	1,327	1,397
Brampton RZ	(1,785)	(1,524)	(1,840)	(2,090)	(3,019)
Horizon RZ				6,349	5,777
Guelph RZ				422	347
Alectra Utilities Net Impact	**35**	**98**	**(477)**	**6,007**	**4,502**

Reference 2

Question(s):

a) Please explain the variance between references 1 and 2 identified by OEB staff above.

b) Please provide "Impact Analysis of Capitalization Policy Change" per Table 9.1 in reference 2 from 2017 to 2026.

c) Please reconcile a) to Table 9-3-17 in reference 1.

d) Per reference 3, the OEB has denied Alectra Utilities' request for approval of proposed DVA to track the impact of changes to DLC policies. Please confirm whether the DLC impact has been included in this account sought for disposition.

i. If yes, please update the DVA continuity of all the rate zones to exclude the DLC impact

e) Please quantify the differences between actual and forecast allocations.

i. Please explain the key drivers of the changes to the capitalization policy impacts for the period from 2022 to 2026.

RESPONSE:

a) The variances identified between Reference 1 and Reference 2 for HRZ, BRZ, and ERZ are attributable to the true-up adjustments recorded in 2019 to reflect the OEB's findings on Alectra Utilities' treatment of post-merger capitalization policy changes, as set out in the EB-2019-0018, Partial Decision and Order, Alectra Utilities' 2020 EDR Application, January 20, 2022, page 35. The total values for ERZ, BRZ, and HRZ for 2017–2019 in Reference 1 reconcile to the corresponding total values for 2017–2019 in Reference 2 for each respective rate zone.

For GRZ, the variances between Reference 1 and Reference 2 relate to the true-up entries recorded in 2022 based on the actual capital expenditures incurred in 2020 and 2021. The total values ($1.2MM) for GRZ for 2020 -2022 in Reference 1 reconcile to the corresponding total values for 2020–2022 in Reference 2. Table 1 below extends Reference 2 from 2021 to 2022.

Table 1 - Impact Analysis of Capitalization Policy Change 2017-2022 in $000's

Capitalization Policy Impact ($000s)	2017	2018	2019	2020	2021	2022
Enersource RZ	1,866	1,712	1,490	1,491	1,601	1,109
Brampton RZ	(1,831)	(1,610)	(1,976)	(2,283)	(3,293)	(2,702)
Horizon Utilities RZ				6,512	6,092	6,785
Guelph RZ				432	367	480
Net PP&E Change	**36**	**102**	**(485)**	**6,153**	**4,766**	**5,672**
Enersource RZ	(47)	(89)	(127)	(164)	(204)	(232)
Brampton RZ	46	86	135	192	275	342
Horizon Utilities RZ				(163)	(315)	(485)
Guelph RZ				(11)	(20)	(32)
Depreciation Impact	**(1)**	**(3)**	**9**	**(145)**	**(264)**	**(406)**
Enersource RZ	1,819	1,622	1,364	1,327	1,397	877
Brampton RZ	(1,785)	(1,524)	(1,840)	(2,090)	(3,019)	(2,360)

Capitalization Policy Impact ($000s)	2017	2018	2019	2020	2021	2022
Horizon Utilities RZ				6,349	5,777	6,300
Guelph RZ				422	347	448
Alectra Utilities Net Impact	**35**	**98**	**(477)**	**6,007**	**4,502**	**5,266**

b) "Impact Analysis of Capitalization Policy Change" per Table 9.1 in reference 2 from 2017 to 2026 has been provided below in Table 2 Impact Analysis of Capitalization Policy Change.

Table 2 - Impact Analysis of Capitalization Policy Change

Capitalization Policy Impact	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Enersource RZ	1,866	1,712	1,490	1,491	1,601	1,109	1,476	1,993	2,143	2,074	
Brampton RZ	(1,831)	(1,610)	(1,976)	(2,283)	(3,293)	(2,702)	(2,922)	(3,443)	(4,566)	(3,731)	
Horizon Utilities RZ				6,512	6,092	6,785	6,783	5,846	8,153	6,633	
Guelph RZ				432	367	480	521	638	982	393	
Net PP&E Change	**36**	**102**	**(485)**	**6,153**	**4,766**	**5,672**	**5,859**	**5,035**	**6,711**	**5,370**	
Enersource RZ	(47)	(89)	(127)	(164)	(204)	(232)	(269)	(318)	(373)	(410)	
Brampton RZ	46	86	135	192	275	342	415	501	616	662	
Horizon Utilities RZ				(163)	(315)	(485)	(654)	(800)	(1,004)	(1,108)	
Guelph RZ				(11)	(20)	(32)	(45)	(61)	(84)	(80)	
Depreciation Impact	**(1)**	**(3)**	**9**	**(145)**	**(264)**	**(406)**	**(553)**	**(678)**	**(845)**	**(936)**	
Enersource RZ	1,819	1,622	1,364	1,327	1,397	877	1,208	1,674	1,770	1,664	
Brampton RZ	(1,785)	(1,524)	(1,840)	(2,090)	(3,019)	(2,360)	(2,507)	(2,942)	(3,950)	(3,069)	
Horizon Utilities RZ				6,349	5,777	6,300	6,129	5,046	7,149	5,525	
Guelph RZ				422	347	448	476	578	898	313	
Alectra Utilities Net Impact	**35**	**98**	**(477)**	**6,007**	**4,502**	**5,266**	**5,306**	**4,356**	**5,866**	**4,433**	**35,394**

Return on Capital	**2,024**
Total	**37,418**

Table 3 below provides an updated Table 9-3-17 capturing the 2025 actuals.

