EXHIBIT 10 - EVIDENCE UPDATE

1. INTRODUCTION AND OVERVIEW

On December 19 2025, Elexicon filed its Custom Incentive Rate-Setting Application for the period of 2027 to 2031 (referred to herein as "Pre-filed Evidence")[1]. As per the OEB's Procedural Order No.1, the OEB directed Elexicon to file its Benefit Cost Analyses for potential Non-Wire Solutions, an updated Exhibit 9 including Group 1 and Group 2 balances, and updates specific to Elexicon's Control Centre OM&A segment. The updated Exhibit 9 was deemed necessary to account for the OEB's decision in Elexicon's 2026 IRM (EB-2025-0046), in which a standalone request for Group 2 disposition for certain accounts was deferred to this application.[2] As Elexicon had also committed to confirming its 2025 audited balances and reviewing the Group 1 year-end balances at a later stage in the process, Elexicon has refiled Exhibit 9 in its entirety to reflect all necessary updates.

This Exhibit, "Exhibit 10", includes the following updates to Elexicon's pre-filed evidence: Benefit Cost Analyses ("BCAs") for potential Non-Wire Solutions ("NWS"), included as Attachment 1 and Appendices A through C, and revisions specific to the Control Centre OM&A segment included as Exhibit 10 – Tab 2 – Schedule 1.

2. ELEXICON'S NWS FRAMEWORK AND BCA RESULTS

In Exhibit 2B - Tab 3 - Schedule 5 of its Pre-filed Evidence, Elexicon's NWS Pre-Screening Framework identified three investments that share characteristics supporting the potential applicability of NWS.

Elexicon indicated it would develop and assess the specific NWS alternatives applicable to each of the pre-screened investments and would proceed with a BCA to evaluate the relative merits, costs, and system benefits of potential NWS in accordance with the OEB's framework[3]. Elexicon committed to reporting the outcomes of these assessments within this application.

[1] Certain exhibits originally filed on December 19, 2025 were updated and re-filed with the OEB on February 20, 2026 and March 3, 2026 as part of Elexicon's submission under the Error Checking Process. In such cases, references to "Pre-Filed Evidence" in this exhibit are to the applicable version filed on February 20, 2026 or March 3, 2026.
[2] OEB, EB-2025-0046, Decision and Order, January 15, 2026, at page 21.
[3] EB-2024-0118, "OEB - Non-Wires Solutions Guidelines for Electricity Distributors", (March 28, 2024)

The investments advanced to detailed benefit cost analyses include:

- Bradshaw MS Capacity Upgrade - Substation Growth (approx. $8.47M) - driven by capacity constraints forecasted in the Bowmanville area.
- Feeder Capacity Enhancements - Grid Enhancements (approx. $14.83M) – integrate new capacity, alleviate thermal constraints, and strengthen system redundancy to support future load growth[4].
- Undersized Conductors - Grid Enhancements (approx. $11.28M) - replace approximately 36 km of undersized conductor wire on main feeder trunks in areas with capacity and contingency constraints.

To support the benefit cost analyses Elexicon engaged specialized external expertise from Charles River Associates Inc. (CRA) to identify technically credible and potentially feasible non-wires solution alternatives against which the conventional investment can be compared. Once potential non-wires solutions are defined, CRA proceeded with benefit cost analyses. The findings of the BCAs are included as Attachment 1 and Appendices A through C of this Exhibit.

The results of the analysis performed indicate non-wires solutions are either not technically feasible or cost-effective alternatives to the planned wires investments for either the Bradshaw MS needs, or the feeder capacity and undersized conductor portfolio needs. The projects proposed by Elexicon remain the best alternatives to address system needs.

3. REVISIONS TO THE FORECAST COSTS OF THE CONTROL CENTRE OM&A SEGMENT

The Control Centre segment includes the OM&A costs associated with control centre-related functions, including the operation of the utility's System Control Centre ("SCC"), which is critical to the safe and reliable operation of Elexicon's distribution system. Since the plan set out in the Pre-Filed evidence was established, the SCC has experienced unanticipated staffing departures in close succession, resulting in increased reliance on short-term staffing measures that are not sustainable. Further details are provided in Tab 2 of this Exhibit. To meet its commitment to maintaining system reliability and managing operational risk, Elexicon has revised its resourcing plan for the Control Centre segment. The revised forecast costs for this segment are presented in Tables 1 and 2 below.

[4] A portion of the distribution capacity and reliability enhancements have been screened out in the process, corresponding to $20.14M removed.

4. REVISED OM&A FORECAST AND REVENUE REQUIREMENT

As a result of the revisions to its Control Centre segment costs, Elexicon's OM&A forecast is higher than initially forecasted in its Pre-Filed Evidence. Tables 1 and 2 present the OM&A expenditures over the bridge and forecast period that incorporate the revised plan amounts for 2026 to 2031. Details of Elexicon's other OM&A segments are provided in Exhibit 4 and have not changed relative to Pre-Filed Evidence. Further details are provided in Tab 2 of this Exhibit.

Table 1: Revised Cost Table By OM&A Program and Segment–Bridge Period (2024-2027) ($M)[5]

Programs	2024 Actuals	2025 Bridge Year	2026 Bridge Year	2027 Test Year	CAGR 2024-2027
System Planning and Design					
Asset Planning & System Engineering	0.95	1.03	1.12	1.53	
Design Services & Connections	0.89	0.85	0.89	1.08	
System Planning and Design Sub-Total	1.84	1.87	2.01	2.61	12.2%
System Operations					
Control Centre	2.38	2.95	5.15	6.00	
Operations	3.04	2.99	3.21	3.40	
System Operations Sub-Total	5.43	5.94	8.36	9.40	20.1%
Sustainment					
Maintenance	7.24	4.47	5.23	6.23	
Maintenance - Distribution System	2.78	2.66	3.36	3.95	
Maintenance - Substations	4.47	1.81	1.87	2.28	
Restoration (storms, trouble calls)	2.42	2.83	2.49	2.33	
Vegetation Management	1.61	1.85	1.77	1.97	
Locates	1.89	2.30	2.10	2.18	
Sustainment Sub-Total	13.16	11.45	11.59	12.71	-1.2%
Customer Care					
Billing	3.37	3.56	3.71	4.00	
Customer Experience/Contact Centre	4.57	4.86	5.15	5.40	
Payments & Collections	2.59	3.01	3.23	3.29	
Metering & Wholesale Settlements	2.96	3.33	3.35	3.55	
Customer Care Sub-Total	13.49	14.76	15.44	16.23	6.4%
Common Corporate					
Technology	5.27	6.83	6.80	12.09	
People & Culture	4.88	5.51	6.15	6.86	
Finance	3.59	4.12	4.69	5.25	
Procurement & Facilities	1.17	1.05	1.26	2.18	
Regulatory Affairs	2.69	2.74	3.17	4.65	
Stakeholder Relations	1.34	1.46	1.51	1.71	
Legal and Corporate Secretariat	3.54	4.97	5.89	6.89	
Common Corporate Sub-Total	22.46	26.67	29.46	39.61	20.8%
Total Recoverable OM&A	56.38	60.69	66.86	80.56	**12.6%**
Adjustments					
Common Corporate					
Less: Regulatory Affairs Adjustment	-0.90	-0.23	-0.67	0.00	
Net Regulatory Affairs	1.79	2.52	2.49	4.65	
Net Common Corporate Sub-Total	21.56	26.45	28.79	39.61	22.5%
Sustainment					
Less: Locates Adjustment	-1.89	-2.30	-2.10	0.00	
Net Locates	0.00	0.00	0.00	2.18	
Net Sustainment Sub-Total	11.27	9.15	9.49	12.71	4.1%
Net Total Recoverable OM&A	53.60	58.17	64.09	80.56	**14.5%**

[5] Numbers may not sum due to rounding.

1 **Table 2: Revised Cost Table By OM&A Program and Segment-Forecast Period (2027-2031) ($M)**[6]

Programs	2027 Test Year	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	CAGR 2027-2031
System Planning and Design						
Asset Planning & System Engineering	1.53	1.67	1.73	1.82	1.86	
Design Services & Connections	1.08	1.17	1.23	1.26	1.29	
System Planning and Design Sub-Total	2.61	2.84	2.96	3.08	3.15	4.8%
System Operations						
Control Centre	6.00	5.98	6.17	5.71	5.82	
Operations	3.40	3.58	3.66	3.76	3.84	
System Operations Sub-Total	9.40	9.56	9.83	9.47	9.66	0.7%
Sustainment						
Maintenance	6.23	7.24	7.16	7.47	7.64	
Maintenance - Distribution System	3.95	4.90	4.73	4.88	5.00	
Maintenance – Substations	2.28	2.33	2.43	2.59	2.64	
Restoration (storms, trouble calls)	2.33	2.42	2.47	2.53	2.59	
Vegetation Management	1.97	2.69	2.82	2.89	3.13	
Locates	2.18	2.22	2.44	2.49	2.54	
Sustainment Sub-Total	12.71	14.56	14.89	15.38	15.90	5.8%
Customer Care						
Billing	4.00	4.05	4.07	4.06	4.05	
Customer Experience/Contact Centre	5.40	5.40	5.53	5.67	5.80	
Payments & Collections	3.29	3.43	3.64	3.58	3.66	
Metering & Wholesale Settlements	3.55	5.25	4.58	4.67	4.75	
Customer Care Sub-Total	16.23	18.13	17.81	17.98	18.26	3.0%
Common Corporate						
Technology	12.09	12.86	12.46	12.77	13.22	
People & Culture	6.86	7.14	7.35	7.55	7.72	
Finance	5.25	5.53	5.97	6.33	6.47	
Procurement & Facilities	2.18	2.28	2.36	2.45	2.54	
Regulatory Affairs	4.65	4.93	4.99	5.06	5.12	
Stakeholder Relations	1.71	1.93	2.18	2.23	2.28	
Legal and Corporate Secretariat	6.89	7.38	8.32	8.72	9.13	
Common Corporate Sub-Total	39.61	42.05	43.64	45.11	46.49	4.1%
Total Recoverable OM&A	80.56	87.16	89.12	91.03	93.45	**3.8%**

Table 3 sets out Elexicon's historical, bridge, test year and forecast period OM&A expenditures and variances, reflecting the revised Control Centre segment for 2026 to 2031.

[6] Numbers may not sum due to rounding.

Table 3: Revised OM&A Expenditures and Variances[7]

	Year	OM&A ($M)	Variance ($M)	Variance (%)
Historical Years	2020	42.3	N/A	N/A
	2021	42.9	0.6	1.4%
	2022	44.9	2.0	4.7%
	2023	46.7	1.7	3.9%
	2024	53.6	6.9	14.9%
Bridge Years	2025	58.2	4.6	8.5%
	2026	64.1	5.9	10.2%
Test Years	2027	80.6	16.5	25.7%
	2028	87.2	6.6	8.2%
	2029	89.1	2.0	2.3%
	2030	91.1	1.9	2.1%
	2031	93.5	2.4	2.7%

The updated SCC plan is reflected in the OM&A forecast for the 2027 to 2031 period (Line 12) in Table 4 below. The resulting updated Service Revenue Requirement (“SRR”) and associated Revenue Growth Factor (“RGF”) are presented in Lines 13 and 19, respectively. Further detail on the RGF and its formula components is provided in Exhibit 1 – Tab 5 – Schedule 1, Section 6.6.

[7] Numbers may not sum due to rounding.

Table 4: Revised Total Revenue Calculation by Formula Component 2027 to 2031[8]

Line	($millions)	2027	2028	2029	2030	
1	Average Net Fixed Assets	581.2	645.0	741.4	836.2	984.5
2	Working Capital Allowance (WCA)	36.3	38.7	40.7	42.5	44.5
3	Rate Base	617.5	683.7	782.1	878.7	1029.1
4	Return on Debt	17.4	19.2	22.0	24.7	28.9
5	Return on Equity	22.5	24.9	28.5	32.0	37.5
6	Depreciation	28.5	29.1	33.6	37.4	43.3
7	PILs Taxes	0.0	0.0	0.0	0.0	0.0
8	**Total Capital Related Revenue Requirement**	**68.4**	**73.3**	**84.1**	**94.2**	**109.7**
9	Less Incremental Capital Related Revenue Requirement related to WCA	0.0	-2.5	-2.6	-2.7	-2.9
10	Add-back WCA at I-X	0.0	2.4	2.5	2.7	2.8
11	**Capital Related Revenue Requirement (with WCA at I-X)**	**68.4**	**73.2**	**84.0**	**94.1**	**109.6**
12	**OM&A Forecast**	**81.4**	**88.0**	**90.0**	**91.9**	**94.3**
13	**Service Revenue Requirement**	**149.8**	**161.2**	**174.0**	**186.0**	**204.0**
14	Increase in SRR ($)		11.4	12.8	12.0	18.0
15	**Increase in SRR relative to Prior Year SRR (%)**		**7.59%**	**7.97%**	**6.91%**	**9.65%**
16	Less: I		-2.00%	-2.00%	-2.00%	-2.00%
17	Less: G		-2.48%	-2.48%	-2.48%	-2.48%
18	Less: IPD_{oma}		-0.14%	-0.13%	-0.12%	-0.12%
19	**Revenue Growth Factor (RGF)**		**2.97%**	**3.36%**	**2.31%**	**5.06%**

Note: The OM&A forecast shown in Line 12 consists of revised OM&A amounts (Table 2 above), including property tax amounts (Exhibit 6, Tab 2, Schedule 1, Table 10). Lines 13, 14, 15, 18 and 19 have changed as a result of the OM&A update; no other inputs were revised.

Consistent with the updated revenue requirement, Elexicon's forecast Custom Revenue Cap Index (CRCI) values for the 2028 to 2031 period have been revised. The revised amounts are presented in Table 5 below. Each of Productivity and Stretch (X), Growth (G), Input Price Differential – OMA (IPD_{oma}) and RGF are proposed for final approval in this application, while Inflation (I) will be updated each year based on the OEB's annual inflation factor applicable to electricity distributors. Details on Elexicon's CRCI framework are provided in Exhibit 1 – Tab 5 – Schedule 1, Section 6.

[8] Numbers may not sum due to rounding.

Table 5: Revised Forecast CRCI Values 2028 to 2031[9]

	2028	2029	2030	2031
Inflation: I	2.00%	2.00%	2.00%	2.00%
Productivity & Stretch: X	0.15%	0.15%	0.15%	0.15%
Growth: G	2.48%	2.48%	2.48%	2.48%
Input Price Differential – OM&A: IPD_{oma}	0.14%	0.13%	0.12%	0.12%
Revenue Growth Factor: RGF	2.97%	3.36%	2.31%	5.06%
CRCI ($I-X+G+IPD_{oma}+RGF$)	**7.44%**	**7.82%**	**6.76%**	**9.50%**

Implementation of the CRCI begins by escalating the prior year's approved service revenue by the current year's CRCI value and removing forecast Other Revenue to yield current year distribution revenue. Table 6 presents the results of applying the revised CRCI to the revised service revenue.