Table 3 – Updated 9-3-17 in $MM

	Actual									Forecast	
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**Total**
HRZ	-	(1.0)	1.0	(6.3)	(5.8)	(6.3)	(6.1)	(5.0)	(7.1)	(8.0)	(44.7)
Carrying Charges	-	(0.0)	0.0	-	-	-	-	-	-	-	0.0
Total Proposed for Disposition	-	(1.0)	1.0	(6.3)	(5.8)	(6.3)	(6.1)	(5.0)	(7.1)	(8.0)	(44.7)
BRZ	1.2	1.7	2.2	2.1	3.0	2.4	2.5	2.9	4.0	4.6	26.6
Carrying Charges	-	-	-	-	-	-	-	-	-	-	-
Total Proposed for Disposition	1.2	1.7	2.2	2.1	3.0	2.4	2.5	2.9	4.0	4.6	26.6
PRZ	-	-	-	-	-	-	-	-	-	-	-
Carrying Charges	-	-	-	-	-	-	-	-	-	-	-
Total Proposed for Disposition	-	-	-	-	-	-	-	-	-	-	-
ERZ	-	(1.9)	(2.9)	(1.3)	(1.4)	(0.9)	(1.2)	(1.7)	(1.8)	(2.5)	(15.6)
Carrying Charges	-	-	-	-	-	-	-	-	-	-	-
Total Proposed for Disposition	-	(1.9)	(2.9)	(1.3)	(1.4)	(0.9)	(1.2)	(1.7)	(1.8)	(2.5)	(15.6)
GRZ	-	-	-	(0.7)	(1.0)	0.5	(0.5)	(0.6)	(0.9)	(0.5)	(3.7)

	Actual								Forecast		
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**Total**
Carrying Charges	-	-	-	(0.0)	(0.0)	0.0	-	-	-	-	0.0
Total Proposed for Disposition	-	-	-	(0.7)	(1.0)	0.5	(0.5)	(0.6)	(0.9)	(0.5)	(3.7)
Alectra Total - Principal Balance	1.2	(1.1)	0.2	(6.3)	(5.1)	(4.3)	(5.3)	(4.4)	(5.9)	(6.5)	(37.4)
Alectra Total - Carrying Charges	-	(0.0)	0.0	(0.0)	(0.0)	0.0	-	-	-	-	0.0
Alectra Total	**1.2**	**(1.1)**	**0.3**	**(6.3)**	**(5.1)**	**(4.3)**	**(5.3)**	**(4.4)**	**(5.9)**	**(6.5)**	**(37.4)**

Alectra Utilities' total capitalization policy impact of $37.4M is consistently reflected in both Table 2 and Table 3.

c) The reconciliation of a) to Table 9-3-17 is provided in Table 3 below.

Table 4 - Reconciliation of a) to Table 9-3-17 in $000's

	HRZ	BRZ	ERZ	GRZ
2017 balance in Reference 1, Table 9-3-17	-	1,212	-	-
True-up for 2017	-	573	(1,819)	-
2017 balance in Reference 2, Table 9.1	-	1,785	(1,819)	-
2018 balance in Reference 1, Table 9-3-17	(967)	1,744	(1,893)	-
True-up for 2018	967	(220)	271	-
2018 balance in Reference 2, Table 9.1	-	1,524	(1,622)	-
2019 balance in Reference 1, Table 9-3-17	967	2,193	(2,912)	-
True-up for 2019	(967)	(353)	1,549	-
2019 balance in Reference 2, Table 9.1	-	1,840	(1,364)	-
2020 balance in Reference 1, Table 9-3-17	(6,349)	2,090	(1,327)	(721)
True-up for 2020	-	-	-	299
2020 balance in Reference 2, Table 9.1	(6,349)	2,090	(1,327)	(422)
2021 balance in Reference 1, Table 9-3-17	(5,777)	3,019	(1,397)	(977)
True-up for 2021	-	-	-	631
2021 balance in Reference 2, Table 9.1	(5,777)	3,019	(1,397)	(347)
2022 balance in Reference 1, Table 9-3-17	(6,300)	2,360	(877)	482
True-up done for 2022	-	-	-	(930)

	HRZ	BRZ	ERZ	GRZ
2022 balance in Reference 2, Table 9.1	(6,300)	2,360	(877)	(448)

1

d) The DLC impact has been excluded in this account sought for disposition.

e) Alectra Utilities relies on the actual impacts derived prior to the ERP convergence to determine the actual impacts of the capitalization policy change since 2019 for HRZ, BRZ and ERZ. Alectra Utilities determined the allocation percentages for these rate zones based on a ratio of the actual impact of the capitalization policy change, to actual distribution plant capital prior to the ERP convergence. There have been no changes to these allocations since 2019, and there are no variances between the actual and forecast allocation amounts.

i. The higher capitalization policy impact in 2023 compared to 2022 is mainly due to increased System Access (customer connections and system expansion work driven by customers) and System Renewal capital (cable renewal and pole remediation) in 2023.

The lower capitalization policy impact in 2024 compared to 2023 is mainly due to reduced capital expenditures in underground asset renewal work in HRZ.

The higher capitalization policy impact in 2025 compared to 2024 reflects higher capital expenditures in System Access (customer connections) and System Renewal (Reactive, pole removal provision, advanced urgent Substation renewal work).

The higher capitalization policy impact in 2026 compared to 2025 is driven by the inclusion of a rate of return on capital.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-265

HRZ, BRZ, PRZ, ERZ
Account 1557 Meter Cost Deferral Account
Ref 1: Exhibit 9 / Tab 3 / Schedule 25 / Section 4.2.24 / p. 1 (pdf p. 495)
Ref 2: Exhibit 2B / Tab 2 / Schedule 1 / Table 2-2-2 footnotes / p. 2 (pdf p. 16)
Ref 3: Exhibit 2B/ Alectra_Attach 2B-1_OEB Appendix 2-BA-Fixed Asset Continuity Schedule_20251121

Preamble:

Per reference 1, Alectra Utilities provides a breakdown of the total incremental costs for Account 1557 which includes incremental capital, OM&A and NBV of Stranded Meters. The total principal balance is $14.1M sought for disposition.

Per references 1 and 2, Alectra Utilities completed the MIST project for all rate zones in 2023. Alectra Utilities also states that 2027 in-service additions and accumulated depreciation balances mostly are related to Account 1557 Meter costs deferral.

Per reference 3, OEB staff notes there was $15.5M in-service additions and $6.4M accumulated depreciation added in 2027.

Question(s):

a) Please explain which account the MIST meter cost was recorded in 2027 on the fixed asset continuity schedule.

b) Please explain why stranded meters costs is part of the incremental cost of MIST project per Table 9-3-58 in reference 1?

RESPONSE:

a) The MIST meter cost has been recorded in 2027 on the fixed asset continuity schedule in Account 1860 ($13.8MM). The related accumulated depreciation has been recorded in 2027 on the fixed asset continuity schedule in Account 2105 ($5.4MM).

b) Alectra Utilities' accounting to defer stranded meter costs is based on the OEB's finding in Guideline G-2011-0001, Smart Meter Funding and Cost Recovery – Final Disposition, December 15, 2011, page 9. In this guideline, the OEB found that the net book value of the stranded meters should be removed from rate base and would be allowed for recovery by means of separate rate riders for the applicable customer classes, rather than by leaving the stranded assets in rate base.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-266

HRZ, PRZ, ERZ
Account 1533 Renewable Generation Connection Funding Adder Deferral Account
Ref 1: Exhibit 9 / Tab 3 / Schedule 21 / Section 4.2.20 / p. 1 (pdf p. 489)
Ref 2: Accounting Procedures Handbook Guidance, March 2015, A.10, p. 10
Ref 3: EB-2024-0006, Decision and Rate Order, December 12, 2024, p. 27

Preamble:
Per reference 1, Alectra Utilities is seeking disposition of a credit $0.3M for Account 1533 for HRZ, PRZ and ERZ. Alectra Utilities also proposes to discontinue this account.

Per reference 2, for approved eligible investments as defined under O.Reg. 330/09 under the OEB Act, the variance account will continue to be used for the purpose of recording variances between the revenue requirement based on actual costs of approved eligible investments and the revenue received from the IESO.

Per reference 3, the OEB approved 2021 RGCRP funding for the Brampton, PowerStream, and Enersource Rate Zones in its decision on Alectra Utilities' 2021 IRM application. The OEB also approved an update to the RGCRP models for these three rate zones by extending the calculations for the RGCRP funding amounts for each year between 2022 and 2026.

Question(s):

a) Please confirm the correct name of this account indicated in reference 1 is Account 1533 Renewable Generation Connection Funding Adder Deferral Account, Sub-account Provincial Rate Protection Payment Variances.
    i. If not confirmed, please explain why not.

b) Please explain why there is no balance recorded in BRZ while BRZ also received funding per reference 3.

c) Please provide breakdown of the account balance from 2022 to 2026:
   i. Revenue requirement impacts for the Provincial Rate Protection eligible amounts.
   ii. Provincial Rate Protection payments, as approved by the Board, and received from the IESO in each year.
   iii. Please reconcile (i) and (ii) above to the DVA continuity of related rate zones.

RESPONSE:

a) Alectra Utilities confirms that the correct name of this account indicated in reference 1 is Account 1533 Renewable Generation Connection Funding Adder Deferral Account, Sub-account Provincial Rate Protection Payment Variances.

b) There is no difference between the BRZ's revenue requirement associated with the actual capital that is eligible for rate protection and the rate protection payments collected from the IESO; therefore, there is no balance recorded in BRZ.

c) The breakdown of the account balance from 2022 to 2026 has been provided as 9-Staff-266_Attach 1_1533 Reconciliation. This attachment also includes a reconciliation of items (i) and (ii) in part c) to the DVA continuity of related rate zones.

9-Staff-266

Attachment 1
1533 Reconciliation

Please see live Excel

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-267

Ref 1: Exhibit 9 / Tab 3 / Schedule 19 / p. 1 (pdf p. 487)
Ref 2: Exhibit 9 / Tab 3 / Schedule 20 / p. 1 (pdf p. 488)
Ref 3: Exhibit 9 / Tab 3 / Schedule 21 / pp. 1-2 (pdf pp. 489-490)

Question(s):

a) For each project/program that contributed to the Renewable Connection accounts 1531, 1532 and 1533, please provide completed Chapter 2 Appendices
   i. Tab 2-JA: Renewable Generation Connection Investment Summary and
   ii. Tab 2-JB: Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments

b) For each program/project in part (a), please provide a written description of the work undertaken, as well as the number and type of connections supported.

RESPONSE:

a) Account 1531 captures the ERZ's investments associated with renewable enabling improvements to connect renewable generation facilities. Alectra Utilities proposes the clearance of a $0.3M debit principal balance as of December 31, 2026. The $0.3M has been removed from the account and added to fixed assets.