Table 6: Revised CRCI less Other Revenue[10]

($M)	2027	2028	2029	2030	2031
Prior Year Service Revenue	N/A	149.78	160.93	173.50	185.23
CRCI	N/A	7.44%	7.82%	6.76%	9.50%
Current Year Service Revenue	149.78	160.93	173.50	185.23	202.83
Other Revenue	-4.88	-4.97	-5.06	-5.16	-5.27
Current Year Distribution Revenue	**144.90**	**155.96**	**168.44**	**180.07**	**197.56**

5. REVISED BILL IMPACTS

Tables 7 through 9 present the proposed distribution rates for 2027 and the forecast rates for the 2028 to 2031 period, showing the impact of the revised revenue requirement on fixed and variable charges by rate class. The methodology used to derive these rates is the same as that described in Exhibit 8.

[9] Numbers may not sum due to rounding.
[10] Numbers may not sum due to rounding

Table 7: Proposed 2027 Distribution Rates

Rate Class	Proposed 2027 Monthly Service Charge ($/month)	Proposed 2027 Variable Rate ($/kW or $/kWh)	Variable Charge Unit
Residential	46.15		
GS < 50 kW	27.87	0.0309	kWh
GS 50 - 2,999 kW	165.94	6.0980	kW
GS 3,000 - 4,999 kW	4,758.36	4.9939	kW
Large Use >5MW	10,722.24	5.5936	kW
Street Light	1.16	5.1361	kW
Sentinel	7.74	22.7610	kW
USL	11.47	0.0309	kWh
Seasonal Residential	84.01		

Table 8: Summary of 2028 and 2029 Distribution Rates

Rate Class	2028	2029				
	Fixed ($) Variable ($)	Fixed ($)		Variable ($)		
Residential	48.73			51.62		
GS < 50 kW	29.76	0.0333	/kWh	31.86	0.0359	/kWh
GS 50 - 2,999 kW	177.83	6.4285	/kW	191.46	6.8491	/kW
GS 3,000 - 4,999 kW	5,052.78	5.1226	/kW	5,473.33	5.3273	/kW
Large Use >5MW	9,907.07	4.9425	/kW	10,118.09	4.6868	/kW
Street Light	1.23	5.4637	/kW	1.32	5.8324	/kW
Sentinel	8.42	24.8113	/kW	9.20	27.1374	/kW
USL	12.43	0.0335	/kWh	13.52	0.0365	/kWh
Seasonal Residential	90.61			98.08		

Table 9: Summary of 2030 and 2031 Distribution Rates

Rate Class	2030			2031		
	Fixed ($)	Variable ($)		Fixed ($)	Variable ($)	
Residential	54.10			58.21		
GS < 50 kW	33.77	0.0383	/kWh	36.72	0.0418	/kWh
GS 50 - 2,999 kW	204.14	7.2724	/kW	223.35	7.8814	/kW
GS 3,000 - 4,999 kW	5,758.38	5.4492	/kW	6,186.74	5.6950	/kW
Large Use >5MW	10,688.91	4.7612	/kW	11,648.44	5.0562	/kW
Street Light	1.39	6.1626	/kW	1.51	6.6824	/kW
Sentinel	9.95	29.3762	/kW	11.04	32.6311	/kW
USL	14.56	0.0393	/kWh	16.08	0.0435	/kWh
Seasonal Residential	105.07			115.52		

Customer bill impacts associated with these changes are presented in Tables 10 and 11, and reflect the cumulative impacts of the updated evidence, including the revised SCC plan presented in this Exhibit and the impacts from the OEB's Decision in EB-2025-0046 as reflected in the revised version of Exhibit 9.

Specifically, the updated bill impacts take into account:

- The updated distribution revenue requirement arising from changes to the forecast System Control Centre segment costs;
- Disposition of Group 1 balances now proposed for disposition within the revised Exhibit 9;
- Revisions to Group 2 balances for disposition as a result of the findings in Elexicon's 2026 rate application (EB-2025-0046) where the OEB ordered Elexicon to defer consideration of balances in accounts 1575 – IFRS-CGAAP Transition PP&E (Veridian), 1508 – Estimated Useful Life (Whitby), and 1508 – GOCA (Elexicon) to its rebasing proceeding within the revised Exhibit 9; and
- Final OEB-approved 2026 rate riders which were lower than anticipated in Pre-Filed evidence due to the findings in the OEB's Decision. All other things equal, lower rate riders in 2026 drive higher bill impacts in 2027.

Table 10 presents Subtotal A bill impacts by rate class and rate zone, reflecting the impacts of all proposed changes to base distribution rates arising from the updated distribution revenue requirement, as well as the update to certain Group 2 rate riders filed in the Exhibit 9 update. Table 11 presents the total bill impacts, which reflect the cumulative impact on customer total bills of all proposed updates, inclusive of Subtotal A and the remaining amendments to Exhibit 9 (i.e. Group 1 account disposition). The outcomes of the OEB's Decision in EB-2025-0046 are the primary driver of the change in bill impacts in 2027, relative to Pre-Filed Evidence.

1 **Table 10: Bill Impacts – Subtotal A**

Veridian Rate Zone	2027		2028		2029		2030		2031		Average
	$	%	$	%	$	%	$	%	$	%	$
Residential	9.89	27.6%	4.97	10.9%	2.89	5.7%	2.48	4.6%	4.11	7.3%	4.87
Seasonal Residential	16.70	25.6%	12.02	14.7%	7.46	7.9%	7.00	6.9%	10.45	9.6%	10.73
GS <50	17.41	24.5%	12.05	13.6%	7.30	7.3%	6.71	6.2%	9.95	8.7%	10.68
GS 50 - 2,999 kW	238.29	23.6%	140.47	11.3%	87.24	6.3%	86.76	5.9%	125.79	8.1%	135.71
GS 3,000 - 4,999 kW	4,932.86	24.0%	1,817.12	7.1%	1,239.35	4.5%	772.65	2.7%	1,411.56	4.8%	2,034.71
Large Use >5MW	10,417.54	19.0%	(3,574.56)	-5.5%	(2,192.56)	-3.6%	1,270.18	2.1%	3,732.53	6.2%	1,930.63
Unmetered Scattered Load	5.02	25.1%	3.77	15.1%	2.44	8.5%	2.30	7.4%	3.41	10.2%	3.39
Sentinel	1.94	19.5%	1.94	16.3%	1.25	9.0%	1.20	7.9%	1.74	10.7%	1.61
Street Light	(1,176.58)	-6.5%	2,271.27	13.4%	1,294.33	6.7%	1,046.24	5.1%	1,751.44	8.1%	1,037.34

Whitby Rate Zone	2027		2028		2029		2030		2031		Average
	$	%	$	%	$	%	$	%	$	%	$
Residential	6.19	15.7%	4.94	10.8%	2.89	5.7%	2.48	4.6%	4.11	7.3%	4.12
GS <50	6.02	7.3%	11.09	12.5%	7.30	7.3%	6.71	6.2%	9.95	8.7%	8.21
GS 50 - 2,999 kW	56.22	4.7%	124.04	9.9%	87.24	6.3%	86.76	5.9%	125.79	8.1%	96.01
GS 3,000 - 4,999 kW	3,901.39	17.9%	1,420.82	5.5%	1,239.35	4.6%	772.65	2.7%	1,411.56	4.9%	1,749.15
Unmetered Scattered Load	(5.24)	-17.6%	4.16	17.0%	2.44	8.5%	2.30	7.4%	3.41	10.2%	1.41
Sentinel	2.32	24.0%	1.89	15.8%	1.25	9.0%	1.20	7.9%	1.74	10.7%	1.68
Street Light	(35,714.60)	-67.5%	3,632.41	21.2%	1,421.89	6.8%	1,143.41	5.1%	1,920.20	8.2%	(5,519.34)

Table 11: Total Bill Impacts – Summary

Veridian Rate Zone	2027		2028		2029		2030		2031		Average
	$	%	$	%	$	%	$	%	$	%	$
Residential	9.06	6.4%	5.23	3.5%	3.56	2.3%	3.13	2.0%	4.72	2.9%	5.14
Seasonal Residential	14.48	9.0%	10.65	6.1%	7.69	4.1%	7.15	3.7%	10.36	5.2%	10.07
GS <50	14.69	4.2%	14.02	3.8%	8.95	2.4%	8.42	2.2%	11.32	2.8%	11.48
GS 50 - 2,999 kW	(988.90)	-6.9%	675.70	5.1%	210.76	1.5%	210.54	1.5%	263.58	1.8%	74.33
GS 3,000 - 4,999 kW	(28,724.61)	-7.8%	15,670.43	4.6%	4,123.31	1.2%	3,604.53	1.0%	4,542.55	1.3%	(156.76)
Large Use >5MW	(9,203.46)	-1.0%	34,038.73	3.7%	4,222.76	0.4%	8,153.72	0.9%	11,472.58	1.2%	9,736.87
Unmetered Scattered Load	4.43	5.3%	3.78	4.3%	2.73	3.0%	2.60	2.8%	3.60	3.7%	3.43
Sentinel	1.72	9.6%	1.65	8.4%	1.18	5.5%	1.14	5.1%	1.63	6.9%	1.46
Street Light	(6,838.86)	-8.3%	4,301.40	5.7%	1,860.59	2.3%	1,581.49	1.9%	2,410.05	2.9%	662.93

Whitby Rate Zone	2027		2028		2029		2030		2031		Average
	$	%	$	%	$	%	$	%	$	%	$
Residential	1.88	1.3%	7.83	5.3%	3.56	2.3%	3.13	2.0%	4.72	2.9%	4.22
GS <50	(4.28)	-1.2%	18.38	5.1%	8.95	2.4%	8.42	2.2%	11.32	2.9%	8.56
GS 50 - 2,999 kW	133.96	1.0%	297.29	2.2%	210.76	1.5%	210.54	1.5%	263.58	1.8%	223.22
GS 3,000 - 4,999 kW	990.31	0.3%	12,870.22	3.8%	4,123.31	1.2%	3,604.53	1.0%	4,542.55	1.3%	5,226.19
Unmetered Scattered Load	(6.78)	-7.4%	5.72	6.7%	2.73	3.0%	2.60	2.8%	3.60	3.7%	1.57
Sentinel	1.74	10.0%	2.05	10.7%	1.18	5.6%	1.14	5.1%	1.63	6.9%	1.55
Street Light	(40,379.73)	-35.2%	4,705.36	6.3%	1,984.18	2.5%	1,670.67	2.1%	2,578.49	3.1%	(5,888.20)

6. LIST OF ATTACHMENTS:

- Attachment 1: Elexicon 2027-2031 DSP Non-Wires Solutions Benefit Cost Analysis Report (pdf), including related appendices:
  - Attachment 1 - Appendix A (Bradshaw MS BCA – Bradshaw Region) (excel)
  - Attachment 1 - Appendix B (Bradshaw MS BCA – Bowmanville Region) (excel)
  - Attachment 1 - Appendix C (Feeder Capacity and Undersized Conductor BCA) (excel)

EXHIBIT 10 – TAB 1 – SCHEDULE 1 – ATTACHMENT 1: ELEXICON 2027-2031 DSP NON-WIRES SOLUTIONS BENEFIT COST ANALYSIS REPORT

Prepared for:

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Elexicon 2027-2031 Distribution System Plan - Non-Wires Solutions Benefit Cost Analysis (BCA)

Prepared by:

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Date: April 1, 2026

CRA Project No. 104025

Executive Summary

Charles River Associates (CRA), on behalf of Elexicon Energy Inc (Elexicon), has completed a Benefit Cost Analysis (BCA) to evaluate whether Non-Wires Solutions (NWS) may offer a viable and cost-effective alternative to the corresponding conventional solution. These investments include Bradshaw MS Capacity Upgrade (Substation Growth); Feeder Capacity Enhancements (Grid Enhancements); Undersized Conductors (Grid Enhancements).[1] CRA applied the Non-Wires Solutions Guidelines and applies the Distribution Service Test (DST) to compare NWS alternatives to the planned traditional wires investments described in Elexicon's Distribution System Plan (DSP).

For both needs, CRA assessed a range of potential NWSs, including demand response, battery energy storage systems (BESS), and other distributed energy resources. The analysis focused on solutions capable of providing targeted, dispatchable capacity relief at the time and location required to maintain system reliability. The BCA was conducted on an incremental basis – relative to the reference wires solutions and evaluated costs and benefits using a discounted cash flow approach.

Both sets of BCA results indicate that NWS are not cost-effective alternatives to the planned wires investments for either the Bradshaw MS or the feeder capacity and undersized conductors' portfolio. While certain NWSs can provide localized peak load relief and offer qualitative benefits such as operational flexibility and planning optionality, the scale of deployment required to address the identified constraints results in costs that exceed the associated distribution capacity benefits.

For the Bradshaw MS, the analysis evaluated whether BESS could defer the planned substation upgrade required to address the forecasted capacity exceedances under N-1 operating conditions. BESS was identified as the only NWS capable of delivering sufficiently targeted and dispatchable relief given the current customer demographics downstream of the station. However, even under a favorable one-year deferral scenario, the BESS alternative produces a negative net present value under the DST, as capital and operating costs materially exceed the avoided cost of deferring the substation upgrade. Longer deferral periods further reduce cost-effectiveness, as required BESS capacity increases with anticipated load growth. As a result, NWSs are not a cost-effective substitute for the planned Bradshaw MS upgrade.

1 Ontario Energy Board, Benefit-Cost Analysis (BCA) Framework for Addressing Electricity System Needs, May 2024. Available at: https://www.oeb.ca/regulatory-rules-and-documents/rules-codes-and-requirements/bca-framework

For the feeder capacity and undersized conductors portfolio, the analysis assessed whether NWS could defer planned feeder upgrades intended to relieve thermal overloads and address reliability risks. Demand response was screened out as a standalone solution due to insufficient and highly constrained feeder level load reduction potential based on the number and types of customers supported by these feeders. CRA evaluated the BESS alternative using the least constrained feeder as a representative case for potential in other deployment areas. The results show that the BESS alternative yields minimal distribution capacity benefits relative to its costs and produces a negative net present value under the DST. The cost-effectiveness of BESS declines further for feeders with larger overloads or longer deferral periods.

Based on the BCA results, CRA concludes that the technically viable NWSs modelled for both sets of needs do not represent economic means of addressing these non-discretionary system needs while maintaining safe and reliable service. NWS may continue to provide complementary benefits and planning value in the future; however, they do not replace the need for the proposed distribution infrastructure investments over the DSP period. To this end, the planned conventional solutions described in Elexicon's DSP are the preferred alternatives for Elexicon to proceed with.