Account 1532 captures 6% of the incremental operating, maintenance, amortization and administrative expenses directly related to renewable enabling improvements for ERZ incurred from 2010 to 2019. The proposed disposition for Account 1532 balance is a debit balance of $0.1M.

Alectra Utilities uses 1533 to record the net of the annual revenue requirement impact on an actual basis and the provincial rate protection payments received from the IESO for ERZ and PRZ. The proposed disposition balance related to ERZ is a credit balance of $7,901. The proposed disposition balance related to PRZ is a credit balance of $205,825. Alectra Utilities is not submitting Chapter 2 Appendices 2-FA Renewable Generation Connection Investment Summary and 2-FB Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments for ERZ and PRZ, as Alectra Utilities has not requested provincial rate protection payments as part of this proceeding.

For HRZ, the credit balance of $106,100 primarily reflects the residual balance from the legacy Horizon Utilities' 2012-2014 rate rider for recovery of Green Energy Act related costs. Alectra Utilities is not submitting Chapter 2 Appendices 2-FA and 2-FB for HRZ, as Alectra Utilities has not requested provincial rate protection payments for HRZ since 2019.

b) Tables 1 and 2 below provide BRZ, ERZ and PRZ's Renewable Generation Connection Investment projects, the work undertaken, as well as the number and type of connections supported.

Table 1 - Renewable Generation Connection Investment Projects

Projects	Work Undertaken
BRZ - OPA FIT/MicroFIT Program Management	Pre-FIT and Pre- MicroFIT consultation applications, the Distribution Acceptance Test and Transmission Acceptance Test (DAT/TAT) process, and general program administration.

Projects	Work Undertaken
BRZ - Maintenance of Connected REG Infrastructure	Maintenance to continue supporting the connected generators over the contractual period with the OPA. This maintenance cost is directly linked to the routine maintenance and site inspection of supervisory control and data acquisition (SCADA) remote terminal units (RTU), meters, overhead line infrastructure and transformers, and relates to ESA Regulation 22/04 as it pertains to public safety.
BRZ - Remote Monitoring and Control of REG	Supervisory Control & Data Acquisition (SCADA) system design, and construction and connection of FIT generation sites.
BRZ - Transformer Replacement	Replacement of two transformers.
BRZ - Rebuilding Existing Line	Upgrade the distribution system to support REGs with bus/feeder capacity constraints.
PRZ - WiMax Communication Network	To provide communications for the remote trip and monitoring of FIT generators 250 kW and larger.
PRZ - CIS modifications for FIT	Update the Customer Information System to accurately track and bill renewable generators.
PRZ -Fault Level Reduction and Station programming	Install Fault Level Reduction Reactors to improve fault current levels in order to accommodate FIT Generator connections. Feeder Protection upgrade to accommodate the Generator transfer trip scheme.
ERZ – Renewable Generation Connection Enabling	Improvements to the distribution system to accommodate the connection of renewable energy generation facilities as part or FIT and micro-FIT programs.

Table 2 - Connections Supported by Renewable Generation Connection Investment Projects

	Type of Connections	Number of Connections
BRZ	FIT	135
BRZ	MicroFIT	848
PRZ	FIT	188
PRZ	MicroFIT	1748
ERZ	FIT	123
ERZ	MicroFIT	709

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-268

Group 2 DVAs

Ref 1: Exhibit 9 / DVA Continuity Schedule_20250416 (all rate zones), Tab 2b

Ref 2: Exhibit 9 / Tab 1 / Schedule 1 / Table 9-1-2 / p. 3 (pdf p. 3)

Preamble:

OEB staff notes that there is no activity recorded in the following Group 2 DVAs:

1) Account 1508 sub-account Green Button Initiative Costs
2) Account 1508 sub-account Customer Choice initiative Costs
3) Account 1508 sub-account ULO Implementation Cost
4) Account 1508 sub-account Retail Service Charge Incremental Revenue
5) Account 1508 sub-account Local Initiatives Program Costs
6) Account 1508 sub-account Designated Broadband Project Impacts
7) Account 1592 sub-account PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)

Question(s):

a) Please confirm Alectra Utilities proposes to discontinue using these accounts on a going forward basis and provide a summary table showing all the continuing/discontinue Group 2 accounts (i.e. reference 2) as applicable.

b) Please also provide Alectra Utilities' position on discontinuing the following Group 2 DVAs (continue/discontinue) since there is no balance as of December 31, 2026, and explain the reason.
   i. Account 1508 sub-account Deferred IFRS Transition Costs
   ii. Account 1521 Special Purpose Charge Assessment Variance Account
   iii. Account 1572 Extra-Ordinary Event Costs

iv. Account 1556 Smart Meter OM&A Variance
v. Account 1575 IFRS-CGAAP Transition PP&E Amounts Balance + Return Component
vi. Account 1576 Accounting Changes Under CGAAP Balance + Return Component
Account 1508 Deferred IFRS Transition Costs

RESPONSE:

a) Alectra Utilities proposes to discontinue using:
1) Account 1508 sub-account Green Button Initiative Costs
3) Account 1508 sub-account ULO Implementation Cost
4) Account 1508 sub-account Retail Service Charge Incremental Revenue
7) Account 1592 sub-account PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)

Alectra Utilities proposes to continue using:
2) Account 1508 sub-account Customer Choice initiative Costs
5) Account 1508 sub-account Local Initiatives Program Costs
6) Account 1508 sub-account Designated Broadband Project Impacts

Table 1 below provides a summary table showing all the Group 2 accounts Alectra Utilities proposed to continue/discontinue (i.e. reference 2).