CRA notes that in the case of the feeder capacity and undersized conductors programs, our analysis focused on a representative subset of potential locations where these investment plan segments may be executed over the DSP timeframe. Consistent with Elexicon's DSP, these investment segments will evaluate a number of candidate locations using the latest operating data. As such, the locations we examined are the earliest-identified representative sample of potential projects ultimately targeted by these segments. As Elexicon proceeds with DSP implementation, other candidate locations for these feeder upgrade projects may be identified in the normal course of system planning and project scoping. We expect that as these incremental projects mature through the normal planning process (including the NWS pre-screening), they may also undergo the BCA analysis, as relevant by the pre-screening process conclusions.

1. RESULTS OVERVIEW

This section summarizes the results of the Benefit Cost Analysis (BCA) completed for two non-discretionary distribution system needs: (i) capacity constraints at the Bradshaw Municipal Station (MS), and (ii) feeder capacity constraints and undersized conductors across the distribution system. In each case, CRA evaluated whether Non-Wires Solutions (NWS) could cost-effectively defer or complement the planned wires investments, consistent with the Ontario Energy Board's (OEB) Non-Wires Solutions Guidelines and Distribution Service Test (DST) framework.

The BCA results indicate that while NWS can provide localized and dispatchable capacity relief, this relief in both cases does not entail a cost-effective alternative to the planned wires solutions. The scale and timing of the identified constraints require NWS deployments of the scope and scale that result in costs exceeding the associated distribution system benefits. Accordingly, our analysis found that the planned conventional investments identified as the preferred alternatives in Elexicon's DSP are economically preferrable to the applicable NWSs explored.

Bradshaw MS Capacity Upgrade (Substation Growth)

The Bradshaw MS BCA (performed at both the Bradshaw MS and Bowmanville regional levels) assessed whether NWS could defer the planned substation upgrade required to address forecasted capacity exceedances N-1 operating conditions. Having examined the downstream customer mix, CRA identified battery energy storage systems (BESS) as the only NWS capable of providing sufficiently targeted and dispatchable capacity relief. As discussed in more detail below and in the attached BCA templates, we screened out other options due to the scale or inability to meet the planning criteria.

CRA sized the BESS solution based on hourly load exceedances relative to planning capacity. We evaluated multiple deferral durations to add comprehensiveness to our analysis. As the modelled deferral period length increases, the required BESS capacity and costs increase materially due to load growth, reducing cost-effectiveness. However, the BESS BCA returns a significantly negative value in the first year of need evaluation. Therefore, a one-year deferral case is the focus of our analysis.

Under the one-year deferral scenario, the BESS alternative results in a negative net present value (NPV) of approximately –$15.8 million under the DST in the Bradshaw MS region, as total NWS costs exceed the avoided distribution costs associated with deferring the substation upgrade. While BESS provides qualitative benefits such as operational flexibility and planning optionality, these benefits do not offset the higher costs. As a result, NWSs are not a cost-effective alternative to the planned Bradshaw MS upgrade.

Feeder Capacity and Undersized Conductors (Grid Enhancements)

CRA notes that unlike a standalone, defined-scope project that is Bradshaw MS, the Feeder Capacity and Undersized Conductors are program segments with multiple potential deployment locations throughout the DSP implementation period. Also of note is the fact that while the segment-level cost magnitude exceeds the $2-million NWS materiality screening threshold, most, if not all, individual projects are likely to cost materially less. In screening these segments into the BCA evaluation from the broader NWS screening project, Elexicon sought to obtain additional experience in evaluating NWSs for feeder projects. Importantly, the reference projects CRA used in the BCA work are a subset of candidate locations within the Feeder Capacity and Undersized Conductors program segment.

To this end, the Feeder Capacity and Undersized Conductors BCA evaluated whether NWSs could defer a portfolio of potential feeder upgrade candidates intended to relieve thermal overloads and address reliability risks. Given the highly localized nature of these constraints, operationally feasible NWSs must deliver targeted feeder-level load relief.

We screened out demand response as a standalone solution, as it would require unrealistically high participation rates relative to the available downstream load. BESS was assessed as the most viable NWS option for further evaluation.

To provide a conservative assessment, the analysis focused on the least constrained feeder (Bell-F2) as a representative case. The DST results indicate that the BESS alternative produces a negative NPV of approximately –$12.03 million for a one-year deferral, with NWS costs substantially exceeding distribution system capacity deferral benefits. Longer deferral periods further reduce cost-effectiveness as required for BESS capacity increases.

While BESS provides qualitative benefits such as localized dispatchability and flexibility, these benefits are insufficient to justify the higher costs and implementation risks. Accordingly, NWS are not a cost-effective alternative to the planned feeder upgrades, and the wires investments remain necessary to ensure reliable service.

2. METHODOLOGY

This section outlines Charles River Associates' (CRA's) approach to evaluating Non-Wires Solutions (NWS) in accordance with the Ontario Energy Board's (OEB) Filing Requirements for Distribution Applications (Chapter 5) and NWS Guidelines. The methodology is designed to ensure that all feasible alternatives to traditional wires investments are assessed on a consistent and transparent basis.

CRA applied a structured framework that: (i) defines the system need and establishes a reference wires solution, (ii) screens and identifies feasible NWS alternatives, and (iii) evaluates costs and benefits using a benefit-cost analysis (BCA) consistent with OEB guidance.

The BCA is conducted on an incremental basis relative to the reference case and uses a discounted cash flow approach over the study period. Both distribution system and broader energy system impacts are considered, consistent with the Distribution Service Test (DST), with costs and benefits treated symmetrically across alternatives.

Qualitative factors, including reliability, implementation risk, and customer participation, are also considered, where relevant to support selection of the preferred solution.

The following subsections describe the key assumptions and analytical steps applied in the evaluation.

2.1 FORWARD-LOOKING UNCERTAINTY

The OEB's BCA framework requires distributors to address forward-looking uncertainty within their analysis. The risks associated with forward looking uncertainty are discussed further in Sections 4.6 and 6.6 for the Bradshaw MS and Feeder Capacity and Undersized Conductor projects, respectively.

2.2 DIFFICULT TO QUANTIFY AND QUALITATIVE IMPACTS

While the BCA Framework encompasses both quantitative and qualitative benefits and costs, the present assessment is confined to those that can be quantified. Qualitative benefits, where applicable, are discussed separately in Section 4.3.

2.3 SYMMETRICAL TREATMENT

Consistent with the OEB's BCA Framework, the DST applies a symmetrical treatment of costs and benefits across all alternatives. Only incremental costs and benefits to the distributor are included, with impacts assessed consistently for both the reference wires solution and NWS options.

The DST reflects distributor costs (e.g., capital, O&M, and NWS program costs) and benefits in the form of avoided or deferred distribution infrastructure. Customer-incurred costs and broader system impacts are excluded to ensure a like-for-like comparison from the distributor perspective.

2.4 INCREMENTAL ANALYSIS

Consistent with OEB guidance, the BCA is conducted on an incremental basis relative to the reference wires solution. Only costs and benefits that differ between the BESS alternative and the reference case are included in the analysis.

This approach ensures that the evaluation reflects the net impact of selecting the BESS alternative, rather than total system costs. Common costs across both alternatives are excluded, and all incremental costs and avoided costs are assessed consistently within the Distribution Service Test framework.

2.5 NET PRESENT VALUE/DISCOUNTED CASH FLOW ANALYSIS

The DST results are evaluated on a net present value (NPV) basis to compare alternatives over the study period. Consistent with OEB guidance, we applied a real social discount rate of 4% to discount cash flows to present value, along with an assumed inflation rate of 2% for conversions between nominal and constant dollars.

All costs and benefits are evaluated on an incremental basis relative to the reference wires solution. Capital expenditures and NWS program costs are annualized over the study period to allow for consistent comparison across alternatives and alignment with avoided cost metrics.

The NPV results reflect the timing and magnitude of costs and benefits over the lifecycle of the investment, with positive NPV indicating that an NWS alternative provides a lower-cost solution from the distributor perspective.

2.6 DISCRETIONARY VS NON-DISCRETIONARY SYSTEM NEEDS

The OEB's BCA Framework defines discretionary needs as those where an investment can be deferred without impacting reliability, while non-discretionary needs require action to maintain safe and reliable service and do not allow for a "do nothing" option.

The substation upgrade and feeder and conductor replacement projects evaluated in this analysis are both non-discretionary. Similarly, across the distribution system, multiple feeders are forecasted to experience thermal overloads and capacity limitations as load grows, driven by a combination of customer growth, localized development, and aging infrastructure. These feeder level constraints pose reliability risks and, in some cases, would result in violations of planning criteria if not addressed.

In both cases, asset intervention is required to maintain safe and reliable service, and a "do nothing" scenario is not viable. The planned wires investments are therefore necessary to address identified capacity and reliability needs. The analysis assesses whether NWS can defer or complement the required wires investments but does not consider NWS as a replacement for meeting the underlying non-discretionary system requirements.

2.7 STUDY PERIOD

The study period is based on the operational lifetime of the substation (40 years) and conductor (60 years),[2] which is sufficient to capture the full stream of costs and benefits associated with both the wires solution and NWS alternatives over their effective lifecycle.

2.8 TRANSPARENCY AND VALIDATION

Assumptions and data sources are detailed in the BCA workbooks attached to this report as Appendix A (Bradshaw MS BCA – Bradshaw Region), Appendix B (Bradshaw MS BCA – Bowmanville Region), and Appendix C (Feeder Capacity and Undersized Conductor BCA).

3. BRADSHAW MUNICIPAL STATION UPGRADE

3.1 DESCRIPTION OF DISTRIBUTION NEED BEING SERVED

The Bowmanville portion of Elexicon's service territory sits within the Clarington operational area, which also encompasses the communities of Newcastle, Orono, and Port Hope. Bowmanville is served from 44-kV feeders egressing from Hydro One-owned Wilson TS.

Table 1. Bowmanville Municipal Stations Voltage and Capacity

	Voltage (kV)	ONAN Capacity (MVA)*
Bradshaw	13.8	10
Liberty North	13.8	15
Spry	13.8	27

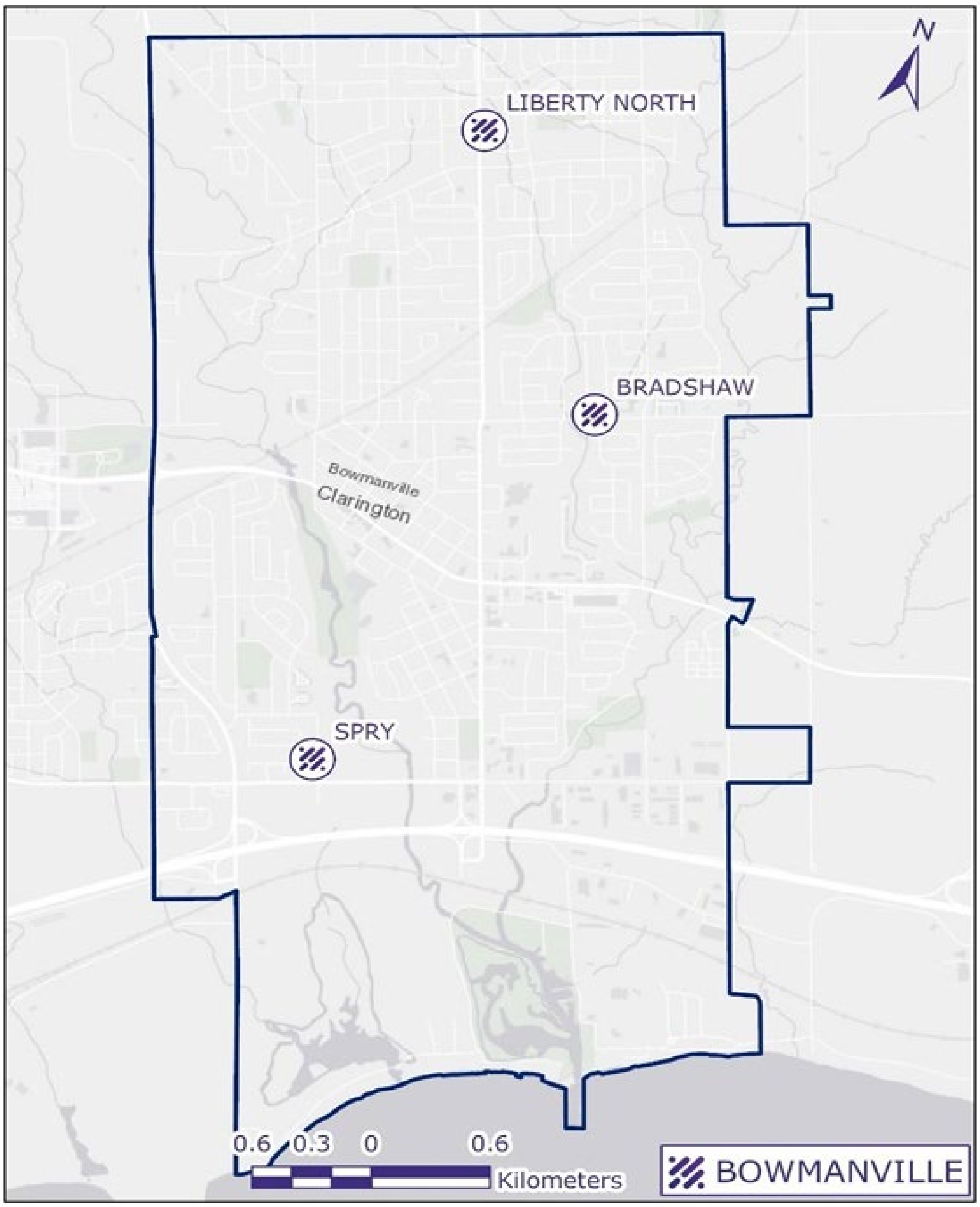
* Capacity at ONAN (Oil Natural Air Natural) Transformer rating: Normal operating capacity without additional mechanical fan cooling

Elexicon's load forecast estimates that the existing capacity of the 13.8kV system in the Bowmanville region is not sufficient. The historical peak load of the 13.8kV system was 37MW in 2025 and is expected to rise to 48MW by 2031. The Bowmanville region is capacity constrained because load in the region is forecasted to significantly exceed the N-1 MS planning capacity, beginning in 2026.

The Bradshaw Municipal Station has been identified by Elexicon as a viable upgrade option to address the aforementioned constraints. Loading beyond the station equipment's rated capacity results in increased deterioration through mechanisms such as thermal degradation. If station equipment is loaded beyond their intended capacity for significant periods of time, the risk of asset failure and service interruptions increases.

[2] Kinectrics Inc., *Asset Depreciation Study for the Ontario Energy Board*, EB-2010-0178, July 8, 2010

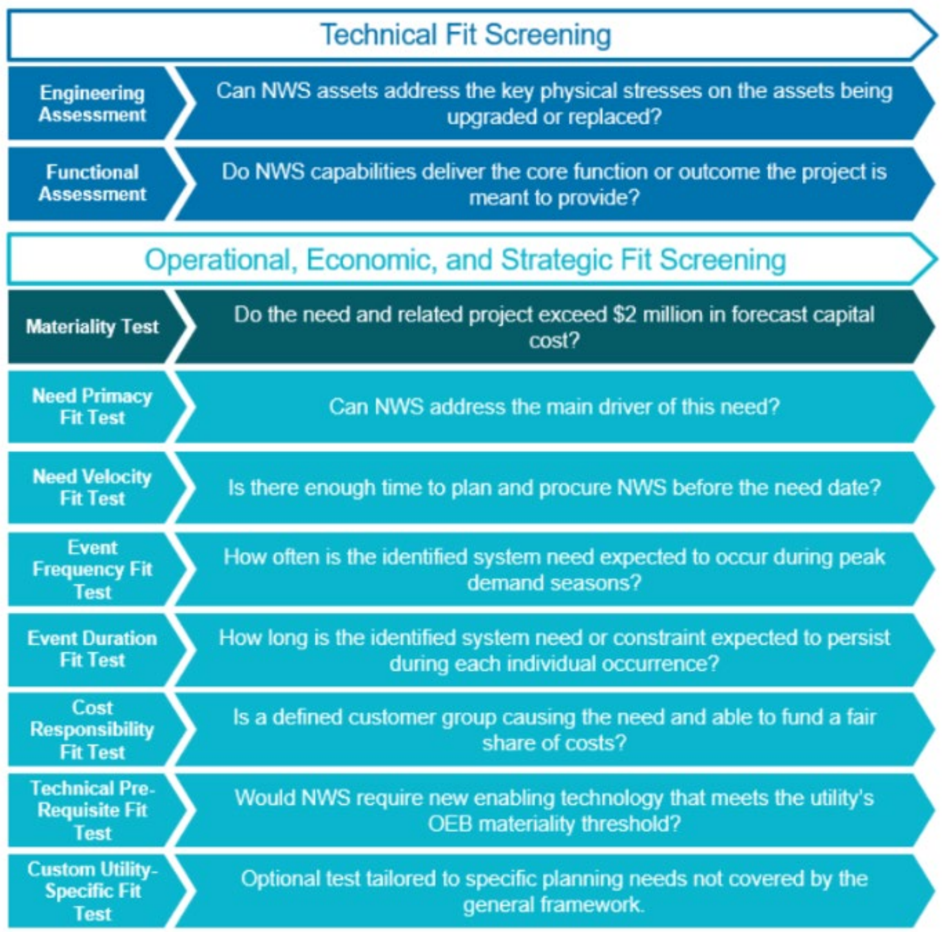
Figure 1: Bowmanville Region



3.2 NWS SCREENING FRAMEWORK

The Ontario Energy Board's Non-Wires Solutions (NWS) Guidelines for Electricity Distributors require distributors to formally consider NWSs as alternatives to traditional capital infrastructure when addressing identified distribution system needs. NWSs include conservation and demand management, demand response, energy storage, distributed generation, managed electric vehicle charging, and other distributed energy resources. Distributors must document this consideration within their distribution system planning, particularly for projects with forecast capital costs of $2 million or more (excluding general plant) and demonstrate that potential NWS options have been assessed alongside conventional "wires" solutions using a defined and transparent methodology.

Figure 2. NWS Pre-Screening Framework applied to Elexicon's DSP



To support regulatory review, distributors are expected to clearly define the system need, assess the applicability, technical feasibility and timing of NWS options, and apply the OEB's Benefit-Cost Analysis Framework to investments screened in by the pre-screening process to compare NWSs with traditional investments. Where NWSs are proposed, distributors must provide appropriate evidentiary support, including cost estimates, performance risks, measurement and verification approaches, and cost recovery treatment.

CRA applied the above NWS pre-screening criteria (shown in Figure 2) to Elexicon's Distribution System Plan (DSP) investment portfolio and identified the Bradshaw Municipal Station Upgrade project as a potential candidate to be addressed by NWS. The Bradshaw

MS project seeks to address anticipated peak time capacity shortfalls in the Bowmanville area under N-1 conditions by increasing the capacity of the station to 25 MVA (ONAF[3] maximum capacity).

3.3 NWS FEASIBILITY DETERMINATION

CRA considered a range of NWSs to address the identified capacity need at Bradshaw MS and within the broader Bowmanville region. Consistent with OEB guidance, CRA screened potential NWS based on technical feasibility, locational effectiveness, timing, and ability to reliably reduce peak demand at the constrained station.

Given the highly localized nature of the constraint and the near-term timing of the need, only NWSs capable of delivering targeted, dispatchable peak load reduction at Bradshaw MS were considered feasible. As a result, the analysis focused on battery energy storage systems (BESS) and demand response (DR), which can provide controllable and coincident load relief during peak conditions.

Other NWS options were screened out for the following reasons:

- **Distributed generation (e.g., rooftop solar):** While capable of reducing net load, these resources are not dispatchable and may not reliably coincide with system peak conditions without paired storage. In addition, deployment at sufficient scale within the constrained area is uncertain within the required timeframe. Moreover, having evaluated the current volumes of distributed customer-sited solar photovoltaic (PV) generation connected downstream of Bradshaw MS, CRA determined that it does not provide a meaningful relief opportunity at the necessary scale and beyond the load reduction that is already occurring.
- **Energy efficiency (CDM):** Energy efficiency provides broad, long-term load reduction but is not well-suited to addressing acute, location-specific capacity constraints, particularly where peak demand reduction must be achieved within a defined and relatively short timeframe.
- **Electric vehicle (EV) managed charging:** While EV load flexibility may offer potential in the longer term, current adoption levels, geographic distribution within the constrained region, and the degree of reliable controllability remain uncertain. In addition, a significant portion of EV charging is expected to occur during overnight periods, which may not consistently coincide with system peak demand. As a result, demand response from this resource may be limited in its ability to contribute to peak demand reduction at the scale required at this time
- **Fuel switching or electrification management:** These measures are either not applicable to the identified constraint or would not provide meaningful or timely peak demand relief.

Accordingly, BESS and DR were therefore identified as the most appropriate NWS options for further evaluation, as they can be deployed in a targeted manner, provide measurable and dispatchable peak load reduction, and align with the timing and magnitude of the identified system need.

Demand Response Feasibility Assessment

3 Measured in terms of ONAF (Oil Natural, Air Forced) capacity. ONAF is a cooling method for oil-immersed transformers allowing the stations to operate at maximum capacity.

DR was evaluated as a potential NWS to address the identified capacity shortfall at Bradshaw MS and within the Bowmanville region. The assessment considered achievable peak demand reduction based on existing customer load, assumed participation rates, and per-customer load reduction values.

Table 2 below shows the number of customers and non-coincident peak demand within the Bradshaw and Bowmanville regions for both commercial and industrial (C&I) and residential customers provided by Elexicon. DR feasibility was assessed based on the values presented here.

Table 2. Bradshaw and Bowmanville Existing Customer Base

Region	Bradshaw		Bowmanville	
Customer Type	**C&I**	**Residential**	**C&I**	**Residential**
Non-Coincident Peak (kW)	1,326	7,469	6,176	31,273
Number of Customers	14	2,636	69	11,227

Residential DR potential was estimated assuming an average peak reduction of approximately 0.8 kW per participating customer, reflecting the upper (optimistic) end of observed impacts from thermostat-based DR programs.[4] Based on the 2031 capacity need, this corresponds to approximately 10.4 MW of required reduction in Bowmanville and 8.9 MW downstream of Bradshaw, which would require approximately 12,887 and 11,039 participating customers, respectively. This exceeds the total available residential customer base in both areas (11,227 in Bowmanville and 2,636 in Bradshaw MS), indicating residential DR alone is not sufficient, as shown in Table 3.

Table 3. Residential DR Capability vs. Required Peak Reduction (2031)

	Bowmanville	Bradshaw
Required peak reduction (kW)	10,439	8,942
Assumed reduction per customer (kW)	0.81	0.81
Customers required	12,887	11,039
Available residential customers	11,227	2,636
Participation required	**115%**	**575%**

Values exceeding 100% indicate that the required reduction exceeds the total available customer base.

C&I DR potential was also assessed. In Bowmanville, approximately 6.2 MW of medium C&I load is available, compared to a 10.4 MW reduction requirement, leaving a shortfall of

[4] Massachusetts Energy Efficiency Advisory Council (EEAC), *Residential Wi-Fi Thermostat Direct Load Control Evaluation Report*, April 1, 2020. Available at: https://ma-eeac.org/wp-content/uploads/2019-Residential-Wi-Fi-Thermostat-DLC-Evaluation-Report-2020-04-01-with-Infographic.pdf

approximately 4.2 MW. In Bradshaw, available C&I load of approximately 1.3 MW falls well short of the 8.9 MW reduction required, as shown in Table 4.

Table 4. C&I DR Capability vs. Required Peak Reduction (2031)

	Bowmanville	**Bradshaw**
Required peak reduction (kW)	10,439	8,942
Available C&I peak load (kW)	6,176	1,326
Required as % of C&I load	169%	674%
Remaining shortfall (kW)	**4,263**	**7,616**

Values exceeding 100% indicate that the required reduction exceeds the total available customer base.

A combined residential and commercial DR scenario was evaluated under an optimistic 40% participation assumption. Under this scenario, total DR potential is approximately 6.1 MW in Bowmanville and 1.4 MW in Bradshaw, leaving remaining shortfalls of approximately 4.3 MW and 7.6 MW, respectively, as shown in Table 5.

Table 5. Combined Residential and C&I DR Capability vs. Required Peak Reduction (2031)

	Bowmanville	**Bradshaw**
Required peak reduction (kW)	10,439	8,942
Residential DR		
Residential customers	11,227	2,636
Assumed participation rate	40%	40%
Participating customers	4,491	1,054
Residential DR potential (kW) (0.81 kW/customer)	3,638	854
C&I DR		
Medium C&I peak demand (kW)	6,176	1,326
Assumed participation rate	40%	40%
Medium C&I DR Potential	2,470	530
Total combined DR potential	6,108	1,384
Remaining shortfall	**4,331**	**7,557**

Assumed participation rate of 40% reflects an upper-bound scenario; actual participation is expected to be lower based on industry benchmarks.

The 40% participation assumption represents an upper-bound case. Industry benchmarks show average utility DR participation around 25%, with 40% representing top-quartile performance.[5] In the U.S., reports show only ~20% of U.S. smart thermostat households are enrolled in DR programs,[6] and a Pennsylvania PUC study assumed initial participation rates of just 15–30% with only 1–3% annual growth.[7] This indicates that moving to 40% participation would require performance above typical initial enrollment ranges and continued program expansion over multiple years. Even with this optimistic participation assumption, there is not sufficient demand response capability to replace the traditional solution.

Based on this analysis, DR alone is not capable of reliably meeting the magnitude of the identified capacity need within the required timeframe. Accordingly, DR was not advanced as a standalone solution in the BCA.

Mobile Battery Rental Consideration

CRA also considered whether deploying distributed batteries could be a feasible option to address the capacity constraints at Bradshaw MS. After evaluating rental BESS, these options were not pursued due to the lack of fit with scale, practicality, and limited cost transparency. Most available systems are relatively small in capacity, meaning that achieving a minimum threshold of 8.9 MW for at minimum a one-year deferral would require deploying over 150 individual units. This creates significant logistical complexity, increases space requirements, and introduces integration and operational risks. As a result, given the scaling inefficiencies and lack of transparent cost data, rental BESS solutions were not advanced for further consideration at this stage.

Residential Battery Storage (e.g., Powerwall) Consideration

Residential battery storage (e.g., behind-the-meter systems such as Tesla Powerwall) was considered as another potential NWS to address the identified capacity need at Bradshaw MS. However, this option was determined to be not feasible based on both scale and cost considerations.

The required peak reduction at Bradshaw MS in 2031 is approximately 8.9 MW during peak hours. A typical residential battery system has a usable capacity of approximately 10.4 kW. Meeting the identified need would therefore require on the order of more than 850 individual battery installations, assuming full availability and dispatchability during peak periods. In practice, a larger number of installations would be required to account for variability in state of charge, customer participation, and operational constraints.

This level of deployment would represent more than 30% of the total residential customer base within the Bradshaw area, which is materially above observed enrolment levels for customer-sited DER programs. By comparison, Berkeley Lab identifies 20% residential

5 KPI Depot, *Demand Response Participation Rate KPI*. Available at: https://kpidepot.com/kpi/demand-response-participation-rate

6 Parks Associates, *New Data Reveals More Targeted Demand Response (DR) Deployment and Improved Participant Experience*, June 17, 2025. Available at: https://www.parksassociates.com/blogs/press-releases/parks-associates-new-data-reveals-more-targeted-demand-response-dr-deployment-and-improved-participant-experience

7 Pennsylvania Public Utility Commission, *Demand Response Potential Study*, May 31, 2021. Available at: https://www.puc.pa.gov/pcdocs/1867287.pdf

enrolment as a notable level of participation in an established utility program,[8] while a California VPP study assumes only 1% of residential customers adopt and behind-the-meter batteries by 2035.[9] In addition, the U.S. Department of Energy (DOE) has found that geo-targeted flexible DER programs for distribution needs remain at an early stage of maturity, with few examples and significant coordination requirements.[10]

Cost considerations further limit the feasibility of this option. Based on typical installed costs of approximately $18,000 per unit,[11] total deployment costs would exceed $12 million. Alternative benchmarks suggest even higher costs when accounting for installation variability and site-specific conditions. These costs materially exceed the benefits associated with deferring the substation upgrade, resulting in a negative net present value.

Accordingly, residential behind the meter battery storage was not advanced for further consideration in the BCA, as it is not capable of cost-effectively or reliably meeting the identified system need.

3.4 NON-WIRES SOLUTION PROPOSED PROJECT OVERVIEW

BESS sizing and duration were determined based on the magnitude and temporal characteristics of load exceedances relative to planning capacity at Bradshaw MS and within the Bowmanville region.

Battery duration was established using 2031 hourly load data provided by Elexicon by identifying the number of consecutive hours during which load exceeds planning capacity. As shown in Table 6, exceedance events persist for multiple consecutive hours, with average durations of approximately 8.7 hours in Bowmanville and 3.3 hours in Bradshaw. Based on this analysis, battery durations of 8 hours (Bowmanville) and 4 hours (Bradshaw) were selected to capture most of exceedance events and ensure reliable peak coverage.