Table 1 - Group 2 DVAs (continue/discontinue)

Group 2 Accounts	Continue /Discontinue
1508 - sub-account Retail Service Charge Incremental Revenue	Discontinue
1508 - sub-account Deferred IFRS Transition Costs	Discontinue
1508 - Deferred IFRS Transition Costs	Discontinue
1508 - Earnings Sharing Mechanism	Discontinue
1508 - Energy East Consultation Costs	Discontinue
1508 - OEB Cost Assessment Variance	Continue
1508 - Other Post-Employment Benefit Deferral Account	Continue
1508 - Advanced Pricing Project	Discontinue

Group 2 Accounts	Continue /Discontinue
1508 - CGAAP IFRS Differential	Discontinue
1508 - Hydro-One Charges	Discontinue
1508 - Pole Attachment Revenue Variance	Discontinue
1508 - Capitalization Policy	Discontinue
1508 - Incremental Capital Module	Discontinue
1508 - Long-term Load Mitigation	Discontinue
1508 - Collection of Account Charge-Related Lost Revenue	Discontinue
1508 - sub-account Green Button Initiative Costs	Discontinue
1508 - sub-account Customer Choice initiative Costs	Continue
1508 - sub-account ULO Implementation Cost	Discontinue
1508 - sub-account Local Initiatives Program Costs	Continue
1508 - sub-account Designated Broadband Project Impacts	Continue
1508 - GOCA Variance Account	Discontinue
1508 - LEAP Emergency Financial Assistance Funding Deferral Account	Discontinue
1509 - Impacts Arising from the COVID-19 Emergency	Discontinue
1511 - Incremental Cloud Computing Implementation Costs	Continue
1518 - Retail Cost Variance Account (RCVA) Retail	Discontinue
1548 - RCVA STR	Discontinue
1521 - Special Purpose Charge Assessment Variance Account	Discontinue
1522 - Pension and OPEB Forecast Accrual versus Actual Cash Payments Differential Tracking Account	Continue
1525 - Miscellaneous Deferred Debits	Continue
1531 - Renewable Connection Capital Deferral Account	Discontinue
1532 - Renewable Connection OM&A Deferral Account	Discontinue
1533 - Renewable Generation Connection Funding Adder Deferral Account	Discontinue
1535 - Smart Grid OM&A Deferral Account	Discontinue
1536 - Smart Grid Funding Adder Deferral Account	Discontinue
1555 - Smart Meter Capital and Recovery Offset Variance Account, Sub-account Stranded Meter Costs	Discontinue
1556 Smart Meter OM&A Variance	Discontinue
1557 - Meter Cost Deferral Account	Discontinue
1568 - Lost Revenue Adjustment Mechanism Variance Account	Continue
1572 - Extra-Ordinary Event Costs	Continue
1575 - IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	Discontinue

Group 2 Accounts	Continue /Discontinue
1576 - Accounting Changes Under CGAAP Balance + Return Component	Discontinue
1592 - sub-account PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	Discontinue
1592 - PILs and Tax Variance for 2006 and Subsequent Years, Sub-account - PILs and Tax Variances CCA Changes	Continue

b) Alectra Utilities proposes to discontinue the following Group 2 deferral and variance accounts, as they have no balances as of December 31, 2026. Any activity previously recorded in these accounts has been disposed of in accordance with prior OEB's approvals. In addition, Alectra does not anticipate incurring any future costs that would require recording activity in these accounts.

i. Account 1508 sub-account Deferred IFRS Transition Costs
ii. Account 1521 Special Purpose Charge Assessment Variance Account
iv. Account 1556 Smart Meter OM&A Variance
v. Account 1575 IFRS-CGAAP Transition PP&E Amounts Balance + Return Component
vi. Account 1576 Accounting Changes Under CGAAP Balance + Return Component

Alectra Utilities proposes to continue using 1572 Extra-Ordinary Event Costs to record extraordinary event costs that meet the qualifying criteria established by the OEB according to the APH.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-269

Non-Wires Solutions Deferral Account (NWSDA)

Ref 1: Exhibit 9 / Tab 8 / Schedule 3 / Section 9.3 / Appendix C / pdf p. 534

Question(s):

a) Please update the accounting order by recording the carrying charge in Account 6035 Other Interest Expense.

b) Please provide Alectra Utilities' proposal regarding the incentives on NWS and the associated accounting treatment.

RESPONSE:

a) The accounting order has been updated to reflect that carrying charges will be recorded in Account 6035, and for a correction to the treatment of Margin on Payments as identified in response to 2-Staff-47 e). Specifically, Margin on Payments incentives would be recorded in the NWSDA in addition to the OM&A costs associated with acquiring and operating distribution-level NWS. Alectra Utilities has also updated the description of the account that was originally provided in Exhibit 9, Tab 8, Schedule 3.

b) Please see response to 2-Staff-47 e).

NON-WIRES SOLUTION DEFERRAL ACCOUNT (NWSDA)

Alectra Utilities requests approval to establish a deferral account under Account 1508, Other Regulatory Assets. The proposed deferral account would be comprised of a Sub-account NWS Program OM&A, and a Sub-account NWS Program OM&A - Carrying Charges for the purpose of recording OM&A costs incurred to acquire DERs and operate and manage the Non-Wires Solutions (NWS) Program. Incentive payments, calculated on a Margin-on-Payments (MoP) as set out in Section 11 of the Distribution System Code would also be recorded in the NWSDA for recovery in addition to the company's actual OM&A costs incurred to acquire DERs and operate and manage the NWS Program. Any amounts recorded will be net of any third-party funding or recoveries (e.g. IESO incentives, municipal/partner contributions, federal grants). Disposition of the NWSDA would be sought at the end of the 2027 to 2031 rate term via appropriate rate riders. If the NWSDA balance were to become material prior to 2031, Alectra Utilities may request approval for an earlier disposition of the account. If approved, Alectra Utilities will file supporting evidence on procurement results, costs, and performance when seeking disposition.