Table 6. Consecutive Hours of Load Exceeding Planning Capacity (2031)

	Bowmanville	Bradshaw
Average	8.7	3.3
Median	5	2
Maximum	14	11

8 Lawrence Berley National Lab, *Distributed Energy, Utility Scale: 30 Proven Strategies to Increase VPP Enrollment*, December 2024, available at: https://eta-publications.lbl.gov/sites/default/files/2024-12/30_strategies_to_increase_vpp_enrollment_12-19-2024.pdf

9 Brattle Group, *California's Virtual Power Potential: How Five Consumer Technologies Could Improve the State's Energy Affordability,* April 2024, available at: https://gridlab.org/wp-content/uploads/2024/04/Californias-Virtual-Power-Potential-Vol-II-Technical-Appendix.pdf

10 U.S. DOE, *TSO-DSO-Aggregator Market and Operational Coordination Requirements*, April 2024, available at: https://www.energy.gov/sites/default/files/2024-06/Coordination%20Platform%20final%20draft%20v6_optimized.pdf

11 Costs converted from USD to CAD, source: PowerOutage.com, *Tesla Powerwall cost analysis,* January 2026, available at: https://poweroutage.us/home-battery-backup/tesla-powerwall-cost-analysis

	Bowmanville	Bradshaw
Selected BESS Duration	**8 hours**	**4 hours**

Battery capacity (MW) was determined by quantifying hourly load exceedances above planning capacity and sizing the BESS to reduce these exceedances within acceptable planning limits. A 1-in-10 exceedance criterion (approximately 2–3 hours per year) was applied, such that the selected capacity reduces annual exceedance hours below this threshold.

Elexicon's load forecast provided to CRA for the purposes of NWS BCA work extends through 2031. To add conservatism to the analysis by assessing a broader range of potential outcomes and evaluating deferral economics beyond the identified need date, CRA extended the forecast using the compound annual growth rate (CAGR) observed from 2025 through 2031. The 2031 hourly load profile was used as the base and projected through 2035 using this growth rate to estimate future demand and determine the BESS sizing required for longer deferral periods.

As shown in Table 7, required BESS capacity increases over time as load growth drives higher and more frequent exceedances are expected to occur. In the near term, a smaller BESS is sufficient to address localized constraints at Bradshaw MS; however, over longer deferral periods, larger capacity is required to manage exceedances at the broader Bowmanville planning level.

Table 7. Required BESS Capacity (MW) by Deferral Length

Deferral length	Deferred Year	Bowmanville (MW)	Bradshaw (MW)
1	2032	13	9
2	2033	15	10
3	2034	17	11
4	2035	19	12

This approach ensures that BESS is sized to both the magnitude and duration of system constraints, providing targeted and dispatchable load relief aligned with the identified system need.

4. DISTRIBUTION SERVICE TEST

Per the OEB BCA Framework, the following discussion of the DST only includes distribution costs and benefits.

4.1 REFERENCE CASE

Hourly load data for the Bowmanville and Bradshaw MS regions provided by Elexicon was used to establish the reference case used in the DST. Capacity values are converted from MVA to MW assuming a 0.9 power factor.

The Bowmanville region represents a broader planning area consisting of three substations and is used to assess system performance under N-1 contingency conditions. In contrast, Bradshaw MS is evaluated as a standalone station and is the specific substation proposed for upgrade.

The reference case represents the expected system conditions absent any NWS intervention and forms the basis for identifying both near-term and long-term distribution system needs. The analysis assesses station loading relative to planning capacity limits to determine when and where constraints emerge.

Results indicate that capacity constraints are present in both areas. In the Bowmanville region, peak load actually exceeded the planning capacity historically, with the shortfall expected to increase to approximately 10.4 MW by 2031 under N-1 conditions. At Bradshaw MS, capacity constraints grow to 8.9 MW by 2031. Under these conditions, planning limits are exceeded, indicating the need for additional capacity.

This reference case establishes the need for investment in the region and serves as the base-line against which NWS alternatives are evaluated.

4.2 QUANTITATIVE BENEFITS

4.2.1. DISTRIBUTION CAPACITY BENEFITS (DEFERRAL OR AVOIDANCE BENEFIT)

Quantitative benefits under the DST are based on the avoided distribution cost approach, consistent with OEB guidance. Benefits are quantified as the avoided or deferred cost of distribution infrastructure that would otherwise be required to address the identified capacity constraints.

Consistent with the OEB's BCA Framework, avoided distribution costs are calculated using the Cost of Service approach, where the annual revenue requirement associated with the reference wires investment is used to represent the value of deferral.

This is expressed as:

$$benefit_{y=p} = NPVCOSReference_{y=p} - NPVCOSDeferred_{y=p}$$

Where the y subscript identifies the given year, and y=p is the present year (2026), and

$$NPVCOSReference_{y=p} = \sum_{y=needDate}^{Yref} \frac{RevRequirementRef_y}{(1 + inflation + socialdiscount)^{(y-p+1)}}$$

$$NPVCOSDeferred_{y=p} = \sum_{y=deferredDate}^{Yref} \frac{RevRequirementDef_y}{(1 + inflation + socialdiscount)^{(y-p+1)}}$$

In this analysis, the need Date is 2031, corresponding to the expected in-service date of the substation upgrade. To evaluate the potential benefits of deferral, CRA assessed BESS sizing requirements to meet system needs and defer the traditional solution by 1 to 10 years. The results indicate that as the deferral period increases, the required BESS capacity grows and the incremental benefit declines. Accordingly, the analysis presented focuses on a one-year deferral case, with a deferral Date of 2032.

Consistent with OEB guidance, an inflation rate of 2% and a real social discount rate of 4% are applied in the analysis.

The resulting annual cost of service represents the value of the conventional wires investment that can be avoided or deferred. This value is applied to the duration and magnitude of peak demand reduction achieved by the NWS portfolio.

The primary benefit of NWS is the reduction in peak demand at Bradshaw MS and within the Bowmanville region, which reduces the magnitude or timing of the required substation upgrade. Benefits are calculated on an incremental basis relative to the reference case and are included only to the extent that NWS contributes to deferring or reducing the need for the planned investment.

4.3 QUALITATIVE BENEFITS

In addition to quantified benefits under the DST, NWS alternatives provide several qualitative benefits relevant to the Bradshaw MS capacity need.

4.3.1. RELIABILITY AND RESILIENCE

Battery energy storage systems provide localized, dispatchable load relief during peak and contingency conditions, supporting system reliability at Bradshaw MS and within the broader Bowmanville region. BESS can respond rapidly to system needs, helping manage peak demand variability and ensuring that loading remains within planning limits. In addition, BESS can enhance system resilience by providing temporary support during outages or abnormal system conditions, improving the ability of the system to maintain service continuity.

4.3.2. INNOVATION AND MARKET TRANSFORMATION

Deployment of BESS supports the continued integration of distributed energy resources (DERs) within Elexicon's system. BESS enables new operational capabilities, including active load management and flexible capacity deployment, and represents a non-traditional approach to addressing distribution system needs. This supports broader market development for storage resources in Ontario and provides experience with integrating dispatchable DERs into planning and operations.

4.3.3. PLANNING VALUE

NWSs provide optionality in addressing system needs by allowing for incremental and scalable solutions that can be adjusted as load forecasts evolve. This flexibility can be particularly valuable in areas with load uncertainty, as it reduces the risk of over- or under-investment associated with traditional wires solutions and can defer near-term capital expenditures while maintaining reliability.

4.4 NON-WIRES SOLUTIONS COSTS

All the capacity acquired from the BESS NWS Program would be situated front-of-the-meter and owned by Elexicon. Under this structure, Elexicon retains ownership and includes capital and fixed O&M costs in the analysis, while operations may be performed by a third party under contract. This approach is consistent with a cost-of-service framework for evaluating distribution service benefits.

4.4.1. NWS ACQUISITION COSTS

The BCA Framework defines NWS acquisition costs as "the cost to acquire, connect, and dispatch the NWS capacity needed to meet the need that would otherwise be met with a traditional poles and wires solution."

CRA developed cost estimates for acquiring a distribution level battery by leveraging the IESO 2024 Resource Costs and Trends,[12] which contains forecasted capital costs of battery storage based on the US National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ATB) Report.[13] A four-hour distribution battery was estimated to have a Capital Cost of ~$3000 ($/kW) falling to ~$1800 ($/kW) in 2050. The IESO data was calibrated to the 2026 NREL data to obtain latest estimates.

This approach aligns with the BCA Framework definition of NWS acquisition costs, which includes the cost to acquire, connect, and dispatch the capacity needed to meet system requirements in place of traditional poles-and-wires solutions. We used the capital cost assumptions from the IESO Annual Planning Outlook (2024 resource trends) to represent the cost of acquiring distribution battery capacity. These values provide a standardized, forward-looking estimate of the cost to procure sufficient capacity to defer or replace conventional infrastructure. By relying on the IESO's resource trends, CRA ensures that the NWS acquisition cost reflects realistic, system-level economic assumptions for distribution battery deployment, consistent with the BCA Framework.

4.4.2. OM&A COSTS

The BCA Framework defines NWS Operations, OM&A costs as the "costs to manage and maintain the NWS project or program. This includes any distribution system maintenance costs specific to the operation of the NWS."

Similar to the approach used to estimate capital costs, CRA developed cost estimates for operating and maintaining a distribution level battery by leveraging the IESO 2024 Resource Costs and Trends[14], which contains forecasted fixed operations and maintenance costs of battery storage based on the US National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ATB) Report. A four-hour distribution battery was estimated to have a Fixed O&M Cost of ~$76 ($/kW-year) falling to ~45 ($/kW-year) in 2050. The IESO data was calibrated to the 2026 NREL data to obtain latest estimates.

4.4.3. ANCILLARY SERVICES COSTS

Electricity distributors are to identify any anticipated impact on distribution system ancillary service costs. Distribution system ancillary services may include, but are not limited to, voltage regulation, harmonic control, frequency management, and reactive power management. For the purposes of this analysis, these costs are considered secondary relative to capital, connection, and operational costs of distribution batteries. Their magnitude is expected to be minor and would not materially affect the benefit-cost outcomes.

4.4.4. PROGRAM COSTS- SUMMARY

Table 8 provides a breakdown of the estimated costs for deploying an 8-hour battery.

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[12] IESO, *Annual Planning Outlook Resource Costs and Trends*, March 2024. Available at: IESO Resource Costs and Trends, 2024

[13] National Renewable Energy Laboratory, *Annual Technology Baselines*. 2024. Available at NREL, 2024

[14] IESO, Annual Planning Outlook Resource Costs and Trends, March 2024. Available at: IESO Resource Costs and Trends, 2024

Table 8. 8-Hour BESS Program Costs ($'000s)

Year	Capital Costs ($M)	OM&A ($M)	Total Cost ($M)
2031	$4.09	$1.57	$5.66
2032	$4.01	$1.54	$5.55
2033	$3.93	$1.51	$5.44
2034	$3.85	$1.48	$5.33
2035	$3.78	$1.45	$5.23
2036	$3.70	$1.42	$5.13
2037	$3.63	$1.40	$5.03
2038	$3.56	$1.37	$4.93
2039	$3.49	$1.34	$4.83
2040	$3.42	$1.31	$4.74
2041	$3.35	$1.29	$4.64
2042	$3.29	$1.26	$4.55
2043	$3.22	$1.24	$4.46
2044	$3.16	$1.21	$4.38
2045	$3.10	$1.19	$4.29
Total Spend	**$53.59**	**$20.59**	**$74.18**
NPV of BESS Costs: $45.8			

Table 9 provides a breakdown of the estimated costs for deploying a 4-hour battery.

Table 9. 4-Hour BESS Program Costs ($'000s)

Year	Capital Costs ($M)	OM&A ($M)	Total Cost ($M)
2031	$1.62	$0.61	$2.23
2032	$1.59	$0.60	$2.19
2033	$1.56	$0.58	$2.14
2034	$1.53	$0.57	$2.10
2035	$1.50	$0.56	$2.06

Year	Capital Costs ($M)	OM&A ($M)	Total Cost ($M)
2036	$1.47	$0.55	$2.02
2037	$1.44	$0.54	$1.98
2038	$1.41	$0.53	$1.94
2039	$1.39	$0.52	$1.90
2040	$1.36	$0.51	$1.87
2041	$1.33	$0.50	$1.83
2042	$1.31	$0.49	$1.79
2043	$1.28	$0.48	$1.76
2044	$1.26	$0.47	$1.73
2045	$1.23	$0.46	$1.69
Total Spend	**$21.29**	**$7.96**	**$29.25**
NPV of BESS Costs: $18.1			

4.5 DST RESULTS

The BESS NWS model would produce a Net Present Value of -$43.6 million and -$15.8 million for the Bowmanville and Bradshaw regions, respectively, as shown in Table 10. These results are based on a one-year deferral of the traditional solution. Longer deferral periods were evaluated; however, as load growth increases the magnitude of capacity exceedances over time, the required BESS capacity and associated costs increase, offsetting the additional benefit of deferral.

Table 10. DST Results ($Millions)

	Bowmanville	Bradshaw
NPV Total DST Benefit	$2.3	$2.3
NPV Total DST Cost	$45.8	$18.1
NPV Net DST Benefit	**-$43.6**	**-$15.8**

4.6 DISTRIBUTION SERVICE TEST RISKS

The results of the DST are subject to several uncertainties that may affect the realized costs and benefits of the BESS alternative relative to the reference wires solution. Consistent with OEB guidance, these uncertainties are considered in assessing the robustness of the results.

A key uncertainty relates to load forecast variability. The DST is based on forecasted peak demand and timing of exceedances; deviations from forecast may impact both the required BESS capacity and the achievable deferral period. Higher load growth could reduce the effectiveness of the BESS in maintaining performance within planning limits, while lower growth could reduce the required investment.

The analysis also reflects assumptions regarding BESS performance, availability, and dispatch. While BESS is modeled as a dispatchable resource capable of providing peak load reduction, realized performance depends on accurate identification of peak conditions and successful operation during those periods. Any misalignment between dispatch and actual system peaks may reduce the effectiveness of the solution.

Asset performance and degradation represent an additional uncertainty. The DST assumes that the BESS maintains sufficient capacity and duration over the deferral period; however, degradation over time may reduce effective output and require augmentation to sustain performance.

There is also uncertainty related to capital cost assumptions. BESS costs are based on current estimates and are subject to market conditions, which may differ at the time of procurement.

Finally, the DST does not explicitly capture implementation and execution risk, including procurement, siting, and interconnection timelines. Delays in deployment could impact the ability of the BESS to achieve the assumed deferral.

In light of these uncertainties, the DST findings should be viewed as illustrative of relative cost-effectiveness under the stated assumptions. Importantly, the analysis is framed conservatively, with any NWS upside treated as a best-case outcome. The analysis is intended to inform decision-making but does not eliminate the need for further detailed design, procurement, and operational planning.

5. FEEDER CAPACITY AND UNDERSIZED CONDUCTORS

5.1 DESCRIPTION OF NEED BEING SERVED

Two investment segments with Elexicon's broader Distribution Capacity and Reliability Enhancements program were screened as being potentially addressable by NWS.