Alectra Utilities' Distribution System Plan (DSP) integrates NWS into capacity planning using Preliminary NWS Framework defined in the DSP Chapter 5.3.5 NWS to Address System Needs. Initial analysis indicates that up to approximately $13.2MM in OM&A expenses may be required through the incentive term, between 2027 and 2031 to procure up to 32 MW of flexible capacity annually to defer five select MS/TS projects at targeted locations. The forecast $13.2MM does not include any amounts for incentive payments, such as Margin-on-Payments (MoP). Market depth and price discovery remain evolving. Alectra Utilities plans to run competitive, transparent RFI/RFP processes and local auctions and refine utilization assumptions through operational experience and evaluation, measurement & verification (EM&V). The requested NWSDA permits prudent scaling while protecting customers from forecast error.

The proposed expenses to be included in the NWSDA are incremental OM&A expenses not included in base rates that are directly caused by the NWS Program, including but not limited to availability, energy and other payments/charges to DER owners/aggregators, contracting costs, equipment and system costs, operation and maintenance, administrative costs and

EM&V where capitalization is not appropriate, and incremental operational costs of coordination with the IESO.

Eligibility Criteria

The OEB's *Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2025 Edition for 2026 Rate Applications* specify that requests for new deferral or variance accounts must satisfy the OEB's eligibility criteria of causation, materiality and prudence. The proposed NWS sub-account satisfies the OEB's eligibility criteria as follows:

Causation - The costs proposed for the NWSDA address documented capacity needs identified in the DSP – Exhibit 2A, Tab 1, Schedule 1, Section 5.3.5 Non-Wires Solutions to Address System Needs. These costs are not included in OM&A for 2027–2031; therefore, eligible costs are incremental, prudently incurred OM&A expenses necessary to deliver NWS capacity relief to five MS/TS, including DER payments, contracting, equipment and system costs, operation and maintenance, administrative costs, EM&V, and costs of coordination with the IESO. The MoP incentive would also be recorded in the NWSDA. Alectra Utilities will offset NWS Program OM&A costs any with third-party funding/recoveries (e.g., IESO incentives, municipal/partner contributions, federal grants).

Materiality - Based on current planning, Alectra Utilities anticipates up to approximately $13.2MM in OM&A expenses by the end of 2031 to acquire and operate up to 32 MW of flexible capacity to defer five MS/TS projects. This exceeds Alectra Utilities' materiality threshold of $1MM, as defined in section 2.0.8 of the OEB's *Chapter 2 Filing Requirements for Electricity Distribution Rate Applications*. Although actual costs may differ from this forecast based on market price discovery, auction results, portfolio size, site-specific utilization, and realized performance, costs are expected to exceed Alectra Utilities' materiality threshold.

Prudence - Alectra Utilities intends to use competitive, transparent RFI/RFP/RFQ processes with clear eligibility, auction rules, performance obligations, penalties/remedies, and settlement mechanics tailored to distribution-level DER portfolios and local needs at targeted

MS/TS. The NWS Program will be supported by application of the OEB's BCA Framework (including the Distribution Service Test), with assumptions updated to reflect realized pricing, utilization, and operating experience. Contracts will include M&V protocols and telemetry/controls requirements appropriate to resource type and response speed; settlement will be tied to verified availability and delivered capacity (or energy where applicable).

A draft accounting order for the proposed NWSDA, which includes a description of the mechanics of the account, examples of the general ledger entries and the proposed manner in which to dispose of the account, is provided below.

Draft Accounting Order - Non-Wires Solutions Deferral Account (NWSDA)

Alectra Utilities will establish the following two sub-accounts under Account 1508, Other Regulatory Assets:

- 1508, Other Regulatory Assets, Sub-account NWS Program OM&A
- 1508, Other Regulatory Assets, Sub-account NWS Program OM&A Carrying Charges

Effective January 1, 2027, Alectra Utilities will record in these accounts the OM&A costs associated with acquiring and operating distribution-level Non-Wires Solutions (NWS). Eligible cost components are limited to OM&A required as payments to DER owners/aggregators, contracting costs, equipment and system costs, operation and maintenance, administrative costs and EM&V, and costs of coordination with the IESO. Incentive payments, calculated on a Margin-on-Payments (MoP) as set out in Section 11 of the Distribution System Code would also be recorded in the NWSDA for recovery in addition to the company's actual OM&A costs incurred to acquire DERs and operate and manage the NWS Program. Any amounts recorded will be net of any third-party funding or recoveries (e.g. IESO incentives, municipal/partner contributions, federal grants).

Interest carrying charges will apply to the account balances based on the OEB's prescribed interest rates.

The sample journal entries are provided below:

Dr. 1508, Other Regulatory Assets, Sub-account NWS Program OM&A
Cr. Account(s) associated with the NWS OM&A costs

To record NWS OM&A not included in base rates

Dr. 1508, Other Regulatory Assets, Sub-account NWS Program OM&A Carrying Charges
Cr. 6035, Other Interest Expense

To record carrying charges on the monthly opening balance in Account 1508, Sub-account NWS Program OM&A.

Alectra Utilities will apply to the OEB to clear the balance in the NWSDA through rate riders at the end of the 2027 to 2031 DSP period. If the NWSDA balance were to become material prior to 2031, Alectra Utilities may request approval for an earlier disposition of the account.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-270

HRZ, GRZ, PRZ
Account 2405 & Account 2425
Ref 1: Exhibit 9 / Alectra_Attach 9-1 DVA Continuity Schedule_HRZ_Updated 20251121
Ref 2: Exhibit 9 / Alectra_Attach 9-3 DVA Continuity Schedule_PRZ_Updated 20251121
Ref 3: Exhibit 9 /Alectra_Attach 9-5 DVA Continuity Schedule_GRZ_Updated 20251121
Ref 4: Accounting Procedures Handbook for Electricity Distributors, December 2011

Preamble:
Per references 1, 2 and 3, Account 2405 has two different names (i.e. Other Regulatory Liabilities & Future Income Tax. Account 2425 also has two different names (i.e. Other Deferred Credits & Misc Revenue Overcharge)

Per reference 4, Account 2405 is Other Regulatory Liabilities or Credits and Account 2425 is Other Deferred Credits.

Question(s):

a) Please clarify the account name discrepancies noted above.

RESPONSE:

a) For Reference 1, Alectra Utilities inadvertently included Account 2425 in Tab 2b. Continuity Schedule, lines 82 and 116; therefore, Account 2425 has been removed from the updated schedule. Additionally, Account 2405, found on line 115, was redundant and has been removed from the updated schedule.

For Reference 2, Alectra Utilities inadvertently included Account 2405 in Tab 2b. Continuity Schedule, line 110, and Account 2425 on line 111. Consequently, these two accounts have been removed from the updated schedule.

For Reference 3, Alectra Utilities inadvertently included Account 2405 in Tab 2b. Continuity Schedule, line 112, and Account 2425 on line 113. Consequently, these two accounts have been removed from the updated schedule.

In the updated DVA Schedules, the descriptions for Account 2405 Other Regulatory Liabilities or Credits and Account 2425 Other Deferred Credits are aligned with Accounting Procedures Handbook for Electricity Distributors, December 2011.

Please refer to 9-Staff-247_Attach 1_DVA Continuity Schedule_HRZ, Staff-249_ Attach 1_DVA Continuity Schedule_PRZ, and 9-Staff-251_Attach 1_DVA Continuity Schedule_GRZ for the updated DVA schedules.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-271

GRZ

Account 1508, Other Regulatory Assets, Subaccount Guelph Hydro wireless attachment costs

Ref 1: EB-2015-0073, Decision and Rate Order, November 26, 2015, Schedule B

Preamble:

Per reference 1, pursuant to the settlement agreement approved by the OEB, Guelph Hydro shall establish the following Deferral Accounts to record the costs and revenues associated with Wireless Pole Attachments.

Question(s):

a) Please provide details of this account:
   i. Why is this account not included in the DVA continuity schedule in this application
   ii. Is there any balance recorded in this account?

RESPONSE:

a)

i. Legacy Guelph Hydro did not include this account in its 2016 DVA continuity schedule.

ii. There were no balances recorded in this account.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-272

Ref 1: Exhibit 9 / Tab 3 / Schedule 10 / pp. 3-4 (pdf pp. 448-449)
Ref 2: Exhibit 9 / Alectra_Attach 9-8_ICM True-Up Model_2019_Road Authority YRRT_PRZ_20251014
Ref 3: Exhibit 2B / Tab 5 / Schedule 1 / p. 2 (pdf p. 143)

Question(s):

a) References 1 and 2 show the variance for capital expenditures between the approved and actual for 2018 and 2019. Variance explanations are provided in reference 3 which states that variances between approved and actual expenditures for 2018 and 2019 are due to the delay of work from 2016 and 2017. Please provide the approved and actual project costs for the entire project, by year and in total, along with variance explanations for material amounts.
   i. Please provide the cost-sharing arrangement details for the project with 2019 York Region Rapid Transit (YRRT).
   ii. Please confirm that the amounts sought for recovery are net of all third party contributions.

b) Table 9-3-26: ICM True-up - Enersource RZ in reference 1 shows a $3M underspend on Leaking Transformer - 2019. Why were less transformers replaced in 2019 than the original plan as stated in reference 3? How many transformers were planned to be replaced and how many were replaced?

RESPONSE:

a) Alectra Utilities provides the table below with the approved and actual project costs for the entire project, by year and in total.

$ in Millions	Approved 2018	Actual 2018	Variance 2018	Approved 2019	Actual 2019	Variance 2019
Gross	25.4	34.3	8.9	27.9	52.1	24.2
Contributions	-14.2	-18.4	-4.2	-14.6	-26.7	-12.1
Net	**11.2**	**15.9**	**4.7**	**13.3**	**25.4**	**12.1**

Minor rounding diff may exist

The costs variances associated with the PowerStream RZ 2018 and 2019 York Region Rapid Transit Corporation (YRRTC) projects were prudently incurred and arose primarily from scope, design and execution requirements driven by the York Region Rapid Transit Corporation (YRRTC") and site-specific constraints. The variances were largely attributable to changes in construction methodology, deeper and more complex civil installations due to congestion and streetscape requirements and winter construction.