Elexicon identified the need to address a range of system limitations affecting multiple feeders across its service territory. Several areas are experiencing growing capacity shortfalls, along with thermal and voltage constraints that limit the system's ability to reliably support continued residential and industrial growth. These constraints pose risks to system reliability, resiliency, and the ability to accommodate future load increases, particularly in rapidly developing communities such as Belleville, Whitby, and Pickering. As stated in Elexicon's DSP, addressing these needs is a growing requirement to relieve constraints and support system resiliency.

In addition, Elexicon identified approximately 12 km of distribution lines with undersized conductors in critical locations. These sections present notable capacity and contingency challenges, contributing to higher line losses, voltage drop issues, and reduced operational flexibility during peak demand periods. The presence of undersized conductors further constrains the system's ability to accommodate evolving grid demands, including increased penetration of distributed energy resources such as solar PV, battery storage, and electric vehicles, which introduce bidirectional power flows and additional stress on existing infrastructure.

Given the overlapping geographic areas, common drivers, and complementary objectives underlying these identified needs, the related investments are planned to be implemented concurrently to capture construction, operational, and planning synergies. As a result, these initiatives have been evaluated within a single BCA to reflect their interdependencies, ensure a holistic assessment of benefits and costs, and accurately represent the combined value of addressing these system needs through a coordinated approach.

5.2 NWS SCREENING FRAMEWORK

CRA followed the same protocol used to screen projects for NWS viability as the Bradshaw MS Upgrade project. CRA applied the screening criteria (shown in Figure 2) to Elexicon's Distribution Service Plan (DSP) and identified that based on the initial scoping of the project, NWS could potentially provide a viable source of capacity.

As noted in the introduction, CRA recognizes that many of the individual feeder capacity and undersized conductor projects included in this portfolio would not, on a standalone basis, exceed the $2 million capital cost threshold that typically triggers a project specific NWS benefit cost analysis under the OEB's guidelines. However, the initial NWS screening was conducted at the portfolio level, reflecting the cumulative scale, timing, and systemwide nature of the feeder capacity and reliability investments planned over the DSP period.

As a result, the Feeder Capacity and Undersized Conductors program was screened in for further evaluation to assess whether NWS could reasonably defer or complement the planned portfolio of upgrades. This approach ensures consistency with the OEB's intent that distributors consider NWS where material system needs exist, while recognizing that individual feeder projects will continue to be scoped and executed incrementally as part of an integrated capital program.

5.3 NWS FEASIBILITY DETERMINATION

CRA considered a range of NWS to address the identified feeder overloads. Because these constraints are highly localized to specific feeders, any feasible NWS must be capable of delivering targeted load relief at the feeder level during the relevant peak periods.

Potential NWS considered include DR, BESS, conservation voltage reduction (CVR), energy efficiency, and other broader distributed energy resource (DER) solutions. Of these, DR and BESS were identified as the most relevant option for further screening given its ability, in principle, to reduce feeder peak demand without requiring major physical infrastructure at each location.

Other NWS options were screened out for the following reasons:

- **Conservation voltage reduction (CVR):** CVR can provide modest peak demand reductions, but the overloads identified on the subject feeders are too large for CVR alone to reliably resolve. As a result, CVR was not considered a sufficient standalone solution.
- **Energy efficiency:** Energy efficiency can reduce overall consumption over time, but it is not well suited to addressing acute feeder-specific overloads that require targeted peak reduction at identified locations and within a defined timeframe.
- **System-wide or upstream resources:** Broader NWS options, including system-wide DR or upstream resources, do not reliably reduce loading on a specific feeder at the time and location required. Because the identified need is feeder-specific, such resources would not provide sufficiently targeted relief.

Based on this screening, DR and BESS (including front-of-the-meter and behind-the-meter solutions) were the only NWS advanced for more detailed feasibility assessment.

Demand Response Feasibility Assessment for Undersized Feeders

DR was assessed by comparing the required feeder-level load relief to the amount of residential and medium C&I demand located downstream of the subject feeders. Feeder capacity, historical and forecasted peak demand, and customer load data were provided by Elexicon. The analysis was performed under both normal (non-contingency) and N-1 planning conditions.

Under normal (non-contingency) planning conditions, only a subset of feeders are forecast to exceed capacity in 2031. DR feasibility was therefore assessed for the affected feeders: Thor-M7, Bell-F2, 8M-9, and Edge-F2.

Table 11 summarizes the required peak reduction and corresponding DR capability for these feeders. As shown, the required reduction represents a large share of downstream load:

- Required reductions range from 60% to 100% of residential peak
- Required reductions range from 95% to 1,003% of C&I peak

These results indicate that even under normal conditions, DR would require very high levels of participation and performance, approaching or exceeding the total available load in some customer classes.

Table 11. DR Capability vs. Required Peak Reduction (Nominal Conditions, 2031)

Feeder	Required Reduction (kW)	Residential Peak Demand (kW) 2031	% of Residential Peak	C&I Peak demand (kW) 2031	% of C&I Peak
Thor-M7	14,849	19,158	78%	1,480	1,003%
8M-9	11,798	19,746	60%	12,048	98%
Edge-F2	4,086	5,008	82%	1,495	273%
Bell-F2	2,564	2,577	100%	2,705	95%

Values exceeding 100% indicate that the required reduction exceeds the total available load from that customer class.

Under N-1 planning criteria, all feeders are forecast to experience capacity shortfalls. As a result, DR feasibility was evaluated across the full set of feeders.

Table 12 summarizes the required reductions and available downstream load. Under these conditions, the magnitude of required reduction increases significantly:

- Required reductions exceed 100% of residential peak for most feeders
- Required reductions exceed 100% of C&I peak in all cases, with several feeders requiring multiple times the available load

This indicates that DR would need to capture the majority or entirety of downstream load across multiple feeders to be effective under contingency conditions.

Table 12. DR Capability vs. Required Peak Reduction (N-1 Conditions, 2031)

Feeder	Required Reduction (kW)	Residential Peak Load (KW)	% of Residential Peak	C&I Peak Load (KW)	% of C&I Peak
8M1	23,152	8,982	**258%**	5,486	**422%**

Feeder	Required Reduction (kW)	Residential Peak Load (KW)	% of Residential Peak	C&I Peak Load (KW)	% of C&I Peak
8M9	23,152	19,746	**117%**	12,048	**192%**
Toro-F1	2,955	1,016	**291%**	276	**1,072%**
Thor-M7	23,152	19,158	**121%**	1,480	**1,564%**
Bell-F2	4,263	2,577	**165%**	2,705	**158%**
Edge-F1	1,434	1,331	**108%**	796	**180%**
Edge-F2	2,263	5,008	45%	1,495	**151%**

Values exceeding 100% indicate that the required reduction exceeds the total available load from that customer class.

Across both planning perspectives, the required feeder-level reductions are large relative to the available controllable load base. This would require unrealistically high participation and performance levels, particularly for feeder-specific deployment.

Accordingly, DR was not considered a feasible standalone NWS for the undersized feeder portfolio. While DR may provide incremental relief on certain feeders, it is not capable of reliably meeting the magnitude and timing of the identified overloads.

5.4 NON-WIRES SOLUTION PROPOSED PROJECT OVERVIEW

As previously discussed, Elexicon is considering a variety of potential candidate projects under the Feeder Capacity and Undersized Conductors segments, which will continue to be refined over the DSP period. To evaluate the potential distribution service benefits of BESS as an NWS to defer these upgrades, CRA assessed the least-overloaded feeder under normal conditions, the Bell-F2 feeder, as a representative case. This approach provides a conservative estimate of feasibility, as the feeder with the smallest overload requires the lowest level of intervention and therefore represents the most favorable conditions under which an NWS could be viable.

If BESS is not cost-effective or technically feasible for the least-constrained feeder, it is expected to be less viable for feeders with larger and more severe overloads, which would require proportionally greater capacity and higher costs. Accordingly, this approach provides a reasonable and efficient basis for assessing the applicability of BESS across the broader portfolio of feeder upgrades.

CRA applied a methodology consistent with the Bradshaw MS analysis to size the BESS required to address forecasted overloads on individual feeders in 2031.

BESS sizing and duration were determined based on the magnitude and temporal characteristics of load exceedances relative to planning capacity at the Bell-F2 feeder in Belleville.

Battery duration was established using 2031 hourly load data by identifying the number of consecutive hours during which load exceeds planning capacity. As shown in Table 13, exceedance events persist for extended periods, with average durations of approximately 11 hours.

A configuration of three 4-hour battery units was selected as the most practical and cost-effective option. This provides sufficient aggregate duration to cover the majority of exceedance events while allowing flexible dispatch across peak periods, avoiding the need to oversize a single long-duration asset.

This approach also aligns with current market offerings, where 4-hour systems are the most common and cost-effective configuration. Compared to longer-duration batteries, which are less mature and higher cost, multiple 4-hour units provide a more scalable and adaptable solution.

Table 13. Conservative Hours of Load at Bell-F2 Feeder Exceeding Planning Capacity (2031)

	Bell-F2 Feeder
Average	11
Median	12
Maximum	66
Selected BESS Duration	**Three 4-hour units**

Battery capacity (MW) was determined by quantifying hourly load exceedances above planning capacity and sizing the BESS to reduce these exceedances within acceptable planning limits. A 1-in-10 exceedance criterion (approximately 2–3 hours per year) was applied, such that the selected capacity reduces annual exceedance hours below this threshold.

Elexicon developed its load forecast through 2031. To evaluate deferral benefits beyond this period, CRA extended the forecast by applying the compound annual growth rate (CAGR) from 2025–2031 to project load growth beyond 2031. The 2031 hourly load profile was therefore extrapolated through 2035 using this CAGR.

As shown in Table 14, required BESS capacity increases over time as load growth drives higher and more frequent exceedances. In the near term, a smaller BESS is sufficient to address localized constraints at the Bell-F2 feeder; however, larger capacity is required for longer deferral periods. The values shown in Table 14 are in total across the three units. As such, per-unit capacity is the value shown here divided by three.

Table 14. Required BESS Capacity (MW) by Deferral length

Deferral length (Years)	Deferred Year	BESS Capacity (MW)
1	2032	6
2	2033	6.5
3	2034	7
4	2035	7.5

This approach ensures that BESS is sized to both the magnitude and duration of system constraints, providing targeted and dispatchable load relief aligned with the identified system need.

6. DISTRIBUTION SERVICE TEST

6.1 REFERENCE CASE

Under the reference case, Elexicon would proceed with a coordinated set of conventional distribution system upgrades and reinforcements as relayed in the DSP to address identified capacity, thermal, voltage, and contingency constraints across its service territory. This project reflects the continuation of standard wires-based planning practices required to maintain system reliability and acceptable performance under forecast residential and industrial load growth.

The reference case includes a combination of feeder-level enhancements and targeted conductor replacements in critical areas. Feeder reinforcements involve upgrading constrained line segments, adding or reconfiguring circuits where necessary, and strengthening supply paths to ensure adequate system capacity and redundancy. In parallel, the project addresses approximately 12 kilometres of distribution lines with undersized conductors that have been identified as limiting feeder performance, contributing to elevated line losses, voltage drop concerns, and reduced flexibility during peak demand and contingency conditions.

Together, these measures are required to ensure the distribution system can continue to meet planning criteria, support growth in rapidly expanding areas such as Belleville, Whitby, and Pickering, and maintain acceptable voltage and loading conditions under both normal and abnormal operating scenarios. The reference case also reflects baseline requirements associated with evolving grid conditions, including increasing customer demand and the growing presence of distributed energy resources such as solar PV, battery storage, and electric vehicles, which introduce bidirectional power flows and additional stress on existing infrastructure

6.2 QUANTITATIVE BENEFITS

6.2.1 DISTRIBUTION CAPACITY BENEFITS

CRA applied a cost-of-service approach to estimate distribution service benefits for the feeder capacity and undersized conductors portfolio, rather than a marginal cost ($/kW-year) approach.

The OEB’s marginal cost framework is best suited to discrete projects with clearly defined incremental capacity additions. In this case, the program is a portfolio of feeder upgrades that share core common characteristics and need drivers, but are expected to exhibit minor to moderate cost, execution timing and capacity shortfall considerations, that will further evolve over the DSP period across the locations.

Given this, a marginal cost approach would require simplifying assumptions that may not reflect the nature of underlying investments. The cost-of-service approach instead allows CRA to estimate the avoided revenue requirement associated with the planned portfolio based on available information and is therefore a more appropriate representation of distribution service benefits in this context.

Quantitative benefits under the DST are based on the avoided distribution cost approach, with the methodology, formula, and input assumptions applied consistently with the Bradshaw MS analysis described above.

6.3 QUALITATIVE BENEFITS

The qualitative benefits associated with BESS described in Section 4.3 are also applicable to the Feeder Capacity and Undersized Conductors portfolio.

In particular, BESS provides localized, dispatchable load relief at the feeder level, supporting reliability by reducing loading during peak conditions. Similar to the Bradshaw MS analysis, BESS offers operational flexibility, can respond rapidly to changing system conditions, and provides planning value through its modular and scalable nature.

These characteristics make BESS well-suited to addressing feeder-specific constraints, where targeted and time-specific load relief is required.

6.4 NON-WIRES SOLUTION COST

The cost assumptions applied to the BESS evaluated for the Feeder Capacity and Undersized Conductors portfolio are consistent with those described in Section 4.4 for the Bradshaw Municipal Station analysis. Specifically, the same capital cost and fixed operations and maintenance (OM&A) assumptions were used, based on CRA's application of the IESO Resource Costs and Trends and calibrated NREL Annual Technology Baseline data.

Applying consistent cost assumptions across both analyses ensures comparability of results and reflects a standardized view of the cost to acquire, connect, and operate distribution level battery storage. Differences in total NWS costs across projects are therefore driven by variations in required BESS capacity, duration, and deployment scale, rather than differences in underlying unit cost assumptions.

6.5 DST RESULTS

The BESS NWS model for the Bell-F2 feeder would produce a Net Present Value of -$12.03 million for the Bell-F2 DST, respectively, as shown in Table 15. These results are based on a one-year deferral of the traditional solution. Longer deferral periods were evaluated; however, as load growth increases the magnitude of capacity exceedances over time, the required BESS capacity and associated costs increase, offsetting the additional benefit of deferral.

Table 15. Bell-F2 DST Results ($Millions)

Category	Value ($M)
Total DST Benefit	$0.02
Total DST Cost	$12.05
NPV Net DST Benefit	**-$12.03**

6.6 DISTRIBUTION SERVICE TEST RISKS

The risks and uncertainties associated with the BESS alternative for the feeder capacity and undersized conductors portfolio are generally consistent with those described for the Bradshaw MS analysis in Section 4.6.

In addition, there are incremental risks specific to feeder-level applications. In particular, BESS must be sited and dispatched to provide targeted relief on individual feeders, increasing locational effectiveness risk relative to a station-level solution. The need for multiple, distributed installations also increases siting, interconnection, and execution risk, as compared to a single centralized deployment.

These factors may impact the ability of the BESS to achieve the assumed level of feeder-specific load relief and should be considered in interpreting the DST results.

CONTROL CENTRE OM&A SEGMENT - EVIDENCE UPDATE

1. PROGRAM OVERVIEW

Table 1: Summary of Revised Control Centre Segment OM&A Costs ($M)[1]

Segment Costs	**Bridge**	**Forecast**				
Year	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Total (Pre-Filed)	2.87	2.70	2.88	3.05	3.13	3.20
Total Revised	**5.15**	**6.00**	**5.98**	**6.17**	**5.71**	**5.82**
Total Variance	2.28	3.30	3.10	3.12	2.58	2.62

2. EXECUTIVE SUMMARY

The Control Centre segment of the System Operations OM&A program is responsible for operating Elexicon's System Control Centre (referred as the "SCC"), as well as the Emergency Management and Asset Records functions. This update relates solely to the SCC component of the Control Centre segment. Elexicon's SCC and qualified staff ("Qualified Operators" or "QOs") are essential to the safe and reliable operation of the utility's grid by monitoring and operating critical equipment through SCADA[2], directing switching operations in the field (e.g., opening and closing breakers and switches), helping crews respond to outages by isolating and sectionalizing faults, and administering planned and unplanned grid disruptions.

Elexicon's pre-filed evidence for its rebasing application, including the details of its 2027 to 2031 OM&A cost forecast, (referred to herein as "Pre-Filed Evidence") was submitted to the OEB on December 19, 2025. In the Pre-Filed Evidence, Elexicon proposed forecast costs for the Control Centre segment of approximately $15.0M over the period of 2027 to 2031, set out in Exhibit 4 - Tab 1 - Schedule 3.[3] For the reasons outlined in this schedule, Elexicon is revising its total OM&A costs for the 2027 to 2031 forecast period for this segment to approximately $29.7M. The proposed funding levels are necessary to ensure

[1] Numbers may not sum due to rounding.
[2] SCADA stands for 'Supervisory Control and Data Acquisition'.
[3] Exhibit 4, originally filed on December 19, 2025, was updated and re-filed with the OEB on February 20, 2026, pursuant to Elexicon's submission under the Error Checking Process. Although Exhibit 4 was updated, the Control Centre segment section remains unchanged from the version filed on December 19, 2025.

that Elexicon has a sustainable resourcing complement in its SCC in the near and longer term to maintain safe and reliable operations and deliver its capital and maintenance work programs.

The urgency for updating the costs of this segment is driven by recent departures of Qualified Operators and Apprentice Operators in the SCC, and the difficulties Elexicon has experienced in attempting to replace these roles through the labour market, resulting in an unacceptably low level of Qualified Operators employed by Elexicon. As of March 31, 2026, Elexicon has only one (1) Qualified Operator and five (5) Apprentice Operators remaining on staff. This depletion of internal staff transpired in 2025 and 2026[4] with the most critical departures occurring in late 2025 and early 2026 when three (3) fully Qualified Operators departed, drastically reducing the number of remaining Qualified Operators to one (1) and increasing the risk to the safe and reliable operation of the grid. Key reasons for the departures included offers to join nearby utilities which offered higher compensation, as well as changes to immigration policy that led to the expiry of certain Apprentice Operators' Temporary Residency status requiring them to be laid off notwithstanding Elexicon's efforts to avoid this outcome.

Elexicon is currently managing resourcing constraints in the SSC by relying on Qualified Operators engaged on a contract basis to cover shifts where possible. While contractor Qualified Operators provide a helpful short-term resource to meet operational requirements, they are not a suitable long-term solution to Elexicon's needs. Contractor Operators are typically recently retired Qualified Operators Elexicon relies on to supplement internal staff and to facilitate the completion of apprentice training and experience requirements. These contractors are willing to fill shifts, but usually not on a full-time basis (i.e. less than 40 hours a week). As a result, these contractor resources do not consistently provide full-time weekly coverage in the SCC's operational schedule, and they can become unavailable on short notice making it difficult to plan beyond a one-to-two week horizon. Moreover, contractor Qualified Operators are more costly than internal staff. Due to these constraints, Elexicon cannot rely on contractor Qualified Operators as a sustainable long-term solution for a lack of acceptable levels of internal staff in the SCC. Additionally, without sufficient Qualified Operator capacity, Elexicon is unable to train Apprentice Operators or mitigate the risk of further departures due to sustained workload pressure and burnout.

[4] From January 2025 to March of 2026, four Qualified Operators (QOs), three Apprentice Operators, and two supervisory staff departed the utility.

Elexicon has not been able to backfill its Qualified Operators due to industry-wide labour shortages and very high levels of competition for existing Qualified Operators ("QOs"). The training pipeline for new Apprentice Operators is underdeveloped due to a lack of formal training programs in educational institutions or industry-related partners. To acquire and maintain a sufficient complement of QOs, Elexicon must establish a multi-pronged strategy that includes a sustainable, consistent, and robust internal apprentice training program to ensure the likelihood of timely progression and apprenticeship retention. Elexicon's difficulty in hiring and retaining QOs is also a result of its geographic proximity to other large utilities with whom it competes for a limited pool of Apprentices and fully QOs. Elexicon cannot solely backfill recent departures from the local labour market given this high degree of competition across utilities. To ensure a sustained talent pipeline, Elexicon must invest in a comprehensive strategy to stabilize its current resource requirements and develop its internal Qualified Operator workforce.

The recent staff departures described above have produced critical resourcing gaps in the SCC that cannot be addressed with the level of funding requested in the Pre-Filed Evidence. Retaining the previous funding levels would leave Elexicon in a precarious position over the upcoming rate term. Elexicon would be unable to effectively respond to high-volume grid events (e.g. storms), maintain safe and reliable continuous operations in compliance with regulatory requirements, and would be unable to execute its capital program which is urgently needed to serve the utility's growing customer base, and renew its deteriorating infrastructure to address reliability performance. To develop a sufficient complement of QOs and supporting resources in the SSC, the staffing model, wage structure and resource strategy for this critical utility function require augmentation as proposed in this evidence update.

Specifically, Elexicon is proposing a revised OM&A forecast ("Revised Plan") for additional funding to: 1) realign compensation for Apprentice and QO positions with the market, 2) invest in significant enhancements to its SCC Operator apprenticeship program, 3) add support positions to improve operations, and 4) increase the overall complement of internal qualified staff by adding more Apprentice roles in 2026 to bring the number of QOs to a sustainable level by 2031. This Revised Plan includes hiring an additional thirteen (13) positions into the SCC from 2026 to 2031, as outlined below in Table 3. These critical investments will reduce the likelihood and impact of unforeseen departures by rebalancing workloads, improving staff retention, and building a sustainable talent pipeline of Qualified Operators to protect Elexicon's ability to safely deliver its capital and maintenance programs and respond to high volume events.

3. THE ROLE OF THE QUALIFIED OPERATOR IN SYSTEM OPERATIONS

A Qualified Operator in a power distribution control centre is the authorized individual responsible for the real-time monitoring and control of the electrical distribution network. The Qualified Operator uses systems such as SCADA and distribution management platforms to monitor grid conditions, perform or direct switching operations in the field (e.g., opening and closing breakers and switches), coordinate with field crews, and manage outages by isolating and sectionalizing faults to restore service. They also enforce safety procedures by establishing equipment isolation to ensure safe conditions of work. These monitoring and control activities are required for Elexicon to distribute electricity and are an essential part of all work performed on its distribution system, including both its planned capital projects, reactive capital work and the maintenance activities it undertakes while restoring power outages due to storms and other system interruptions. The Qualified Operator provides the operational authority and system coordination required to safely modify or restore the electrical network.

For capital program activities (such as equipment replacements, feeder upgrades, or new infrastructure installations), the Qualified Operator coordinates and executes the switching operations needed to safely isolate portions of the system so construction or maintenance work can occur. Qualified Operators will establish clearances, confirm safe work areas and ensure that field crews can work safely without risk of inadvertent energization. Qualified Operators also manage temporary network configurations during projects, reroute power where possible to minimize customer outages, and return the system to normal configuration once work is complete. The resulting safe work boundaries, established through the Qualified Operator's switching plan, allow multiple projects to be completed safely and efficiently.

During emergency response, the Qualified Operator serves as the central command point for grid operations. They monitor alarms and system conditions, identify faulted sections of the network, remotely operate enabled equipment to isolate damaged assets, and implement switching strategies to restore service to unaffected areas as quickly as possible. The Qualified Operator also coordinates closely with field crews and external agencies to prioritize restoration efforts, maintain system stability, and ensure safety during hazardous conditions. The Qualified Operator enables work on the physical grid to proceed safely, efficiently, and with minimal service disruption, making the role essential to both planned infrastructure programs and rapid response to system emergencies.

For Elexicon, Qualified Operators are also critical to meeting its additional obligations specific to the transmission system as it owns and operates a Municipal Transformer Station, (Seaton MTS, which came online in 2022). Elexicon is obligated as a Licensed Market Participant under Section 4 of its distribution system license to comply with the IESO's Market Rules. These Rules require Elexicon to have a sufficient complement of Qualified Operators to continuously monitor the IESO-controlled grid, to carry out emergency procedures such as load shedding, to inform the IESO of any interactions with facilities connected to the IESO-controlled grid, and to promptly inform the IESO of conditions that can have material effects on the grid such as decreasing reliability.[5] These requirements mean that Elexicon must at minimum have always at least one Qualified Operator on shift at its SCC. Due to the staffing shortages recently experienced, Elexicon is not currently able to meet this requirement without reliance on contractor Qualified Operators.

4. LABOUR MARKET CONDITIONS

Labour market shortages in electricity-specific trades have resulted in increased general competition for qualified tradespeople, and an acute shortage of Qualified Operators and apprentices, which has been noted as a distinct challenge by other large distributors in their recent rate applications.[6] These challenges are occurring at a time when Ontario's electricity sector is experiencing high growth in demand, more operational complexity and more frequent emergency conditions, as documented by the IESO.[7] These factors have increased labour market competition for qualified staff, with Electricity Human Resources

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[5] The Independent Electricity System Operator's (IESO) Market Rules are effective pursuant to the *Electricity Act, 1998* and govern the Ontario Electricity Market. See: Renewed Market Rules, Chapter 1, section 1.1.1, Chapter 5, sections 3.7 and 5.2, Chapter 7, sections 7.2 and 7.6.

[6] Alectra Utilities, EB-2025-0252, "2027 Rebasing Application", Exhibit 4, Tab 2, Schedule 9, Page 7 and also Hydro Ottawa, EB-2024-0115, "2026-2030 Custom IR", Exhibit 4, Tab 1, Schedule 3, Attachment B, Page 16.

[7] Independent System Electricity Operator, "NPCC 2024 Ontario Comprehensive Review of Resource Adequacy", published November 2024.

Canada ("EHRC") 2023-2028 Labour Market Insights report noting that retirements and sector growth are driving projected labour shortages for nearly 50% of the electricity sector's core occupations by 2028.[8]

Adding to the challenge for Elexicon's SCC is its geographical proximity to the control centres of several utilities including Toronto Hydro, Hydro One, and Alectra, and the inability to compete with these organizations, including from a compensation perspective, to recruit and retain Apprentices and Qualified Operators. Recent changes in the proximity of Toronto Hydro's control centre operations has intensified recruitment and retention pressures, contributing to increased attrition as Qualified Operators pursue employment opportunities elsewhere. In addition, Elexicon has also lost Qualified Operators to other utilities operating in Southeastern Ontario and the United States, and supervisory staff to operations jobs outside of the utilities sector.

The staffing challenges are further exacerbated by a limited supply of available independent contractor Qualified Operators in the market. The contractor pool, made up primarily of retired Qualified Operators, remains in high demand. These contractors are generally only available on short notice and typically provide their availability only one week in advance. Contractor hourly rates are significantly higher than internal labour costs, and many contractors prefer not to work full-time hours or accept night and weekend shifts. Some contractors are at a career stage where they may stop working with limited notice, reducing service availability. These factors highlight the risks associated with Elexicon's current reliance on contractors and demonstrate that contactor resourcing is not a sustainable long-term solution for staffing shortages.

Hiring for Qualified Operator positions is further constrained by the limited talent pipeline for these positions in Ontario. Due the highly specialized nature of these roles there is no external certification and training programs for Qualified Operators, which means that all the training must occur on the job under the supervision of Qualified Operators.

Based on industry guidelines (including MEARIE standards) and operational risk assessments for minimum qualifications required to operate Elexicon's grid, the utility requires its Qualified Operators to achieve 8,000 hours of on-the-job training over a span of four years. Figure 1 below shows an Operators'

[8] EHRC 2023-2028 report, page 13.

qualification to perform tasks independently and with supervision over the course of their training period. As shown in Figure 1, an Apprentice Operator cannot perform Order To Operate (OTO) checking or authorization until they meet the Level 5 qualifications, which is expected to take at least four years. OTO preparation, checking and authorisation tasks are an essential part of the switching operations required to safely energise and isolate the distribution system. These are one of the most labour-intensive and crucial activities that Qualified Operators perform. As a result, an Apprentice cannot undertake independent control room operation and is not eligible to provide shift coverage until they reach Level 5 competence.

Figure 1: Summary of System Operator Apprentice Exposure Guidelines by Operator Level

Task Category	Level 1 (expected by 6 months)	Level 2 (expected by 12 months)	Level 3 (expected by 24 months)	Level 4 (expected by 36 months)	Level 5 (expected by 48 months)
Control Room Communication & Readiness	🔴	🔴	🟡	🟢	🟢
Document Preparation & Work Requests	🔴	🔴	🟡	🟢	🟢
OTO Preparing & Switching Documentation	🔴	🔴	🟡	🟢	🟢
OTO Checking & Authorization	🔴	🔴	🔴	🟡	🟢
Work Permits & Test Authorizations	🔴	🔴	🟡	🟡	🟢
Switching Operations (Planned & Unplanned)	🔴	🔴	🟡	🟡	🟢
Hold-Off Preparation & Administration	🔴	🟡	🟡	🟡	🟢
Working with Other Apprentices	🔴	🔴	🔴	🟡	🟢
Independent Control Room Operation	🔴	🔴	🔴	🔴	🟢
Eligible for Shift Coverage	🔴	🔴	🔴	🔴	🟢

Legend: Task competency and authorization achieved at the corresponding training level and time horizon:
🟢 Can do function independently
🟡 Can do function with supervision
🔴 Cannot do function

5. DEVELOPMENT OF ELEXICON'S SCC RESOURCING PLAN

In its Pre-Filed Evidence, Elexicon put forward a proposed budget for the Control Centre segment that included a lean complement of positions within its SCC which was based on the minimum requirements to keep the SCC operational.[9] This resourcing plan, which was finalized in Q2 of 2025, included a target complement of thirteen (13) Operator roles, comprised of one (1) Apprentice Operator, eleven (11) Qualified Operators, and one (1) Senior System Operator by 2031. This organizational structure included two (2) supervisory positions and three (3) auxiliary positions (one (1) trainer, one (1) analyst and one (1) student), and supplemental support from an independent Qualified Operator contractor. Elexicon determined these initial resourcing requirements with best-known information at the time and in line with its objective of balancing identified operational needs with customer preferences for affordability (see Exhibit 4 - Tab 1 - Schedule 1, Section 2). The minimum incremental resourcing investments deemed necessary based on conditions at the time of planning did not include any provisions in the Control Centre segment budget to mitigate the high-levels of attrition and labour shortages recently experienced.