The variance in gross amounts is primarily driven by scope and constructability changes, most notably within the Y2.1 section of the project. These changes were largely associated with the requirement to construct underground portions of the distribution system, where an overhead configuration was initially considered but ultimately determined to be not feasible due to limited boulevard space and YRRTC streetscape design requirements. Additional contributing factors include the need to install infrastructure at deeper depths than originally planned due to congestion within roadway corridors and due to changes in work sequencing which resulted in a portion of the work being constructed during winter. Further variances in the H2 section of the YRRTC project arose due to scope refinements and design changes including the installation of concrete poles in place of wood poles and the requirement to relocate major crossing at Highway 400 and Highway 7, where limited overhead options necessitated selecting an underground configuration to address operational, maintenance and safety considerations.

The variance in capital contributions arose from higher contributions associated with the incremental scope requested by YRRTC. Increases in gross capital attributable to YRRTC-driven design requirements, including requests to perform underground specific

sections or modify the configuration of the distribution system, were associated with incremental costs borne by YRRTC, resulting in increased capital contributions for those sections. This was partially offset by lower contributions in some sections where the gross capital increased due to Alectra driven prudency decisions of selecting an underground configuration to address operational, maintenance and safety considerations at Highway 400 and Highway 7. Alectra Utilities sought additional funding from the YRRTC; however, YRRTC was not willing to contribute further. These explanations have been documented in Alectra's prior filings and undertaking responses.

i. The cost sharing arrangements for the YRRTC relocation projects in 2019 were undertaken in accordance with the Public Service Works on Highways Act (PSWHA), with project specific cost apportionment negotiated between Alectra and YRRTC. This was based on the scope of work and the extent to which incremental costs were YRRTC requested design requirements such as undergrounding, concrete pole or non-standard configurations. When such incremental scope was requested, the associated costs were borne by YRRTC and reflected in capital contributions. This matter has been addressed in detail in prior Incremental Capital Module (ICM) applications and related interrogatories. We request the OEB to refer to the following documents for further details.

   1. EB-2018-0016: - "Alectra_ICMReplySUB_20190109.pdf, page 27, 40" - Discusses the mandatory nature of the project under the PSWHA and the cost-sharing arrangement.

   2. EB-2017-0024: - "dec_order_Alectra_20180405.pdf, page 37" - Approves ICM funding for the YRRT project and acknowledges the cost-sharing arrangement.

ii. Yes, it is confirmed that amounts sought for recovery are net of all third-party contributions.

b) Alectra Utilities planned to replace 470 leaking transformers and replaced 273 transformers in 2019 as part of the multi-year leaking transformer project. 2019 was the last year of a multi-year project to address a backlog of leaking transformers in Mississauga. In the last year of the multi-year leaking transformer replacement project, Alectra Utilities planned to address the remaining backlog which included moderate and minor leakers as well as leaking transformers. Prior to replacement, Alectra Utilities crews conducted examinations of each transformer and determined that 197 transformers did not require replacement and could be resolved more effectively through maintenance and restoration.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-273

Ref 1: Final Notice of Amendments to the Distribution System Code, June 16, 2025
Ref 2: EB-2024-0092, Final Rate Order, March 20, 2025, Extended Horizons Variance Account,
Ref 3: Exhibit 9

Preamble:
Appendix C of reference 1 outlines changes to the Distribution System Code to extend the customer revenue horizon to 40 years for residential customers (as defined in Appendix C). On March 20, 2025, the OEB created a Group 2 variance account, the Extended Horizons Variance Account, effective November 18, 2024.

Question(s):

(a) Please confirm the capital contributions in the forecast period incorporate the changes to the customer revenue horizon as outlined in reference 1. If not confirmed, please provide revised customer contributions as required by the changes.

(b) The Extended Horizons Variance Account has not been included in Exhibit 9. Please confirm that Alectra Utilities has not recorded material balances in this account for clearance.

(c) Please confirm that Alectra Utilities has incorporated the changes in reference 1 in its customer agreements in the historic and bridge period, as required.

RESPONSE:

(a) Alectra Utilities confirms that the capital contributions for the forecast period incorporate the changes to the customer revenue horizon of 40 years for residential developments.

(b) Alectra Utilities confirms they have not recorded material balances in the extended horizons variance account for clearance.

(c) Alectra Utilities confirms that the changes to the customer revenue horizon of 40 years have been incorporated into its customer agreements in the historic and bridge period, effective upon the changes coming into force as per the OEB requirements.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-274

Ref 1: EB-2024-0092, Final Rate Order, December 23, 2025

Preamble:

The OEB has established generic deferral and variance accounts (DVAs) for electricity distributors to track the capital costs, customer capital contributions and financing charges related to the Capacity Allocation Model (CAM).

Question(s):

a) Please discuss whether Alectra Utilities has thought about the DSC amendments for housing connections and the CAM DVAs.

b) Please confirm that Alectra Utilities does not propose any DVA related to CAM for this rate term.

RESPONSE:

a) Alectra Utilities has considered the DSC amendments for housing connections and the CAM DVAs. Alectra has amended some of its processes to align with the potential formation of CAM projects in the future, however, at this time no CAM projects have been established. Alectra Utilities is working with Developers to identify eligible CAM projects. As it is difficult to predict whether, if, and what CAM projects might be identified in the future, and, given the relative newness of the policy itself, Alectra is not in a position to accurately predict if future budget variances might arise due to projects being eligible to be classified under the CAM designation.

b) The Rate Order establishing the VA was issued by the OEB on December 23, 2025. As described in the response to part a) above, Alectra has not yet identified if there will be CAM projects over the rate term, nor how any such future CAM projects may impact budgets. As a result, Alectra proposes to establish a CAM VA and has updated its application consistent with the Rate Order. At this time, Alectra does not forecast any balances for clearance in this account.