As noted above, attrition occurring subsequent to the development of the Pre-Filed Evidence, and challenges filling these roles in the market, resulted in the SCC having fewer Qualified Operators on staff than is necessary to maintain operations, leading to an unsustainable reliance on contractor Qualified Operators and significant levels of overtime among remaining internal staff. These resourcing constraints and sustained workloads have placed tremendous strain on remaining employees, increasing the likelihood of further departures and creating a significant operational risk. Elexicon must take immediate action to mitigate this operational risk in the near-term and put in place a revised resourcing strategy to ensure sustainable future operations in the SCC over the 2027-2031 rate term and beyond.

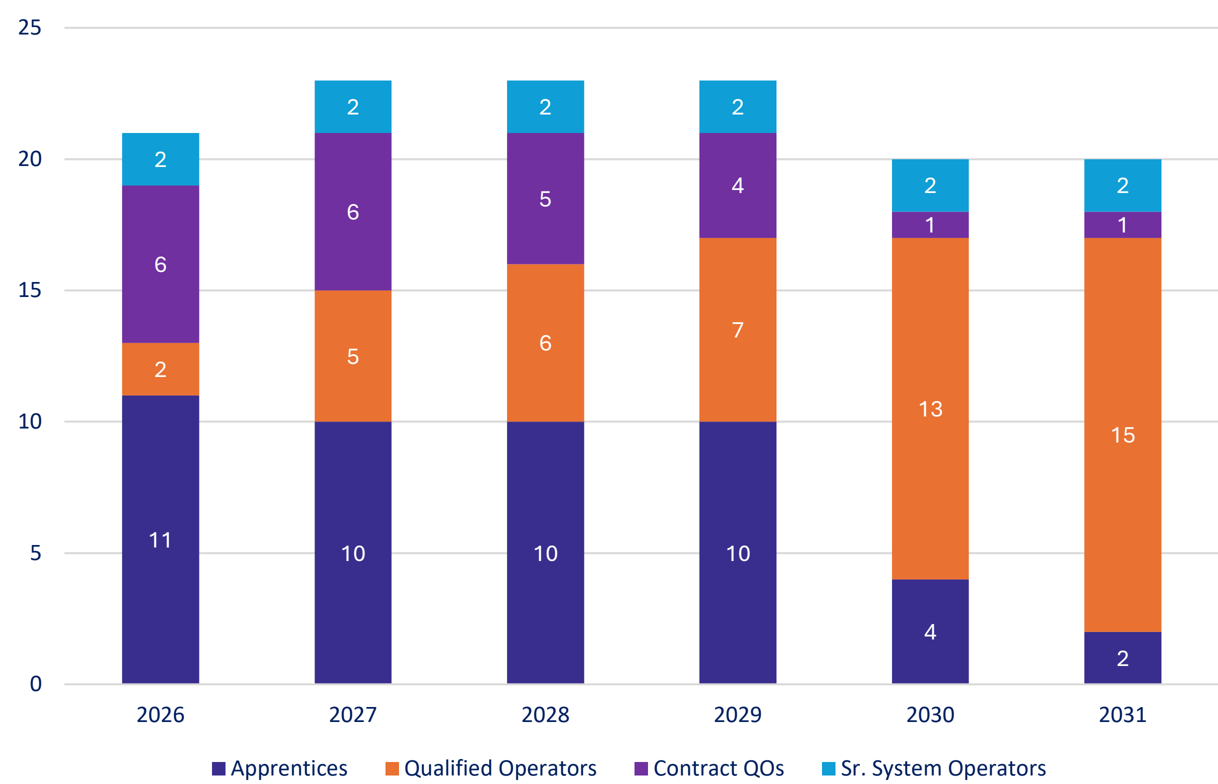
6. REVISED RESOURCING STRATEGY FOR ENSURING SCC'S CONTINUED OPERATIONS

In light of the challenges described above, in Q1 2026, Elexicon revisited its SCC resourcing strategy to develop a Revised Plan that can both restore and strengthen operational capacity. Table 2 below presents the SCC internal staffing complement under the Revised Plan. By the end of the upcoming rate term,

[9] EB-2025-0312, Exhibit 4 - Tab 1 - Schedule 3.

Elexicon plans to have two (2) Apprentice Operators and seventeen (17) Qualified Operators on staff, two (2) of which would be Senior System Operators and fifteen (15) of which would be Qualified Operators (most expected to be developed through the Apprenticeship program). This operator staffing complement, together with additional supervisory staff, dispatchers and supporting roles, supports sustainable operations in the SCC, the safe and reliable delivery of electricity to customers, compliance with regulatory requirements, and the execution of planned work programs. Throughout the rate term, Elexicon will need to continue to closely monitor and manage the talent development and retention risks in this program, and respond accordingly to keep pace with changes in the labour market or incremental operational demands that may present themselves over the rate period (e.g. higher than expected demand-driven investments, increased frequency of extreme weather events, and similar unforeseen changes in operating conditions that may drive up program work volumes).

Figure 2: Revised Plan for SCC Operator Staffing Complement (2026 to 2031)



Elexicon's Revised Plan has four primary elements that are described below.

1. Competitive Compensation for Operators

An internal review conducted by Elexicon of publicly available market wage information found that comparator utilities in close geographic proximity offer wage levels exceeding those currently in place at Elexicon for Qualified Operator positions. This differential was expected given the scarcity of Qualified Operators within the local labour market. To address recruitment challenges and retention risks, Elexicon's Revised Plan aligns Operator wage levels more closely with comparable utilities to prevent further attrition. Elexicon chose to align its compensation with Toronto Hydro's, which was assessed to be the most comparable based on both geographic proximity to Elexicon's operations, as well as the complexity of operational responsibilities and relative size in the area. The relevance of this comparator is further supported by recent Qualified Operator attrition, as departing QOs cited acceptance of a role at Toronto Hydro as their reason for departure. This utility offers higher hourly wage rates resulting in compensation levels that exceed Elexicon's by more than $20,000 annually.

2. An Enhanced Organizational Structure

Elexicon's Revised Plan, as further detailed in Table 4 below, features an enhanced organizational structure with additional auxiliary staff positions as follows:

- **Dispatchers:** Elexicon's Revised Plan includes the creation of the dispatcher role and the addition of two (2) dispatcher positions to the SCC in 2026. Commonly used at other utilities, dispatchers provide critical operational coordination and administrative support to Qualified Operators in the SCC. Their responsibilities include receiving, interpreting, prioritizing and logging customer service requests, outage notifications and system events, and coordinating and assigning field resources. Dispatchers also play a critical coordination role during high volume events by assisting Qualified Operators to direct standby resources as needed to respond to trouble calls. Adding dispatchers to the SCC will improve operational efficiencies by providing better triaging and coordination of tasks and logistics in the SCC, and by enabling Qualified Operators to focus on activities requiring their specific qualifications and operational authority. The dispatcher role also establishes a career progression pathway to Apprentice Operator positions, which will produce an internal talent pipeline for Apprentice Operators with strong institutional knowledge of Elexicon's SCC.

- **Senior System Operator:** In 2026, Elexicon also plans to add another Senior System Operator into its complement of Qualified Operators to serve in a critical planning support role for Elexicon's delivery of its capital and maintenance programs and to improve retention of its most experienced staff.
- **Supervisors:** In 2026, Elexicon plans to increase the complement of supervisors from two (2) to three (3) positions. Supervisors provide oversight of technical projects and procedures, administrative management of SCC and staff, and shift scheduling. These additional resources are required to support improved shift coverage, and manage workloads as the number of Apprentice Operators and Qualified Operators in the SCC increases.
- **Trainer:** Elexicon plans to add a full-time internal trainer position to support the training of a larger number of operator roles. As Apprentice Operators will be at varying stages of their programs over the upcoming rate term, the addition of this resource is required to efficiently train Operators and achieve the target number of Qualified Operators by 2031.
- **Analysts and Students:** In 2026 and 2027, Elexicon plans to add: two (2) analysts and one (1) student to the SCC to perform data analysis, undertake reporting and process mapping, and drive continuous improvement in the SCC. These cost-effective resources will support Operators with reliability data analysis and reporting, while developing foundational knowledge of system operations. They may also provide an internal talent pipeline for filling Dispatcher and Apprentice Operator positions in the SCC.

Table 2: Pre-Filed Evidence SCC Internal Staffing Plan (2026 to 2031)

Positions	Starting Org Structure in 2025 Bridge	Staffing Additions						Organizational Structure by 2031
		2026	2027	2028	2029	2030	2031	
Operators/ Apprentices	**10**	-	-	1	1	-	-	**12 (11 Qualified, 1 Apprentice)**
Dispatchers	**N/A**	-	-	-	-	-	-	**0**
Senior System Operator	**1**	-	-	-	-	-	-	**1**
Supervisor	**2**	-	-	-	-	-	-	**2**
Trainers	**1**	-	-	-	-	-	-	**1**
Programs Analysts	**1**	-	-	-	-	-	-	**1**
Students	**1**	-	1	-	-	-	-	**2**

Table 3: <u>Revised</u> SCC Internal Staffing Plan (2026 to 2031)

Positions	Starting Org Structure in 2025 Bridge	Staffing Additions						Organizational Structure by 2031
		2026	2027	2028	2029	2030	2031	
Operators/ Apprentices[10]	**10**	3	2	1	1	-	-	**17 (15 Qualified, 2 Apprentices)**
Dispatchers	**N/A**	2	-	-	-	-	-	**2**
Senior System Operator[11]	**1**	1	-	-	-	-	-	**2**
Supervisor	**2**	1	-	-	-	-	-	**3**
Trainers	**1**	-	1	-	-	-	-	**2**
Programs Analysts	**1**	2	-	-	-	-	-	**3**
Students	**1**	1	1	-	-	-	-	**3**

3. <u>Increasing Staffing Capacity and Institutional Knowledge</u>

In light of the attrition risks and labour market constraints identified, and considering the critical role of the SCC in utility distribution system operations, Elexicon has determined that insufficient staffing at the SCC threatens its ability to carry out safe and reliable operations and execute planned capital and maintenance programs. Therefore, the utility has decided that increasing the number of Qualified

[10] Additions expected to be Apprentices due to inability to hire fully qualified operators in the labour market.
[11] Hired internally from existing QO complement.

Operators beyond the initial proposal is vital for ensuring successful SCC operations in the 2027-2031 rate term and beyond.

Exit interviews conducted in Q4 2025 and Q1 2026, together with feedback from remaining employees, have highlighted that Elexicon's original target of thirteen (13) Operators by 2031 (eleven (11) QOs, one (1) Senior System Operator, and one (1) Apprentice), as outlined in its Pre-Filed Evidence, is not sufficient to prevent burnout and maintain appropriate work-life balance among Qualified Operators. This challenge contributed to recent staff departures and was a significant factor in Elexicon's decision to reconsider its staffing requirements and propose a larger complement of Qualified Operators to ensure safe and reliable continued operations in the SCC. By increasing the complement of Qualified Operators, Elexicon's revised plan addresses employee retention concerns, fosters greater institutional knowledge and mitigates the significant operational risks associated with an understaffed SCC.

Immediate hiring is required in the SCC to address these operational risks and strengthen the talent pipeline. To that end, Elexicon plans to add an additional three (3) Operator positions in 2026, two (2) in 2027, one (1) in 2028, and one (1) in 2029. These new Operator positions are expected to be filled by Apprentices. These additional positions put Elexicon on track for its organizational target of having seventeen (17) Qualified Operators by 2031, comprising two (2) Senior Operators and fifteen (15) Qualified Operators.

4. Reducing Elexicon’s Long-term Reliance on Contractors

The Pre-Filed Plan did not include any incremental contractor assignments from 2026 to 2031. The Revised Plan incorporates additional contractor assignments in 2026 to address the shortages in Qualified Operators and ensure safe and reliable SCC operations. As Apprentices are trained and become Qualified Operators, Elexicon aims to reduce its reliance on contractors to a single assignment for a contractor Qualified Operator the end of the rate term. Table 4 below provides details on the contractor assignments and expected requirements.

Table 4: Planned SCC Independent Contractor Assignments (2026-2031)

	Pre-Filed Evidence Plan	Revised Plan

2026	No incremental contractor assignments	+6 Qualified Operator contractor assignments that taper off to 1 assignment by 2030:
		• Expected contractor QO requirements:
		  ○ 6 in 2027
		  ○ 5 in 2028
		  ○ 4 in 2029
		  ○ 1 in 2030
		  ○ 1 in 2031
		+1 Training Coordinator assignment (until December 2027)
		
		+1 Policy and Process Coordinator assignment (until December 2027)

In 2026 and 2027, Elexicon plans to retain the services of a Training Coordinator and a Policy and Procedure Coordinator to ensure the timely delivery of a training program that can handle a larger number of apprentices, and the related process documentation to drive consistency needed to support of Elexicon's enhanced training program. These temporary contractor assignments will be focused on delivering the tools and frameworks needed to stand-up and manage the training program effectively and efficiently. Once the training program is established, these assignments are not expected to be required after 2027.

7. RISKS OF INADEQUATE FUNDING

The SCC plays an essential role in the ongoing operation of Elexicon's distribution system, performing safe energization, isolation and switching activities that are a prerequisite for planned and reactive capital work, as well as Elexicon's ability to respond to high volume events. A lack of sufficient SCC staff has the potential to cause lengthy and costly operational disruptions and poses the significant risk of noncompliance with the IESO's Market Rules, which are critical to the safety and reliability of Ontario's interconnected grid.

Over the 2027-2031 rate period, the challenges and demands facing the SSC will persist and increase as the utility must make critical incremental investments in new system capacity alongside investments in the maintenance and renewal of aging and deteriorating infrastructure. To mitigate both the near-term labour shortage risks and address the operational requirements facing the SSC over the upcoming rate term, Elexicon requires adequate funding for appropriately resourcing this program. This includes the need to develop a robust talent pipeline of Apprentice Operators that can become skilled Qualified Operators over the rate term to meet increased future operational demands, replenish aging talent exiting the organization, execute a robust talent strategy to make staffing in this segment sustainable in the long-term and reduce Elexicon's reliance on external contractors.